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July 23, 2012

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("FEFN" or "Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI"), and FortisBC Energy (Whistler) Inc. ("FEW") Common Rates, Amalgamation and Rate Design Application (the Application)

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 2

In accordance with Commission Order No. G-83-12 setting out the Regulatory Timetable for the review of the Application, the FEU respectfully submit the attached response to BCUC IR No. 2.

If there are any questions regarding the attached, please contact Paul Craig at 604-592-7459.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Request for Legal Amalgamation

Exhibit B-9, BCUC 1.5.1, 1.5.3, 1.5.11, 1.58.1

Evaluation Framework – Key Evaluation Criteria

The FEU state in BCUC 1.5.1: "The FEU agree that the six evaluation criteria (a) through (f) from page 19 of the 2005 KMI Decision are relevant factors for the Commission to consider when evaluating a proposal to amalgamate."

The FEU state in BCUC 1.5.3: "... in evaluating if legal amalgamation is beneficial in the public interest, the Commission should evaluate amalgamation plus rates that would address the objectives of the FEU."

The FEU estimate in BCUC 1.5.11: "the net present value (NPV) of benefits arising from amalgamation to be $4.4m to $6.7m, and the NPV of the costs of amalgamation at $3.5m. The FEU state "the net present value cost benefit analysis should be regarded with caution as there are several assumptions, particularly with respect to future interest savings that are difficult to ascertain."

The FEU state in BCUC 1.58.1: "... amalgamation does not materially change FEI's ability, pre-and post-amalgamation, to diversify its risks."

1.1 Do FEU consider the key components of an evaluation of the amalgamation proposal against the KMI framework to be (i) net benefits as identified in the cost benefit analysis in BCUC 1.5.11, and (ii) public interest considerations related to the postage stamp rates proposal? Please explain why or why not.

Response:

The FEU clarify that the NPV analysis in the response to BCUC IR 1.5.11 included the costs and benefits associated with both amalgamation and postage stamp rates. Since the benefits of postage stamp rates cannot be achieved in the absence of legal amalgamation, the FEU regard the benefits of postage stamp rates as benefits of legal amalgamation. Although the FEU believe that the costs and benefits should not be isolated from one another, please refer to the response to BCUC IR 2.30.1.2 where the FEU have provided an NPV analysis that excludes the benefits of postage stamp rates.

Of the six criteria identified in the KMI decision referenced in BCUC IR 1.5.1, the key component of an evaluation of the FEU's proposal to amalgamate is the public interest considerations. The net benefits identified in the response to BCUC IR 1.5.11 fall within this criteria. The FEU have identified what they consider to be the key factors in evaluating the FEU's Amalgamation proposal in Section 6 of the Application. All of these factors fall within the category of public interest considerations.

1.2 Please indicate the level of confidence that the Commission should place on the estimated NPV of benefits from amalgamation of $4.4m to $6.7m. Please include in your response an estimate of the probability that actual benefits fall outside of this range, and whether the probability of outcomes outside of this range is symmetrical (for example, if there is an equal chance of lower than forecasted savings compared to higher than forecasted savings).

Response:

The range provided in the response to BCUC IR 1.5.11 is the FEU's estimate of the most likely benefit to be received from Amalgamation and postage stamp rates; however, like all forecasts it may be different than actual results. The purpose of the NPV analysis provided in the response to BCUC IR 1.5.11 was to provide a scale of the projected savings, and the FEU noted that the benefits are indicative.

The savings consist of two primary components. The first is the operational savings of $2.2 million of which the FEU have a high degree of comfort that these savings will be achieved. Operational savings reflect all benefits excluding the short-term interest differential, as shown in the table in the response to BCUC IR 1.5.11. If the tax shield benefits associated with the amalgamation costs are excluded, operational savings are $1.5 million.

Second, the range included in the NPV analysis shown in BCUC IR 1.5.11 includes interest savings between $2.2 million to $4.4 million which are primarily dependent on key assumptions as to the relative short-term interest rate differential between FEVI and FEI Amalco, based on projected outstanding short-term debt balance of FEVI of $25 million to $50 million. The FEU believe this estimate of short-term debt balance is reasonable and the range of savings for interest is achievable with a reasonable degree of comfort. FEVI cannot quantify the probability that actual benefits may fall outside of this range but FEVI expects that the probability of outcomes is such that there is a greater chance of higher than forecasted savings.

1.3 Do FEU consider whether costs related to the amalgamation application which are sunk (i.e. not avoidable) should be included in the amalgamation cost benefit analysis? Please explain why or why not.

Response:

Yes, the costs of the Application reflect a necessary component of achieving amalgamation and postage stamp rates and thus are an appropriate cost to include in the analysis.

1.3.1 Please identify what proportion of the estimated $3.5m amalgamation cost would be avoidable in the event approval was obtained for amalgamation following the regulatory review process but the FEU did not proceed with the amalgamation.

Response:

Of the total forecasted amalgamation costs, approximately $2.0 million would not be incurred if amalgamation did not proceed. The remaining forecast of $1.5 million pertains to the Application costs which will be incurred regardless of whether approval is received.

1.4 Please file a colour map of the BC natural gas pipeline system, identifying ownership of the main pipelines and the service territories of FEI (by region), FEW, FEFN and FEVI.

Response:

Please see Attachment 1.4 for the requested colour map identifying ownership of the main pipelines and service territories of FEI (by region), FEW, FEFN and FEVI.

2.0 Reference: Request for Legal Amalgamation

Exhibit B-9, BCUC 1.5.11

Cost Benefit Analysis

The FEU in BCUC 1.5.11 include the following net present value (NPV) cost benefit analysis for amalgamation (excluding any costs or benefits associated with postage stamp rates).

Approximate NPV of Amalgamation Costs & Benefits, 10 Years ($ Thousands)

	$25 Million Short Term Debt	$50 Million Short Term Debt	
Discount Rate	6.69%	6.69%	After Tax WACC of amalgamated entity
Present Value of Benefit of Amalgamation			
Depreciation and Amortization extended	402	402	Net difference in Whistler Pipeline Dep & Amort - ~ 50 years
Income Tax recovery	243	243	Mainly related to various deferrals - assumed 3 year benefit
Short-Term Interest Differential	2,227	4,453	Based on a 1.25% unfunded debt rate differential as at May 28, 2012
Legal, Audit and Rate Agency Savings	846	846	Approximately $700/yr legal, $18,000/yr audit and $100,000/yr rating
Tax Shield on Amalgamation Costs	733	733	
Total of Present Value of Benefits	4,451	6,678	
Present Value of Cost of Amalgamation			
Total Cost of Amalgamation	(3,550)	(3,550)	Legal, transactional, operational and application costs
Total Present Value of Cost	(3,550)	(3,550)	
Net Present Value of Benefits	$ 901	$ 3,128	

2.1 Please provide a working excel spreadsheet supporting the cost benefit analysis above and clearly state all assumptions used.

Response:

As clarified in the response to BCUC IR 2.1.1 above, the response to BCUC IR 1.5.11 included the costs and benefits associated with both amalgamation and postage stamp rates. In order to have common rates, the FEU require legal amalgamation. Therefore, savings associated with postage stamp rates are dependent on achieving legal amalgamation. Since the benefits of postage stamp rates cannot be achieved in the absence of legal amalgamation, the FEU regard the benefits of postage stamp rates as benefits of legal amalgamation. Although the FEU believe that the costs and benefits should not be isolated from one another, please refer to the response to BCUC IR 2.30.1.2 where the FEU have provided an NPV analysis that excludes the benefits of postage stamp rates.

Please refer to Attachment 2.1 for the working excel spreadsheet which supports the NPV analysis found in the response to BCUC IR 1.5.11.

2.1.1 Please update the above analysis assuming amalgamation is limited to: (i) FEI/FEVI/FEW; (ii) FEI/FEVI; and (iii) FEVI/FEW.

Response:

Please refer to the response to BCUC IR 2.2.1.

Please refer to the table below which provides the results of the various scenarios, all of which include the costs and benefits of both legal amalgamation and postage stamp rates.

The results of Scenario (i) are equal to the results of all four entities because the exclusion of FEFN does not have an impact on the costs or benefits. In Scenario (ii) the NPV analysis has been adjusted as follows: the interest benefit has been reduced to account for the FEW debt that will no longer be financed at the lower FEI rate, the cost of service reduction associated with depreciation and amortization of the Whistler Pipeline has been excluded and the income tax recovery has been adjusted to exclude FEW. Finally, Scenario (iii) has been adjusted to remove the interest differential benefit that would no longer exist, the legal, audit and rating agency savings that would no longer occur and the costs have been adjusted to reflect reductions in tax and rating agency costs.

Approximate NPV of Amalgamation and Postage Stamp Rates
Costs & Benefits, 10 Years ($ Thousands) [1]

	FEI, FEVI, FEW, FEFN		i) FEI, FEVI, FEW		ii) FEI, FEVI		iii) FEVI, FEW
	Short Term Debt		Short Term Debt		Short Term Debt		
	$ 25,000	$ 50,000	$ 25,000	$ 50,000	$ 20,000	$ 45,000	
Discount Rate	6.69%						
Present Value of Benefit of Amalgamation							
Depreciation and Amortization extended ~ 50 Years	$ 402	$ 402	$ 402	$ 402	$ -	$ -	$ 402
Income Tax Recovery - assumed 3 Year Benefit	243	243	243	243	163	163	95
Short Term Interest Differential - 10 Year Benefit 1.5%	2,227	4,453	2,227	4,453	2,004	4,008	-
Legal, Audit & Rate Agency Savings	846	846	846	846	846	846	-
Tax Shield on Amalgamation Costs	733	733	733	733	733	733	710
Total of Present Value of Benefits	4,451	6,678	4,451	6,678	3,746	5,750	1,207
Present Value of Cost of Amalgamation							
Total Cost of Amalgamation	3,550	3,550	3,550	3,550	3,550	3,550	3,265
Total Present Value of Cost	3,550	3,550	3,550	3,550	3,550	3,550	3,265
Net Present Value of Benefits	$ 901	$ 3,128	$ 901	$ 3,128	$ 195	$ 2,199	$ (2,058)

Although the FEU believe that the costs and benefits should not be isolated from one another, please refer to the response to BCUC IR 1.30.1.2 which provides this calculation for the various scenarios requested assuming separate service areas are maintained without common rates.

2.2 For each line item included in the analysis above, please explain (i) the nature of the saving, (ii) if the saving could be achieved in the absence of legal amalgamation, and (ii) if the saving represents a net benefit to current and future FEU customers (for example, please explain the net benefit to consumers of extended depreciation and amortization).

[1] There are minor legal and audit costs in FEW which would be saved under scenario (ii) and included in scenario (iii); however, these amounts are very minor and do not impact the analysis.

Response:

The adjustments to the cost of service and the savings associated with the FEU Amalgamation and postage stamp rates are discussed in Section 6.6 of the Application, Section 8.1.1, Section 8.2.1.2 as well as the response to BCUC IR 1.5.11. To achieve postage stamp rates legal amalgamation is required and as a result, the benefits identified in the analysis assume both postage stamp rates and legal amalgamation occur together.

Each item of the NPV analysis is described in additional detail below:

a) Depreciation and Amortization Extended

i. As discussed in Section 8.1.1.3, the cost of service decrease of approximately $30 thousand per year in depreciation and amortization expense is related to the Whistler Pipeline. In FEW, the contribution paid to FEVI is amortized over 50 years; however, in FEVI the Whistler Pipeline is depreciated over the average life of Transmission Mains of approximately 65 years with the contribution received from FEW amortized with other Transmission contributions over an average life of 55 years. Upon amalgamation, the contribution is eliminated and correspondingly the cost of service is lowered for approximately 50 years due to the difference in the depreciation rate of the pipeline versus the amortization rate of the contribution.

iii. These savings result from the amalgamation of the rate base and the cost of service, which could not occur without legal amalgamation; therefore, this decrease in the cost of service could not be achieved in the absence of legal amalgamation.

iv. This represents a net benefit to current and future customers in that the cost of service is reduced over the ten year analysis period, all else equal.

b) Income Tax Recovery

i. As discussed in Section 8.1.1.5, the cost of service decrease of approximately $92 thousand in tax expense results from changes to rate base and earned return upon amalgamation. The primary component of the change in rate base pertains to deferrals and the analysis assumes that this difference will cease to exist after a three year period.

ii. These savings are a result of other changes to the rate base and cost of service because of amalgamation and could not occur without legal amalgamation; therefore, these income tax expense savings could not be achieved in the absence of legal amalgamation.

iii. This represents a net benefit to current and future customers in that the cost of service is lower for a three year period, all else equal.

c) Short Term Interest Differential

i. As described in Section 8.1.1.5 and the response to BCUC 1.5.11, the short-term interest savings reflect the financing of FEVI and FEW short-term debt at the lower FEI short-term debt rate.

ii. All else equal, a decrease in the cost of service of this magnitude pertaining to short-term interest expense is not expected to be achieved in the absence of legal amalgamation.

iii. This represents a net benefit to current and future customers in that the cost of service is expected to be lower on an ongoing basis, all else equal.

d) Legal, Audit, Rating Agency Savings

i. The potential legal, audit and rating agency savings are described in Sections 6.6.2 and 6.6.4 and are related to serving one entity as opposed to the existing legal entities.

ii. The legal, audit and rating agency savings could not be achieved in the absence of legal amalgamation.

iii. These savings represent a net benefit to current and future customers in that the cost of service is expected to be lower on an ongoing basis, all else equal.

e) Tax Shield on Amalgamation Costs

i. There are tax benefits associated with the amalgamation costs as follows: the tax, legal and rating agency costs result in cumulative eligible capital allowance deductions, IT software expenditures result in capital cost allowance deductions, while the remaining amalgamation costs would be expensed in the year incurred for tax purposes.

ii. These tax savings could not be achieved in the absence of legal amalgamation and are directly attributable to the costs of amalgamation.

iii. These savings represent a net benefit to current and future customers in that the tax benefits of the amalgamation costs extend beyond the year the costs are incurred and offset a portion of the total amalgamation costs.

f) Amalgamation Costs

i. The amalgamation costs are described in Section 8.2.1.2, on page 154 of the Application and include the legal, transactional, operational and application costs associated with the amalgamation.

ii. As described in the response to BCUC IR 2.1.3 and 2.1.3.1, of the total forecasted amalgamation costs, approximately $2.0 million would not be incurred if amalgamation did not proceed. The remaining forecast of $1.5 million pertains to application costs which will be incurred regardless of whether approval is received; however, the costs of the Application reflect a necessary component of achieving amalgamation and thus an appropriate cost to include in the analysis.

iii. These items represent a one-time cost to current customers. To the extent that the amortization of the amalgamation costs deferral account extends beyond the 2014 period, these one-time costs may have some impact on future customers.

2.2.1 If any of the items in the analysis above can be achieved without legal amalgamation or do not represent an overall reduction in costs to existing and future customers, please exclude these items from the analysis, redo the NPV cost benefit analysis and provide an explanation for the change.

Response:

No changes to the analysis are required. Please refer to the response to BCUC IR 2.2.2.

3.0 Reference: Request for Legal Amalgamation

Exhibit B-9, BCUC 1.2.3

Proceeding with Amalgamation

The FEU state in response to BCUC 1.2.3: "The FEU would proceed with amalgamation if an alternative rate design to the common rates proposal included in the Application were approved that sufficiently addressed the rate discrepancies that currently exist across the FEU. The acceptable rate designs under which the FEU would proceed with include two of the options identified in Section 5.7 of the Application that were assessed against the common rates proposal. These two options are:

1. Implementing common rates for FEI (Mainland), FEVI and FEW.

2. Implementing common rates for all services areas, while maintaining regional midstream rates. ...

The FEU would also proceed with amalgamation if there were an approval of common rates that proposed different 'phase-in' options for all service areas."

3.1 Please outline the advantages and disadvantages of amalgamation and postage stamping rates of the following utilities: (I) FEI/FEVI/FEW; (ii) FEI/FEVI; (iii) FEVI/FEW. Please include in your response whether or not the FEU consider there would be a net benefit overall to customers as a result of these scenarios.

Response:

The response to the question is framed with respect to the objectives of the Application, specifically the criteria used in Section 5 of the Application and the benefits achieved from Common Rates as discussed in Sections 6.4 through 6.6 of the Application. Two of the three options have previously been discussed in the Application (refer to Section 5.5.3 of the Application) – (I) FEI/FEVI/FEW is the same as Option C-1; (II) FEI/FEVI is the same as Option C-4.

In order to determine the advantages/disadvantages of each option, the FEU reviewed them against the following:

1. If the option minimizes rate differences across the FEU's service areas it will be considered advantageous.

2. If the option addresses the revenue deficiency for FEVI it will be considered advantageous.

3. If the option provides long-term rate stability it will be considered advantageous.
4. If the option mitigates the rate impact to FEI (Mainland) customers it will be considered advantageous.
5. If the option mitigates the rate impact to FEFN customers it will be considered advantageous.
6. If the option results in rates that are both more easily understood by customers and more easily administered by the Company (as described in Section 6.4 of the Application) it will be considered advantageous.
7. If the option facilitates the expansion of service offerings (as described in Section 6.5 of the Application) it will be considered advantageous.
8. If the option enables regulatory, reporting or operational efficiencies (as described in Section 6.6 of the Application) it will be considered advantageous.

If an option has significantly more advantages compared to disadvantages there would be a net benefit to customers.

The FEU acknowledge that in all scenarios except the Status Quo or where FEI remains as a stand-alone utility there will be a minor impact to FEI rates. Similarly, in all scenarios except the Status Quo or where FEFN remains as a stand-alone rate base there will be an impact to FEFN rates.

(I) FEI/FEVI/FEW (referred to as Option C-1 in the Application)

As discussed in Section 5.5.3 of the Application, the option of amalgamating FEI, FEVI and FEW meets some of the criteria, but leaves FEFN vulnerable. Each of the eight criteria has been separated into 'Advantages' or 'Disadvantages' and is shown below:

- Advantages
  a. This option addresses the rate disparity issue for the large majority of the FEU's customers, FEFN excluded.
  b. The option fully addresses the revenue deficiency for FEVI.
  c. The option addresses long-term rate stability for the large majority of the FEU's customers.

d. As FEFN remains 'as-is' there is no impact to FEFN customers.

e. As separate rates and rate structures would be required for the amalgamated FEI/FEVI/FEW entity and FEFN, the FEU would be required to continue to administer multiple rate structures. Likewise customers will continue to see multiple rates and rate structures in communications such as bill inserts, media releases, etc. However, the majority of the FEU's customers would be on the same rate and rate structure.

f. Service offerings could be expanded to all areas with the exception of FEFN which would have to apply separately to the BCUC for a similar set of service offerings.

g. Reporting, operating and regulatory efficiencies could be achieved; however, they would not be optimized as separate reporting and operating requirements to manage FEFN separately would be required to be continued.

- Disadvantages

  a. The option will drive a rate increase for FEI (Mainland) customers as it will be combined with FEVI and FEW.

  b. The option does not address long-term rate stability for FEFN.

Overall, as discussed in Section 5 of the Application, this option meets a number of the objectives that the FEU are seeking to achieve with the Application; however, as summarized in Section 5.7.4, it would result in additional rate increases to the amalgamated FEI/FEVI/FEW entity, a rate discrepancy would continue between the amalgamated FEI/FEVI/FEW entity and FEFN, and FEFN customers would continue to be vulnerable to long-term rate instability.

That being said, relative to the FEU's proposal there is minimal additional impact to FEI's rates, FEFN would remain unaffected and there would be no material change to other customers compared to the proposal. The FEU therefore believe that this option would result in net benefits for customers.

(II) FEI/FEVI (referred to as Option C-4 in the Application)

As discussed in Section 5.5.3 of the Application, the FEU concluded that this option did not sufficiently meet the FEU's qualitative objectives. For the purpose of the question, each of the eight criteria identified above has been separated into 'Advantages' or 'Disadvantages' and is shown below:

- Advantages

    a. This option addresses the rate disparity issue of the FEU for the majority of their customer base; however, three different rates would exist, with FEW rates continuing to be significantly higher than the amalgamated FEI/FEVI entity and FEFN's rates.

    b. The option addresses the revenue deficiency for FEVI.

    c. As FEFN remains 'as-is' there is no impact to FEFN customers.

    d. Separate rates and rate structures would be required for the amalgamated FEI/FEVI entity, FEW and FEFN. Therefore, the FEU would be required to continue to administer multiple rates; likewise, customers will continue to see multiple rates and rate structures in communications such as bill inserts, media releases, etc. However, the majority of the FEU's customers would be on the same rate and rate structure.

    e. Reporting, operating and regulatory efficiencies could be achieved; however, they would not be optimized because separate reporting and operating requirements to manage three utilities separately would be required to be continued.

- Disadvantages

    a. FEW and FEFN will remain vulnerable to long-term rate instability.

    b. The option will drive a rate increase for FEI (Mainland) customers as it will be combined with FEVI.

    c. Service offerings would be expanded only to FEVI; therefore, FEW and FEFN would have to apply separately to the BCUC for a similar set of service offerings. This would incur additional costs for customers to go through a regulatory process.

Overall, in this option the majority of the FEU's customers benefit and the FEU believe it would result in a net benefit for customers. However, issues would remain for the customers that would not be part of the amalgamated entity (FEW and FEFN customers). Further, the impact of leaving FEW out of the amalgamated entity results in no material change to FEI's rate impact. As there is minimal benefit to other customers from excluding FEW and a material benefit to

FEW customers from being included, the FEU believe it is more appropriate to include FEW in the amalgamated entity.

(III) FEVI/FEW

The option is reviewed against each of the eight criteria identified above and separated into 'Advantages' or 'Disadvantages', as shown below:

- Advantages
    a. As FEI remains 'as-is' there is no impact to FEI customers.
    b. As FEFN remains 'as-is' there is no impact to FEFN customers.

- Disadvantages
    a. This option does not address the rate disparity issue for the FEU as three different rates would exist, with the rates of the amalgamated FEVI/FEW entity continuing to be significantly higher than FEI's and FEFN's rates.
    b. The option does not address the revenue deficiency for FEVI as it is combined with another utility that has a high rate base per customer and small customer base.
    c. The amalgamated FEVI/FEW entity and FEFN would remain vulnerable to long-term rate instability. The amalgamated FEVI/FEW entity would not achieve either a lower rate base per customer or customer/industry diversification if amalgamated.
    d. Separate rates and rate structures would be required for FEI, the amalgamated FEVI/FEW entity and FEFN. Therefore the FEU would be required to continue to administer multiple rates. Likewise, customers would continue to see multiple rates and rate structures in communications such as bill inserts, media releases, etc.
    e. Service offerings would not be expanded. Therefore, the amalgamated FEVI/FEW entity and FEFN would have to apply separately to the BCUC for a similar set of service offerings. This would incur additional costs for customers to go through a regulatory process.

f. Reporting, operating and regulatory efficiencies would be limited because separate reporting, operating and regulatory requirements to manage three utilities separately would continue.

Overall, the disadvantages associated with this option outweigh the advantages. Therefore, the FEU do not believe there is a net benefit to customers.

In sum, the FEU believe that the appropriate option is the common rates and amalgamation proposal as filed in the Application. The FEU also submit that, of the three options, options (I) FEI/FEVI/FEW and (II) FEI/FEVI would result in a net benefit to customers.

3.1.1 If the FEU consider that there would be a net benefit from any of the scenarios above compared to the status quo, please explain why the FEU would not proceed with amalgamation and postage stamp rates. If the FEU consider that there would not be a net benefit from any of the scenarios above, please identify the key differences in the evaluation between FEU's current proposal and those alternative scenarios which cause one option to be acceptable to the FEU and the other not. Where possible, please quantity these changes in benefits.

<u>Response:</u>

The FEU understand the first part of the question to be: *If the FEU consider that there would be a net benefit from any of the scenarios above compared to the status quo, please explain why the FEU would not proceed with the amalgamation and postage stamp rates for any such scenario(s).*

In the response to BCUC IR 2.3.1, the FEU identified that option (I) FEI/FEVI/FEW would provide a net benefit to customers. In BCUC IR 1.2.3, the FEU discussed that, in the event that the common rates proposal was not approved as filed, they would consider as an alternative rate design an option that involved implementing common rates for FEI (Mainland), FEVI and FEW, in other words, option (I) FEI/FEVI/FEW. Therefore, the FEU would proceed with option (I) FEI/FEVI/FEW.

In addition, while the FEU believe that there is minimal overall benefit to customers from omitting FEW from the amalgamated entity versus the benefits received by FEW customers from being part of the amalgamated entity, the FEU may also proceed with option (II) FEI/FEVI.

However, the FEU would not proceed with option (III) FEVI/FEW.

Please refer to the response to BCUC IR 2.3.1, where the FEU identify the key differences in the evaluation between the FEU's current proposal and those alternative scenarios.

3.2 If the Commission approves postage stamp rates for some regions but not all, would the FEU amalgamate only the companies which will adopt postage stamp rates? Please explain why or why not.

Response:

The FEU cannot definitively answer this question as it would depend on which regions and utilities would be subject to postage stamp rates and the relative benefit to amalgamating utilities that are not subject to postage stamp rates. The FEU are pursuing amalgamation in order to implement postage stamp rates and it is the FEU's view that amalgamation without a change in rate structure does not provide material benefits.

While the FEU are confident that they could proceed with the proposed amalgamation and postage stamp rates or similar scenarios as identified in the response to BCUC IR 1.2.3, the FEU would have to study any other option to determine if it could proceed. In particular, as explained in the Application (page 132), amalgamation should not be prejudicial to bondholders:

> *"FEI's Trust Indentures permit amalgamation of FEI with one or more other companies if certain terms and conditions are complied with. For instance, FEI's Trust Indentures contain a "Successor Company" provision which essentially requires that FEI not enter into any transaction whereby all or substantially all of its undertaking would become the property of another company – called the successor company – unless, among other things, the successor company executes an indenture that is satisfactory to the Trustee to evidence the assumption by the successor company of the due and punctual payment of all the debentures under the trust indenture and the agreement of the successor company to observe and perform all of the obligations of the Company under the trust indenture. Additionally, the transaction shall, to the satisfaction of the Trustee and in the opinion of counsel, be upon such terms as substantially to preserve and not to impair any of the rights and powers of the Trustee or the holders of the debentures under the trust indenture upon such terms as are in no way prejudicial to the holders."*

Please also refer to the response to BCUC IR 2.3.3.

3.3 If the Commission approves amalgamation, but requires that FEI Amalco maintain regional rate bases with regional rates for FEI, FEFN, FEW and FEVI customers (i.e., FEVI and FEW are treated as consistent with FEFN), would the FEU amalgamate? Please explain why or why not.

Response:

Under the scenario contemplated in the question, the FEU would not legally amalgamate. As discussed in the Application, the primary approval sought in the Application is common rates and in order to implement common rates across the FEU's utilities, legal amalgamation is required.

As identified in the preamble, the FEU's response to BCUC IR 1.2.3 discussed that the Companies would consider an alternative rate design to the common rates proposal if it sufficiently addressed the rate discrepancies that exist across the FEU.

As described in Section 5 of the Application, one of the options that the FEU have assessed is similar to the scenario described in the question, namely Option A (Status Quo). The only difference between Option A and the scenario in this question is that FEI, FEVI and FEW would legally amalgamate. Therefore, the reasons why the FEU would not amalgamate under the proposed scenario can be viewed through the same lens as the reasons why Option A was determined to be insufficient in meeting the FEU's objectives. Those reasons were:

1. Keeping regional rates based on regional rate bases does not address the existing rate disparity between the FEU's customers;
2. The loss of the government subsidies for FEVI will not be mitigated, which will result in further rate disparity for the FEU's customers located in FEVI's service territory; and
3. FEW, FEFN and to a lesser extent FEVI will remain vulnerable to the impact of significant capital projects or a significant loss of load.

Further, as discussed in response to BCUC IR 1.5.12, amalgamation alone would not achieve the benefits of postage stamp rates. While amalgamation alone would allow for small cost efficiencies from a legal and reporting perspective (as described in Section 6.6.2), and interest savings may be achievable assuming that the legal amalgamation resulted in the amalgamated entity maintaining the current credit rating of FEI, other efficiencies could not be achieved. As discussed in the response to BCUC IR 2.1.2, however, the interest savings are less certain under this scenario. While the FEU believe that amalgamation with postage stamp rates will likely be credit neutral, it is not certain that that would be the outcome of legal amalgamation with regional rates similar to the existing rates in place today.

In addition, the rating agency impacts of amalgamation with regional rates would need to be understood as it might impact the ability to amalgamate. On page 162 of the Application, the FEU explain that FEI's trust indentures stipulate that the amalgamation transaction shall, to the satisfaction of the Trustee and in the opinion of counsel, be upon such terms as substantially to preserve and not to impair any of the rights and powers of the Trustee or the holders of the debentures under the trust indenture upon such terms as are in no way prejudicial to the holders. If there are adverse rating agency impacts, the FEU would have to consider whether it may still be able to proceed with amalgamation.

Please also refer to the response to BCUC IR 1.2.1.

3.4 If the Commission approves amalgamation with one FEI Amalco rate base, but requires that FEI Amalco maintain regional rates based on separate COSA for each service areas of FEI, FEFN, FEW and FEVI customers (i.e., FEVI and FEW are treated in a consistent manner as FEFN with the exception of the allowed return on equity which would be postage stamped), would the FEU amalgamate? Please explain why or why not.

Response:

The FEU do not consider the option described in the IR to be materially different from the regional rate option described in BCUC IR 2.3.3 and accordingly the FEU's position on this option is the same as described in the response to BCUC IR 2.3.3.

3.5 If the Commission approves amalgamation with one FEI Amalco rate base and postage stamp rates, but requires the FEU to maintain the same level of regional data for FEI, FEFN, FEW and FEVI as exists at present, would the FEU amalgamate? Please explain why or why not.

Response:

Yes, the FEU would amalgamate under the scenario described as it principally aligns with the FEU's proposal.

However, as stated in the response to BCUC IRs 2.31.1 and 2.31.2, certain data that is required to calculate the revenue requirements by service area will no longer be readily available once amalgamation proceeds and only one legal entity exists. For example, it would not be possible to have a separate lead/lag study performed when there is no legal entity data available as an input. In order to provide the same level of regional data that exists today to the Commission, post-amalgamation would therefore require the development of allocation methodologies to regionalize costs. This would be accomplished in a manner similar to how FEFN's rate base and cost of service is determined today.

The FEU do not expect that there will be an ongoing need to see regional data after the proposed amalgamation and postage stamp rates are approved, but that such data could be provided upon request of the Commission.

3.6 If the Commission approves amalgamation and postage stamp rates, but considers that one of the benefits is a reduction in overall shareholder risk and so decreases the FEI Amalco ROE risk premium as a result or requires the FEU shareholder to make a financial contribution, will the FEU still proceed with amalgamation and postage stamp rates? Please explain why or why not.

Response:

While the FEU believe the 12 basis point risk premium is a reasonable premium over the current benchmark ROE, the FEU would proceed with amalgamation and postage stamp rates if it is determined by the Commission that FEI Amalco should have either a lower or no risk premium relative to the benchmark ROE. Amalgamation results in marginally higher risks for FEI Amalco versus FEI and the FEU have filed evidence to establish that a 12 basis point risk premium is reasonable.

With respect to whether the FEU would proceed with the proposal subject to the requirement of a shareholder contribution, it is a hypothetical question without knowing what that contribution would entail. However, the FEU do not believe that there is any basis for the FEU shareholder to make a financial contribution and therefore would likely not proceed with amalgamation and postage stamp rates under this scenario.

3.6.1 Please quantify the maximum ROE risk premium reduction and/or financial contribution that FEU are willing to accept in order to proceed with amalgamation and postage stamp rates. In undertaking this analysis, please assume all other items requested in the application are approved.

Response:

Please refer to the response to BCUC IR 2.3.6.

4.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.8.1

Evaluation Framework - Alberta

BCUC 1.8.1 quotes the Alberta Energy and Utilities Board (EUB) June 12, 1996 Nova Gas Transmission Ltd. (NGTL) Decision on a 1995 General Rate Application – Phase II (Decision U96055) with regard to postage stamp versus distance sensitive gas transmission rates:

> "Before making a change in toll design, the Board would need to be satisfied, on the basis of clear and convincing evidence, that <u>greater efficiencies or cost savings would accrue to the benefit of shippers overall</u>. The Board would also need to be satisfied that the <u>magnitude of the changes to affected parties are acceptable</u> and that <u>benefits in the broad public interest would result</u>. The Board would also look for transitional measures designed to manage such changes. Absent such considerations, the Board is concerned that a decision to change NGTL's rate design could have negative effects on investor confidence in NGTL, the province's natural gas industry and on the industry's overall well-being." [emphasis added]

The FEU state in the response to BCUC 1.8.1: "The potential for efficiencies and cost savings, the magnitude of the rate changes, and the benefits in the public interest are all relevant considerations when determining whether to recognize a "distinct or special area." However, the statements made by the Alberta EUB in the referenced case were made in the context of a particular factual matrix in which the Alberta EUB was taking into account the particular consequences of determining a regional rate for the utility in question at that time. ... In each case, the unique circumstances of the utility in question should be taken into account and in each case there may be other factors than those specifically mentioned by the EUB which are relevant or determinative. Therefore, the FEU would not adopt the criteria used by the Alberta EUB as a general rule."

4.1 The FEU state they would not adopt the Alberta evaluation framework to assess the implementation of postage stamp rates. Please identify which specific criteria in the framework FEU is opposed to and provide the reasons why. If the FEU consider that the Alberta framework is missing relevant criteria, please describe and explain why they are not included in the 'broad public interest' component of the Alberta framework.

Response:

The quote from the EUB in the preamble above is not "the Alberta" evaluation framework, but a particular set of conclusions by the EUB after a detailed discussion in the 1996 NGTL case. Further, the conclusions in the 1996 NGTL case cannot be directly applied to the current Application as it concerns a toll for a transmission pipeline system in Alberta and different factual circumstances. Because the NGTL is an inter-provincial transmission pipeline company, it is more comparable to the Spectra system in B.C. than the FEU, making it difficult to draw any relevant conclusions for this case.

The quote from the EUB in the preamble above represents conclusions of the EUB based on its detailed consideration of the particular circumstances relevant to NGTL's tolls. The EUB's reference to "greater efficiencies or cost savings would accrue to the benefit of shippers overall" shows that the EUB was considering shippers on a pipeline, which presents very different dynamics and economics that are not comparable to the FEU's situation. For example, the paragraph of the Decision immediately before the quote in the preamble illustrates some of the dynamics that the EUB was considering in that situation. The EUB states:

> *"In the matter of efficiency, the Board is of the view that the price signals suggested by PanCanadian's proposal would invariably alter the utilization of existing pipeline facilities by changing flow patterns on the system from all other areas of the province to one favouring areas of the south. As a result, certain parts of the NGTL system and the production facilities behind them might no longer be efficiently used or might be stranded. In addition, because locational tolls can result in significantly different tolls to shippers in close proximity, they would likely have the same effect on a more localized basis. The Board is not persuaded by PanCanadian's argument that it should ignore these secondary effects on income distribution and asset values on the assumption that its proposal would ultimately lead to long term efficiencies, lower rates for all users of the system and enhanced investment."*

The EUB was concerned that the change to locational rates would result in secondary effects, such as changing flow patterns on the system and potentially leading to inefficiencies, or stranded costs on a regional and localized basis. For this reason and others, the EUB was concerned that the efficiencies should accrue to the benefit of shippers overall, that the magnitude of the changes to affected parties are acceptable and that benefits in the broad public interest would result. The dynamics at play in the 1996 NGTL case are not relevant to the FEU and it would therefore be a mistake to apply the same considerations expressed by the EUB as being applicable as a general rule.

Furthermore, the quote from the preamble is not representative of the full framework that the EUB used. At the beginning of its reasoning on this issue in the 1996 NGTL case, the EUB stated what is closer to a general framework. It stated:

> *"In assessing the appropriateness of postage stamp rates versus the locational rates proposed by PanCanadian, the Board believes that it must have regard to generally accepted rate design principles. The Board notes that the rate design principles advanced by several parties were remarkably similar. There were, however, obvious differences of opinion between PanCanadian and other parties on the weight to be attributed to each in establishing a rate design that will yield just and reasonable rates. The Board agrees with parties that the basic attributes of an appropriate rate design include simplicity, understandability and public acceptability; freedom from controversy; effectiveness in achieving revenue sufficiency and in providing revenue and rate stability; fairness in the apportionment of total costs and avoidance of undue discrimination; and the encouragement of efficiency. The weight to be given to each of these characteristics will depend largely on the desired balance between various goals, objectives and interests. The Board does not believe that there exists a rate design which will accommodate all interests and satisfy each and every individual shipper. In addition, in determining the need and desirability of changing from postage stamp rates to locational rates, the Board also believes it must assess the overall benefits which would result and the manner in which change would be implemented."*

After several pages of reasoning on this issue, the EUB concluded:

> *"For the foregoing reasons, the Board is not persuaded that a fundamental shift in NGTL's rate design as embodied in PanCanadian's proposal for locational tolls would be justified at this time. The Board is of the view that the evidence in this proceeding favours the continuation of postage stamp rates on NGTL. They continue to satisfy generally acceptable rate design criteria and to appropriately balance various objectives, goals and interests. Therefore, the Board finds that postage stamp rates continue to be in the public interest."*

It is clear that the in the 1996 NGTL case, the EUB applied rate design principles similar to those put forward by the FEU in the present proceeding. In addition, the EUB considered the "various goals, objectives and interests" and "overall benefits" that were relevant to that situation.

The FEU submit that, like the EUB in the 1996 NGTL case, the Commission should consider the applicable rate design principles and the unique circumstances of the case before it. The full text of the EUB Decision is available online at:
http://www.auc.ab.ca/applications/decisions/Decisions/1996/U96055.pdf

4.2 Do FEU agree that by using the Alberta evaluation framework, the Commission could determine that it would be appropriate to postage stamp the rates of some regions but not others? If no, please explain why not.

Response:

Please refer to the response to BCUC IR 2.4.1. The FEU believe that under the framework applied by the EUB as described in the response to BCUC IR 2.4.1, the Commission should determine that it is appropriate to postage stamp the rates of all regions. Postage stamp rates are consistent with rate design principles, and provide overall benefits in the public interest. Please refer to the response to BCUC IR 2.3.1 for a discussion of the advantages and disadvantages of postage stamping the rates of different combinations of utilities.

4.3 While acknowledging that the FEU have not applied for Chetwynd or any other area to be considered as a distinct or special area, please describe the evaluation framework that the FEU would propose the Commission use if such an application were received. Please identify and explain any differences between the evaluation framework proposed in that case and the evaluation framework for common rates proposed by the FEU in this Application.

Response:

Since the FEU have not applied for Chetwynd or any other area to be considered as a distinct or special area, the FEU have not considered in any detail the appropriate framework and are not in a position to propose what framework the Commission should use if an application were received. The FEU submit that it is premature to consider this issue.

5.0 Reference: Request for Common Rates

2010 NZ Electricity Commission Standardization Information Paper, Executive Summary, Appendix 1; 2011 NZ Electricity Authority Standardization Consultation Paper, Executive Summary

Evaluation Framework – New Zealand

In September 2010, the New Zealand Electricity Commission (now Electricity Authority) published an Information Paper titled, “More standardized line distribution tariff structures and use of system rules: key findings.” [2] The Paper’s Executive Summary states that this paper was the result of an extensive information gathering exercise to determine whether greater standardisation of distribution tariff structures and Use of System Agreements could provide a net long-term benefit to consumers (New Zealand has 28 traditional distributors and over 10 retailers).

The evaluation framework, described in Appendix 1 of the paper, includes the following:

> *Project drivers:* it is assumed that a project will not be undertaken unless it results in a lower price and/or improved quality. The market failure/barrier that the project addresses should be clearly identified.
>
> *Fairness:* fairness in and of itself is not a driver – all consumer classes are treated equally and existing distribution rate structures are therefore considered fair. However, changes that result in bill impacts should be avoided unless there is a demonstrable net benefit, and economic hardship created during a period of transition should be mitigated to the extent possible, whilst balancing fairness considerations against potential efficiency improvement.
>
> For example, several distributors opposed the Low Fixed Charge Regulations on the basis that they were ‘unfair’. However, fairness could be interpreted in many ways, including: ensuring no bill impacts; high users paying more than low users; and (as the wires costs are primarily sunk) all connected customers paying the same amount regardless of usage.
>
> For distribution tariff structures, it is assumed that changes would only be recommended by the Authority where it would support the price/quality key drivers, rather than just move from one definition of fairness to another.

[2] http://www.ea.govt.nz/document/11385/download/our-work/programmes/market/consumer-rights-policy/model-arrangements/distribution-tariff/

Long-term focus: cost/benefit analysis should show a net benefit over the long-term, with long-term defined as 'for generations'. This reflects the long lived nature of generation and network assets, and the potentially even longer term implications of emissions related trade-offs made today. To achieve net benefits over the long-term, it is therefore important that innovation is promoted and potential future market changes (such as advanced meters, distributed generation, electric cars, etc.) are taken into account.

In May 2011, the New Zealand Electricity Authority published a follow up Consultation Paper titled, "More standardization of distribution arrangements: Proposed amendments to the Code" stated in the Executive Summary (page B):[3]

"The Authority does not propose full standardisation of distribution tariff structures because:

(a) transaction cost inefficiencies arising due to multiple tariff structures can be addressed by standardising the way in which tariff information is exchanged, rather than the tariff structures themselves; and

(b) the 'one size fits all' approach required for full standardisation would result in inefficient outcomes and risks unnecessary 'rate shocks' to consumers."

5.1 Do FEU agree that the approach used in New Zealand to evaluate electricity postage stamp versus regional distribution tariff structures is generally consistent with the approach used in Alberta, in that it is focused on determining whether there would be a net long-term benefit to customers, rather than on "moving from one definition of fairness to another?" If no, please explain why not.

Response:

Assuming the phrase "moving from one definition of fairness to another," is meant to characterize the FEU's proposal, it is a mischaracterization. Within each of the FEU's rate bases (FEI, FEFN, FEVI and FEW), the rates in effect reflect postage stamp rates, other than minimal differences in FEI's midstream rates. This is the case even though the customer base in each service area is heterogeneous and there are different costs to serve different customers. In this Application, the FEU are seeking to apply the same methodology (or the same "definition of fairness" as referred to in the IR) for the one utility rate base of FEI Amalco.

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3 http://www.ea.govt.nz/document/13926/download/our-work/consultations/priority-projects/more-standardisation-proposed-code-amendments/

The FEU believe that a consideration of long-term benefits to customers from postage stamp rates is appropriate. As set out in the FEU's Application, there will be net long-term benefits to customers from amalgamation and postage stamp rates, including cost savings and efficiencies, more stable rates for customers, and rates that are easier to understand and administer. However, the exhibits on record in this proceeding do not establish that the approach used in Alberta and New Zealand focus on whether postage stamp rates would provide net long-term benefits to customers.

First, the FEU assume that by "the approach used in Alberta" the IR is referencing the quote from the 1996 NGTL EUB Decision quoted in the preamble of BCUC IR 2.4.1. As indicated in the response to that IR, the quote does not represent "the approach used in Alberta." In its response to BCUC IR 2.4.1, the FEU address the approach taken by the EUB in the 1996 NGTL case.

Second, for the reasons discussed below, the New Zealand documents referenced in this IR are not directly relevant or applicable to an evaluation of postage rates as proposed in the FEU's Application. The New Zealand electricity market is very different than either the gas or electric distribution markets in B.C., whereby there is a near complete separation of the different functions: generation, transmission, distribution, and retail. The New Zealand Electric Authority (the "Authority") is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market and its principle objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[4]

The vast majority of New Zealand electric consumers buy their power supply from one of approximately 20 retailers. In addition there are currently 29 regional distribution companies that distribute power to the end user. The reference documents were consultation documents that were part of an assessment that was undertaken by the Authority as part of a broader program of initiatives to lowering barriers to retailer entry into and expansion on distributor networks. The assessment included an examination of what measures could be undertaken to provide for more 'standardisation' of distribution arrangements to improve competition and choice for end-use customers by standardising aspects of distributor use of system agreements and tariff structures. This is very different from the concept of postage stamp rates as proposed in the FEU's Application. The FEU therefore submit that these documents are not applicable to the present case and caution should be used in applying the statements from them.

[4] Section 15 of the New Zealand Electricity Act 2010. Available online at: http://www.legislation.govt.nz/act/public/2010/0116/latest/DLM2634233.html?search=ts_act_electricity_resel&p=1

5.2 Do FEU agree with the New Zealand approach that, in the context of regional vs. postage stamp rates, fairness in and of itself should not be a driver as it can be interpreted in many ways? If no, please explain why not.

Response:

The suggestion that fairness should be disregarded is inconsistent with the Utilities Commission Act (the "UCA") and the Commission's own interpretation of its mandate. For instance, the Commission's October 19, 2010 Decision on FortisBC Inc.'s 2009 Rate Design and Cost of Service Analysis states (at page 6):

> *"The Commission's primary responsibility is the regulation of public utilities under its jurisdiction to ensure that the rates charged for service are <u>fair, just and reasonable</u>, that utility operations are safe, that adequate and secure service is provided to customers, and that the opportunity for utilities to earn a <u>fair</u> and adequate financial return is preserved."* [Emphasis added.]

Similarly, the BCUC website states:

> *"The Commission's mission is to ensure that ratepayers receive safe, reliable, and non-discriminatory energy services at <u>fair rates</u> from the utilities it regulates, and that shareholders of those utilities are afforded a reasonable opportunity to earn a <u>fair return</u> on their invested capital."* [Emphasis added.]

The *UCA* itself requires the Commission to determine what rates are "just and reasonable." As stated in Section 59(5) of the UCA, a rate is "unjust" or "unreasonable" if the rate is:

> *"(a) more than a <u>fair</u> and reasonable charge for service of the nature and quality provided by the utility,*
>
> *(b) insufficient to yield a <u>fair</u> and reasonable compensation for the service provided by the utility, or a <u>fair</u> and reasonable return on the appraised value of its property, or*
>
> *(c) unjust and unreasonable for any other reason."* [Emphasis added.]

In accordance with its ratemaking duties, the Commission routinely determines what rates are fair, despite disagreement amongst the parties before it. Other tribunals and the courts are similarly called upon to weigh the equities in particular cases and make judgements about what is fair. For instance, in administering its duties, the Commission is bound by a duty of procedural fairness. The concept of fairness in this context is well understood and has given rise to the articulation of various procedural rules by the courts that embody what is fair from a procedural perspective. The Commission routinely abides by these principles of fairness in setting the procedure for the hearing of the applications before it. The concept of fairness is also routinely applied in ratemaking and is one of the widely accepted Bonbright ratemaking principles.

In the present Application, the FEU have proposed postage stamp rates as being the rates for an amalgamated entity that are fair, just and equitable rates to apply for customers. As discussed in the Application, the FEU currently have postage stamp rates for 850,000 FEI customers. These 850,000 customers are not all the same, reside in various locations across the province and do not all have the same cost to serve, even within the same rate class. Despite the different costs to serve, all customers within the same class pay the same rate regardless of location. Postage stamp rates give access to natural gas to all customers at the same reasonable and stable rate regardless of cost to serve due to location, which recognizes the integrated nature of the system and the FEU's operations. The FEU believe this is appropriate for such an important energy source. Since 850,000 customers currently enjoy this benefit, the FEU believe it is fair that their other approximately 100,000 customers that are served by the same integrated system should also enjoy this benefit.

As discussed in the Application and the responses to information requests, postage stamp rates are in fact the most common form of rate structure put in place by regulators for natural gas distribution, as it is in this province with rates set by the Commission. The FEU's view that postage rates are "fair" is therefore consistent with the determinations of regulators, including the Commission. Furthermore, postage stamp rates are often supported by government policy, as it has been in this province, suggesting that, politically, postage stamp rates have been considered to be the most fair approach.

In addition, the Application has set out the other benefits of postage stamp rates, including cost efficiencies, more stable rates, and rates that are more easily understood and administered. Altogether, the FEU submit that these attributes make the Application of postage stamp rates fair, just and reasonable for the proposed FEI Amalco.

With respect to the New Zealand approach referenced, please refer to the response to BCUC IR 1.5.1.

5.3 Do FEU agree that, barring consideration of whether postage stamp rates or regional rates are 'more fair', the key issues in the evaluation of postage stamp rates for FEU are similar to the key findings in New Zealand, namely (i) transaction cost inefficiencies, (ii) efficiency of rate design, and (iii) bill impacts? Please explain why or why not.

Response:

The New Zealand Electric Authority was not assessing the issue of postage stamp rates in the referenced documents and therefore these documents are not relevant to the Commission's evaluation of postage stamp rates in this proceeding. Please refer to the response to BCUC IR 2.5.1.

The Application sets out what the FEU believe are the key issues in the evaluation of the proposed postage stamp rates. The FEU believe that fairness should be considered as discussed in the response to BCUC IR 2.5.2.

The "transaction cost inefficiencies" referenced in the New Zealand documents refer to how business is transacted over the much more fragmented system and business model in New Zealand. These considerations are not relevant in this proceeding. However, the closest analogy may be the FEU's costs of the amalgamation transaction, which is a valid consideration. In the Application and information request responses,[5] the FEU have described the costs of the transaction and explained that the cost savings from amalgamation and postage stamp rates will outpace the costs in year 2, resulting in a positive NPV. Thus, "transactions cost inefficiencies" are not a key issue in the evaluation of the postage stamp rate proposal.

The FEU discuss efficiency of rate design in response to BCUC IR 2.33.1. For the reasons discussed in that response, the FEU do not believe that efficiency of rate design is a key issue in the evaluation of implementing postage stamp delivery rates for the FEU.

Bill impacts are likely a key consideration in evaluating the postage stamp rate proposal. The FEU have described the bill impacts to customers and proposed phase-in of those impacts for FEI Mainland and FEFN customers in Sections 6.7 and 8.4 of the Application.

[5] See Section 8 of the Application and the response to BCUC IR 1.5.11 in particular.

6.0 Reference: Request for Common Rates

Exhibit B-3, Section 5.1; UCA Section 60(1); BC Energy Plan, p. 39; Exhibit B-9,

BCUC 1.7.2.4; Exhibit B-8 BCOAPO 1.6.2

Evaluation Framework

The FEU include as two of the objectives on page 80 of the Application:

1. "Minimize the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW.

2. Implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts."

Section 60(1) of the *Utilities Commission Act* (UCA) states: "In setting a rate under this Act ... the Commission must have due regard to the setting of a rate that ... encourages public utilities to increase efficiency, reduce costs, and enhance performance."

The BC Energy Plan Policy Action No. 4 (p. 39) states: "Explore with BC utilities new rate structures that encourage energy efficiency and conservation."

The FEU state in BCUC 1.7.2.4 that if the Commission accepts the objective of 'Minimiz[ing] the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW', it would "be consistent with existing postage stamp rate designs in the province and would not set a new precedent."

6.1 Do FEU agree that the appropriate starting point for an evaluation of the FEU postage stamp rates proposal is existing rates? For example, in evaluating whether the proposed rate encourages public utilities to increase efficiency, reduce costs, and enhance performance should consideration be given to whether the proposal is better or worse than the status quo? Please explain why or why not.

<u>Response:</u>

The FEU agree that the appropriate starting point for an evaluation of the FEU's postage stamp rates proposal is existing rates. The FEU have identified the benefits of the proposed amalgamation and postage stamp rates compared to the status quo in Section 6 of the Application. For the reasons discussed in the Application, the proposed postage stamp rates increase efficiency, reduce costs, and enhance performance compared to the status quo, particularly as amalgamation and postage stamp rates will lead to cost savings, efficiencies and a rate that is simpler to understand and easier to administer.

Furthermore, the FEU's proposal is to extend FEI's existing rate structure to the service areas of FEVI, FEW and FEFN. FEI's rate structure has been previously approved by the Commission at which time the Commission had "due regard to the setting of a rate that ... encourages public utilities to increase efficiency, reduce costs, and enhance performance."

Please also refer to the response to BCUC IR 2.6.2.

6.2 Please explain how accepting an objective of 'Minimiz[ing] the regional rate differences that are in effect today, in particular the existing higher rates for FEVI and FEW,' would not restrict the Commission's ability to ensure rates increase efficiency, reduce costs and enhance performance, or reduce the Commission's ability to support Energy Plan Policy Action No. 4.

<u>Response:</u>

Minimizing the regional rate differences that are in effect today across the FEU is appropriate and results in rates that increase efficiency, reduce costs, enhance performance and are consistent with Energy Plan Policy Action No. 4.

Minimizing the regional rate differences in effect today across the FEU would not curtail the Commission's ability to ensure rates increase efficiency, reduce costs and enhance performance, or to support Energy Plan Policy Action No. 4. The FEU are not proposing a new rate structure, but expanding the existing FEI rate structure to FEVI, FEW and FEFN. This structure has been previously approved by the Commission having consideration for rates that increase efficiency, reduce costs and enhance performance. Further, within a postage stamp rate structure, ample opportunity exists to create new rate classes and rate structures that encourage efficiency, reduce costs or enhance performance, or to encourage energy efficiency and conservation in accordance with Energy Plan Policy Action No. 4. Such is the case in FEI today, where postage stamp rates currently exist. The existing level of diversity within FEI's customer base of approximately 850,000 is significant, and FEI rate classes and structures have been designed to accommodate the various types of customers and numerous regions with varying levels of economic development, population density and environmental and social considerations. Bringing the Vancouver Island, Whistler and Fort Nelson areas within the FEI rate structures will not pose any greater challenges to FEI and the Commission compared to the level of diversity already present within FEI.

Moreover, increased efficiency, reduction of costs and enhanced performance will be encouraged with the extension of postage stamp rates across the FEU. For instance, as discussed by EES Consulting in Appendix D-1 of the Application, regional pricing requires a greater administrative burden. Also, as discussed in the Application, operational, regulatory and financial efficiencies will be realized as a result of common rates. In addition, having the FEI rate structure in place across the FEU will give customers from FEVI, FEW and FEFN service areas the opportunity to partake in rate classes not previously available to them that could foster gains in efficiency, performance or cost savings.

6.3 Please explain the underlying problem which is addressed by FEU's objective to "implement a long-term solution for FEVI customers to the loss of the government subsidies and associated rate impacts." For example, would the loss of government subsidies result in FEVI becoming uneconomic, FEVI customers experiencing rate shock, or are there unique economic development, social or environmental considerations which require addressing?

Response:

As indicated in Section 4 of the Application, in the absence of amalgamation FEVI customers are projected to face rate increases in the range of 20% upon depletion of the existing RSDA balance.[6] In the long-term and in the absence of any mitigating strategies, this will result in FEVI facing increasing challenges in retaining and adding load and has the potential for FEVI to become uneconomic. The FEU are not aware of any unique economic development, social or environmental considerations which require addressing.

Amalgamation and common rates as proposed in this Application provides a permanent solution for FEVI by mitigating the rate increase that would ensue if FEVI were to remain on a stand-alone basis and by making it easier to retain and add load in the long-term due to lower, more stable rates.

[6] See Section 4.3 of the Application for full discussion.

6.4 With regard to BCOAPO 1.6.2, please describe the evaluation criteria EES Consulting would use to determine if regional rates are appropriate for a particular utility.

Response:

Some of the factors that EES Consulting would look at in determining the appropriateness of regional rates would include the interconnectedness and use of common facilities, the similarity of the service offered, the similarity of the customers' consumption patterns, the ownership structure, how the utility is operated, and the existence of unique facilities in a particular region.

EES Consulting looked at these factors in determining whether or not it was appropriate to postage stamp the rates for the FEU. The separate rates were appropriate when there was different ownership of the utilities. Under common ownership, the system has become more integrated in terms of the use of the existing facilities, the addition of new facilities, and the operation of the system. Further, EES Consulting did not see any unique facilities or differences in the customer base that would warrant a continuation of regional rates. Given these findings, EES Consulting concurred that postage stamped rates were appropriate for the FEU.

6.5 Is it FEU's position that, if postage stamp rates are found not to be 'more fair' than regional rates, a move to postage stamp rates would still provide a net benefit for all FEU customers? Please explain why or why not for each of FEVI, FEI, FEFN and FEW.

Response:

The Commission does not have to explicitly conclude that postage stamp rates are "more fair" than regional rates to conclude that they are the appropriate for FEI Amalco. Postage Stamp rates are the most appropriate rates for FEI Amalco based on accepted rate design principles as discussed in the expert report of EES Consulting (Appendix D-1 of the Application) and as shown in response to BCRUCA IR 2.1.3. Amongst other factors, postage stamp rates reflect the common ownership of the FEU, the integrated operation and management of the FEU, and the integrated nature of the system used to serve customers. It is difficult to justify the historical rate differences between FEI, FEVI and FEW given the diversity within FEI itself over which postage stamp rates currently apply.

While the FEU believe that postage stamp rates are the equitable, there are other benefits resulting from common rates that will provide a net benefit for all the FEU's customers. As explained in Section 6 of the Application and expanded on in response to various information requests, all of the FEU's customers will derive some benefit from the amalgamation and postage stamp rates proposal. As discussed in Section 6.2 of the Application, postage stamp rates will mitigate the future rate increases for FEVI as a result of the loss of government subsidies. As also discussed in Section 6.2 of the Application, postage stamp rates will provide more stable rates for the smaller service areas of FEVI, FEW and FEFN. The susceptibility of these smaller rate bases to rate instability is discussed in Section 4.4 of the Application. The rate stability benefit will also accrue to FEI. For instance, FEI customers will benefit from sharing the costs of its aging infrastructure costs over a relatively larger customer base as discussed on page 125 of the Application. At the same time, the cost of the relatively new FEVI and FEW systems will decrease as they continue to depreciate. All customers of the FEI Amalco will benefit from the simplicity and ease of administration of the proposed rates as described in Section 6.4 of the Application. FEFN, as well as FEVI and FEW, will benefit from the facilitation of service offerings and the expanded rate options offered by the FEI rate structure. In addition, the proposed amalgamation and postage stamp rates will result in regulatory, reporting and operational efficiencies, which will reduce the overall cost of service for FEI Amalco compared to the FEU as discussed in Section 6.6 of the Application.

7.0 Reference: Request for Common Rates

2011 Delta School CPCN, MEM Final Submission; 2011 AES Inquiry, MEM Submission; Exhibit B-9, BCUC 1.13.1; BCUC Order G-56-12, Appendix A, pp. 3, 6

Government Support

In the FortisBC Energy 2011 Delta School District 37 Thermal Energy Service Contracts CPCN, the BC Ministry of Energy and Mines and the Climate Action Secretariat provided a final submission in support of FortisBC Energy's Inc. (FEI) application.[7]

In the FortisBC Energy Inc. 2011 AES Inquiry, the BC Ministry of Energy and Mines provided a submission pertaining to the implications of the Greenhouse Gas Reduction (Clean Energy) Regulation for the AES Enquiry.[8]

The FEU state in BCUC 1.13.1: "No, the provincial government has not requested that postage stamp rates be applied to the FEU's service areas. However, provincial government policy has been in favour of postage stamp rates."

The Commission, in the Reasons for Decision attached as Appendix A to Order G-56-12 on the BC Hydro Dawson Creek/Chetwynd Area Transmission Project, state:[9] "In an effort to set the agenda for scoping issues, BC Hydro referred to its letter of March 23, 2012. This letter set out five topics that BC Hydro suggests are out of scope, re-categorized into four issues as follows:

> **1. RATES:** whether rolled in rate principles should apply on the BC Hydro system; whether distinctions should be made between old and new customers for ratemaking; and, whether postage stamp rates, which have been in effect since BC Hydro was created in 1962, remain appropriate on its system; (page 3) ...
>
> The Panel acknowledges the submissions from the MEM that the government is planning a broader review of industrial electricity policy, including retail access and rate design issues. Accordingly, questions that relate to the appropriateness of rolled in rate principles, or postage stamp rate principles, as a system wide BC Hydro policy, are out of scope for this hearing." (page 6)

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7 http://www.bcuc.com/Documents/Arguments/2012/DOC_29810_02-10-2012_MEM_Final-Submission.pdf

8 http://www.bcuc.com/Documents/Proceedings/2012/DOC_30877_06-08-2012_MEM-Submission_GHG-Regulation.pdf

9 http://www.bcuc.com/Documents/Proceedings/2012/DOC_30568_A-28_G-56-12_Reasons-Revised-Regulatory-Timetable.pdf

7.1 Have the FEU requested that the provincial government provide it with written support for this Application, for example similar to that provided for the 2011 Delta School Application? If no, please explain why not. If yes, please describe the outcome of that request.

Response:

The FEU have discussed the Application with the Ministry of Energy and Mines (the "Ministry"), including providing a copy of this response and the response to BCUC IR 2.7.2 for the Ministry's review before filing.

Regarding the two proceedings mentioned in the question preamble, there were specific reasons why the Ministry made submissions in those cases. Firstly, in the Delta School District ("DSD") Application the Ministry had a direct interest because the DSD was a recipient of grants under the provincial government's PSECA program. The FEU's DSD project provided a means for the government's goals for the PSECA program to be achieved (for that specific project) in circumstances where public sector funding is very constrained.

In the second case, regarding the implications of the Greenhouse Gas Reduction (Clean Energy) Regulation ("GGRR") for the AES Inquiry, the Ministry's submission in the AES Inquiry was to provide clarification on the intent of the GGRR in response to the submissions of interveners. The reply phase of the regulatory process in the AES Inquiry with respect to the GGRR allowed interveners to respond to concerns in the submissions of other interveners. The Ministry did not comment on the submissions of the FEU in that situation because it agreed with them.

While, as stated in the response to BCUC IR 1.13.1, the FEU believe that it has been long held government policy to have postage stamp rates[10], the FEU are not aware of any directives to the BCUC regarding postage stamp rates for any utility including BC Hydro. As such, while the government would have the power to do so, the FEU believe that it is not necessary to have such a direction for the BCUC to approve this Application. As discussed in the response above, the DSD Application was a new circumstance and a program in which the government was involved. This is not the case here; the policy is well established so it was not necessary for the government to intervene.

[10] According to BC Hydro Power Pioneers website postage stamp rates were first implemented for BC Hydro in October 1962 (http://www.powerpioneers.com/bc_hydro_history/history/1962-1972/chronology.aspx), shortly after the formation of BC Hydro in March 1962. Postage stamps rates have been in effect ever since, including the entire period of the Commission's regulation of BC Hydro which began in 1980, concurrent with the establishment of the Commission by the enactment of the *UCA* in August 1980

7.2 In light of the planned government broader review of industrial electricity policy, including retail access and rate design issues, is it FEU's position that the provincial government's policy is currently, and will continue to be, in favour of postage stamp rates? Please explain why or why not.

Response:

Yes, the FEU believe that the provincial government's policy is, and continues to be, in favour of postage stamp rates. The FEU do not believe that the planned review of industrial electricity policy by the provincial government marks a change in the government's views in this matter, particularly with respect to postage stamp rates as they apply to other customer classes such as residential, commercial and general service classes.

The references in Appendix A of BCUC Order G-56-12 (Exhibit A-28 in the Dawson Creek / Chetwynd Area Transmission "DCAT" Project) to the government review of industrial electricity policy are drawn from two sources, DCAT Exhibits B-22 and C16-2. Exhibit B-22 is a letter dated March 23, 2012, from BC Hydro requesting reactivation of the DCAT proceeding, which had been suspended on November 30, 2011. Exhibit B-22 includes an attached letter from the Minister of Energy and Mines, which states that the provincial government intends to review BC Hydro's Transmission Service Rate and industrial tariff over the next two years and that further information would be provided by Ministry staff in regard to this proposed review. DCAT Exhibit C16-2, a letter from the Deputy Minister dated April 3, 2012, provides the further information referenced in the Minister's letter attached to Exhibit B-22. The government review process referred to in Exhibit C16-2, including whether rolled-in rate principles should continue to apply, whether distinctions should be made between old and new customers and whether postage stamp rates remain appropriate, is limited to industrial electricity policy.

The FEU believe the government's planned review of industrial electricity policy has been necessitated by the potential for large new industrial loads such as from the electrification of the oil and gas sector in the northeast of the province or the development of LNG export facilities on the northwest coast of the province. The addition of such large industrial loads has the potential to bring about rate increases for all electricity consumers in the province and brings these policy concerns to the forefront. The fact that an industrial electricity policy review is to be conducted, including reviewing rolled-in rate principles, new and old customer concerns and postage stamp rates, does not mean that the current policies with respect to these principles will be abandoned in general, but particularly not for the residential and smaller volume customer classes. The FEU believe that there are cogent ratemaking and rate design principles in support of rolled-in rates and postage stamp rates that continue to be valid for the industrial customer class.

However, even if the government's review process results in policy changes for industrial electricity consumers in BC there is no suggestion that such changes will be applied to other customer classes which make up over 99% of BC Hydro's customer base.

The FEU have provided this response to the Ministry for review prior to filing and the Ministry has not expressed any concerns with the response.

8.0 Reference: Request for Common Rates

UCA Section 59 (1); Exhibit B-9, BCUC 1.11.1; 1; BCUC Reasons for Decision to Order

G-124-08, pp. 68-71

Regional Impacts

Section 59(1) of the UCA states that a public utility must not make, demand or receive an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia. [emphasis added]

In BCUC 1.22.2, the FEU agreed that rates that are approved by the Commission are by law just, reasonable and not unduly discriminatory. [emphasis added]

Reasons for Decision to Order G-124-08 (BC Hydro Residential Inclining Block Rate Application) state:[11]

> "BC Hydro submits that it does not believe the proposed RIB rate structure unduly discriminates on the basis of region for the following reasons:
>
> 1. Most of the customers in each of the Zone I four regions (Vancouver Island, Lower Mainland, Southern Interior and Northern) will have lower annual bills under the RIB rate structure than under the otherwise applicable flat rate structure. ...
>
> 2. No region has a preponderance of customers with larger consumption, and therefore no region has a predominance of customers with adverse bill impacts." (page 67) [emphasis added]

"BC Hydro submits that to the extent that there are regional variances in consumption, with meaningfully distributed variances in bill impact, there are corresponding regional variations in customers' ability to conserve and corresponding regional variations to mitigate bill impacts, on the premise that larger users are generally more price responsive and able to conserve." (page 68)

"BC Hydro observes that there is no evidence suggesting that Vancouver Island customers have fewer options or alternatives to save electricity compared to customers in other regions." (page 71)

8.1 Does the Application result in certain regions having a preponderance of customers with adverse bill impacts? If yes, please explain if this could result

11 http://www.bcuc.com/Documents/Decisions/2008/DOC_19755_BCH-RIB-Decision-WEB.pdf

in the postage stamp rates proposal being considered unduly discriminatory on the basis of region (given that existing rates, by law, are not).

Response:

The FEU assume that by adverse bill impacts the Commission is asking whether there is a preponderance of customers who will experience increases in their annual bills. As described in the Application, the impact of common rates on customers in FEI and FEFN service areas will be one time rate increases, which the FEU are proposing to phase-in, whereas FEVI and FEW customers will see rate decreases.

While FEI and FEFN customers will see increases, this impact does not result in undue discrimination on the basis of region. The proposed postage stamp rates are consistent with rate design principles and as indicated by the COSA results in Section 9 of the Application, the rates proposed by the FEU are within the range of reasonableness. Postage stamp rates are the most common form of rate structure for natural gas distribution utilities and are in use in B.C., including by BC Hydro. The FEU therefore believe that implementing postage stamp rates for FEI Amalco is not unduly discriminatory. In addition, with the proposed phase-in of the rate increases, the impact will be mitigated.

Please refer also to the FEU's responses to the BCUC IR 1.10 series.

8.2 Are regions which would see bill increases as a result of the postage stamp proposal (FEFN, FEI) generally more price responsive than regions which would see bill decreases as a result of the postage stamp proposal (FEVI, FEW)? Please explain why or why not.

Response:

The FEU's analysis indicates the price elasticity of demand coefficient for FEI residential customers (including FEFN) is approximately -0.22 and for FEI commercial customers (including FEFN) is approximately -0.19. However, the FEU's analysis of FEW and FEVI did not result in reliable elasticity estimates. At this time the FEU do not believe there are regional variations regarding price responsiveness.

8.3 Do FEFN and FEI customers have the same options or alternatives for reducing their gas consumption, compared to customers in FEVI and FEI? Please explain why or why not.

Response:

The FEU assume that the second reference to FEI in the question was intended to refer to FEW.

The FEU believe that FEFN and FEI customers have the same options or alternatives for reducing their gas consumption, compared to customers in FEVI and FEW. The primary determinant of natural gas usage is the number and type of end uses, which are options for all the FEU's customers. As the main alternative to natural gas is electricity, which is available throughout the FEU's service areas, all the FEU's customers have the same choices with respect to the type and number of gas appliances that they use. All the FEU's customers also have available the same range of energy efficient appliances to install for these end uses. While some customers relying on natural gas for home heating may experience colder weather than others and thus have to consume more natural gas as a consequence, all customers have similar options in terms of controlling usage or installing energy efficiency measures.

In particular, all the FEU's customers have equal access to EEC programs. In the original EEC Application, filed in May of 2008, the Companies put forward a series of EEC Guiding Principles. Guiding principle #2 states:

> *"Wherever possible, programs will be uniform, so that customers in one part of the service territories of the Terasen Utilities [now the FEU] have access to the same programs as customers throughout the service territories."*[12]

This principle has been adopted in subsequent regulatory proceedings. The Negotiated Settlement Agreements in the 2010-2011 Revenue Requirements proceeding expanded EEC funding to interruptible industrial customers of the FEU. In the most recent Revenue Requirements proceeding, the FEU received approval to expand eligibility to all customers including those in FEFN and FEW,[13] as well as received clarification that any interruptible industrial customers of FEVI are eligible for EEC programs.[14]

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[12] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., Energy Efficiency and Conservation Programs Application, May 2008, page 47.

[13] BCUC Order G-44-12, FortisBC Energy Utilities, 2012-2013 Revenue Requirements and Rates, April 12, 2012, Appendix A, page 13

[14] BCUC Clarification Letter, FortisBC Energy Utilities, 2012-2013 Revenue Requirements and Rate, May 11, 2012, page 1.

8.4 Do FEU agree that, in Order G-124-08, the Commission did not rule that postage stamp rates were inherently fairer than regional rates, but that there was insufficient evidence before it to justify a departure from the status quo? If no, please explain why.

Response:

Yes, the FEU agree that Order G-124-08 did not make a determination that either postage stamp rates or regional rates were fairer than the other. However, in the 2008 RIB proceeding BC Hydro defended the fact that postage stamp rates were provincial policy and that it would not be appropriate to move away from this in having regionally differentiated rates. The BCUC Decision on the BC Hydro RIB Application did not challenge BC Hydro's assertions on postage stamp rates being reflective of provincial policy (Order G-124-08, Reasons for Decision, pages 65, 80 and 108). One year later, in the FortisBC Inc. 2009 Rate Design and Cost of Service Analysis proceeding, the Commission Panel agreed in its Decision that postage stamp rates were provincial policy and used this as a basis for directing FortisBC Inc. to apply for a residential inclining block rate structure (BCUC Order G-156-10, Reasons for Decision, page 69, see also the response to BCUC IR 1.13.1, Item 4 (Exhibit B-9, page 57)).

8.4.1 If the Commission determined that postage stamp rates are 'more fair' than regional rates, do FEU consider that that this principle should also apply to other utilities regulated by the Commission? Please explain why or why not.

Response:

The applicability of postage stamp rates versus regional rates will depend to some extent upon the particular circumstances of the utility, so to this extent a determination made in the context of the FEU would not be applicable to other utilities regulated by the Commission. However, postage stamp rates are already in place for the majority of the utilities regulated by the Commission, including BC Hydro, FortisBC Inc., FEI, FEVI and FEW.

The Commission should consider the principles used for other utilities in B.C., the policy in the province and utility-specific considerations in its assessment of postage stamp rates for each utility. However, a postage stamp rate structure is favourable in many circumstances and provides benefits to customers through the pooling of resources, revenues, costs and risks and through economies of scale.

8.4.2 If the Commission determined that postage stamp rates are 'more fair' than regional rates, do FEU consider that this principle should also apply to other utilities acquired by FEU? Please explain why or why not.

Response:

The applicability of postage stamp rates for other utilities acquired by the FEU in the future would depend on the specific circumstances of the utility in question. However, the FEU expect that, in general, postage stamp rate structures would be appropriate to adopt for utilities providing the same kind of energy and service within the same jurisdiction.

9.0 Reference: Request for Common Rates – 'More Fair'

Exhibit B-9, BCUC 1.13.2, 1.15.1, 1.8.2

Practice of Other Utilities

The FEU state in BCUC 1.13.2: "The FEU do not believe that mitigating potentially high electricity costs in remote communities was a key driver in BC Hydro's postage stamp approach ... it is reasonable to assume that the key driver was to have the same rates across the province for grid-connected customers."

BCUC 1.15.1 asked: "Recognizing that postage stamp and regional rates can be the result of past ownership structures, has the general trend in the gas delivery industry over the last 20 years been to move from postage stamp to regional rates, or regional rates to postage stamp rates?"

The FEU responded: "The FEU has not completed an extensive review of trends in gas delivery rates over the past 20 years that would allow it to conclude if a trend exists. EES Consulting provides examples that include both postage stamp and regional rates and concludes that postage stamp rates are more common."

The FEU state in BCUC 1.8.2: "Postage stamp rates are the most common rate design ..."

9.1 Please explain what the FEU consider were the <u>specific</u> drivers for BC Hydro's postage stamp rates (for example, provision of essential services to remote communities; economic development; etc).

<u>Response:</u>

The FEU do not have information on what the government in 1962 considered to be the specific drivers in the establishment of postage stamp rates. BC Hydro was established in March 1962 by the amalgamation of the BC Power Commission and BC Electric Company. Postage stamp rates were established shortly after that in October 1962 but there is little information available on the expected benefits from postage stamp rates. The FEU believe that it is reasonable to suppose that electricity was considered to be an important public good that would be an enabler of economic development across the province and that would support the development of other public infrastructure and services such as schools and hospitals. The availability of electrical power on a postage stamp basis would provide similar economic and public infrastructure development opportunities throughout the province. It is also reasonable to surmise that having power accessible in rural and remote areas at the same rates as in more developed areas would extend such opportunities more broadly in B.C. than would have been the case without postage stamp rates.

9.2 Please summarize (in table form) the results of the analysis undertaken by or on behalf of FEU which led the FEU to conclude that postage stamp rates are the most common rate design.

Response:

The FEU relied upon the information provided by EES Consulting with respect to the prevalence of postage stamped rates. EES Consulting provided examples of utilities within Canada with postage stamp and regional designs on page 5 of their report. It has also been their experience that the majority of gas and electric utilities in the U.S. use postage stamp rates. The following table summarizes the information provided by EES Consulting.

Utilities with postage stamp rates	Utilities with regional rates
BC Hydro	Pacific Northern Gas
FortisBC Electric	ATCO Gas
AltaGas	Union Gas
Centra Gas Manitoba	
Heritage Gas	
Gaz Metro	
SaskEnergy	
Majority of US Gas Utilities	
Majority of US Electric Utilities	

9.3 Please provide a comprehensive list of all the utilities that the FEU or EES Consulting is aware of where there has been a change in the gas delivery rates from postage stamp to regional rates, or regional rates to postage stamp rates. Where changes have been made, please describe and explain the drivers for the change.

Response:

As stated in BCUC IR 1.15.1, the FEU have not completed an extensive review of trends in gas delivery rates. The Commission has previously approved a change from regional to postage stamp rates for the FEI (formerly BC Gas) Rate Design proceeding in 1993. Neither the FEU nor EES Consulting is aware of other gas delivery utilities that have changed to or from postage stamp rates.

9.3.1 Is it FEU's position that, when a change is made to gas delivery rates, it is 'more common' for the change to be from regional to postage stamp rates rather than postage stamp to regional rates? Please provide supporting evidence. Do FEU agree that the concept of regional rates is also common among gas distribution utilities? If no, please explain.

Response:

As stated in response to BCUC IR 2.9.3, the FEU do not have a list of utilities that have changed to or from postage stamp rates and therefore cannot determine which is more common. Based on EES' general experience, they have not seen switching to or from postage stamp rates as a frequent occurrence in the gas industry. The FEU acknowledge that both regional and postage stamp rates exist as discussed on page 5 of the EES Consulting Report (Appendix D-1), but would not consider regional rates to be common. (Refer to the response to BCUC IR 2.9.2).

10.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.8.2, 1.89.2, 1.13.1, 1.14.1; Exhibit B-8, BCOAPO 1.6.1; Exhibit B-3, Section 10.4.1, p.232

Socialization of Costs

The FEU state in BCUC 1.8.2: "Postage stamp rates are the most common rate design and it is appropriate to socialize the costs of public utility services so that all customer classes have access to the same service at the same cost. There should be a compelling reason to recognize a "distinct and special area" that would justify moving away from a postage stamp rate."

The FEU state in BCUC 1.89.2: "The rationale for postage stamp rates does not depend on any service area providing an "up-front" contribution."

The FEU state in BCUC 1.13.1: "The provincial government supported the retention of BC Hydro's postage stamp rate structure in the establishment of the Remote Communities Regulation[15] ... these require the Commission to allow BC Hydro to recover the costs of the projects undertaken in the specified remote communities in its revenue requirements and that the customers in those communities be charged the existing postage stamp rates."

BCUC 1.14.0 includes an extract from March 26, 2010 Reasons for Decision on an Application by BC Hydro on the Southern St'at'imc Electrification Project Application (G-58-10) which shows that a $9 million customer contribution was made to render the grid connection revenue neutral to BC Hydro ratepayers.

The FEU state in BCOAPO 1.6.1: "... a customer with a proposed service line through rock and a well-established garden may pay more than a neighbor who has a proposed service line through an undeveloped yard with clay ground conditions."

The FEU state on page 232 of the Application: "there is a very high seasonal occupancy rate for properties in Whistler (during the conversion project from propane to natural gas FEW found that approximately 70% of the residential dwellings in Whistler were not occupied year-round), ... many property owners live outside of British Columbia."

10.1 Do FEU consider that there is a compelling argument that natural gas in more costly to serve regions should be subsidized by natural gas consumers in lower cost regions? If yes, please explain why. In your response please explain how delivered natural gas differs from other products and services where regional variations in price are accepted (rent, groceries, gasoline etc).

[15] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/11_240_2007

Response:

The FEU disagree with the characterization in the question with respect to cost sharing being subsidization. The FEU's current service areas and rate structures are a result of the utilities growth via acquisition, with service regions retaining historical regulatory structures set by each predecessor company. When the FEU's service areas had separate ownership they were operated as stand-alone entities and needed to rely only on their own facilities to deliver gas to customers. However, each separate utility still had postage stamp rates within their service areas, including the FEI (with the exception of midstream rates).

Public utilities, by the nature of the service provided, must pool costs at some level as costs can vary from one customer to another. The FEU are no exception. Today the FEU are operating with a common management structure and essentially operate as one amalgamated entity. This includes greater integration of existing facilities and processes and installation of new facilities that benefit all of the utilities. As the systems become more and more integrated, the expansion of FEI postage stamp pricing across the remaining approximately 100,000 customers (FEVI, FEW and FEFN customers) becomes more appropriate, as discussed in Section 6 and Section 9 of the Application. Common rates better reflect the fact that utility systems have a high level of interconnection, and facilities are most often shared among large groups of customers.

With respect to how the delivery of natural gas differs from other products such as groceries, gasoline, etc., a key differentiation is that delivery of natural gas is a monopoly market in which prices are determined through regulation of rates, whereas most other products are neither monopolies nor subject to the same form of regulation. Other goods for the most part are available in a more broadly competitive market with more providers and more choice available to consumers and the determinants of pricing are therefore more complex and varied for those goods. The FEU submit that a comparison to the pricing for natural gas delivery is not readily appropriate.

Setting aside the relevance of the comparison to a regulated monopoly, differentiated pricing for competitive goods and services may not arise solely because of locational differences. The pricing of groceries could vary within the same city due to pricing strategy of the store, the brand preference or customer loyalty, and the composition of the market and willingness or ability to pay, even though the cost of the groceries would be comparable.

As an alternative example, there are goods that employ a constant pricing strategy, irrespective of distance, such as the products of Apple Corporation, whose flat pricing for products does not reflect regional cost differences.

10.2 While FEU state that "the rationale for postage stamp rates does not depend on any service area providing an "up-front" contribution," do FEU agree that an "up-front" contribution by FEVI and FEW customers, similar to that made by the Southern St'at'imc community, would be more equitable than the existing proposal? Please explain why or why not.

Response:

No, for the reasons discussed below, the FEU do not agree that an 'up-front' contribution by FEVI and FEW customers similar to that made by the Southern St'at'imc community ('SSC') would be more equitable than the FEU's proposal in the Application. As stated in BCUC IR 1.89.2, the rationale for postage stamp rates does not depend on any service area providing an 'up-front' contribution. The primary rationale for harmonizing rates is that it is fair and equitable for all of the FEU's classes of natural gas customers to be charged the same rate for natural gas delivery service regardless of location. This rationale applies whether or not any service area provides an 'up front' contribution. The FEU have, however, proposed to use the balance in FEVI's RSDA to mitigate rate increases to FEI and FEFN. As discussed in response to BCUC IR 1.89.2, the FEW does not have a similar revenue surplus to contribute. Therefore, any contribution from FEW would have to be in the form of a phase-in of the rate decrease. The FEU have outlined 3 and 5 year phase-in scenarios in its response to BCUC IR 1.24.2 and further expanded on in the series of the responses to BCUC IR 2.57.2. The FEU are open to such scenarios if the Commission determines them to be more equitable than the FEU's proposal.

The SSC Project is not comparable to the amalgamation and postage stamp rate Application proposed by the FEU. The following is an overview of the SSC Project as interpreted by the FEU:

- In 2006, British Columbia Hydro and Power Authority ("BC Hydro") created the Remote Community Electrification Program to expand or take over electricity service to 30 to 40 remote communities in British Columbia.
- In 2007, the BC Government expressed its support for the Remote Community Electrification Program by way of Policy Action Items 27 and 28 of the 2007 Energy Plan, the Remote Community Regulation, as well as Special Direction No. 10 to the British Columbia Utilities Commission. Under the Remote Community Regulation, BC Hydro is obligated to provide electrical service to anyone in a designated remote community who applies for service if their premises are within 90 metres of a distribution

system owned by BC Hydro in the remote community. Costs are to be recovered in part from responsible agencies, such as the Department of Indian and Northern Affairs, with the balance of costs recovered from BC Hydro ratepayers.

- On December 1, 2009, BC Hydro filed an application on behalf of BC Hydro and British Columbia Transmission Corporation, for acceptance of a Project pursuant to Sections 44.2(3)(a) and 58 to 61 of the Utilities Commission Act and the Remote Communities Regulation. The Project proposed to provide electricity service under the Remote Community Electrification Program to the SSC. The SSC were listed in Amendment 35/2009 to the Remote Community Regulation and were served by their own electrical distribution systems supplied by diesel generation and funded by Indian and Northern Affairs Canada.

- The Project consisted of:

    - The acquisition of two substation sites; one substation (Sachteen) to serve the communities of Baptiste Smith and Skookumchuck and the other (Upper Harrison Terminal) to serve Tipella and Port Douglas.
    - Connection of both substations each comprising a single phase 4 MVA transformer to the existing 360 kV line from Bridge River.
    - The construction of approximately 30 km of single-phase distribution line connecting the new substations to the on-reserve distribution systems.
    - Acquisition of the on-reserve distribution system from the SSC /INAC which had been upgraded to BC Hydro standards.

- Under Policy Action 27 and Special Direction No. 10 (SD10), the Commission was directed to make available to customers in the SSC the same rates as non-integrated area customers (Rate Zone 2 rates). However, as the SSC would be receiving grid-connected electricity service, BC Hydro believed that it was appropriate for customers to pay the same rates as other grid-connected customers – Rate Zone 1 rates. The effect of this request was to reduce the revenues from the customers in the SSC. The present value of the incremental revenue difference between Rate Zone 1 rates for customers in the SSC and Rate Zone 2 rates was estimated to be $250,000.

- The SSC were served by diesel generation facilities. Transmission facilities transit the area, however significant infrastructure and an incremental expenditure of ~$9 million was required to connect the SSC to the electrical grid. The St'at'imc signed a grid connection agreement with BC Hydro to fund the incremental difference. The Commission accepted that the added $9 million costs of grid connection (over the minimum costs of providing service by way of diesel generation) was off-set by a customer contribution in aid of construction.

- The SSC were not satisfied with continued reliance on diesel generation given their proximity to BC Hydro's existing infrastructure and their long-standing position in negotiations that the existing BC Hydro infrastructure had negative impacts on their communities. The SSC advised BC Hydro that connecting the SSC to the electric grid would be a critical component of a long-term settlement agreement in the negotiations.
- BC Hydro and the SSC agreed under the Grid Connection Agreement that the additional cost of grid connection relative to diesel generation would be off-set against any final settlement or court judgment. The amount of the off-set was agreed, at the time, to be $9 million. The Grid Connection Agreement also transferred the SSC's distribution systems to BC Hydro, provided BC Hydro with distribution line rights-of-way, removed the substation sites (purchased by BC Hydro) from the proposed Treaty Settlement Lands and committed the SSC to support the Project.
- BC Hydro agreed that until a settlement with the SSC was achieved or if a settlement was not achieved and BC Hydro did not receive the SSC Contribution, that the $9 million would not be borne by ratepayers.

As discussed above, the principle reason that the SSC provided a contribution was based on a negotiated agreement with BC Hydro. The contribution was used as a trade-off to provide service and as part of a larger settlement agreement between the SSC and BC Hydro (outside of the scope of the project). The SCC project is quite unique and the reasons for the contribution paid by the SCC are not applicable to the FEU's proposed amalgamation and postage stamp rates.

10.2.1 Please calculate (i) the amount of the contribution that would be required by the FEVI and FEW communities to ensure FEI customers were not negatively affected by a move to postage stamp rates, and (ii) the fixed and/or variable monthly charge which would be required by residential and commercial customers if this contribution was paid for over a period of 10 years. Please calculate these amounts separately for FEVI and FEW customers, and state all assumptions used in the analysis.

Response:

It is not possible to collect a contribution from FEVI and FEW customers that would result in no impact on rates for FEI customers since, unlike the SSC and other customers that contribute up front amounts, the FEU do not have the ability to collect a one-time up front contribution from these customers. The only method that the FEU are aware of is for the FEU to collect a contribution from FEVI and FEW customers through a debit (charge) rate rider for those customers, which would be offset by a credit rate rider for FEI customers. To have existing FEI customers completely unaffected by the amalgamation and postage stamping of rates, the rate rider would have to be equal to the same amount that FEVI and FEW customers' bills are proposed to decrease by. This rate rider would continue over whatever period it was desired to hold FEI customers unaffected (10 years in this scenario).

Such a proposal would result in a situation that is the same as the existing rates today and would not achieve the benefits of amalgamation and postage stamping.

10.3 Please explain how FEU's proposal that postage stamp rates are ‘more fair’ than regional rates is consistent with FEU's policy of charging a customer with a proposed service line going through rock or a well-established garden more than a neighbor who has a proposed service line through an undeveloped yard with clay ground conditions.

Response:

The FEU are proposing to implement common rates and treat all customers equally, regardless of location, which is consistent with the service line policy in place today for FEI and FEVI customers.

The current service line policy dictates that there is a maximum amount of capital that the Company will install to serve a customer (the Service Line Cost Allowance or “SLCA”) and a customer pays a contribution only when the service line cost is higher than the SLCA. With Order No. G-152-07, the Commission approved the FEU's proposal to apply the same SLCA across the service areas of FEI and FEVI.

The SLCA was calculated using the MX test on a proxy (typical) customer, and does not differ from customer to customer based on region or a location's geographical features. The companies do not discriminate between those customers with a proposed service line going through rock or a well-established garden more than a neighbor who has a proposed service line through an undeveloped yard with clay ground conditions, as long as the estimated direct cost of the service line does not exceed the SLCA.

The proposal for common rates aligns with the fundamental principle of fairness that is the foundation of the SLCA. The current SLCA policy is a common methodology that consistently applies to all customers; it is not unduly discriminatory and is effectively a "postage stamp" structure.

11.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.10.2, 1.7.2.5; Exhibit B-3, Appendix D-1, p.6

Cost Causation Principle

FEI state in BCUC 1.10.2: "The FEU agree that cost causation should be a foundation of rate setting..."

The FEU state in BCUC 1.7.2.5: "The FEU disagree with the statement that they are moving away from cost causation principles."

EES state on page 6 of its report in Appendix D-1 of the Application, "Regional pricing can provide a greater reflection of actual costs ... " and "Postage stamp pricing better reflects the fact that utility systems have a high level of interconnection, and facilities are most often shared among large groups of customers."

11.1 Do FEU agree that the postage stamp rates proposal results in rates which, <u>on a regional basis</u>, are less aligned with costs to serve than the status quo? If no, please explain.

<u>Response:</u>

No. The FEU believe that both the existing rates and the proposed postage stamp rates are aligned with costs. Costs differ for every single customer and for every region. It is impractical, however, to determine the costs accurately for every single customer. With any regional allocation, there is still uncertainty associated with the costs, particularly for an integrated system where common costs must be allocated among the regions.

11.2 Do FEU consider that FEFN, FEVI and FEW each have a high level of system interconnection with FEI and a high level of facilities shared among large groups of customers? Please explain why or why not.

<u>Response:</u>

This response addresses BCUC IRs 2.11.2, 2.11.2.1, and 2.11.2.2.

The FEU do consider that FEVI and FEW have a high level of physical interconnection and share a high level of facilities with FEI, while FEFN shares facilities to a much lesser extent. For example, FEVI is directly connected to and relies on FEI's Coastal Transmission System (CTS) for transport of all its gas supply. FEW directly connects to FEVI's transmission system and therefore indirectly also shares the use of CTS. FEW also shares the use of Tilbury and FEI's Southern Crossing Pipeline (SCP) / Interior Transmission System (ITS) as it is part of FEI's gas portfolio. FEVI, FEW and FEI all share the use of the FEVI transmission system and Mt. Hayes storage facility for storage and delivery services. Although FEFN is not directly connected to any of the FEU's facilities other than the lateral connection to Westcoast's system, FEFN still benefits from being part of the overall midstream portfolio as discussed in responses to other information requests, such as BCUC IR 1.47.1 and 1.47.2.

The FEU manage and operate on a fully integrated basis as a single system and have common management control and decision making systems, common distribution, transmission, and business support operations, and optimize the supply of natural gas based on managing the needs of a portfolio of resources that minimizes costs for all customers. The FEU do not track the portion of assets that are shared by each of the utilities because of the integrated management and operation of the utilities and so cannot provide percentages of shared assets. However the following are a few examples that illustrate the sharing of some of the significant elements of the combined system:

- FEVI's Mt. Hayes LNG & Transmission system – FEI (and indirectly FEW) – has firm rights to two thirds (68%) of Mt. Hayes capacity and relies on approximately the same portion of the FEVI transmission system for redeliveries to the Lower Mainland whether directly or by displacement.
- FEI's Coastal Transmission System (CTS) - FEVI (and indirectly FEW) has firm rights on approximately 11% of the capacity on the CTS (approximately 148/1350 TJ/d) that otherwise serves FEI's Lower Mainland customers.
- FEI's Southern Crossing Pipeline (SCP) and Interior Transmission System - Primarily serves FEI's Inland and Lower Mainland service areas and indirectly serves FEW's service area. Following amalgamation and a move to a single gas portfolio, it would also be used to serve customers in the territory currently served by FEVI.

11.2.1 If the response is yes for any of the utilities above, please identify the percentage of system assets that are shared with FEI as a percentage of the total assets used by that company. Please describe the shared assets.

Response:

Please refer to the response to BCUC IR 2.11.2.

11.2.2 For FEFN, FEVI and FEW, please also identify the percentage of assets shared by utilities other than FEI (for example, the percentage of assets used by FEW which are also used by FEVI). Please describe the shared assets.

Response:

Please refer to the response to BCUC IR 2.11.2.

12.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.10.1

BC Gas 1993 Decision

BCUC 1.10.1 asked if the FEU agreed that previous Commission decisions appeared to support an approach of only moving to postage stamp rates where costs in the different regions are similar. Extracts of Commission decisions included:

1. *1993 BC Gas Utility Ltd Phase B Rate Design (G-101-93):* "The Company also suggested that the results of the Fully Distributed Cost Studies prepared by BCGUL indicated that the <u>costs of serving residential customers in the three Divisions were comparable and therefore the Utility should move toward consolidation and postage stamp rates.</u> ...The Commission approved consolidation with certain conditions. ... internal divisional accounts must be maintained so that rate base and cost of service can be determined in future rate design applications. ... BCGUL will be required to demonstrate each time that any rate change will preserve or enhance the revenue to cost ratio for each divisional rate class as determined in this Decision." (p. 6) [emphasis added]

FEI responded "No, the citations in the preamble to this IR ... do not make statements about when it is appropriate to move to postage stamp rates generally. ... The 2001 BC Gas Rate Design Application citation above states that costs must be weighed against the various benefits of postage stamping across the regions of the utility. In other words, the costs considered have to be weighed against the various benefits of the postage stamp rate design that was already in place for BC Gas at the time."

12.1 Do FEU agree that the purpose of Commission Order G-101-93's requirement that BCGUL maintain internal <u>divisional</u> accounts, and demonstrate each time that any rate change will preserve or enhance the revenue to cost ratio for each divisional rate class, was to ensure a move to postage stamp rates would not undermine regional cost causation principles? If no, please explain why not.

<u>Response:</u>

A reasonable interpretation of the purpose of the Order G-101-93's requirement to maintain internal divisional accounts was to demonstrate that any rate change would preserve the revenue to cost ratios for each divisional rate class within acceptable tolerances. The FEU believe that the Commission wanted to review the movement in revenue to cost ratios to ensure that postage stamp rates did not change the revenue to cost ratios significantly over time.

However, the Commission did not explicitly make a reference to regional cost causation principles anywhere in its G-101-93 Reasons for Decision.

Furthermore, FEI filed with the Commission its subsequent 1996 and 2001 Rate Design COSAs that more accurately reflected the increasingly integrated nature of its gas supply, operations and management across the regions of the Company. For example:

1. In the 1996 Rate Design, the general plant was functionalized in proportion to the total functional plant costs of the manufactured gas, storage, and transmission and distribution. The general plant is used to support work that relates to the identified functions and the approach taken is a means of spreading the cost responsibility broadly. This approach was maintained in the 2001 and current COSAs.

2. Gas supply costs are integrated for the whole and not by service area, while the costs can be allocated to customers within the service areas. This was not the case for the Columbia Service Area at the time of the 1993 RDA Decision. When the gas supply requirements for the Columbia Service Area were integrated into the overall FEI portfolio a few years later, customers in the Columbia Service Area gained access to very cost effective needle peaking resources by having a share in the Tilbury LNG facility.

The COSAs in both of these Rate Designs were reviewed by the Commission and stakeholders in the 1996 and 2001 proceedings.

The costs for the FEU's distribution and transmission systems vary with growth, age of the system and sustainment capital requirements, which can result in as much if not greater cost disparity in pockets within regions as between regions. The regions are specifically areas defined by acquisition with different ages reflected in the costs. However, these variations also exist within the regions.

Over the years the FEU have become increasingly integrated in terms of their gas supply and midstream resources, operations and management. As stated in the response to BCUC IR 2.11.2 there is not only a significant portion of system assets which are shared amongst the entities, but also common operations, common management systems and a common gas supply market for FEI, FEW and FEFN. The FEU believe that their rate design must adhere to consolidated cost causation principles today in order to reflect this integration.

13.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.17.4, 1.10.3

Evaluation Framework – BC Gas 1993

In BCUC 1.17.4 FEU quotes Commission Order No. G-101-93 (in the context of a request by BC Gas to approve consolidation and postage stamp margins on the delivery component of its rates to residential and commercial customers in the Lower Mainland, Inland, and Columbia Divisions) as follows:

> "The Commission is of the view that, on balance, where the revenue to cost ratios and other conditions are similar, the perceived fairness and simplicity of postage-stamping outweighs the other considerations. However, where the nature of the rate base, the customer makeup, the gas supply administration, the operational characteristics and the overall cost structures between Divisions have historically differed, and there is no anticipation of early closer alignment, postage-stamping may not be appropriate."

13.1 Do FEU consider the evaluation framework quoted above to be an appropriate framework for the Commission to use in evaluating FEU's postage stamp proposal? Please explain why or why not.

Response:

While the quoted conclusion of the Commission from the BC Gas 1993 Decision may have been a reasonable analysis to apply to BC Gas in 1993, the Commission in this proceeding should determine what the key considerations are in determining whether the proposed postage stamp rates are appropriate in the circumstances of the FEU at the present time almost 20 years later.

In any case, the FEU's proposed amalgamation and postage stamp rates should be approved under the analysis quoted above. In particular, the conditions between FEI, FEVI, FEW and FEFN are sufficiently similar such that the fairness, simplicity and other benefits of postage stamping outweigh any other considerations.

The similarities between the service areas that the FEU are seeking to amalgamate in this Application include the following, which are organized in accordance with the topics used by the Commission in the 1993 BC Gas Decision quoted above:

Nature of the Rate Base

1. The same system design standards, codes and regulations[16]
2. Similar main extension policies[17]
3. The same policy regarding ownership of services & connections[18]
4. Similar current meter and service costs[19]

Customer Makeup

5. Similar heat sensitive load characteristics and load factors of residential & commercial customers[20]
6. Similar residential end use consumption[21]
7. Similar growth in customers and sales[22]
8. Similar variation in density as across FEI

Gas Supply Administration

9. The same gas supply purchase market area[23]
10. The same industry standard gas purchase sale agreements
11. The same pool of gas purchasers and suppliers[24]
12. Sharing of integrated transmission and storage system assets[25]

[16] Application p. 206, minimum size standard for distribution systems.
[17] Application pp. 136 to 141, continuance of FEI/FEVI's Main Extension Test.
[18] BCUC IRs 1.38.2 and 1.151.3, and BCOAPO 1.6.1, the same service line cost allowance.
[19] BCUC IR 1.148.1, average meter and service cost per residential customer.
[20] BCUC IRs 1.150.1 and 1.153.2, load factors for existing service areas.
[21] BCUC IR 1.158.1, review of end use consumption by service area.
[22] BCUC IR 1.147.1 and 1.154.1 review of growth trends in volumes and sales.
[23] BCUC IR 1.146.1 and CEC IR 1.4.3.
[24] BCUC IR 1.146.1, BCUC IR 1.147.1, and BCOAPO IR 1.1.1.
[25] BCUC IR 1.54.1, 1.54.2, 1.54.9, 1.145.1, 1.147.2, 2.11.2, 2.12.1.

Operational Characteristics

13. The same operations and maintenance standards[26]

14. Similar tariff General Terms and Conditions[27]

15. The same regulator (BCUC)

16. Operational & administrative management is from one single management group[28]

17. The same customer service call centres in Prince George and Burnaby

18. The same labour unions and similar collective agreements

Overall Cost Structures

19. Similar growth in O&M Expenses[29]

20. Similar Cost of Capital[30]

21. Similar Capital Structure[31]

22. The same accounting methodologies[32]

23. Similar depreciation rates[33]

24. The same test year

25. Similar long run incremental costs for gas costs[34]

The main difference amongst the FEI, FEFN, FEVI and FEW service areas are the overall cost and age of the systems, with FEVI and FEW being relatively newer and higher cost. Within FEI itself, however, there are similar variations in costs and age of the system over which postage stamp rates are employed. Areas of new growth within FEI for instance would consist of newer plant and relatively higher cost to serve. In addition, any area that requires a large capital asset,

[26] Application p. 215, and BCUC IR 1.63.1 and 1.156.1.1.
[27] Application pp. 134 – 136.
[28] Application pp. 1, 51, 144, 154, and BCUC IR 1.2.1, 1.2.6, 1.4.2, 1.5.7, 1.17.3, 1.20.2, 1.149.1, 2.10.1, 2.11.2, and 2.12.1.
[29] BCUC IR 1.147.1 growth in gross O&M expenses.
[30] Application p. 5-6, and BCUC IRs 1.58.1, 1.64.1, 2.18.1, 2.21.3, and 2.26.1.
[31] Application pp. 5-6 and 157-163, and BCUC IRs 1.58.1 and 1.64.1.
[32] BCUC IR 1.60.2.
[33] BCUC IR 1.60.2.
[34] BCUC IR 1.17.1, and 2.36.1.

such as the Kootenay River Crossing (Shoreacres) project as discussed on page 76 of the Application, will have a higher cost structure. Postage stamp rates, however, allow for the costs of new assets to be smoothed and shared by a larger group of customers over the asset life so that a particular area is not, potentially, subject to a significant rate increase having to bear the full costs of the asset. Examples of large shared capital assets are the Southern Crossing Pipeline and the Mt. Hayes LNG Storage Facility which are used across multiple areas. Over time, all areas will likely require asset replacement and upgrades, so it is fair that costs be pooled and shared in this manner. Similarly, over time the overall cost structures of the service areas will converge as the assets in the FEVI and FEW service areas depreciate and more asset replacement occurs within FEI and FEFN. Overall, therefore, the service areas are more similar than they are different and will converge towards greater similarity over time.

The FEU submit that the differences between the service areas are outweighed by the similarities described above and the benefits of postage stamp rates as described in the Application, including:

- The fairness of postage stamp rates;
- The simplicity and ease of understandability of postage stamp rates;
- The operational, regulatory and legal cost savings and efficiencies realized through amalgamation and postage stamp rates;
- The rate stability provided by postage stamp rates;
- The lower rates provided to FEVI and FEW; and
- The facilitation of the expansion of all services across all service areas.

It is also relevant that postage stamp rates are used for most utilities in the Province, are the most common form of rate for gas distribution utilities, and are supported by government policy, despite regional cost differences that exist within currently postage stamped areas.

14.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.10.1

Big White 2007 Decision

BCUC 1.10.1 asked if the FEU agreed that previous Commission decisions appeared to support an approach of only moving to postage stamp rates where costs in the different regions are similar. Extracts of Commission decisions included:

> *2007 FortisBC Inc. Rate Design for Big White (G-87-07):* "The EES Report submits that "The pertinent technical question is whether or not the revenues and allocated costs from/to the Big White area are significantly different from those revenues and allocated costs collected from/to other areas within the FortisBC service territory to warrant special and unique retail rate treatment for the Big White area. ... The Commission Panel, therefore, agrees with FortisBC that an analysis of the revenues and allocated costs indicates that Big White is not sufficiently different from other areas in FortisBC's service territory to warrant special and unique retail rate treatment." (pp. 5, 15-16)

FEI responded "No, the citations in the preamble to this IR ... do not make statements about when it is appropriate to move to postage stamp rates generally. ... While the 2007 FortisBC Inc. Rate Design on the Big White Ski Project Decision states that the cost of service of the area relative to other areas is an important consideration, the decision cites other considerations for postage stamping the rates of the Big White Ski Project in with the rest of FortisBC."

14.1 Do FEU support EES's statement that "The pertinent technical question is whether or not the revenues and allocated costs from/to [one] area are significantly different from those revenues and allocated costs collected from/to other areas within the [FEU] service territory to warrant special and unique retail rate treatment"? Please explain why or why not.

<u>Response:</u>

The FEU do not support the statement in relation to the current Application. The statement must be understood within the context in which it was made, and given that context, it is not meaningful for this proceeding.

In looking at the Big White Decision, it is important to note that in the case of Big White, FortisBC was proposing to maintain current postage stamp rates and it was the Commission that specifically requested that the utility address whether the project in question should be rolled in with the costs of the entire utility or collected only from the customers in the Big White region.

The quoted statement was from the EES Consulting Report that was filed as part of that proceeding. The report was commissioned by FortisBC for the sole purpose of providing the cost of service for the Big White area on a stand-alone basis. The quoted statement was in reference to the task assigned to EES Consulting. The following paragraph immediately followed the quoted statement in the EES Consulting Report:

> *"There are currently no zonal rates in place for either BC Hydro or FortisBC. It would be inappropriate to put zonal rates in place for one specific area, such as Big White, without considering zonal rates for the entire Province. An electric service grid is ever-changing. There are capital additions every year to meet additions to load and to improve aging infrastructure. Some additions benefit the entire service area and others benefit only a certain geographical group of customers. Because capital additions are "lumpy" and are usually built with extra capacity to meet loads that will grow over time, there are continually situations where more is spent on certain customers than on others. The costs to serve a specific customer will fluctuate a great deal over time as capital additions occur and loads change. Over time, it is generally accepted that these capital additions will average out."*

Given the context of the statement, the FEU do not believe that the quoted statement has any bearing on the current Application. Further, the lack of a significant cost differential between regions would tend to make regional rates unnecessary. That does not imply that the reverse is true, i.e. that regional rates are appropriate only on the basis of a significant cost difference between regions.

15.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.31.2, 1.151.3

Fairness Between Existing and New Customers

The FEU state in response to BCUC 1.31.2: "This analysis shows that FEVI and FEW customers PI values would decrease, FEI PI values would increase and, overall, amalgamation would have a minimal impact on PI values in aggregate. This means that more FEVI and FEW customers will be required to make a contribution to reach the requisite individual PI value of 0.8."

The FEU state in BCUC 1.151.3 that the 2011 costs per service line were: FEI: $1,673; FEVI: $2,286; FEW: $3,033 and FEFN $970.

15.1 Do FEU agree that, should postage stamp rates be approved, FEVI and FEW customers who connected just prior to the implementation of postage stamp rates would generally have paid a lower contribution compared to similar FEVI and FEW customers who connect after the implementation of postage stamp rates? Please provide some illustrative examples of potential contribution size differences.

Response:

FEW and FEVI customers will be more likely to have to provide a contribution in aid of construction (CIAC) following amalgamation. The table below summarizes the impact on the number of customers that would have to provide a CIAC as a customer of FEI, FEVI and FEW compared to if the same customers were FEI Amalco customers. The data below is based on the entire 2010 MX population for FEI, FEVI and FEW. The analysis is similar to that provided in Section 7.4.2.3[35] of the Application that examined the change in profitability index following amalgamation. Specifically, in the table below the Companies compare the CIAC results using the 2013 proxy MX Test inputs from Table 7.1[36] of the Application.

Utility	Total Number of Main Extensions*	Required Contributions - 2013 Parameters	Required Contributions - AMALCO Parameters	Change - 2013 VS AMALCO	% Change
FEI	227	35	27	-8	**-3.5%**
FEVI	114	68	97	29	**25.4%**
FEW	4	1	3	2	**50.0%**
TOTAL	**345**	**104**	**127**	**23**	**6.70%**

35 Continuance of FEI/FEVI's Main Extension Test

36 High Level Overview of Changes to MX Test Inputs Resulting from Amalgamation

In sum, 3.5% fewer FEI customers will hypothetically have to provide a CIAC as an FEI Amalco customer. 25% and 50% more FEVI and FEW customers respectively would have to provide a CIAC, while 6.7% more customers overall would have to provide a CIAC. The FEU believe that 6.7% is a reasonable increase in the number of customers that will have to provide a CIAC following amalgamation.

In order to estimate the impact of amalgamation on CIAC amounts for both FEI and FEVI customers, the Companies performed a comparative MX Test analysis based on a typical single family residential customer. The Companies compared the expected CIAC for FEVI and FEI versus FEI Amalco customers using the MX Test inputs described above. For FEI, FEVI and FEI Amalco customers the CIAC amount was calculated based on three consumption scenarios, ranging from a simple gas range and fireplace (20 GJ per year) representative of a small residential customer, to a higher end home with multiple gas appliances (85 GJ per year). The forecast consumption values used are from the annual average usage estimates by appliance type and region used in the MX Test to determine the projected delivery margin.[37] Under each scenario, the CIAC amount was calculated for a range of main extension costs. 2010 FEI and FEVI average service line costs were used along with standard meter and regulator costs for a single family dwelling. The results of the CIAC analysis are summarized in the tables below.

[37] The response to BCUC IR 2.67.1.1 includes the complete data for the annual average usage estimates by appliance type and region.

		FEVI RESIDENTIAL CIAC $ AMOUNTS											
		20 GJ per Year Range, Fireplace				**51 GJ per Year** Range, Barbeque, Furnace				**85 GJ per Year** Range, Barbeque, Furnace, Fireplace, Hot Water			
Parameters		2013 FEVI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*	2013 FEVI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*	2013 FEVI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*
Mains Cost	$1,000	$ 953	$ 1,502	58%	*+ $549*	$ -	$ 373		*+ $373*	$ -	$ -		
	$3,000	$ 3,344	$ 3,904	17%	*+ $560*	$ 1,385	$ 2,775	100%	*+ $1390*	$ -	$ 1,536		*+ $1536*
	$5,000	$ 5,735	$ 6,306	10%	*+ $571*	$ 3,775	$ 5,176	37%	*+ $1401*	$ 1,626	$ 3,938	142%	*+ $2311*
	$10,000	$11,711	$12,310	5%	*+ $599*	$ 9,752	$11,180	15%	*+ $1429*	$ 7,603	$ 9,942	31%	*+ $2339*
	$15,000	$17,688	$18,314	4%	*+ $626*	$15,728	$17,185	9%	*+ $1456*	$13,579	$15,946	17%	*+ $2366*
Approximate Impact of AMALCO Parameters on CIAC Amounts					$600				$1,400				$2,300

**Average FEVI 2010 Service line Cost of $1200*
***Standard Meter and Regulator cost of $55 and $36*
****Consumption based on Zone 6A - Victoria and South Island*

		FEI RESIDENTIAL CIAC $ AMOUNTS											
		24 GJ per Year Range, Fireplace				**71 GJ per Year** Range, Barbeque, Furnace				**109 GJ per Year** Range, Barbeque, Furnace, Fireplace, Hot Water			
Parameters		2013 FEI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*	2013 FEI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*	2013 FEI CIAC $	2013 AMALCO CIAC $	*AMALCO CIAC IMPACT %*	*AMALCO CIAC IMPACT $*
Mains Cost	$1,000	$ 1,563	$ 1,427	-9%	*- $136*	$ 70	$ -		*- $70*	$ -	$ -		
	$3,000	$ 3,966	$ 3,829	-3%	*- $137*	$ 2,472	$ 2,111	-15%	*- $361*	$ 1,265	$ 722	-43%	*- $543*
	$5,000	$ 6,368	$ 6,231	-2%	*- $138*	$ 4,875	$ 4,513	-7%	*- $362*	$ 3,668	$ 3,124	-15%	*- $544*
	$10,000	$12,375	$12,235	-1%	*- $140*	$10,882	$10,517	-3%	*- $365*	$ 9,674	$ 9,128	-6%	*- $546*
	$15,000	$18,381	$18,239	-1%	*- $143*	$16,888	$16,521	-2%	*- $367*	$15,681	$15,132	-3%	*- $548*
Approximate Impact of AMALCO Parameters on CIAC Amounts					-$140				-$360				-$540

**Average FEI 2010 Service line Cost of $1264*
***Standard Meter and Regulator cost of $55 and $36*
****Consumption based on Zone 1A - Vancouver and Richmond*

The results illustrate that CIAC amounts are highly contingent upon both the costs and consumption inputs used in the MX Test. In general, the greatest percent impact on CIAC resulting from amalgamation is seen in a scenario with relatively low main extension costs. For example, an FEVI customer with 20 GJ of consumption and a main extension cost of $1,000 could expect an increase of 58% in the required CIAC resulting from amalgamation. In comparison, the same FEVI residential customer with 20 GJ of consumption could expect an increase of 4% in the required CIAC if the main extension cost was $15,000. Overall, amalgamation could result in an increase in CIAC amounts for FEVI single family home customers of approximately $600 to $2,300 (equivalent to 4% to 142%) depending on consumption and main extension costs whereas FEI customers will realize a decrease in CIAC ranging from $140 to $540 (1% to 43%).

The FEU believe that FEVI and FEW customers are being treated fairly overall since the increase in CIAC described in these examples is offset by the benefits related to amalgamation.

Furthermore, there is past precedent for the Commission approving proposals whereby new system extension customers are treated differently than existing ones. For example, following the system extension and customer connection review in 2007, some existing customers would have potentially paid more to access the Companies system compared to new customers that would have paid less due to the elimination of the service line improvement fee ("SLIF") and the increase of the service line cost allowance ("SLCA"). As part of the same review, TGVI adopted the TGI methodology and therefore customers who undertook main extensions post Application approval would have been required to contribute different amounts than prior to the Application Decision. Lastly, when Squamish amalgamated with TGI in 2007, customers post amalgamation used the TGI test which was different than the TGS test. As such new customers would have potentially paid a different amount to connect than prior to amalgamation. In all these examples, the Commission determined that in light of the proposed changes, both new and existing customers were being treated fairly.

15.2 Do FEU consider that treating old FEVI and FEW connections differently from new FEVI and FEW connections is fair? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 2.15.1.

15.3 It appears that of all the parties, (i.e. FEI, FEVI, FEW, and FEFN customers), affected by the FEU proposal, FEW customers will benefit by way of a significant rate decrease without having to make a financial "contribution." FEI and FEFN customers will make a financial "contribution" by virtue of an increase (regardless whether it is immediate and/or phased-in) in their existing natural gas rates. FEVI customers will make a financial "contribution" by virtue of providing a $90.3 million "up front" contribution. Please provide FEU's views on these statements and discuss whether this situation is fair.

Response:

Please refer to the response to BCUC IR 1.89.2.

The rationale for postage stamp rates does not depend on any service area providing an "up-front" contribution. As discussed in the Application, the primary rationale for harmonizing rates is that it is fair and equitable for all of the FEU's classes of natural gas customers to be charged the same rate for natural gas delivery service regardless of location. This rationale applies whether or not any service area is able to provide an "up front" contribution or not.

The balance in the RSDA is a result of the unique situation in FEVI, which is not applicable to the FEW. In anticipation and recognition of the loss of government subsidies, rate structures for FEVI were maintained specifically to accumulate a surplus balance in the RSDA which could be used to mitigate future rate increases caused by the loss of the government subsidies. As the postage stamp rate proposal addresses the FEVI rate discrepancy, it is appropriate to utilize the RSDA to offset rate increases that will result from the move to postage stamp rates.

FEW has not developed an equivalent RSDA mechanism and rates have generally been reset each year to reflect the cost of service. Therefore, FEW has no revenue surplus to contribute towards amalgamation. While the FEU disagree in principle with the requirement for FEW to provide a contribution, if the Commission determines that FEW should make a contribution, it would have to be in the form of a phase in of the rate decrease to FEW. The FEU outline possible phase-in approaches in the responses to BCUC IRs 1.24.2 and the 2.57.2 series. Under these scenarios, both FEVI and FEW provide a financial contribution by effectively financing lower rates in the Mainland region over the phase-in period.

15.3.1 Please explain FEU's position on an option that FEVI and FEW customers connected in, for example, the last 10 years, be required to make a contribution to FEI (Amalco) reflective of what they would have been required to pay if postage stamp rates were in place at the time of their connection?

Response:

As discussed below, the proposal outlined in the information request would not be practical, fair or consistent with the Commission's jurisdiction to set rates on a prospective basis.

It would not be practical to require all customers that have connected in the last 10 years to make a contribution reflective of what they would have been required to pay if postage stamp rates were in place at the time of their connection. Customers that connected in the last 10 years may no longer own the property, may have moved, become deceased or become unreachable. Developers similarly may have moved on, stopped operating or become unreachable.

It would also be unfair to those customers that have connected in the past 10 years to have to pay a fee to connect that they did not know existed at the time they chose to connect. Assuming postage stamp rates are approved, FEVI and FEW customers that have connected in the past 10 years will have paid much higher rates since they connected compared to those customers that connect after postage stamp rates are implemented. Those customers that connect after postage stamp rates will pay a higher connection charge, but will pay lower rates afterwards. It is difficult to justify why customers connecting in the past 10 years should pay both the higher rates and the higher connection charge.

It would also be inappropriate to retroactively change the conditions on which customers have connected to FEVI's and FEW's systems in the past 10 years. These customers paid the fees and connection charges required by the applicable Commission-approved rates at the time that they connected. It would be retroactive ratemaking and outside the jurisdiction of the Commission to now revise the required connection charges for these customers.

16.0 Reference: Implementation of Common Rates

Exhibit B-9, BCUC 1.27.2

Exhibit B-3, Section 7.4, p. 136

Operational Effects: GT&Cs and Rate Schedules

The FEU response states: "27.2; A Black-lined proforma FEI Tariff with GT&C and Rate Schedules was provided in the Application under Appendix B-3 in electronic format. A black-lined version of the GT&Cs and tariffs for FEVI, FEFN and FEW under FEI Amalco has been submitted as Attachment 27.2 as requested, in electronic format only to conserve paper. Upon amalgamation the GT&Cs and tariffs for FEVI, FEFN and FEW will be cancelled."

The FEU have interpreted BCUC IR 27.2 incorrectly and responded by providing the FEVI, FEW and FEFN GT&Cs and Rate Schedules as cancelled in Attachment 27.2. The question had requested that the FEU file blacklined versions of each FEVI, FEFN and FEW GT&Cs and Rate Schedules that shows how each of the exiting (before the proposed Amalgamation and Common rates) GT&Cs and Rate Schedules would change, irrespective of the fact that the schedules would be cancelled.

The intent BCUC IR 1.27.2 was to determine each and every change proposed for each and every GT&C and Rate Schedules for the FEVI, FEFN and FEW.

16.1 Please provide the GT&C and corresponding Rate Schedules for FEVI, FEW and FEFN that show each of the proposed changes as indicated in the proforma FEI Tariff GT&C and Rate Schedules as originally filed in this application and as amended in response to BCUC IR 110.1 and BCUC IR 118.1.

<u>Response:</u>

Please refer to Attachment 16.1 (filed in electronic format only to conserve paper and resources). Please note that the FEU have not proposed any amendments to Section Part B Transmission Transportation Service of the FEVI General Terms and Conditions. As stated in the response to BCUC IR 2.78.3.1, the FEU cannot blackline amendments to this tariff section at this time as no amendments have been proposed. The FEU will file a revised Part B for approval upon completion of negotiations with VIGJV and BC Hydro and the filing of those new agreements if amalgamation and common rates is approved.

16.2 Where changes to the GT&Cs and Rate Schedules for FEVI, FEW and FEFN have not been explained in the application, please provide an explanation of the changes and the effect of those changes to the respective customer classes identifying where possible the implications to the customers affected by the change in the GT&C and Rate Schedules.

Response:

The FEU have in the Application and in the responses to information requests offered explanations for the changes to FEI's GT&Cs to reflect the proposed FEI Amalco's GT&Cs that are not simply in the nature of housekeeping. Some of the housekeeping items are also explained in the responses to information requests (See BCUC IR 1.118.1, BCUC IR 1.22.1, BCUC IR 1.123.1, BCUC IR 1.25.1, BCUC IR 1.114.1, BCUC 1.113 series, and BCUC IR 1.111.1).

The explanation of changes described below is limited to the formatting changes resulting from FEVI, FEW and FEFN adopting the proposed FEI Amalco rate structure. The rate impact for the changes to each service area as a whole is addressed in Appendices J-3 and J-4 of the Application.

The FEU have provided descriptions of all the rate classes in Section 3 of the Application and provided an analysis of how the FEVI, FEW and FEFN rate classes map onto the FEI rate classes in Section 9 of the Application. In addition, the FEU provide below the requested explanation of the impact of the changes in rate schedules for FEVI, FEW and FEFN residential, commercial and industrial customers.

FORTISBC ENERGY INC. (VANCOUVER ISLAND)

FEVI – ADOPTION OF PROPOSED FEI AMALCO GT&Cs APPLICABLE TO ALL FEVI RATE SCHEDULES

	Change	Impact
1.	Addition of relevant definitions for the purpose of administering the proposed FEI Amalco GT&Cs	Required to administer the changes expressed in the subsequent changes in this table.
2.	Addition of "Areas served by FortisBC Energy"	Areas served expanded to include FEW, FEFN and FEI service areas.
3.	Addition of 12B : Vehicle Fueling Stations	NGT now available to FEVI service area. Refer to Section 6.5 of the Application.

4.	Addition of 17: Thermal Energy	Expansion of Thermal Energy Pilot program to FEVI. Change in definition of the reference to gas; no Impact to customers.
5.	Addition of 18: Section reserved for future use	No impact to customers.
6.	Addition of Section 23.3: Application to former tariffs	Discontinuance with notice and refusal without notice terms applicable to all bills rendered under previous FEVI GT&Cs.
7.	Addition of 26: Direct Purchase Agreements with respect to FortisBC's right to collect incremental direct purchase costs from customers, agents, broker and marketers and Conditions upon the return of customers to FortisBC Energy's system supply	Customers, agents, brokers and/or marketers may be subject to paying incremental direct purchase costs to FortisBC Energy Inc. resulting from Direct Purchase Agreements; Customers wishing to return to FortisBC system supply may be required to give 1 year written notice and subject to costs incurred for returning to the FortisBC system supply.
8.	Addition of 27: Commodity Unbundling Service	Upon expansion of Customer choice, in the event an FEVI customer enters into a gas supply contract with a marketer for commodity unbundling service, he/she will be required to act in accordance with the conditions set out under this Section of the GT&Cs. Refer to Section 6.5 of the Application.
9.	Addition of 28: Biomethane Service	Biomethane service expanded to the FEVI service area; if a FEVI customer contracts biomethane service, he/she will be required to act in accordance with the conditions set out under this Section of the GT&Cs. Refer to Section 6.5 of the Application.
10.	Deletion of "Special Rate Schedule", replaced with "Standard Fees and Charges Schedule"	Standard Fees once applicable only to Special Services and circumstances now applicable to all customers.

***** *FEVI Part B has been left unaltered to indicate the impact of FEVI adopting the proposed FEI Amalco GT&Cs. As discussed in BCUC IR 2.78.3.1, Part B will be updated for FEI Amalco once agreements have been reached with VIGJV and BC Hydro.*

Residential General Service (RGS) to Proposed FEI AMALCO Rate Schedule 1: Residential Service

	Change	Impact
1.	Adoption of proposed FEI Amalco Rate Schedule 1 definition of Availability & Applicability	No Impact

	Change	Impact
2.	Adoption of proposed FEI Amalco Rate Schedule 1 table of charges	Rate Impact. See Appendices J-3 and J-4
3.	Addition of all proposed FEI Amalco Rate Schedule 1 rate riders	See Section 8 of the application for treatment of riders
4.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
5.	Addition of Minimum charge, which will be the aggregate of the basic charge, and the franchise fee charge	Charge reflects the application of the franchise fee.
6.	Removal of optional Rate Rider A: Service Line Charge	Rider closed January 1, 2006 to new customers. Rate Rider A no longer applicable, pre-2006 customers who enjoy the benefit of the Rate Rider, receive the rate decrease benefit as outlined in Appendices J-3 and J-4.

Small Commercial Service 1 (SCS-1), Small Commercial Service 2 (SCS-2), Large Commercial Service 1 (LCS-1), Apartment General Service (AGS) to Proposed FEI Amalco Rate Schedule 2: Small Commercial Service

	Change	**Impact**
1.	Adoption of proposed FEI Amalco Rate Schedule 2 definition of Availability & Applicability	All customers in SCS-1, SCS-2, LCS-1 and those customers in AGS with consumption < 2000 GJs will be segmented into proposed FEI Amalco Rate Schedule 2.
2.	Adoption of proposed FEI Amalco Rate Schedule 2 table of charges	Rate Impact for SCS-1, SCS-2, LCS-1 and those customers in AGS with consumption < 2000 GJs. See Appendices J-3 and J-4.
3.	Addition of all proposed FEI Amalco Rate Schedule 2 rate riders	See Section 8 of the application for treatment of riders.
4.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
5.	Addition of Minimum charge, which will be the aggregate of the basic charge, and the franchise fee charge	Charge reflects the application of the franchise fee.

Large Commercial Service 2 (LCS-2), Large Commercial Service 3 (LCS-3), Apartment General Service (AGS) High Load Factor (HLF), Inverse Load Factor (ILF) to Proposed FEI Amalco Rate Schedule 3: Large Commercial Service

	Change	Impact
1.	Adoption of proposed FEI Amalco Rate Schedule 3 definition of Availability & Applicability	All customers in LCS-2, LCS-3, HLF, ILF and those customers in AGS with consumption > 2000 GJs will be segmented into proposed FEI Amalco Rate Schedule 3.
2.	Adoption of proposed FEI Amalco Rate Schedule 3 table of charges	Rate Impact for LCS-2, LCS-3, HLF, ILF and those customers in AGS with consumption > 2000 GJs. See Appendices J-3 and J-4.
3.	Addition of all proposed FEI Amalco Rate Schedule 3 rate riders	See Section 8 of the application for treatment of riders.
4.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
5.	Addition of Minimum charge, which will be the aggregate of the basic charge, and the franchise fee charge	Charge reflects the application of the franchise fee.
6.	Removal of LGS-25: Unauthorized Overrun Rate and LGS-26: Authorized Overrun Rate	No Impact as there are no customers in this rate class.

FORTISBC ENERGY INC. (WHISTLER)

FEW – ADOPTION OF PROPOSED FEI AMALCO GT&Cs APPLICABLE TO ALL FEW RATE SCHEDULES

	Change	Impact
1.	Addition of relevant definitions for the purpose of administering the proposed FEI Amalco GT&C	Required to administer the changes expressed in the subsequent changes in this table.
2.	Addition of "Areas served by FortisBC Energy"	Areas served expanded to include FEVI, FEFN and FEI service areas.
3.	Addition of 12A: Alternative Energy Extensions	FEW customers now eligible for Alternative Energy Extensions. Refer to Section 6.5 of the Application.
4.	Addition of 12B : Vehicle Fueling Stations	NGT now expandable to FEW service area. Refer to Section 6.5 of the Application.

5.	Addition of 17: Thermal Energy	Expansion of Thermal Energy Pilot program to FEW. Change in definition of the reference to gas; No Impact to customers.
6.	Addition of 18: Section reserved for future use	No Impact to customers.
7.	Addition of Section 23.3: Application to former tariffs	Discontinuance with notice and refusal without notice terms applicable to all bills rendered under previous FEW GT&Cs.
8.	Addition of 26: Direct Purchase Agreements with respect to FortisBC's right to collect incremental direct purchase costs from customers, agents, broker and marketers and Conditions upon the return of customers to FortisBC Energy's system supply	Customers, agents, brokers and/or marketers may be subject to paying incremental direct purchase costs to FortisBC Energy Inc. resulting from Direct Purchase Agreements; Customers wishing to return to FortisBC system supply may be required to give 1 year written notice and subject to costs incurred for returning to the FortisBC system supply.
9.	Addition of 27: Commodity Unbundling Service	Upon expansion of Customer choice, in the event a FEW customer enters into a gas supply contract with a marketer for commodity unbundling service, he/she will be required to act in accordance with the conditions set out under this Section of the GT&Cs. Refer to Section 6.5 of the Application.
10.	Addition of 28: Biomethane Service	Biomethane service expanded to the FEW service area; in the event an FEW customer contracts biomethane service, he/she will be required to act in accordance with the conditions set out under this Section of the GT&Cs. Refer to Section 6.5 of the Application.
11.	Deletion of "Special Rate Schedule". Replaced with "Standard Fees and Charges Schedule"	Standard Fees once applicable only to Special Services and circumstances now applicable to all customers.

<u>FEW – General Service Rate to Proposed FEI Amalco Rate Schedules 1,2,3: Residential, Small Commercial and Large Commercial Service</u>

1.	Adoption of proposed FEI Amalco Rate 1 definition of Availability & Applicability	No Impact.

	Change	Impact
2.	Division of single endorsed General Service Rate (SGS) schedule into proposed FEI Amalco Rate Schedule 1, 2, 3	Customers will now be more appropriately segmented based on the characteristics of the proposed FEI Amalco Rate Schedules 1, 2 and 3 – Residential customers will be segmented to proposed FEI Amalco Rate Schedule 1; commercial customers consuming < 2000 GJ will be segmented to Rate Schedule 2, those consuming >2000 GJs will be segmented to Rate Schedule 3.
3.	Adoption of proposed FEI Amalco Rate Schedule 1, 2 and 3 table of charges	Customers charged a rate depending on the rate class they are in. Refer to Appendices J-3 and J-4 of the Application.
4.	Addition of all proposed FEI Amalco Rate Schedule 1, 2 and 3 rate riders	See Section 8 of the application for treatment of rate riders.
5.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
6.	Addition of Minimum charge, which will be the aggregate of the basic charge, and the franchise fee charge	Charge reflects the application of the franchise fee.

FORTISBC ENERGY INC. (FORT NELSON)

<u>FEFN – Domestic Service to Proposed FEI Amalco Rate Schedule 1: Residential Service</u>

The impact of moving FEFN residential rate schedules to the proposed FEI Amalco rate classes consist of:

	Change	Impact
1.	Adoption of proposed FEI Amalco GT&Cs	As FEFN is currently under the purview of the endorsed FEI GT&Cs, the impact of the adoption of the proposed FEI Amalco GT&Cs will be as that discussed in Section 7.4.2 of the Application, BCUC IR 1.118.1 and BCUC IR 1.120 series.
2.	Adoption of proposed FEI Rate 1 definition of Availability & Applicability	No Impact.

3.	Changed Promotional Incentive Structure in Option A	Option A promotional incentive calculation changed to the following for customers who have availed themselves of the promotional incentive prior to 1990: $0.0407 times the amount of the promotional incentive divided by $100; no more declining block rate (see change 4).
4.	Adoption of proposed FEI Amalco Rate Schedule 1 table of charges	First two GJs/month no longer included with basic charge; customers charged single rate regardless of gas consumed – no declining block rate; See Appendices J-3 and J-4 for the appropriate rate impacts.
5.	Removal of Option B	Option B customers now subject to proposed table of charges; customers charged single rate regardless of gas consumed – no declining block rate.
6.	Addition of all proposed FEI Amalco Rate Schedule 1 rate riders	See Section 8 of the application for treatment of rate riders.
7.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
8.	Addition of Minimum charge, which will be the aggregate of the basic charge, any charge under Option A and the franchise fee charge	Charge reflects the application of the franchise fee.

FEFN – General Service Rate 2.1, General Service Rate 2.2 to Proposed FEI Amalco Rate Schedule 2: Small Commercial Service

	Change	Impact
1.	Adoption of proposed FEI Amalco GT&Cs	As FEFN is currently under the purview of the endorsed FEI GT&Cs, the impact of the adoption of the proposed FEI Amalco GT&Cs will be as that discussed in Section 7.4.2 of the Application, BCUC IR 1.118.1 and BCUC IR 1.120 series.
2.	Adoption of proposed FEI Rate Schedule 2 definition of Availability & Applicability	No impact to GSR 2.1 customers as they all consume under 2000 GJ of firm gas annually, Only those GSR 2.2 customers consuming under 2000 GJ of firm gas annually are eligible.
3.	Adoption of proposed FEI Rate Schedule 2 table of charges	See Appendices J-3 and J-4.

	Change	Impact
4.	Addition of all proposed FEI Rate Schedule 2 rate riders	See Section 8 of the application for treatment of rate riders.
5.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
6.	Addition of Minimum charge, which will be the aggregate of the basic charge and the franchise fee charge	Charge reflects the application of the franchise fee.
7.	Removal of GSR 2.3 (Natural Gas Vehicle Fuel Service) & GSR (2.4 Compression/Dispensing Service)	No impact. There are no customers in these rate schedules
8.	Removal of General Service General Conditions	Previous GSR 2.1 – GSR 2.3 Customers can no longer opt for monthly contracts.

FEFN – General Service Rate 2.2, General Firm Transportation (GFT) Rate 25, to Proposed FEI Amalco Rate Schedule 3: Large Commercial Service

	Change	**Impact**
1.	Adoption of proposed FEI Amalco GT&Cs	As FEFN is currently under the purview of the endorsed FEI GT&Cs, the impact of the adoption of the proposed FEI Amalco GT&Cs will be as that discussed in Section 7.4.2 of the Application, BCUC IR 1.118.1 and BCUC IR 1.120 series
2.	Adoption of proposed FEI Amalco Rate Schedule 3 definition of Availability & Applicability	All GFT customers under terms and conditions of proposed FEI Amalco Rate Schedule 3, only those customers in GSR 2.2 consuming over 2000GJ of firm gas annually are eligible
3.	Adoption of proposed FEI Amalco Rate Schedule 3 table of charges	See Appendices J-3 and J-4 for rate impacts.
4.	Addition of all proposed FEI Amalco Rate Schedule 3 rate riders	See Section 8 of the application for treatment of rate riders.
5.	Addition of Franchise Fee Charge	Franchise fee charge of 3.09% now applicable to select territories where Operating Agreements permit Franchise fees.
6.	Addition of Minimum charge, which will be the aggregate of the basic charge and the franchise fee charge	Charge reflects the application of the franchise fee.

7.	Removal of terms, conditions of service and transportation agreements for GFT Rate 25	All customers now subject to the GT&Cs of FEI Amalco.

17.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.55.1

Interest Expense Savings

"The information provided below is forecast; there is no actual data for the years requested as they are in the future. … There is no test year forecast for 2014 for short term debt. The current forecast of the short term debt rates is the following: FEI 4.0 percent, FEVI 5.6 percent, and FEW 4.9 percent."

17.1 Please confirm that the short term debt rate forecasts for FEI at 4.0 percent, FEVI at 5.6 percent and FEW at 4.9 percent are for the year 2014. Please also provide the sources for these forecasts.

Response:

Confirmed.

The 2014 forecast for short-term debt rates, for the purpose of responding to BCUC IR 1.55.1, was determined by using the same source for interest rate forecasts as used in the determination of the 2012 and 2013 Revenue Requirements. The short-term interest rate forecast is determined by using the averages of projections made by leading economists at several Canadian Chartered Banks. Please refer to Attachment 17.1 for the source of the short-term interest rate forecasts.

Please note that there was an error in the table provided in the response to BCUC IR 1.55.1. The row titled "FEW" inadvertently reflected FEFN data and not FEW data. Please refer to the revised table below which correctly provides FEW data:

	2012			2013		
	Amount $000's	% of Capitalization	Embedded Cost	Amount $000's	% of Capitalization	Embedded Cost
FEI	$ 52,425	1.93%	2.50%	$ 84,007	3.03%	3.50%
FEVI	$ 102,406	13.13%	4.00%	$ 134,867	16.69%	5.00%
FEW	$ 4,876	11.76%	3.50%	$ 4,040	10.08%	4.50%

17.2 Please provide the sources for the short term interest rate forecasts for the test years 2012-2013.

Response:

Please refer to Attachment 17.1 in the response to BCUC IR 2.17.1.

17.3 From the data presented in the response to BCUC IR 1.55.1, the % of capitalization for 2012 and 2013 are respectively 13.13 percent and 16.69 percent. Please explain why FEVI has such disproportionately high short term debt compared to FEI and FEW.

Response:

The higher forecast short-term debt balance for FEVI is mainly due to the Revenue Stabilization Deferral Account (RSDA), which is projected to be approximately $74 million (after-tax) at the end of 2012 and $68 million (after-tax) at the end of 2013 (Appendix J-1, Schedule 33). On a forecast basis, the surplus cash provided by the RSDA is included in the financing of the rate base attributable to short-term debt. For example, of the $139 million in FEVI short-term debt forecast for 2013, approximately $68 million can be attributed to the RSDA, resulting in forecast short-term debt of approximately $71 million or approximately 9% short-term debt capitalization.

To clarify, on an actual basis the RSDA reduces the amount of short-term debt that is required. In the absence of the RSDA all together, it is likely that FEVI would have issued additional long-term debt bringing its forecast capitalization ratio of short-term debt in line with FEI and FEW.

17.4 Please confirm that the "Embedded Cost" in the table refers to only the short term interest cost. Is the embedded cost for FEVI higher than FEI and FEW due to timing or other financing risk factors? Please explain.

Response:

Confirmed. Please refer to the revised table provided in the response to BCUC IR 2.17.1.

The embedded cost of short-term debt (i.e. short-term debt rate) in FEVI and FEW is higher than FEI, which is primarily related to the fact that FEI borrows at a lower short-term debt rate due to its higher credit rating.

17.5 Will the higher percentage in short term debt capitalization and higher cost for FEVI likely to persist in the near future if amalgamation does not proceed?

Response:

Please refer to the response to BCUC IR 2.17.3.

Should Amalgamation not proceed, with the gradual decrease of the RSDA as it is amortized into rates and a potential long-term debt issue to offset the financing previously provided by the RSDA, a lower forecast short-term debt capitalization balance in FEVI is expected. However, it is likely that, all else equal, FEVI will maintain higher short-term debt rates, and thus higher cost than FEI, due to FEVI's lower credit rating as compared to FEI.

18.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.56.1, BCUC IR 1.56.2

Derivation of the Proposed 9.62% for the FEI Amalco

The FEU response to BCUC IR 1.56.1 demonstrates that 9.62 percent, the ROE proposed for the FEI Amalco, is the weighted average of the four rate bases (FEI, FN, FEVI, FEW) with respect to their deemed equity thickness and allowed ROEs.

18.1 Do FEU agree that if the Commission were to approve the applied for 9.62 percent ROE, it should not be characterized as a determination of FEI Amalco having 12 basis points above the current benchmark ROE but that the 9.62 percent is simply an effect of the proposed amalgamation? If not, why not?

Response:

The FEU arrived at the 9.62% by determining the risk premium of 12 basis points, calculated by using a weighted average of the current risk premium and rate bases, and adding the premium to the 9.50% benchmark. From this perspective, the 9.62% is an effect of the proposed amalgamation.

This approach was used so that any change in the benchmark ROE would also result in a change to the ROE of FEI Amalco. This allows the Commission to make a determination on the relative merits of the risk premium of FEI Amalco relative to existing FEI, for which evidence of Ms. McShane was provided, and to allow for the determination of the benchmark ROE to occur through the Generic Cost of Capital proceeding, which is the appropriate proceeding for that review.

As the proceedings are occurring concurrently, the interim rates proposed for FEI Amalco will allow the results of the Generic Cost of Capital Proceeding to flow through to the rates of FEI Amalco on conclusion of that proceeding. Regarding the risk premium, this Commission will determine the appropriate risk premium or defer, as the rates are interim, to a future proceeding following approval of amalgamation.

18.1.1 If the Commission approves the Amalgamation application, it is likely only because it has been persuaded that there are net benefits resulting from amalgamation and harmonized rates. Do FEU agree that potential net benefits, and the resultant diminished risk attributable to the former FEVI and FEW areas, would enable the

Amalgamated Entity to take advantage of a lower ROE than the weighted average ROE of 9.62 percent? If not, why not?

Response:

No, for the reasons set out in Section 8.3 of the Application and related appendices, including the expert report of Ms. McShane (Appendix C-4), the FEU believe that it is reasonable to have a 12 basis point premium over the benchmark ROE, which is currently 9.5%, for FEI Amalco. Please also refer to the response to BCUC IR 2.3.6.

18.2 Do FEU anticipate that if the newly Amalgamated Entity is approved, the ROE is only interim and will be superseded by a Commission review in order to establish a risk premium for FEI Amalco in relation to the new benchmark utility's ROE and capital structure following the Generic Cost of Capital Proceeding? If not, please explain FEU's understanding of the process.

Response:

Yes, please see Sections 2.5 and 8.3 of the Application. The FEU recognize that the cost of capital for the Amalgamated Entity will need to be updated to take into account the outcome of the GCOC proceeding.

19.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-3, Section 8.3.2, pp. 161-162; Exhibit B-9, BCUC 1.58.0

FEVI and FEW Long-Term Risks

On page 161 of the Application, the FEU state :"These additional risks, as outlined in the Business Risks Evidence filed as part of Appendix C-1 of this Application are the following:

• Both FEVI and FEW are relatively smaller utilities that cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated;

• Greater supply risk due to dependency on a single pipeline system that traverses rugged terrain and incorporates numerous stream crossings and, in the case of FEVI, a high pressure marine crossing; and

• FEVI faces the elimination of Royalty Revenues at the end of 2011 that have ranged from $17 to $43 million in recent years and cover approximately 15%-25% of the current cost of service."

BCUC 1.58.1 asked: "With regard to the first risk listed above, do FEU agree with the fact that, under the proposed Amalgamated Entity, <u>FEVI and FEW</u> will be able to diversify their risks, at least to the same extent as FEI currently does, because they will benefit from FEI‟s assets, geography and economic bases, which are less concentrated? If not, please explain why not." [emphasis added]

The FEU response to BCUC 1.58.1 submitted that "with amalgamation, FEVI and FEW no longer exist; they are integrated into FEI Amalco." In order to compare risks pre- and post-amalgamation it is only feasible to compare the risks of those entities that exist both prior to and subsequent to amalgamation."

19.1 With regard to the first risk listed above, do FEU agree with the fact that, under the proposed Amalgamated Entity, <u>the former FEVI and FEW service areas</u> will be able to diversify their risks, at least to the same extent as FEI currently does, because they will benefit from FEI‟s assets, geography and economic bases, which are less concentrated? If not, please explain why not.

<u>Response:</u>

The FEU are unable to answer the question as posed. Under the proposed common rate design, since FEVI and FEW no longer exist as either stand-alone utilities or service areas with amalgamation, the only feasible way to compare risks is to compare FEI Amalco, inclusive of the former FEVI and FEW service territories, to FEI pre-amalgamation. FEI Amalco, which includes the former FEVI and FEW service areas, will have a similar ability to diversify its risks to that of FEI pre-amalgamation.

In a scenario where the FEVI and FEW utilities continued as stand-alone service areas with their current rate structures within FEI, with respect to the first risk listed above, it is not clear how amalgamation would reduce risk as they would continue on a stand-alone basis.

19.2 The FEU reiterated Ms. McShane's evidence in their Response to BCUC IR 58.1 that in a portfolio framework, amalgamation does not create any meaningful diversification for FEI Amalco. Assuming Ms. McShane is correct, how similar are pre-amalgamation FEI and FEI Amalco in terms of business risk and financial risk?

Response:

The implication is that, from this specific risk perspective only (no meaningful diversification for FEI pre-amalgamation versus FEI Amalco), FEI Amalco is of similar risk to FEI pre-amalgamation.

The FEU state in BCUC 1.58.2: "The proposal to harmonize rates will address the increase in the competitive price pressures in the former FEVI service area brought about by the termination of the royalty revenues. Rate harmonization will improve the competitiveness of natural gas in the former FEVI service area, as well as in the former FEW service area from a strictly price (operating cost) perspective, but will tend to decrease the Mainland's competitive price advantage, leading, on balance, to slightly higher competitive price risk for FEI Amalco compared to FEI pre-amalgamation."

19.3 Do FEU believe the proposed changes in delivery rates in FEVI, FEW and FI respectively, to be comparable in magnitude, resulting in similar shifts of competitive risks (in terms of delivery rates), although in opposite direction? Please elaborate.

Response:

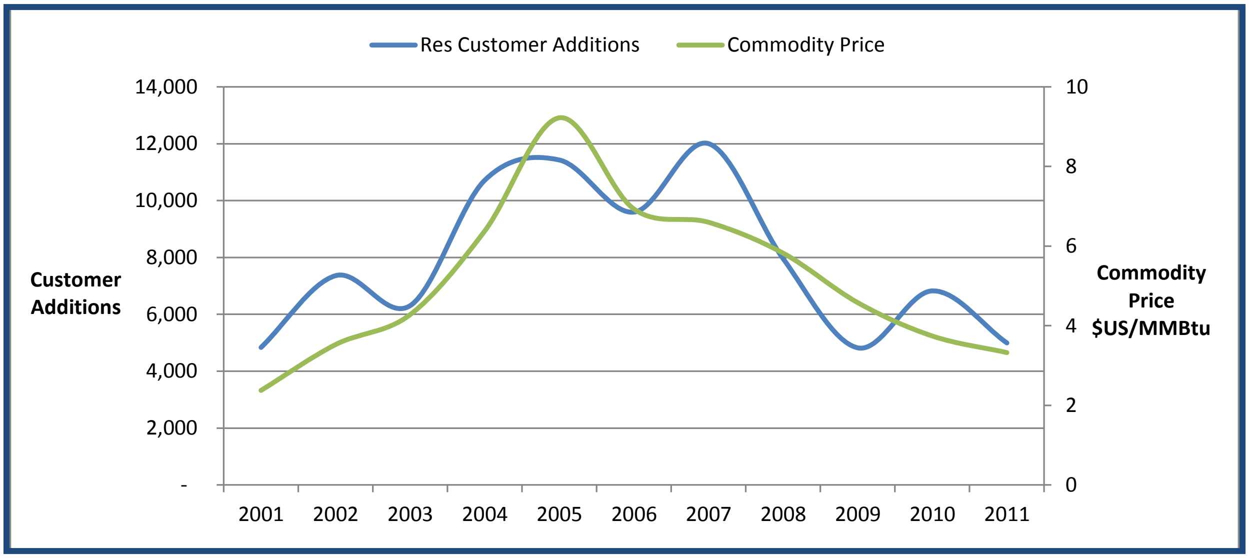
The change in delivery rates is not comparable in magnitude. The reduction in the delivery rates in the former FEVI and FEW service areas will be proportionally greater than the increase in delivery rates in the former FEI Mainland service area. Because of the larger relative decrease at FEVI and FEW, it is reasonable to expect, all else equal, that the larger relative decrease in rates will have moderately greater beneficial impact on the competitiveness. However, as noted previously, price differences in competing energy forms is not the only factor that determines competitiveness. See also the response to BCUC IR 1.58.2.

19.4 Please confirm that rate harmonization will set forth further deterioration in capture rates for the former FEI service areas and will improve the capture rates in the former FEVI and FEW service areas, all things being equal. If not, why not? If so, please compare the shifts in capture rate risks.

Response:

In theory, the proposed rate changes, all else equal, could lead to a change in capture rates. However, the price competitiveness of one energy form against another is just one factor that can impact capture rates. There are many other factors, such as economic conditions, energy policy, technology advancements, upfront capital costs, the magnitude of the change in rates, and customers' perception of energy sources, that when combined, influence the market share and capture rates. As shown in the graph below, in a period of high gas prices, capture rates were high, thus, price alone is not the sole determinant in capture rates.

Figure: FEI's Residential Customer Additions and Commodity Prices



The FEU state in BCUC 1.58.5: "under a scenario where the allowed ROE were "materially changed" negatively, or reduced, there would now be lower cash flow to support the same fixed obligations of the business, which would result in greater financial risk to possibly warrant a downgrade."

The FEU state in BCUC 1.58.6: "A material reduction in equity thickness and/or approved ROE could cause a downgrade; likewise an increase could prompt an upgrade."

19.5 Please clarify how much percentage reduction in equity thickness and/or approved ROE is considered "material."

Response:

The FEU do not know what the reduction would be to prompt a downgrade as this Decision would be ultimately made by the Rating Agencies, and a threshold level has never been disclosed by the Agencies. In the FEU's view, materiality is used in this context to note that any change in ROE/Equity Thickness, if considered material by the rating agencies, could prompt the ratings change. The FEU note that such a decision would be based on both its revised credit metrics and qualitative considerations, and may also take into consideration comparisons to decisions in other jurisdictions.

19.6 Assuming that: (a) the cash flow for FEI Amalco shows no improvement from the sum of cash flows from the former FEI, FEVI and FEW and that no meaningful diversification of risks resulted from the amalgamation; and (b) the Commission is not persuaded to allow the amalgamation and harmonized rates to go ahead unless the FEU can produce some evidence of benefits; would FEU find, e.g., an ROE of 9.5 percent, as an attractive benefit for customers and, at the same time, the Companies still retain their ability to earn their expected returns on investment?

Response:

Yes, assuming the reference to the 9.5% is intended to mean that FEI Amalco would be allowed the benchmark ROE, which will be subject to the Generic Cost of Capital Proceeding.

Please refer to the response to BCUC IR 2.3.6.

20.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC IR 1.63.1, BCUC IR 1.63.2

Business Risks of FEW and FEVI

According to the information provided in Response to BCUC IR 63.1, five projects since December 16, 2009 submitted for regulatory approval required First Nations consultation.

According to information provided to BCUC IR 63.2, 19 applications filed with the Commission since December 16, 2009 involved government energy policy considerations regarding the environment, GHG emissions, carbon neutrality, and related policy, legislative or statutory obligations.

20.1 Please confirm that, among all projects that require First Nations consultation, only one project took place in the FEVI area -- Mt. Hayes LNG Storage Facility Project, and the FEW service area has not been affected at all by First Nations consultation.

Response:

Not confirmed. In addition to the Mt. Hayes LNG Storage Facility Project, First Nations were also involved in the Whistler Pipeline project that began prior to 2009. The Whistler Pipeline project involved both FEVI and FEW. In particular, two accommodation agreements were signed on April 28, 2006 and March 8, 2006 between two First Nations (the Squamish Nation and Li'Liwat Nation) and five Terasen companies, including what are now FEI, FEVI and FEW (and also what were then Terasen Gas Inc. and Terasen Gas Squamish Inc.). To effectively conduct its business, the FEU require secure access to land and resources, thus it needs sound relationships with aboriginal peoples. British Columbia has the largest number and greatest cultural diversity of First Nations groups in the country with two hundred and three (203) First Nations communities, who amongst them have almost 1,800 Indian reserves, as well as their asserted ownership and rights to traditional territories which extend through the majority of the province's land base. In addition, unlike most of the rest of Canada, B.C. has not reached treaty agreements that clarify issues of ownership, jurisdiction, governance and responsibility over land and resources. Aboriginal issues are always challenging and are at the forefront at all times for the FEU.

20.2 Please confirm that as a non-Crown utility, the FEU do not have a duty to consult First Nations.

Response:

The FEU confirm that the Crown alone owes the duty to consult with and seek a workable accommodation with Aboriginal peoples in relation to their rights under Section 35 of the Constitution Act, 1982.

However, the Crown often delegates the procedural aspects of the duty to the FEU as proponent of its projects and may rely on the actions of a private party such as a proponent to satisfy these aspects of the duty. In *Haida Nation v. British Columbia (Minister of Forests)*, [2004] 3 S.C.R. 511, the Supreme Court of Canada stated (at para. 53): "The Crown may delegate procedural aspects of consultation to industry proponents seeking a particular development; this is not infrequently done in environmental assessments." The delegation of the procedural aspects of the process of consultation and accommodation makes good sense, as the proponent is most knowledgeable about the proposed project and it is uniquely situated to provide the First Nation with the information required to assess any impacts on their Aboriginal right or title. The Crown has relied on the FEU's actions to satisfy aspects of the duty to consult with respect to the FEU's projects.

Moreover, if the Crown fails to satisfy the duty in the judgement of the Commission or other decision-maker, it is the FEU's project that will suffer the consequences, whether that means not receiving approval from the Commission or being delayed due to an injunction received by a First Nation or Aboriginal group. Even if the FEU and the Crown were successful in ultimately demonstrating that the duty has been met, it is the FEU's project that will have been delayed as litigation of the issue winds its way through the courts. In these circumstances it makes little difference that the Crown holds the duty to consult and not the FEU.

For these reasons, the FEU cannot wait for the Crown to fulfill the duty to consult, but must proactively engage with First Nations and ensure that the procedural aspects of the duty to consult are satisfied.

Therefore, although the legal duty to consult rests with the Crown, the business risk is borne by the FEU, as well as some practical aspects of consultation. Indeed, this complexity in the relationship between private parties such as the FEU and the Crown creates uncertainty, which increases the risk of litigation and the FEU's business risk.

20.3 Please confirm that out of the 19 applications involving government energy policies, FEVI has only two applications -- the Regional Operations Centre CPCN Application and the Price Risk Management Plan.

Response:

Not confirmed. The Price Risk Management Plan, the 2010 Long Term Resource Plan, the FEU 2012/2013 RRA and the Common Rates, Amalgamation and Rate Design Application were submitted by the FEU, which includes FEVI.

20.4 The evidence from the Responses to the above two IRs does not appear to support actual increase in long-term business risk anticipated in 2009 for FEVI and FEW. Do the responses demonstrate that there is no or little increased business risks that require mitigation and the less than expected exposure to risk for FEVI and FEW dampens the support for Ms. McShane's opinion that the regulated deemed common equity for FEVI and FEW should be increased from 40 percent to 45 percent?

Response:

The FEU disagree with the premise of the question, as it implies that FEVI and FEW have less risk than FEI pre-amalgamation in regards to government energy policy and Aboriginal rights. The FEU disagree with that premise, as indicated in the response to BCUC IR 2.20.6. In its 2009 Decision, the Commission recognized that the evidence suggests that both FEVI and FEW have greater long-term business risk than FEI and directed those utilities to file evidence as to what equity component best reflects their respective long-term business risk. Ms. McShane's opinion is that a 45% deemed common equity for FEVI and FEW addresses the higher long-term business risk of FEVI and FEW relative to FEI.

As described in Appendix C-1 of the Application, the evidence suggests that the long-term business risk factors that apply to FEI pre-amalgamation outlined in TAB 1 of the 2009 ROE Application, including government energy policies and Aboriginal rights, also apply to FEVI and FEW today, with no material major changes in exposure for any of FEI, FEVI or FEW compared to 2009. In addition, FEW and FEVI also face the following long–term business risks:

- Both FEVI and FEW are relatively smaller utilities that cannot diversify their risks to the same extent as FEI, whose assets, geography and economic bases are less concentrated.
- Greater supply risk due to a dependency on a single pipeline system that traverses rugged terrain and incorporates numerous stream crossings and, in the case of FEVI, a high pressure marine crossing.

- FEVI faces the elimination of Provincial royalty revenues at the end of 2011 that have ranged from $17 to $43 million in recent years and cover approximately 15-25% of the current cost of service.

As such, the FEU agree with Ms. McShane's assessment that, in the absence of amalgamation, an appropriate common equity ratio for both FEVI and FEW would be 45%, to compensate for their higher long-term business risks relative to FEI pre-amalgamation.

However, in recognizing the benefits of amalgamation in reducing business risks that are unique to FEVI and FEW, the FEU, in this Application, proposed a 40% common equity thickness for FEI Amalco.

20.5 Please confirm that in the 2009 Capital Structure/Return on Equity Decision for Terasen Utilities (FEU), the Commission agreed with the Interveners that all risks cited by Terasen existed in 2005 with the exception of the climate change related risks and those related to First Nations (2009 ROE Decision, p. 36)

Response:

Confirmed.

20.6 While FEVI and FEW may well have business risks that are unique to them, do FEU agree that when it comes to risks arising from First Nations and government energy policy, evidence shows that FEVI and FEW have lower exposure than FEI?

Response:

FEI, FEVI and FEW are all subject to the same provincial policies and legislation. As such, government policies that discourage consumers from using natural gas can have a similar effect of reducing throughput volumes on the FEVI and FEW systems and reducing the attachment of new customers. In addition, as recognized by the Commission in the 2009 ROE and Capital Structure proceeding, uncertainty as to the nature and extent of aboriginal rights and title in B.C. and the lack of treaties creates operational and regulatory complexity, and a risk of litigation that is greater than that faced by similar businesses in other jurisdictions. FEVI and FEW are equally exposed to these risks as FEI.

The FEU believe that FEVI and FEW have the same exposure to risk arising from First Nations and government energy policy as FEI and that these risks have increased for all utilities since 2005.

20.7 Do FEU have any other reason to maintain an increase of 12 basis points in the allowed ROE derived from the weighted average calculation despite certain risks being mitigated as a result of amalgamation?

Response:

The preamble does not show that any of the FEU's reasons for proposing an increase of 12 basis points are invalid. For the FEU's reasons for proposing an increase of 12 basis points, please see Appendix C-4 of the Application. Please also refer to the response to BCUC IR 1.70.1, which addresses the risks of FEI pre-amalgamation and of FEI Amalco and the response to BCUC IR 2.20.4.

21.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.64.0

FEVI's and FEW's Long-Term Business Risks and Equity Thickness

The FEU state in BCUC 1.64.3: "The discussion and the analysis of FEVI's and FEW's long term business risks and equity ratios was prepared and submitted as part of this proceeding to satisfy the Commission's directive to provide evidence on FEVI and FEW's equity component , as discussed in Section 8 of the Application. <u>This expert opinion</u>, and Ms. McShane's other expert opinion on "Impact of Amalgamation on Cost of Capital for the FortisBC Utilities" (Appendix C-4 of the Application), are <u>expected to be tested in a regulatory review as part of this process</u>." [emphasis added]

The FEU also state in BCUC 1.64.8: "As explained in the Application, the FEU are not seeking in this Application an increase to the deemed equity for FEVI or FEW."

21.1 Please confirm that the terms "this expert opinion" used by FEU in response to BCUC 1.64.3 refers to Ms. McShane's Opinion on Common Equity Ratios. (Exhibit B-3, Appendix C-2)

<u>Response:</u>

Confirmed.

21.2 FEU's expert is recommending 45 percent equity ratios for a stand-alone FEVI and FEW when assessing the equity thickness for the Amalgamated Entity. Since the FEU are not seeking approval for the proposed 45 percent equity thickness for FEVI and FEW in this proceeding, will the FEU be proposing 45 percent in a future Commission proceeding following the GCOC Proceeding if the Amalgamation Entity is not approved?

<u>Response:</u>

As indicated in Appendix C-1 of the Application, the discussion and the analysis on FEVI's and FEW's long-term business risks were prepared to satisfy the Commission's approval (as per Order No. G-129-11) to defer the filing of evidence with respect to FEVI and FEW's equity component on a stand-alone basis (Directive No. 7 of Order No. G-158-09) to this proceeding instead of the 2012-2013 RRA. The determinations from the GCOC Proceeding will have implications for the capital structure and risk premium of FEVI and FEW, which would be addressed in a future application in accordance with the procedural order for the GCOC Proceeding in the event that amalgamation does not proceed. The FEU cannot indicate now with certainty what they will propose in the future proceeding before the results of the GCOC proceeding are known. Thus, the FEU respectfully suggest that it is more efficient to leave a full examination of FEVI and FEW's common equity ratio and risk premium to a future proceeding following the outcome of the GCOC Proceeding should amalgamation not proceed.

21.2.1 In the alternative to the proposed 45percent, will an additional 5 per cent to the equity ratio of the new benchmark utility's equity thickness for stand-alone FEW and FEVI be acceptable to FEU?

Response:

The GCOC proceeding will be making a determination on the characteristics of a benchmark utility and if that utility is a hypothetical utility or an existing utility. The FEU are unable to respond to this question in the absence of a determination from the GCOC proceeding regarding the parameters for the benchmark utility.

The FEU state in the response to BCUC IR 1.64.7.2: "Even if, hypothetically, the current equity thickness of 40 percent for FEVI and FEW were the appropriate stand-alone equity ratios reflective of their long-term business risks, the applicable equity ratio for FEI Amalco would be 40%, given Ms. McShane's conclusion that amalgamation will not lower FEI's cost of capital."

On page 162 of the Application, the FEU state: "FEI Amalco is seeking to maintain the 40% equity 60% debt ratio on an amalgamated basis <u>as the Companies recognize that amalgamation will mitigate certain business risks that are unique to stand alone FEVI and FEW</u>." [Emphasis added]

21.3 If hypothetically the current equity thickness of 40 percent for FEVI and FEW were the appropriate stand-alone equity ratios reflective of their long-term business risks, is it not true that the fact the Companies recognize that amalgamation will mitigate certain business risks unique to FEVI and FEW implies that a downward adjustment to FEI Amalco would be required?

Response:

No, the FEU disagree with this rationale. As indicated in the response to BCUC IR 1.64.1 and 1.64.6.1, Ms. McShane suggests that an *appropriate range* for the common equity ratio for the amalgamated entity is bounded at the lower end of the range by FEI's cost of capital pre-amalgamation and at the upper end of the range by the weighted average of the appropriate stand-alone equity ratios of FEI pre-amalgamation, and FEVI and FEW on a stand-alone basis. If the appropriate equity thickness for stand-alone FEVI and FEW were hypothetically 40% (as indicated in this question), this would only lower the *upper end* of the range to 40% without having any impact on the lower end of the range. Therefore, the proposed lower end of the range of 40 percent remains appropriate given that amalgamation will not lower FEI's cost of capital.

22.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.65.0

Size of Firms by Market Capitalization

The FEU state in BCUC 1.65.2: "Table 1 is re-submitted below with the additional column requested. The minimums and maximums for the Low Cap (6-8) group have been corrected from the values that appeared in Ms. McShane's Opinion."

22.1 Please explain what prompted the correction to the minimums and maximums for the Low Cap (6-8) Group.

Response:

In responding to BCUC IR 1.65.2 it was discovered that the minimum and maximum values for the Low Cap Group (deciles 6-8) had been incorrectly typed as those for deciles 7 (minimum) and 5 (maximum). The median value for the Low Cap Group was correct as filed.

In BCUC 1.65.4 and 1.65.5, the FEU provide tables with the price/earnings ratios for the six publicly traded Canadian utilities and the 13 U.S. low risk relatively pure play gas and electric distribution utilities used to gauge the range of likely P/E ratios for FEI (copied below for ease of reference).

	Price/Earnings Ratios				
	2007	2008	2009	2010	January to June 2011
CANADIAN UTILITIES	17.1	14.7	11.7	14.3	15.2
EMERA INC	19.4	15.3	16.6	16.4	18.8
ENBRIDGE INC	20.7	20.8	16.1	17.4	22.9
FORTIS INC	20.1	18.2	15.7	18.9	19.5
TRANSCANADA CORP	18.6	16.8	15.0	19.1	19.8
VALENER INC	14.0	11.0	11.6	12.4	16.9
Median	**19.0**	**16.0**	**15.4**	**16.9**	**19.1**

	Price/Earnings Ratios				
	2007	2008	2009	2010	January to June 2011
AGL RESOURCES INC	15.1	13.4	10.2	12.3	13.2
ATMOS ENERGY CORP	13.7	13.6	12.6	14.3	17.3
CH ENERGY GROUP INC	15.9	16.4	20.9	16.9	17.8
CONSOLIDATED EDISON INC	14.7	12.3	15.0	13.8	14.2
INTEGRYS ENERGY GROUP INC	19.8	16.6	25.6	17.6	14.9
NEW JERSEY RESOURCES CORP	10.7	27.6	23.3	19.3	21.3
NICOR INC	14.3	13.6	13.2	13.2	18.3
NORTHWEST NATURAL GAS CO	18.1	17.9	15.5	16.6	17.9
NSTAR	17.1	15.5	14.6	16.2	17.9
PIEDMONT NATURAL GAS CO	18.3	18.5	15.8	16.7	19.4
SOUTH JERSEY INDUSTRIES INC	15.0	20.0	13.9	22.3	21.6
VECTREN CORP	17.1	15.5	14.1	14.7	17.5
WGL HOLDINGS INC	15.5	14.0	13.3	15.3	15.3
Median	**15.5**	**15.5**	**14.6**	**16.2**	**17.8**

22.2 From the data in the table above, please explain how the FEU conclude that the typical price/earnings ratios of publicly traded Canadian utilities and relatively pure play low risk U.S. gas and electric distribution utilities is situated within an approximate range of 16 to 18 times.

<u>Response:</u>

The approximate range of 16 to 18 represents the approximate central tendency of the P/E ratios of the two samples over the period analyzed. As the table below shows, the median of the average values for the Canadian companies over the period was 17.6, or approximately 18 (the upper end of the range). The average of the annual median values was 17.3, approximately at the mid–point of the range. For the U.S. sample, the two corresponding values are both 16, the lower end of the range.

	Price/Earnings Ratios					
	2007	2008	2009	2010	January to June 2011	Average
CANADIAN UTILITIES	17.1	14.7	11.7	14.3	15.2	14.6
EMERA INC	19.4	15.3	16.6	16.4	18.8	17.3
ENBRIDGE INC	20.7	20.8	16.1	17.4	22.9	19.6
FORTIS INC	20.1	18.2	15.7	18.9	19.5	18.5
TRANSCANADA CORP	18.6	16.8	15.0	19.1	19.8	17.9
VALENER INC	14.0	11.0	11.6	12.4	16.9	13.2
Median	**19.0**	**16.0**	**15.4**	**16.9**	**19.1**	**17.6**
Average of annual medians						**17.3**
AGL RESOURCES INC	15.1	13.4	10.2	12.3	13.2	12.9
ATMOS ENERGY CORP	13.7	13.6	12.6	14.3	17.3	14.3
CH ENERGY GROUP INC	15.9	16.4	20.9	16.9	17.8	17.6
CONSOLIDATED EDISON INC	14.7	12.3	15.0	13.8	14.2	14.0
INTEGRYS ENERGY GROUP INC	19.8	16.6	25.6	17.6	14.9	18.9
NEW JERSEY RESOURCES CORP	10.7	27.6	23.3	19.3	21.3	20.4
NICOR INC	14.3	13.6	13.2	13.2	18.3	14.5
NORTHWEST NATURAL GAS CO	18.1	17.9	15.5	16.6	17.9	17.2
NSTAR	17.1	15.5	14.6	16.2	17.9	16.2
PIEDMONT NATURAL GAS CO	18.3	18.5	15.8	16.7	19.4	17.7
SOUTH JERSEY INDUSTRIES INC	15.0	20.0	13.9	22.3	21.6	18.6
VECTREN CORP	17.1	15.5	14.1	14.7	17.5	15.8
WGL HOLDINGS INC	15.5	14.0	13.3	15.3	15.3	14.7
Median	**15.5**	**15.5**	**14.6**	**16.2**	**17.8**	**16.2**
Average of Annual Medians						**16.0**

22.2.1 If, based on the tables above, a different range should be used, please re-estimate the market capitalization using the updated umbers.

Response:

As demonstrated in the response to BCUC IR 2.22.2, the range of P/E ratios of 16 to 18 is a reasonable representation of the central tendency of the data and no re-estimation of the market capitalization of FEI pre- and post-amalgamation is required.

23.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.66.0

Correlation of Cash Flows

The FEU state in BCUC 1.66.1: "Ms. McShane's conclusion set forth in the preamble to the question that "from a diversification perspective, amalgamation does not lower FEI's overall cost of capital" is based on the correlation of cash flows in the future. As stated (again in the preamble), "Given all of the similarities in the fundamental characteristics (e.g., same provincial economy, same provincial energy policy, similar competitive pressures, same regulator) of each of the FortisBC Energy Utilities, **the cash flows will be highly correlated.**" [emphasis in original]

23.1 By using the future tense "will be" do FEU imply that, it their view, it is a certainty that "future cash flows will be highly correlated given the similarities of the fundamental characteristics?"

Response:

No, it is impossible to state with certainty that the cash flows will be highly correlated. The statement is intended to reflect the high likelihood that they will be correlated, given the close similarities in the FEU's fundamental characteristics among the regions. As well, post amalgamation, with the introduction of common rates and one amalgamated rate base, the correlation between the existing FEVI and FEW service areas with FEI would be expected to continue to be highly correlated.

23.2 The FEU provided a graph entitled "Cash Flow from Operations" in response to BCUC 1.66.2.

23.3 Please explain the two scales on this graph and the measurement unit used for each scale. Please also explain which scale should be used to read which line in the graph?

Response:

The left hand scale refers to the combined (FEI, FEVI and FEW) and FEI only cash flows; the right hand scale refers to the cash flows of FEVI and FEW, inasmuch as their cash flows are so much smaller than FEI's. All cash flows are expressed in millions of dollars.

23.4 While it is true that the graph shows that FEI's and FEVI's cash flows exhibit very similar movements over the period, they move in opposite direction from 2002 to 2004. Please explain why.

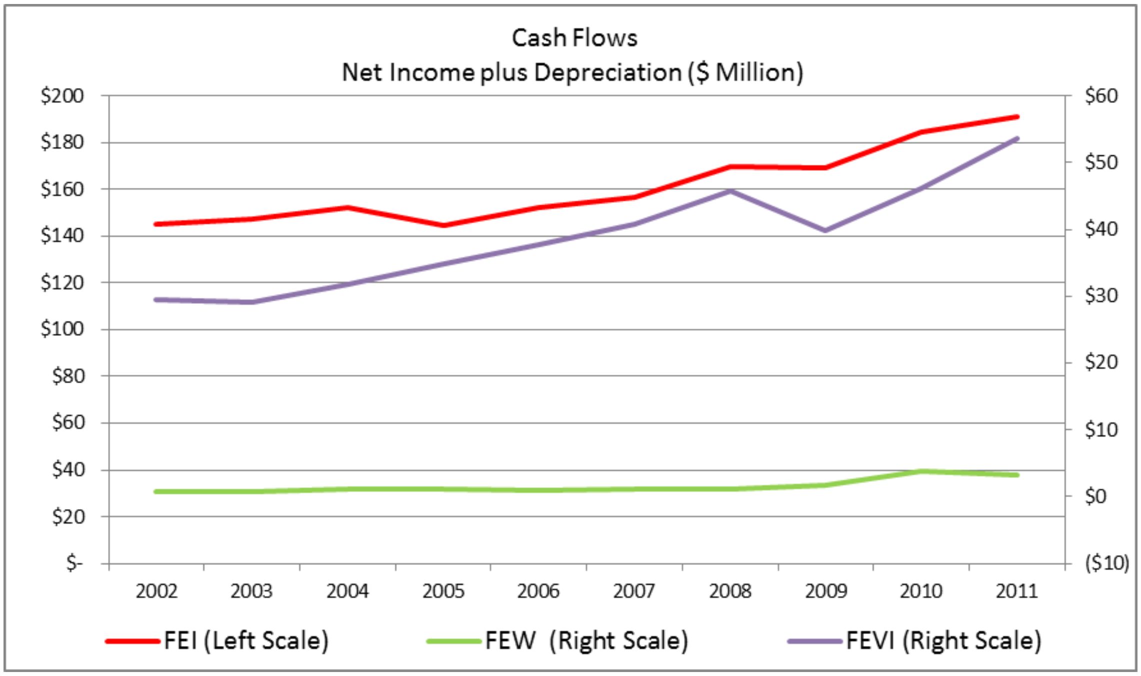
Response:

In reviewing the data for the purpose of responding to this question, it was discovered that the wrong set of data for FEI had been used in the graph and the correlation coefficients for FEI vs. FEVI and FEI vs. FEW.

More importantly, however, the graph and the correlation coefficients were prepared using cash flows defined as net earnings plus depreciation and amortization plus changes in rate stabilization accounts plus changes in non-cash working capital. Both the operation of rate stabilization accounts and changes in non-cash working capital can result in wide swings from year to year in cash flows measured in this manner. For example, due to volatile gas prices in the early 2000's, the operation of FEI's commodity deferral accounts (GCRA and later CCRA and MCRA) resulted in significant swings in the cash flows measured in this way. Also in 2003, not only did FEVI's regulatory model change, its revenue deficiency account experienced a shift from a revenue deficiency to a revenue surplus, as a result of which the cash flows used in the graph and correlations provided exhibited a material increase. As a result, cash from operations is not the best measure to use for this purpose.

A more appropriate manner of measuring cash flows for purposes of estimating the historical degree of correlation among the three utilities is to focus solely on earnings and depreciation and amortization, thus more accurately capturing the underlying annual returns on and of capital. This is the logical approach as, in a cost of service model, there will be changes in the components of cost of service that typically flow through revenue requirements or deferral account mechanisms, whereas the earnings and depreciation and amortization, which reflect the return on and of capital, remain more stable. Please note that the two studies referenced in response to BCUC IR 2.23.14 and Attachment 23.13 provided in response to BCUC IR 2.23.13, define cash flow as net income plus depreciation or operating income before depreciation. Under either definition the annual impacts of both non-cash working capital and rate stabilization accounts would be ignored. However, even when measured in this manner, as rate stabilization account balances may be amortized through depreciation, unusual year-to-year fluctuations in reported cash flows may still occur.

Below is a graph of the FEI, FEVI and FEW cash flows covering 2002 to 2011, the full period for which data are available for all three utilities, where cash flow is defined as net income plus depreciation. Please refer to the discussion in response to BCUC 2.23.7 regarding FEW's cash flows.



Absent the annual effects of the rate stabilization accounts and changes in non-cash working capital (i.e., earnings plus depreciation), and with the correct FEI data, the FEI-FEVI cash flow correlation coefficient for 2002-2011 is 0.92.

23.5 Response to BCUC 1.66.2.1 states: "it is clear that since conversion, FEW's cash flows have more closely correlated with those of the other two utilities." Please confirm that the conversion refers to the conversion from distribution of propane to distribution of natural gas in the FEW service area. If so, please state the effective date of the conversion. If not, please clarify what is meant by conversion.

Response:

Confirmed. The Whistler pipeline was put into service in April 2009 and the conversion project was completed in August 2009.

23.6 Which years are FEU referring to when describing a closer correlation between FEW's cash flows with the other two utilities' cash flows?

Response:

The response was referring to 2009-2011, but was incorrect, based on the cash flows as filed.

Despite the differences in scale between the cash flows of FEW on one side and FEI or FEVI on the other, the graph demonstrates that FEW's cash flows actually move in opposite direction to both FEI's and FEVI's cash flows for the entire period except for 2008/2009.

23.7 Please explain why FEW's cash flows actually move in opposite direction to both FEI's and FEVI's cash flows for the entire period except for 2008/2009.

Response:

As was the case with FEI and FEVI, FEW's historical total cash flow numbers used in response to BCUC 1.66 reflected the annual impacts of rate stabilization accounts and fluctuations in non-cash working capital, as well as one-time events that skew the results (i.e., FEW's 2009 provision for disallowed conversion costs and the 2010 reversal of the preponderance of the provision).

Normalizing FEW's 2009 and 2010 cash flows, i.e., to account for net effect of the disallowed costs in the year incurred (2009), the FEI-FEW and FEVI-FEW correlation coefficients are 0.88 and 0.75 respectively.

In BCUC 1.66.3, the FEU provided the following correlation coefficients of cash flows between each pair of utilities:

FEI FEVI	0.33	2002-2011
FEI FEW	0.00	2001-2011
FEVI FEW	0.04	2002-2011

23.8 Would the FEU agree that the correlation coefficient of 0.00 between the cash flows of FEI and FEW demonstrate that there is no correlation at all between the cash flows of these two utilities for the period 2001-2011?

Response:

Please refer to the response to BCUC IR 2.23.7, which shows that when cash flows are appropriately measured, including the normalization of FEW's 2009 and 2010 cash flows, the FEI-FEW correlation coefficient for 2002-2011 is 0.88, demonstrating a high degree of correlation

23.8.1 Would FEU agree that this result is consistent with the fact that the cash flows of FEI and FEW are moving in opposite direction during 2001-2011 as shown in the graph?

Response:

Please refer to the responses to BCUC IRs 2.23.6 and 2.23.7. The result would be consistent with cash flows moving in the same direction.

As a point of clarification, a correlation coefficient at or around zero signifies minimal to no correlation, and would suggest that there is no discernible relationship, either positive or negative.

23.9 Would the FEU agree that the correlation coefficient of 0.04 between the cash flows of FEVI and FEW demonstrate that there is no degree of correlation between the cash flows of these two utilities for the period 2002-2011?

Response:

Please refer to the response to BCUC IR 2.23.7, which indicates that, when the cash flows are appropriately measured using cash before working capital and rate stabilization adjustments, the FEVI-FEW correlation coefficient is 0.75, which indicates a high degree of correlation.

23.9.1 Would the FEU agree that this result is consistent with the fact that the cash flows of FEVI and FEW are moving in opposite direction during 2002-2011 as shown in the graph?

Response:

Please refer to the response to BCUC IR 2.23.7. As noted in BCUC IR 23.8.1, as a point of clarification, a correlation coefficient at or around zero signifies minimal to no correlation, and would suggest that there is no discernible relationship among the cash flows, either positive or negative.

23.10 Would the FEU agree that the correlation coefficient of 0.33 between the cash flows of FEI and FEVI can be described as a low correlation at best, but certainly not a high correlation?

Response:

Please refer to the response to BCUC IR 2.23.4, which indicates that when the cash flows are appropriately measured using cash flow before the effect of working capital, the FEI-FEVI correlation coefficient is 0.92, which indicates a high degree of correlation.

23.11 Given the correlation results for the past 10 years, please justify how either FEU or Ms. McShane can assert that the cash flows of each of the FEU utilities will be highly correlated in the future?

Response:

When the cash flows are appropriately measured (reflecting the underlying earnings and return of capital from depreciation), the correlation coefficients are much higher. Further, FEI, FEVI and FEW are all now gas distribution utilities; their rate stabilization accounts are similar and FEVI is now operating on a similar cost of service model to FEI and FEW. Furthermore, post amalgamation with the introduction of postage stamp rates, a single rate base and a common regulatory construct across the FEU, the cash flows from the regions would remain highly correlated.

23.12 Provided that the four fundamental characteristics listed (i.e., same provincial economy, same provincial energy policy, similar competitive pressures, same regulator) were also similar during the past 10 years for each of the FEU utilities, please elaborate on the circumstances that can explain why the cash flows would suddenly become highly correlated from a state when they were absolutely not correlated.

Response:

Please refer to the responses to BCUC IRs 2.23.4, 2.23.7, 2.23.8 and 2.23.11. The analysis indicates a high degree of correlation historically and the circumstances with amalgamation support a high degree of correlation going forward.

On page 6 of Appendix C-4 (Exhibit B-3) Ms. McShane state: "Some empirical studies have shown that diversification by a firm does lower its cost of capital. However, the identification of a lower cost of capital has been associated with diversification among business segments, e.g., different but related lines of business, and where the cash flows from the different lines of business are less correlated."

23.13 Please submit the empirical studies (or abstracts) referred to in the quote above.

Response:

Please refer to Attachment 2.23.13 containing Rebecca Hann, Maria Ogneva, Oguzhan Ozbas, *Corporate Diversification and the Cost of Capital*, September 18, 2009, Rock Center for Corporate Governance at Stanford University Working Paper No. 58; Marshall School of Business Working Paper No. FBE 32-09 and Lilian Ng, Hyeongsop (Harold) Shim, and Valeriy Sibilkov, *Does corporate coinsurance enhance shareholder value?*, University of Wisconsin, March 2010.

23.14 Ms. McShane, please confirm that the empirical studies referred to above would have analyzed the historical correlations of cash flows from the different lines of business, as opposed to speculate about what the future correlations might be, to conclude that "a lower cost of capital has been associated with diversification among business segments … where the cash flows from the different lines of business are less correlated."

Response:

The literature on diversification and the impact on market valuation (and thus implicitly, if not explicitly cost of capital) initially stemmed largely from the observed spate of firm mergers in the 1960s, at around the same time as market portfolio theory was gaining ground. As expressed in an early theoretical article, according to market portfolio theory and the Capital Asset Pricing Model, diversification through merger should not result in a higher valuation for the merged firm (and implicitly a lower cost of capital).

As articulated by Hiram Levy and Marshall Sarnat in "Diversification, Portfolio Analysis and the Uneasy Case for Conglomerate Mergers", *Journal of Finance*, September 1970, pages 795-802, (1) in the absence of perfect correlation between the returns of the individual firms, post-merger variance is lower than the simple sum of the individual variances; (2) the expected return is a weighted average of the individual returns, i.e., one for which the risk has been reduced with no reduction in the level of return; (3) no premium will be forthcoming in a perfect capital market because the superior risk-return combination could have been achieved by investors by combining the shares in a portfolio; and after the merger has been effected, no increase in the market value of the two firms can be expected, or is even possible. A premium would indicate that the diversified firm is worth more than the sum of its parts, consistent with a reduction in the cost of capital.

The notion that diversification through mergers could have a positive effect on market valuation was discussed from a theoretical perspective in Wilbur G. Lewellen, "A Pure Financial Rationale for the Conglomerate Merger", *Journal of Finance*, Volume 26, Issue 2, pages 521–537, May 1971. In this early article, the author noted the same arguments as Levy and Sarnat:

> *"There is no question that, as long as the prospective earnings of the combining enterprises are not perfectly correlated, the surviving firm will yield an income stream for its owners having a lesser degree of dispersion per dollar of expected return than was attainable in portfolios which included only one of its predecessors [cite]. On the other hand, to claim that the market will pay a premium for the new income stream ignores the opportunity which individual investors had prior to the merger to combine the predecessor shares in their own securities portfolios and achieve the same effects that the merger merely formalizes.* [fn] *Indeed, in a world with a well-functioning capital market of the sort analyzed by Lintner [cite] and Sharpe [cite], the merging firms' shares would already be included in every investor's portfolio in precisely the merger proportions."*

The author went on to argue that, from the perspective of debt holders, the joint probability of default on the outstanding loans that each party brings to a merger is reduced because each can be supported by excess cash flows of the other. Such an outcome is consistent with an increase in the market valuation (lower cost) of the merged firm's debt. Lewellen also suggests that the reduction in the probability of bankruptcy is a benefit to the equity shareholders.

Since these early theoretical articles, there has been a stream of literature focusing on the impacts of corporate diversification on market valuation of the surviving firms. Many of these studies, typically focused on conglomerate-type mergers, which have used market valuations of debt and equity in their analysis, identified a diversification discount, as noted in footnote 10 of Ms. McShane's Opinion (Exhibit B-3, Appendix C-4). Studies attempting to explain why market valuations of merged firms displayed diversification discounts either identified or hypothesized that such discounts are the result of factors such as (1) the diversifying entities and their acquisition targets trading at a discount before diversification (e.g., underperformance leads to diversification rather than diversification causing underperformance); (2) cross-subsidization or sub-optimal resource allocation among business units; (3) the degree of diversification and diversification into unrelated businesses, resulting in inefficiencies in operations and (4) the mis-specification of business segments when studying the effects of diversification.

The study referred to in footnote 11 of Ms. McShane's Opinion (and included in Attachment 23.13 in response to BCUC IR 2.23.13) explicitly studied the impact of diversification on the cost of capital and used historical cash flows in the analysis. The study concluded that: "Using measures of implied cost of capital constructed from analyst forecasts, we find that diversified firms have on average a lower cost of capital than stand-alone firms. In addition, diversified firms with less correlated segment cash flows have a lower cost of capital, consistent with a coinsurance effect." The study used historical correlations of cash flows, but at an industry level, not a company-specific level, because (1) the distribution of segments' future cash flows is not observable and (2) using the distribution of historical segment-level cash flow to estimate coinsurance is problematic because firm composition usually changes over time. Cash flow in this study was defined as operating income before depreciation.

The Ng, Shim and Sibilkov study, also provided in Attachment 23.13 in response to BCUC IR 2.23.13, used historic cash flows of the pre-merger firms and the merged firms, where cash flow was defined as net income plus depreciation. The authors concluded:

> *"We observe that in merger deals of firms with low cash-flow correlation, synergistic gains enhance shareholder as well as bondholder wealth. The difference in their cash-flow volatilities is positively related to shareholder return around merger announcements and to changes in bond rating of acquiring firms two months after the merger. On the other hand, in mergers of firms with high cash-flow correlation, the result shows a wealth redistribution, where shareholder wealth, and not bond-holder wealth, is reduced."*

23.15 Ms. McShane, in light of the correlation coefficients of cash flows respectively between FEW and FEI, FEW and FEVI and FEI and FEVI, which show no correlation to low correlation, do you still maintain the view that: "With a high degree of correlation in cash flows among the three individual utilities, amalgamation does not create any meaningful diversification for FEI. Thus, from a diversification perspective, amalgamation does not lower FEI's overall cost of capital?"

<u>Response:</u>

Yes, based on the responses to the other IRs in the BCUC 2.23 series.

23.15.1 If so, please justify in light of the correlation results.

Response:

Please refer to the responses to BCUC IRs 2.23.4, 2.23.7, 2.23.8, 2.23.9, 2.23.11 and 2.23.12.

23.15.2 If not, would you agree that from a diversification perspective, amalgamation does lower FEI's overall cost of capital?

Response:

As noted in the response to BCUC IR 2.23.15 and justified in the response to BCUC IR 2.23.15.1, Ms. McShane continues to hold the view that amalgamation does not create any meaningful diversification for FEI, and thus, from a diversification perspective, amalgamation does not lower FEI's overall cost of capital.

24.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, General

Third Parties' Assessment of Business Risks of FEVI and FEW

FEW is an unrated utility and FEVI receives private rating.

24.1 Please describe if, since the end of 2009, any third party (credit agency or financial institution) has expressed concerns regarding the deterioration of FEVI's and FEW's business operations and contractual agreements with customers, credit metrics, exposure to external risks and the ability to earn its return on capital. If so, please provide examples.

Response:

The FEU are not aware of any third party agency such as credit rating agencies or financial analysts commenting on the business operations of FEW.

FEVI's debt is rated by Moody's and DBRS. Both credit rating agencies have expressed concern over the long-term competitiveness challenges of FEVI relative to electricity given the end of royalty payments in 2011. Please refer to Exhibit B-9-1, Attachments 71.1.1 and 72.1.1 for the credit rating agency reports from 2008 to 2012.

24.2 Please describe if, since the end of 2009, any third party (credit agency or financial institution) has expressed opinions on improvements in business earnings for FEVI and FEW.

Response:

Please refer to the response to BCUC IR 2.24.1 for a discussion on institutions that have expressed an opinion on FEVI and FEW.

Moody's and DBRS comment on FEVI's earnings, business risks and credit metrics in their respective reports that are published annually to confirm FEVI's credit ratings. Please refer to the reports of each agency for the actual opinions of each agency.

The credit ratings for both agencies have remained unchanged since 2009. The rating agencies note that earnings have shown "steady growth over time" (DBRS – Summary November 2010), however, it is also recognized that FEVI has received royalty payments to help manage the competitiveness of its rates – as stated by Moody's in 2010:

> *"While TGVI has been able to recover its costs of service and the accumulated RDDA balances since 2003, it has only been able to do so with the benefit of the Provincial royalty payments. Under the terms of the VINGPA, these royalty payments terminate at the end of 2011. Consequently, TGVI's rates will need to increase in 2012 to offset the loss of the Provincial royalty revenues. Initially, the rate impact of the loss of royalty revenues is expected to be partially mitigated by the amortization of accumulated revenue surpluses that are anticipated to occur during 2010 and 2011. Pursuant to the BCUC-approved negotiated settlement for TGVI's 2010/2011 rates, the company expects to recover more than its cost of service during those two years and will record any surpluses in a new deferral account, the Rate Stabilization Deferral Account or RSDA. Following the termination of the Provincial royalty revenues, the RSDA balance will be amortized and therefore reduce the need to increase rates to offset the lost royalty revenues. However, when the RSDA has been fully amortized, TGVI's rates will need to increase."*

Please refer to Exhibit B-9-1 containing the Attachments for the responses to BCUC IR No. 1, Attachments 71.1.1 and 72.1.1 for the credit rating agency reports.

The FEU are not aware of any other financial institution commentary regarding FEVI or FEW.

25.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.67.3.1

Characteristics of FEI, FEVI and FEW

In the table the FEU provided in response to BCUC 1.67.3.1, the FEU state that there is a regulatory lag and disconnect between government policy and utility regulation.

25.1 Please elaborate on both regulatory lag and disconnect between government policy and utility regulation and provide specific examples to support this view.

Response:

In recent years, the regulatory environment that the FEU operate in has required regulatory oversight of more of the utility's activities. Also the consistency of findings with some previous decisions and regulatory principles and processes are coming under question. This is particularly true for natural gas utilities, where some of the long standing regulatory mechanisms, such as Price Risk Management, have come into question. Whereas previously the FEU operated in a regulatory environment that was relatively stable and predictable, in recent years, the energy environment and energy policy have changed the energy landscape in BC. The FEU have brought forth new initiatives to serve customers in this new energy environment, which has presented challenges to the BCUC in setting the regulatory course for these initiatives. Some natural gas service offerings, such as biomethane and natural gas transportation (NGT) services, are under scrutiny and are being challenged in the AES Inquiry proceeding. There are also inconsistencies in terms of treatment of costs to customers across utilities (e.g. the higher costs of the clean biomethane service offering is streamed to particular customers who choose the service, whereas IPP clean power is rolled in to all customers' electric rates).

Furthermore, there are disconnects between policy and regulation, which have created more process and uncertainty for utilities. The need for the regulator to consider the CEA and therefore British Columbia's energy objectives, when it reviews long-term plans, applications for a CPCN, applications for approval of expenditure schedules and energy purchase contracts under the UCA, has led to different interpretations. These different interpretations by all stakeholders, have led to more regulatory uncertainty and process while the business models for new initiatives get established. All of this has created regulatory lag, less predictability and less stability in the regulatory environment in which the FEU operate.

26.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.68.0

Range for FEI's post-amalgamation cost of capital

26.1 From FEU's response in BCUC 1.68.1, please confirm that the following table is correct. If not, please correct it.

	Return on Equity	Common Equity Ratio
Lower end of the range	9.5%	40%
Higher end of the range	9.62%	41.2%

Response:

Confirmed.

26.2 Please confirm that the FEU are seeking approval for a 40 per cent common equity ratio for FEI Amalco, which constitutes the lowest end of what FEU believe is the appropriate range.

Response:

Confirmed.

26.3 Please confirm that the FEU are seeking approval for a 9.62 per cent ROE for FEI Amalco, which constitute the highest end of what the FEU believe is the appropriate range.

Response:

Not confirmed. The FEU are requesting an ROE of 9.62%, based on the current benchmark utility ROE plus a 12 basis point risk premium based on the equity risk premiums that were adopted for FEVI and FEW in the 2009 ROE and Capital Structure proceeding. To the extent the benchmark ROE is changed in the upcoming Generic Cost of Capital Proceeding, the FEI

Amalco allowed ROE would also be expected to change, so it is not correct to say that 9.62% is at the highest end of an appropriate range for ROE.

26.4 Please explain how the FEU can justify seeking approval for the higher end of the range for the ROE but the lower end of the range for the common equity ratio.

Response:

As discussed in Ms. McShane's Opinion (Appendix C-4), the cost of capital for FEI post-amalgamation lies within a range, bounded at the lower end by FEI pre-amalgamation's cost of capital and at the upper end of the range by the weighted average of the costs of capital of the three stand-alone utilities, FEI pre-amalgamation, FEVI and FEW. The FEU's proposed combination of capital structure and ROE is below the mid-point of the range, that is, closer to the FEI cost of capital, incorporating a small risk premium in the ROE relative to the current benchmark ROE (for FEI pre-amalgamation) to compensate for marginally higher risk for FEI post-amalgamation.

27.0 Reference: Return on Equity / Cost of Capital of the Amalgamated Entity

Exhibit B-9, BCUC 1.70.1

Utility-Specific Risks

In the table provided in response to BCUC 1.70.1, on the last line of the first table, the FEU state that "Pre-amalgamation FEI has a large, diverse customer base but with exposure to industrial margin. Amalgamation of FEVI transfers risk associated with exposure to the two major industrial customers in the Vancouver Island service area to FEI Amalco, resulting in marginally higher exposure for FEI Amalco compared to pre-amalgamation.

27.1 If pre-amalgamation FEI is already exposed to industrial customers and in addition, its customer base is already large and diverse, please explain how adding two large industrial customers into the rate base of FEI Amalco would have a material impact on FEI amalco's exposure to industrial customers.

Response:

To be clear, the response to BCUC IR 1.70.1 states that adding two large industrial customers into the customer base of FEI Amalco would have a "marginally higher exposure" (as stated in the preamble) and not "material impact" (as stated in the question).

As discussed in Section 4 of the Application, stand-alone FEVI is highly dependent on industrial load from BC Hydro and the VIGJV both in absolute *and* percentage terms. To illustrate, in 2010, those two customers together accounted for approximately 15 percent of FEVI's gross margin and 60 percent of the throughput.

While the addition of BC Hydro and VIGJV into the customer base (not rate base as proposed in the question) of FEI Amalco will not have the same *percentage* impact for FEI Amalco as they did for FEVI, they would still jointly account for approximately 2.2% (or approximately $17 millions) of FEI Amalco's delivery margin.[38] All else equal, this addition will result in marginally higher exposure to industrial customers for FEI Amalco, compared to FEI.

Please also refer to the table below for a high level analysis of FEI and FEI Amalco delivery margin split between Residential/Commercial and Industrial customers.

[38] Using the 2013 test year numbers as applied for.

		FEI Amalco Margin		**FEI Margin**	
		$	**%**	**$**	**%**
Res/Com	Rates 1, 2, 3, 23	667,435	87.1%	551,130	87.9%
Industrials	***All*** other Rate Classes	99,115	12.9%	76,209	12.1%
		766,550	100.0%	627,339	100.0%

28.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.59.1

Equity of Historic Risk Premiums

BCUC 1.59.1 quotes a 1994 Briefing Document for State Commissions by Scott Hempling titled "The Regulatory Treatment of Embedded Costs Exceeding Market Prices: Transition to a Competitive Electric Generation Market" (Exhibit A2-13):

> "If the decision is asymmetrical against a utility's customer, it means that the government compelled the customer (due its captive status) to cover a utility's risk (e.g., by paying for a return on equity reflecting the risk of unmarketability) and then also to pay for that risk when it did not work out. That type of asymmetry, ... is certainly a cross-subsidy and likely to be unlawful under State law on that basis. If the regulator intends to act within the limits of regulatory law and logic, therefore, he or she has no choice but to determine the historic quid pro quos. ...
>
> It is one thing to say that historically, a utility's legally compelled investments were not subject to systematic competition. It is another thing to say that no matter what the external event, utility shareholders have no risk. That statement sounds wrong when made, and it is. If there were no risk, regulators would set authorized return on equity at the level of a highly-rate bond."

28.1 Do FEU agree that, in theory, ratepayers should not be required to (i) pay a risk premium to the shareholder of an immature utility to reflect the risk that the utility may not be a viable business when it matures, and then (ii) when the utility matures, indemnify the shareholder from any loss if the utility is not economic. Please explain why or why not.

Response:

The FEU disagree with the premise of the question. The FEU are not asking ratepayers to indemnify the Company, but are asking that the fundamental premise of regulation be respected, that is, that they should have a reasonable opportunity to recover their prudently incurred costs.

The assessment of the FEU's business risk and cost of capital has always proceeded on the fundamental premise that utilities are to have rates established which provide an opportunity for recovery of their prudently incurred costs, as supported by case law and Commission decisions, as discussed in response to BCUC IR 1.59.1. Management has obligations to both ratepayers and the shareholder to manage the utility in a prudent manner so as to (1) provide safe and reliable service to customers at reasonable rates; and (2) take steps to minimize the probability that prudently incurred costs are not recoverable. Nevertheless, the risk premium that the utility is allowed an opportunity to earn recognizes that the Commission cannot guarantee that the shareholder will be fully compensated for its investment "no matter what the external event", to quote the Hempling, Rose and Burns briefing document, e.g., should the utility ultimately not be economic.

29.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.20.1

FEVI / Squamish History

The FEU state in BCUC 1.20.1: "Westcoast Energy (the parent of New Centra) agreed to fund revenue deficiencies incurred by New Centra from 1996 – 2011 inclusive, to a specified maximum amount."

The FEU state in BCUC 1.18.1 that Order-in-Council 766 exempted TGI and TGS from Section 53 of the Utilities Commission Act for the purpose of amalgamation of those two utilities. FEU state in BCUC 1.18.2 that the shareholder was responsible for paying the Province $1.75 million as part of the TGS Termination Agreement.

29.1 Please state the specified maximum amount that Westcoast Energy agreed to fund revenue deficiencies incurred by New Centra from 1996 – 2011.

Response:

The FEU understand that the maximum amount Westcoast Energy agreed to fund revenue deficiencies incurred by New Centra was $120 million.

29.1.1 Do FEU consider that the above requirement demonstrates the Westcoast Energy shareholder was responsible for the risk that FEVI would not be an economic mature utility by 2011? Please explain why or why not.

Response:

Westcoast Energy was the shareholder of what was then New Centra at the time of the execution of the VINGPA agreement, in which Westcoast agreed to fund the development of revenue deficiencies up to a maximum amount over a defined period. In exchange for this investment, significant government support was provided to assist the development of New Centra.

The FEU believe that Westcoast's risk as a shareholder was represented by its equity investment in New Centra. The FEU believe that the risk profile of the investment to fund the revenue deficiencies was much less and did not reflect the risk of FEVI becoming an economic mature utility by 2011. It is reasonable to assume that Westcoast would have had an expectation that the investment to fund revenue deficiency would be fully recovered from customers over time as the utility matured. In any event, FEVI is an economic utility and the funds invested to fund the revenue deficiency, along with the revenue deficiency itself have been repaid and the risk noted above is no longer relevant.

29.2 Please explain why the shareholder was required to pay the Province $1.75 million as part of the TGC Termination Agreement. Please specifically identify the risks the shareholder had which were eliminated or mitigated through the TGC Termination Agreement.

Response:

The payment of $1.75 million was the result of a negotiation between the Province and TGS. As part of that negotiation, TGS agreed to pay the Province $1.75 million, and TGS relieved the Province of its obligation to fund the Rate Stabilization Facility (RSF). In return, the RSF was eliminated, TGS was amalgamated into TGI and TGS was relieved of any financial obligation to the Province. Specifically, by eliminating the RSF, not only did the Province limit its exposure to fund the RSF, TGS also eliminated its exposure to repaying the Province if the RSF was in a "draw" position.

30.0 Reference: Request for Common Rates

Exhibit B-3, Section 6, pp. 115-124

Administrative Cost Savings

The FEU include in Section 6 of the Application administrative cost savings related to ease of administration (Section 6.4), regulatory efficiencies (Section 6.6.1) and other financial efficiencies – auditing and rating agency requirements (Section 6.6.4).

30.1 Please prepare a NPV analysis which quantifies the cost impacts related to ease of administration, regulatory efficiencies and auditing and rating agency requirements, together with any additional administrative related costs/benefits, under the following amalgamation/postage stamp rates scenarios: (i) FEVI/FEI/FEW/FEFN; (ii) FEI/FEVI/FEW; and (iii) FEI/FEVI and FEVI/FEW.

Please only include cost impacts related to postage stamp rates, and exclude any cost impacts related to amalgamation. Please include in the analysis any costs related to regulatory approval and implementation of postage stamp rates. Please include a detailed description of each line item included in the analysis, and state all assumptions made.

Response:

Amalgamation is essential to achieve whatever savings are possible from postage stamping. That is, in order to have common rates, the FEU require legal amalgamation. Therefore, savings are dependent on both legal amalgamation and postage stamping occurring together and as such, the costs and benefits should not be isolated or segregated from one another.

As such, please refer to the response to BCUC IR 2.2.1.1 for the NPV analysis which quantifies the impacts under the various scenarios as requested. While regulatory efficiencies will be achieved, as discussed it is difficult to quantify and we have excluded this upside. Please refer to the response to BCUC IR 2.2.2 for a description of each line item.

Please also refer to the response to BCUC IR 2.30.1.2 for the NPV analysis which assumes that separate service areas are maintained without common rates, for the various scenarios as requested.

30.1.1 Please revise the analysis above on the assumption that there was a requirement for no loss of granularity of costing data from postage stamp rates compared to the status quo (i.e. continued maintenance of regional records).

Response:

Please refer to the response to BCUC IR 2.31.2 which discusses the availability of regional costing data. Regulatory efficiencies have not been included in the analysis for reasons described in the response to BCUC IR 2.30.1, thus no change is required to the analysis to reflect no loss of granularity of costing data for regulatory purposes.

30.1.2 Please revise the analysis above on the assumption that FEI Amalco would be required to treat FEI, FEFN, FEW and FEVI as separate service areas with their own rate bases (i.e., maintain regional rates within FEI Amalco).

Response:

If FEI Amalco is required to maintain separate rate bases and separate rates / revenue requirements then there would not be the savings associated with postage stamping as discussed in response to BCUC IR 1.5.12. Legal amalgamation alone will still result in cost savings related to audit and rating agency fees and may result in reduced financing costs associated with short-term debt to the extent that the credit rating of the amalgamated company remains at the existing FEI level. As discussed in the response to BCUC IR 2.1.2, while the credit rating agencies have indicated that amalgamation with postage stamp rates will likely be credit neutral, the credit rating agencies have not expressed their view on the credit impact of legal amalgamation with regional rates similar to the existing rates in place today. It is therefore not a certainty that the short-term interest benefit would carry on in a scenario where regional rates were maintained.

As clarified in the response to BCUC IR 2.2.1, the NPV analysis in response to BCUC IR 1.5.11 included the costs and benefits of amalgamation and postage stamp rates. The analysis in the response to BCUC IR 1.5.11, in addition to the various scenarios, has been updated below to assume separate service areas are maintained without common rates. This analysis therefore provides the NPV of amalgamation alone, without any cost and benefits of postage stamp rates.

This NPV analysis assumes that the existing FEI credit rating carries forward; however, without this interest benefit, the maintenance of a regional rate structure with legal amalgamation results in a negative net present value in all cases.

Approximate NPV of Amalgamation Costs & Benefits, 10 Years ($ Thousands)

Postage Stamp Benefits Excluded

	FEI, FEVI, FEW, FEFN		i) FEI, FEVI, FEW		ii) FEI, FEVI		iii) FEVI, FEW
	Short Term Debt		Short Term Debt		Short Term Debt		
	$ 25,000	$ 50,000	$ 25,000	$ 50,000	$ 20,000	$ 45,000	
Discount Rate	6.69%						
Present Value of Benefit of Amalgamation							
Depreciation and Amortization extended ~ 50 Years	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Recovery - assumed 3 Year Benefit	-	-	-	-	-	-	-
Short Term Interest Differential - 10 Year Benefit 1.5%	2,227	4,453	2,227	4,453	2,004	4,008	-
Audit Savings	128	128	128	128	128	128	-
Tax Shield on Amalgamation Costs	733	733	733	733	733	733	710
Total of Present Value of Benefits	3,088	5,315	3,088	5,315	2,865	4,869	710
Present Value of Cost of Amalgamation							
Total Cost of Amalgamation	3,550	3,550	3,550	3,550	3,550	3,550	3,265
Total Present Value of Cost	3,550	3,550	3,550	3,550	3,550	3,550	3,265
Net Present Value of Benefits	$ (462)	$ 1,765	$ (462)	$ 1,765	$ (685)	$ 1,319	$ (2,555)

30.2 Do FEU consider that costs related to the postage stamp rates proposal which are sunk (i.e. not avoidable) should be included in the postage stamp rates cost benefit analysis? Please explain why or why not.

Response:

Yes, all costs related to the amalgamation and postage stamping should be included at this time to assess whether it is beneficial to proceed with the proposal to amalgamate and establish postage stamp rates. As discussed in the responses to BCUC IR 2.1.3 and BCUC IR 2.1.3.1, the one-time costs for amalgamation are still avoidable with the exception of approximately $1.5 million related to forecast Application costs. However, the costs of the Application reflect a necessary component of achieving amalgamation and thus are an appropriate cost to include in the analysis.

30.2.1 Please revise the analysis above to exclude any costs which would not be avoided after the conclusion of this proceeding.

Response:

Please refer to the response to BCUC IR 2.30.2. The FEU do not believe that it is appropriate to exclude the Application costs, which are not avoidable, from this analysis.

Nevertheless, the FEU have provided the analysis as requested below. The first table includes all other costs and benefits of amalgamation and postage stamp rates. The second table assumes that regional rates are maintained (while this table assumes interest costs savings, please refer to the response to BCUC IR 2.30.1.2 for a discussion of the lack of certainty around these interest cost savings).

Table 1: Common Rates, Excluding Application Costs

Approximate NPV of Amalgamation Costs & Benefits, 10 Years ($ Thousands)
Application Costs Excluded

	FEI, FEVI, FEW, FEFN		i) FEI, FEVI, FEW		ii) FEI, FEVI		iii) FEVI, FEW
	Short Term Debt		Short Term Debt		Short Term Debt		
	$ 25,000	$ 50,000	$ 25,000	$ 50,000	$ 20,000	$ 45,000	
Discount Rate	6.69%						
Present Value of Benefit of Amalgamation							
Depreciation and Amortization extended ~ 50 Years	$ 402	$ 402	$ 402	$ 402	$ -	$ -	$ 402
Income Tax Recovery - assumed 3 Year Benefit	243	243	243	243	163	163	95
Short Term Interest Differential - 10 Year Benefit 1.5%	2,227	4,453	2,227	4,453	2,004	4,008	-
Legal, Audit & Rate Agency Savings	846	846	846	846	846	846	-
Tax Shield on Amalgamation Costs	358	358	358	358	358	358	335
Total of Present Value of Benefits	4,076	6,303	4,076	6,303	3,371	5,375	832
Present Value of Cost of Amalgamation							
Total Cost of Amalgamation	2,050	2,050	2,050	2,050	2,050	2,050	1,765
Total Present Value of Cost	2,050	2,050	2,050	2,050	2,050	2,050	1,765
Net Present Value of Benefits	$ 2,026	$ 4,253	$ 2,026	$ 4,253	$ 1,320	$ 3,324	$ (933)

Table 2: Regional Rates, Excluding Application Costs

Approximate NPV of Amalgamation Costs & Benefits, 10 Years ($ Thousands)

Postage Stamp Benefits & Application Costs Excluded

	FEI, FEVI, FEW, FEFN		i) FEI, FEVI, FEW		ii) FEI, FEVI		iii) FEVI, FEW
	Short Term Debt		Short Term Debt		Short Term Debt		
	$ 25,000	$ 50,000	$ 25,000	$ 50,000	$ 20,000	$ 45,000	
Discount Rate	6.69%						
Present Value of Benefit of Amalgamation							
Depreciation and Amortization extended ~ 50 Years	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Income Tax Recovery - assumed 3 Year Benefit	-	-	-	-	-	-	-
Short Term Interest Differential - 10 Year Benefit 1.5%	2,227	4,453	2,227	4,453	2,004	4,008	-
Audit Savings	128	128	128	128	128	128	-
Tax Shield on Amalgamation Costs	358	358	358	358	358	358	335
Total of Present Value of Benefits	2,713	4,940	2,713	4,940	2,490	4,494	335
Present Value of Cost of Amalgamation							
Total Cost of Amalgamation	2,050	2,050	2,050	2,050	2,050	2,050	1,765
Total Present Value of Cost	2,050	2,050	2,050	2,050	2,050	2,050	1,765
Net Present Value of Benefits	$ 663	$ 2,890	$ 663	$ 2,890	$ 440	$ 2,444	$ (1,430)

31.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.8.2, 1.146.1, 1.132.1; BCUC Decision G-101-93, p. 7

Granularity of Data

The FEU state in BCUC 1.8.2: "... moving to postage stamp rates based on the FEI rate design will provide the requisite data required to ensure efficient regulation."

Commission Decision G-101-93 (Exhibit A2-2) stated on page 7 "... the Commission approved consolidation [of the Lower Mainland, Inland and Columbia Divisions] with certain conditions. The impact of consolidation will be closely monitored by the Commission and if necessary, this approval may be reconsidered in future. In addition, internal divisional accounts must be maintained so that rate base and cost of service can be determined in future rate design applications. ... BCGUL will be required to demonstrate each time that any rate change will preserve or enhance the revenue to cost ratio for each divisional rate class as determined in this Decision."

The FEU state in BCUC 1.146.1, in response to a request to provide operating data for Lower Mainland, Inland and Columbia: "A breakdown of rate base and O&M expenses by service area is not available. This data is not tracked by service area, but is recorded for FEI as a whole. Therefore the system is unable to generate regional data."

The FEU state in BCUC 1.132.1: "There are no costs that have been directly assigned to customer classes in the COSA study filed with the Application."

31.1 Please describe the type of data that may no longer be available if amalgamation with postage stamp rates is approved.

Response:

Based on the current methods used to provide data for each of the existing utilities, and as described in the response to BCUC IR 1.146.1, certain data that is required to calculate the revenue requirements by service area will no longer be directly available once amalgamation proceeds.

The FEU currently maintain, and will continue to maintain, the following information by service area within their systems:

- Sales volumes

- Customers
- Delivery (including RSAM), commodity and midstream revenues
- Other revenues such as late payment fees and service charges

Other items can be determined through a process of adding together specific locations that are assigned to a service area. These would include:

- Property taxes on assets that physically reside in and provide service to a service area
- Property plant and equipment and related depreciation for assets that physically reside in a service area and provide service only to that area
- Inventories that physically reside in a service area and provide service only to that area
- O&M expenses for those cost centres that provide service directly to a service area

Finally, there are some items that the FEU would not be able to track by service area. For these items, some alternate allocation methodology would need to be developed, potentially within the COSA model. These include:

- O&M expenses for shared cost centres (currently these are allocated using shared services agreements that would cease to exist)
- Property plant and equipment and related depreciation for assets that provide service to a broader group of customers and also for most general plant items (currently these costs are generally allocated through charges between the service areas and those related agreements would cease to exist)
- Property taxes on assets that are shared or provide service to more than one service area
- Centralized inventories
- Deferred charges and related amortization – as there would be no separate approval of deferred charges by service area, they could not be tracked by service areas
- Gas costs, gas in storage and associated line pack – with combined gas portfolios there would no longer be a basis to record these items to particular service areas. Today the FEI gas supply portfolio is allocated to the various FEI service areas, including FEFN. Since 2010, after the FEW distribution system was converted from propane to natural

gas, the FEW natural gas requirements have been fully amalgamated into the FEI gas supply portfolio and no separate cost allocations are needed for current gas cost recovery rate setting. Today the FEVI gas supply portfolio is managed as a separate portfolio however, with the amalgamation of the FEVI and FEI gas supply portfolios, an allocation would then also be required to allocate costs to the FEVI service territory.

- Cash working capital – the underlying data to support the studies to calculate lead/lag days would not be available.

Although income tax is calculated based on the items above, additional allocations of undepreciated capital cost (UCC) and other tax permanent and timing differences would need to be made.

For the purposes of the COSA model, all the current information that is currently used to allocate the costs will continue to be available by service area.

31.1.1 For each type of data, please state if this has been provided to, or requested by, the Commission in previous regulatory filings.

Response:

All of this data has been provided to, or requested by, the Commission in previous regulatory filings.

31.2 Please detail the specific requirements that would have to be made of FEI Amalco to ensure that there would be no loss of granularity of data if postage stamp rates were accepted.

Response:

If postage stamp rates are approved, then the information as indicated in response to BCUC IR 2.31.1 would no longer be directly available by service area in the same manner. If the Commission required a separate cost of service for each of the pre-amalgamation utilities, or if some other regional rate structure is approved by the Commission, FEI Amalco would need to develop alternate allocation methodologies for each of the items listed. For example, today FEFN uses FEI's lead/lag days to calculate cash working capital. This same approach could be used for the former FEVI and FEW service areas if acceptable to the Commission.

31.3 Is it FEU's position that it has complied with Commission Order G-101-93 to maintain internal divisional accounts so that rate base and cost of service of the Lower Mainland, Inland and Columbia regions can be determined in future rate design applications? Please explain why or why not.

Response:

Yes. The amalgamation and then postage stamping of the delivery (and later commodity) rates for FEI's three divisions had the same effect that the postage stamping of all the remaining service areas of the FEU will have. That is, certain information is no longer directly available, and a number of allocation methodologies have been developed to share those costs that are now common to all service areas. By developing these allocation methodologies FEI is able to provide COSA models for each of Inland, Columbia and Lower Mainland today (see attachment to BCUC IR 2.31.3.1), and will be able to provide COSA models for the former FEVI, FEW and FEFN in the future.

Commission Order No. G-101-93 was the first of several Commission Orders regarding FEI rate design applications. Three other decisions are relevant to the discussion:

- G-98-96 dated October 7, 1996, re 1996 Rate Design Application;
- G-74-00 dated July 27, 2000, re Southern Crossing Pipeline Cost Allocation; and
- G-116-01 dated November 7, 2001 re 2001 Rate Design Application.

In the subsequent rate design applications since 1993, the Company has consistently moved away from COSA results based on the historical service areas. In terms of the asset management and operations within the Company there is no separation between Inland and Columbia and in many instances there is no relevant separation between any of the service areas. The operation of the Company and its costs occur on a centralized basis for service to all customers. The creation of Lower Mainland, Inland or Columbia rate bases and embedded cost of service can only be accomplished by performing allocations of significant common costs.

Even in the 1996 Rate Design proceeding in responding to an information request the Company wrote the following response:

> *"For rate setting purposes, the boundaries of former companies are no longer meaningful. Separate rates would only be meaningful if BC Gas were to establish rate zones for all groups of similarly situated customers throughout the BC Gas service territory. Rate zones would need to be based on thorough analysis of the underlying cost to serve and include such criteria as customer density, construction and operating cost differences.*
>
> *For day to day operational purposes, Inland and Columbia are operated as a common service area. Furthermore, for gas supply and transmission purposes, the BC Gas system operates in many respects as an integrated network. Therefore, BC Gas no longer considers the divisional FDC results to be appropriate for rate setting purposes."*

In 2000, the Southern Crossing Pipeline Cost Allocation Application and Decision did not regard the SCP transmission asset as belonging to any particular geographical service area but rather as a cost for the whole of the Company, and in the cost allocation process identified certain customers who would not be allocated costs, due to the fact they were bypass customers, large industrial customers (Rate Schedule 22B) who were located in an area where they would not benefit from SCP and large industrial interruptible customers in the Lower Mainland. Aside from approximately 50 industrial customers, all customers regardless of location benefitted from this asset and were to share in the cost of the Pipeline that is located in the Inland, West Kootenay and South Okanagan regions.

31.3.1 If the answer to the above question is yes, please provide recent internal divisional accounts and cost of service studies for the Lower Mainland, Columbia and Inland divisions.

Response:

Attached as requested are the COSAs for the three service areas which contain an allocation of the accounts by division: Lower Mainland, Inland and Columbia, consistent with the methodology used for the FEI Mainland COSA presented in Appendix H-5. This methodology is discussed in the Application Table 9-5 Delivery Cost of Service Methodology Comparison and Table 9-6 Gas Supply Commodity and Midstream Cost Methodology Comparison, and allocates costs to the service areas using various factors, rather than directly assigning specific assets by location code. As the systems and operations of the areas have become increasingly integrated, the amount of information that can be directly tracked in an account by service area has decreased, and FEI relies more on the allocation of costs to accounts. This enables FEI to maintain the rate base and cost of service elements that are required to address any future rate designs.

Since the 1993 Phase B Rate Design and prior to this year's Rate Design, FEI is not aware of being requested to provide the Rate Base and embedded cost of service studies by service area for Lower Mainland, Inland and Columbia. For its Rate Design applications in 1996 and 2001, FEI prepared regional COSAs but, as discussed in the response to BCUC IR 2.31.3, the Company believes that due to the significant level of common costs and integrated nature of its operations, regional COSAs are no longer relevant for rate setting. See also the response to BCUC IR 2.12.1.

As discussed in response to BCUC IR 2.31.1, FEI continues to maintain divisional accounts for sales volumes, customers, delivery (including RSAM), commodity and midstream revenues, and other revenues such as late payment fees and service charges. These are readily available and provided in annual filings with the Commission and have not been duplicated here.

In addition, consistent with BCUC IR 2.31.1, FEI has the ability to calculate property taxes on assets that physically reside in and provide service to a service area, property plant and equipment and related depreciation for assets that physically reside in a service area and provide service only to that area, inventories that physically reside in a service area and provide service only to that area, and O&M expenses for those cost centres that provide service directly to a service area. However, gathering some of this information is a manual process and the information is not readily available without additional effort.

However, in the table below, FEI provides a breakdown of its distribution assets by region (through a summation of location codes) as at December 31, 2010, as recorded in the SAP system. These distribution assets not only comprise 62% of total PP&E but also are the bulk of assets that physically reside in and provide service to a service area as described above.

Note that for the asset classes 474 and 478 related to meters (where some amounts are shown as "unassigned"), FEI does not rely on the regional data below from its SAP system but instead relies on its Meter Management System to produce more granular information. Since meters are managed centrally through the meter shop, and due to the large volume of meter movements and the costly administrative effort that would be associated with tracking each meter individually, meters are not tracked by region.

FEI Distribution Plant						Unallocated		
Class	Description	Inland	Columbia	Lower Mainland	Total	Overhead	Unassigned	Grand total
47000	DS Land	963,606	50,717	2,356,432	3,370,754	43,672		3,414,427
47200	DS Structures & Improvements	8,135,011	1,100,763	3,242,570	12,478,345	3,272,310		15,750,655
47300	DS Services	163,029,214	19,013,721	407,516,672	589,559,607	118,051,250		707,610,857
47400	DS Meters/Regulators Installations	39,212,199	2,291,249	65,764,287	107,267,736	30,466,475	13,051,507	150,785,718
47500	DS Mains	189,957,564	17,715,398	563,386,667	771,059,629	138,173,064		909,232,693
47600	DS Compressor Equipment	311,964		228,559	540,523	485,806		1,026,329
47710	DS Meas/Reg Equipment	33,975,242	3,680,497	36,144,444	73,800,183	13,885,566		87,685,749
47810	DS Meters	22,043,782	409,122	63,867,863	86,320,767	26,092,989	102,090,592	214,504,348
		457,628,582	**44,261,467**	**1,142,507,495**	**1,644,397,544**	**330,471,132**	**115,142,099**	**2,090,010,774**

31.3.2 If the answer to the above question is no, do FEU consider there is a risk of loss of granularity of data following approval of postage stamp rates even if the Commission requires that FEU ensure no loss of granularity of data? Please explain why or why not.

Response:

The FEU do not believe that it is necessarily true that there will be a loss of granularity due to amalgamation but rather there may be a change in how costs are tracked, which would require an allocation of costs to the service areas. If directed, the 'granular' information can be tracked and allocated, which while feasible, will incur additional effort.

31.4 Has there been an overall reduction in the number of directly assigned assets in the FEI costing study since the revenue requirement and rate base of the Inland and Columbia regions were amalgamated with the Lower Mainland? If yes, please explain why, and if this negatively affects the accuracy of the COSA.

Response:

Yes, there has been an overall reduction in the number of directly assigned assets in the FEI COSA study. These reductions do not impact the accuracy of the COSA study.

The costs for serving Byron Creek in previous COSA studies for Rate Design applications were directly assigned. Since the asset costs are now fully depreciated it would make no difference in the COSA studies if they were or were not directly assigned since they are at zero dollars.

There were a few other asset costs that were directly assigned in COSA studies for previous Rate Design applications which no longer exist and as such do not affect the accuracy of the current COSA study.

The FEU note that the Inland, Columbia and Lower Mainland regions were legally amalgamated in 1989. This differs from the present situation, where both a legal amalgamation and an amalgamation of the cost of service are occurring at the same time.

32.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.79.1, 1.76.2;

Regional Variations

The FEU state in BCUC 1.79.1: "The FEU do not believe that regional rate designs would be considered more efficient than postage stamp rate designs."

The FEU state in BCUC 1.76.2: "If amalgamation and postage stamp rates are not approved, then the FEU will consider filing rate design applications for each utility, which may involve rebalancing given the current R:C ratios as shown above. As a part of the individual rate design applications, FEU may also evaluate the current rate schedules and rate structures in place for each individual entity."

32.1 Do FEU consider that there are regional variations in incremental delivery costs in its delivery system? Please explain why or why not.

Response:

The FEU note that there are some regional variations in incremental delivery costs in their delivery system. However, it is important to note that similar variation does exist within a region for some customers. For instance, residential customers in the Fraser Valley might have some variations in terms of delivery costs incurred by the FEU to serve them as compared to customers in North Vancouver. However, these customers, despite some variations, are paying the same delivery rate as they both are located in the Lower Mainland region.

Since the delivery system of the FEU is all interconnected both within a region and between different regions, it is difficult to separate out the incremental delivery costs in their delivery system to serve those customers. Therefore, the FEU believe that all customers within a rate class should pay the same rate, regardless of location within their service areas.

32.1.1 Do FEU agree that regional rate designs are more efficient than postage stamp rate designs when there are meaningful regional differences in incremental costs? Please explain why or why not.

Response:

No, the FEU do not believe that regional rate designs are more efficient than postage stamp rate designs. Please see the responses to BCUC IR 2.32.1 and BCUC IR 2.39.5 indicating that customers served in one region could still have some meaningful variations in terms of incremental delivery costs to serve them. However, these customers are paying the same rate no matter where they are located in that region under the current rate design which has been thoroughly reviewed and approved by the BCUC.

32.2 Do FEU consider that there are regional variations in customer types, customer growth levels, and customer price responsiveness? Please explain why or why not.

Response:

There are some variations amongst the service areas of FEI, FEVI, FEW and FEFN in customer types, customer growth levels and customer price responsiveness. However, similar variation exists within a service area for some customers. For instance, residential customers in the Fraser Valley would have some variations in the above mentioned factors as compared to customers in Vancouver. However, these customers, despite their variations, are paying the same rate as they are both located in the Lower Mainland service area.

The table below demonstrates the amount of disparity between customers in various cities within the Lower Mainland service area.

2011 Actual Rate 1	Consumption (GJs)	Premises	UPC (GJ)
Abbotsford	2,746,293	29,026	94.6
Chilliwack	1,821,464	23,823	76.5
Hope	175,180	2,276	77.0
New Westminster	813,661	8,342	97.5
Surrey	10,807,224	100,273	107.8
Vancouver	10,617,435	93,739	113.3
West Vancouver	2,071,535	12,379	167.3

32.2.1 Do FEU agree that regional rate designs are more efficient than postage stamp rate designs when there are meaningful regional differences in customer types, customer growth levels, and customer price responsiveness? Please explain why or why not.

Response:

The FEU do not agree that regional rate designs are more efficient considering the types of differences presented. The differences in customer types are already handled by the different customer classes. Both customer growth levels and customer price responsiveness already vary within the regions and so it would be inappropriate to base rates on differences between regions while ignoring the differences within regions.

32.3 Do FEU consider that there are regional variations in customer preferences, for example, regarding price/reliability trade-offs? Please explain why or why not.

Response:

The FEU have not done any research in this area and do not know if there are differences in preferences across the regions. The FEU expect that the differences between FEI, FEVI, FEW and FEFN would be no greater than the differences across areas within FEI or the difference between specific customers in any given neighborhood.

32.3.1 Do FEU agree that regional rate designs are more efficient than postage stamp rate designs when there are meaningful regional differences in customer preferences (for example, regarding price/reliability trade-offs)? Please explain why or why not.

Response:

The FEU do not agree that regional rate designs are more efficient considering the types of differences presented. Customer preferences are likely to vary within the regions as much as they vary between regions. It would be inappropriate to base rates on differences between regions while ignoring the differences within regions.

32.4 Do FEU consider that there are regional variations in competition risk? Please explain why or why not.

Response:

The FEU interpret 'competition risk' to mean competitiveness between different energy sources versus natural gas.

As indicated in Sections 4.1 and 6.8 of the Application and several other IRs, customer energy choices and usage are informed by many factors such as capital cost investments, type of housing built, government policy, perceptions of the green attributes of energy sources and the price of energy. The FEU believe that regional variations exist only with respect to type of housing built and cost of delivered natural gas. Other factors, such as government policy, capital cost investment and perceptions about the green attributes of energy sources are equally applicable to all regions within British Columbia.

32.4.1 Do FEU agree that regional rate designs are more efficient than postage stamp rate designs when there are meaningful regional differences in competition risk? Please explain why or why not.

Response:

The FEU believe regional rate designs may be more effective at responding to competition risk than postage stamp rate designs in certain situations. However, the FEU do not agree that regional rate designs are more efficient than postage stamp rate designs. As elaborated in the response to BCUC IR 2.32.4, there are only a few components of competition risks that are regional within British Columbia. The regional components of competitive risk mainly arise from the varying price differential of natural gas prices within the FEU to other energy forms that exist across BC. For example, FEVI, whose rates are higher than FEI, faces higher competition risk from alternative energy sources than FEI. For this reason, the postage stamp rate design as proposed in this Application, aligns the rates within the FEU region, and as such is more efficient in addressing the regional differences in competition risk.

32.5 Do FEU consider that there may be differences in the regional changes in incremental delivery costs, customer types, customer growth levels, customer price responsiveness, customer preferences and competition pressures over time? Please explain why or why not.

Response:

While there may be differences in the regional changes in the factors listed above over time, the potential for such differences does exist within a region as well. Since FEI has postage stamp rates within its three service areas, which have some differences in the changes in factors mentioned above over time, the FEU believe that a regional rate structure is not warranted as discussed in the Application and as elaborated in the responses to BCUC IRs 2.32.1 to 2.32.4. The FEU in their future rate design might look at some of these factors and the differences in the changes in these factors over time to design a rate structure and customer classes that would best address these differences. As discussed in the Application, the current service area structure of the FEU is a function of past acquisitions and not indicative of a regional rate design. Moreover, these service areas are not homogenous. As indicated in the response to BCUC IR 2.45.3, some regions of FEI could be more similar to certain regions of FEVI, FEW or FEFN from, for example, an annual income and housing type perspective. Because similarities and differences amongst customers within and across service areas exist, the fact that the existing service areas may differ is irrelevant.

32.5.1 Do FEU consider that moving from regional rate designs to a postage stamp rate design could result in sub-optimal outcomes over time by restricting the ability of the utility to use innovative regional rate designs to respond to issues that are specific to that region? Please explain why or why not.

Response:

No. The proposed postage stamp rate design provides ample ability to respond to specific issues within the regions, just as the current postage stamp rate design within FEI is able to respond to the variety of issues found within the 850,000 customers served by that utility. The

FEU do not see issues specific to FEVI, FEW or FEFN that are not experienced within FEI to one degree or another or that could be dealt with more optimally with a regional rate design.

To clarify, the current service areas with FEVI and FEW are a function of past acquisitions and not indicative of a regional rate design. As mentioned in the responses to BCUC IR 2.32.1 to 2.32.4, the FEU believe the current situation does not warrant a regional rate design and that postage stamped rates are the most appropriate approach at this time. The current FEI region in effect is postage stamped and does not reflect sub-optimal outcomes. Should changing conditions require an alternative approach, it could be dealt with in a future application.

33.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.82.2, 1.153.1

Regional Variations - Utility Incremental Costs

The FEU include in BCUC 1.82.2 a table which shows, for each region, anticipated major growth related infrastructure projects (i.e. greater than $1m).

The FEU in BCUC 1.153.1 provide load duration curves for each of FEI (Mainland), FEVI, FEW and FEFN.

33.1 Do FEU consider that, in theory, an efficient rate design signals incremental costs on the margin, and recovers all costs in a way which least impacts customer consumption decisions? Please explain why or why not.

Response:

In theory, the FEU agree that an efficient rate design would be based on incremental costs. The FEU do not agree that an efficient rate design should minimize the changes that customers make in their consumption level. In some cases, it may be efficient to signal customers to reduce their consumption. This is generally the case when large costs would be incurred if overall consumption for the utility were to increase. In other cases it may be efficient to signal customers to increase their consumption level. This is generally the case when there are large fixed costs and there is little or no cost associated with increased consumption.

In the case of the FEU, the cost of gas is already placed at the marginal cost to the utility, reflecting an efficient rate design.

For delivery charges, the FEU face a large amount of fixed costs for the existing transmission, storage and distribution facilities. There are also some incremental costs associated with operating expenses as well as future capital needs. The proposed postage stamp rates are based on the current FEI rate design, which has been reviewed and approved by the Commission in several proceedings. The FEU consider that this rate design is efficient and meets the Bonbright principles discussed in the Application. As stated previously, changes in rate design may be considered in a future application. In developing rate design, efficiency is only one of the many factors that would be considered and using incremental costs in designing rates will be considered if it is determined to be appropriate.

On a theoretical basis, setting an efficient rate where there are low incremental costs for delivery would result in a rate design with a high customer charge and low energy charge. This would signal to customers that they should consume more energy. A high incremental cost might result in a rate design with a low customer charge and a high energy charge. However, if the energy charge is below the incremental rate, customers might still get a signal that would encourage energy use beyond what the incremental cost would indicate. If an inclining block rate were used such that the upper block were set at the incremental cost, then customers with large usage levels would face that upper block and would be given a signal to decrease consumption. However, in this case the lower block rate would have to be set significantly lower than the average rate in order to avoid collecting revenue amounts that exceed the cost. Customers with low usage would see this lower price signal and would be incented to consume more energy.

Because delivery charges are only a portion of the total charges for customers, these impacts would be tempered with the cost of gas.

33.1.1 Do FEU consider that it could also be argued that efficient rate designs can over-signal incremental costs at the margin where market barriers result in customers not responding efficiently (for example, where short payback periods are required in order to invest in efficient appliances). Please explain why or why not.

Response:

From a customer perspective, the decision about consumption generally includes both the cost of the fuel in question along with the capital costs of any appliances. The Application discusses this issue on pages 128-129 cited below, and the conclusion is that the FEU do not expect a material amount of fuel switching from electric to gas as a result of postage stamp rates.

> *"Overall, the FEU expect the fuel switching between natural gas and electricity to not be sufficiently material one way or the other. Amalgamation and common rates will improve natural gas prices in the FEVI and FEW service areas; however, operational price differential is only one of the many determinants that inform customers' energy choices. Other factors include initial capital cost investment, perceptions about the green attributes of the fuel and space concerns, as discussed in Section 4. Taking all these factors into account, the FEU do not expect any material fuel switching to take place from electricity to natural gas for space heating and hot water as a result of amalgamation and common rates."*

The FEU are not sure what is meant by rates that over-signal incremental costs, but in theory would agree that even a low energy rate will not signal customers to use more natural gas in the short-term when there is high capital cost associated with a new gas appliance. As discussed in the response to BCUC IR 1.81.6, over the long-term, customers will tend to better account for both the energy rate and cost of the appliance when making consumption decisions.

33.2 Please update the FEI Mainland Design Load Duration Curve provided in response to BCUC 1.153.1 to show system capacity.

Response:

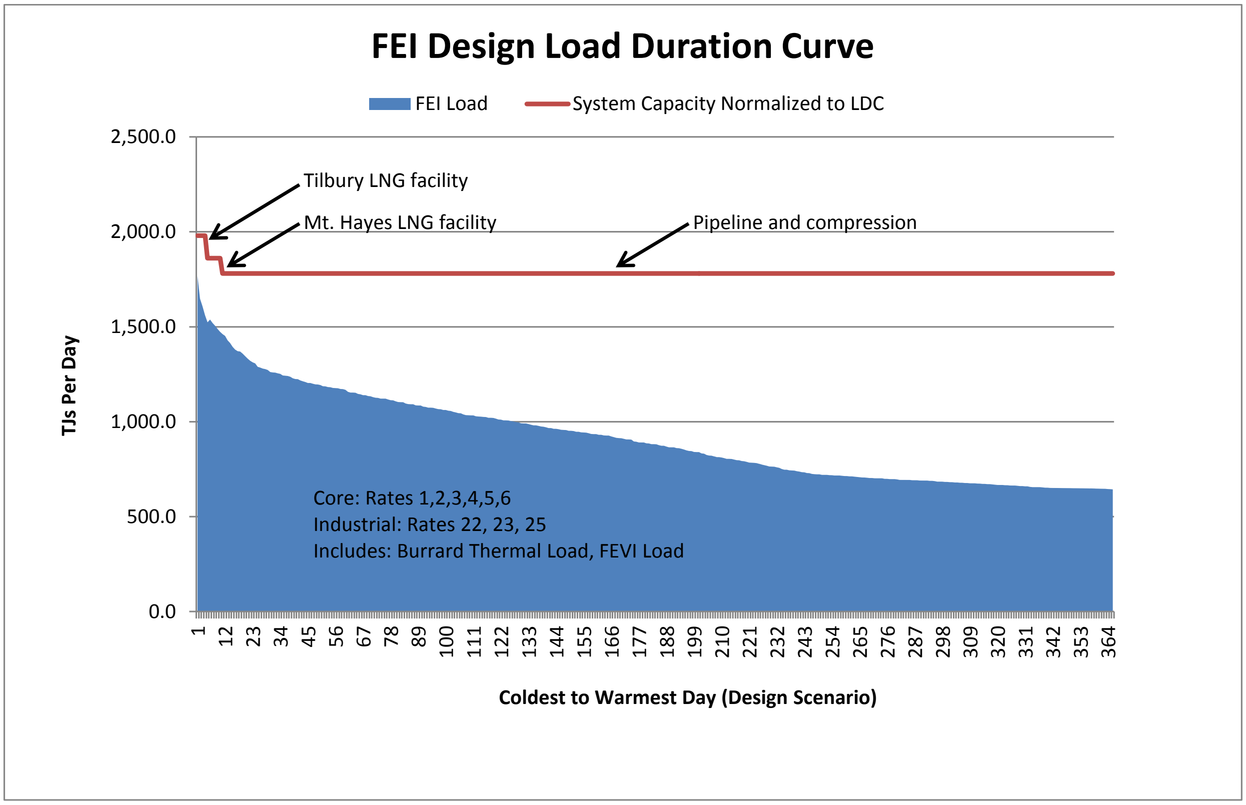
In the course of responding to this IR, the FEU reviewed the load duration and system capacity curves[39] filed in the response to BCUC IR 1.153.1 and determined that the load duration curve for FEI and the system capacity curves for FEVI, FEW and FEFN needed to be revised to provide a consistent basis of comparison. In particular, the graphs needed to be revised to reflect:

- the loads for Burrard Thermal and FEVI which flow through the FEI system;
- the availability of Mt. Hayes to meet system peak loads;
- the FEW load profile and limited line pack of the intermediate pressure Whistler Pipeline; and
- the FEFN load profile and limited line pack of the Fort Nelson lateral.

The revised load duration and system capacity curves presented below now reflect a consistent basis of comparison as discussed for each of FEI, FEVI, FEW and FEFN below.

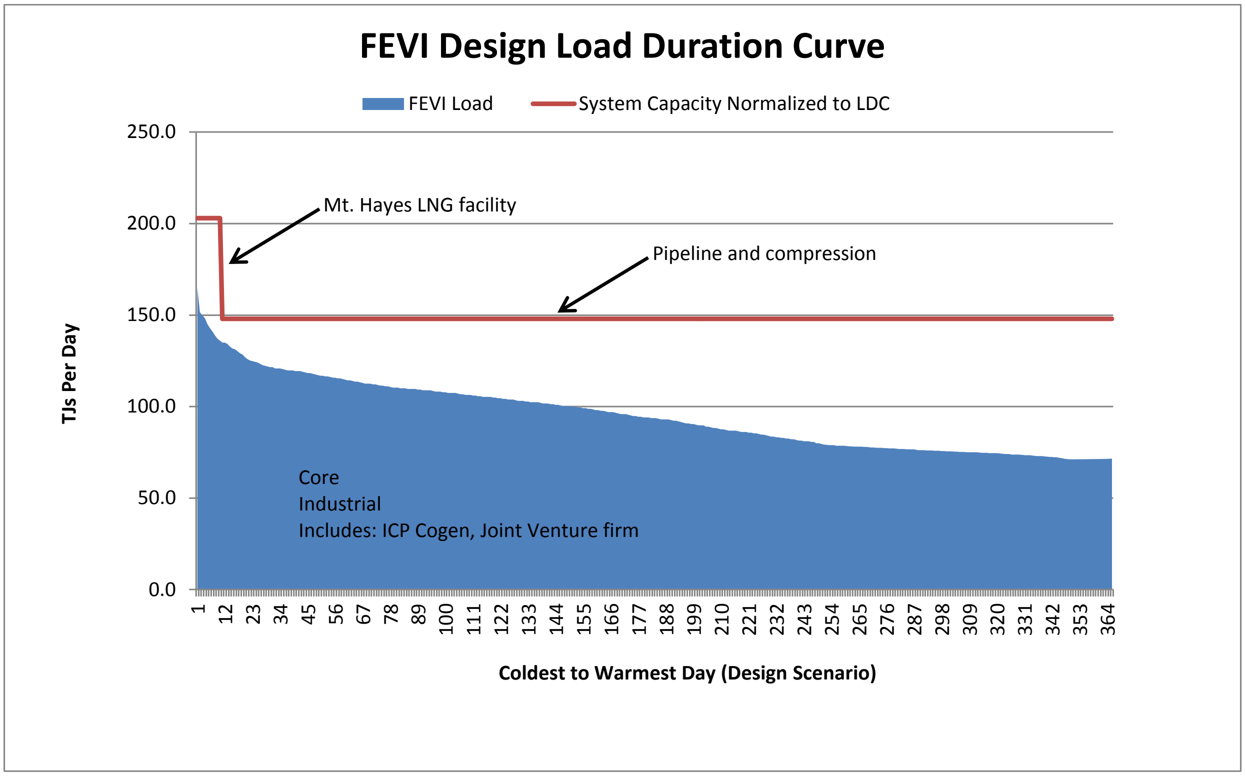
[39] The system capacity curves in each of the graphs represent the daily average system capacity values for comparison against the daily average demands represented by the load duration curves (i.e. they are normalized to the LDC in each graph).

FEI



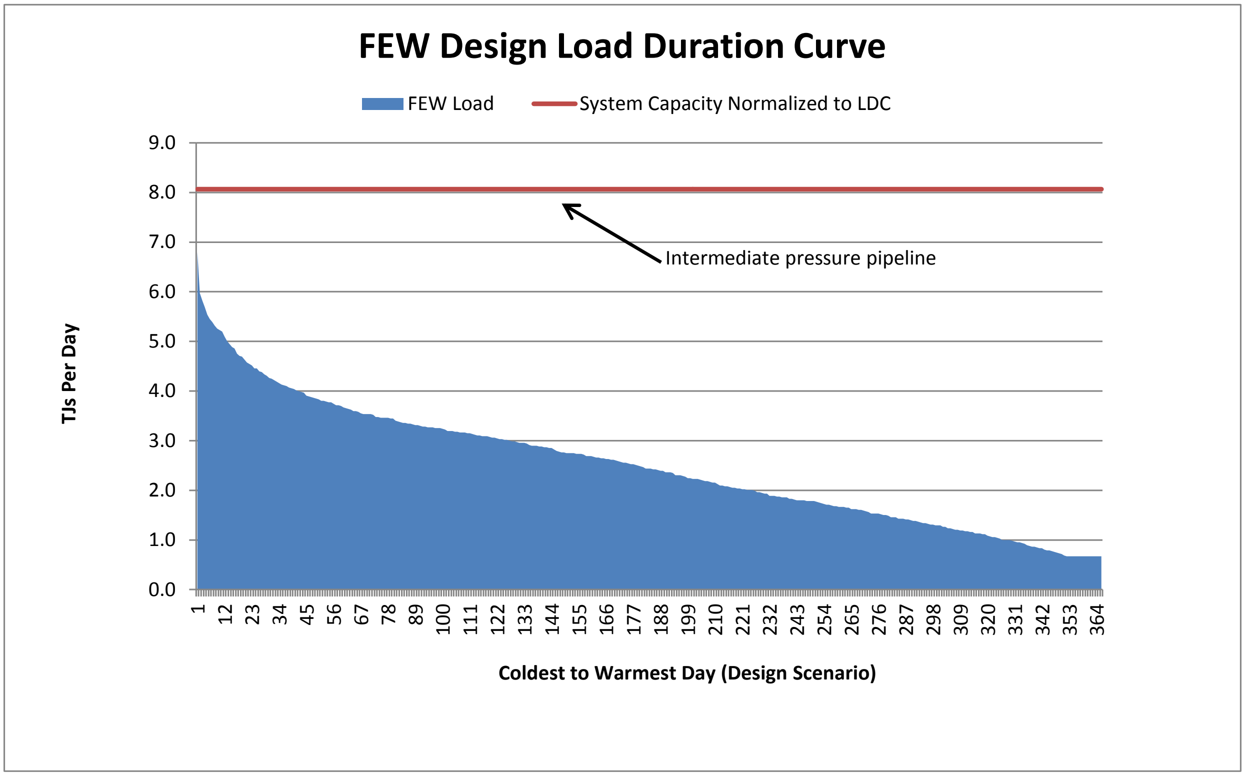
The load duration curve for FEI now includes the loads for Burrard Thermal and FEVI, which flow through the FEI system. The system capacity curve reflects the capacities of the Lower Mainland, Inland and Columbia regions in FEI as well as the availability of Tilbury and Mt. Hayes to meet system peak loads.

FEVI



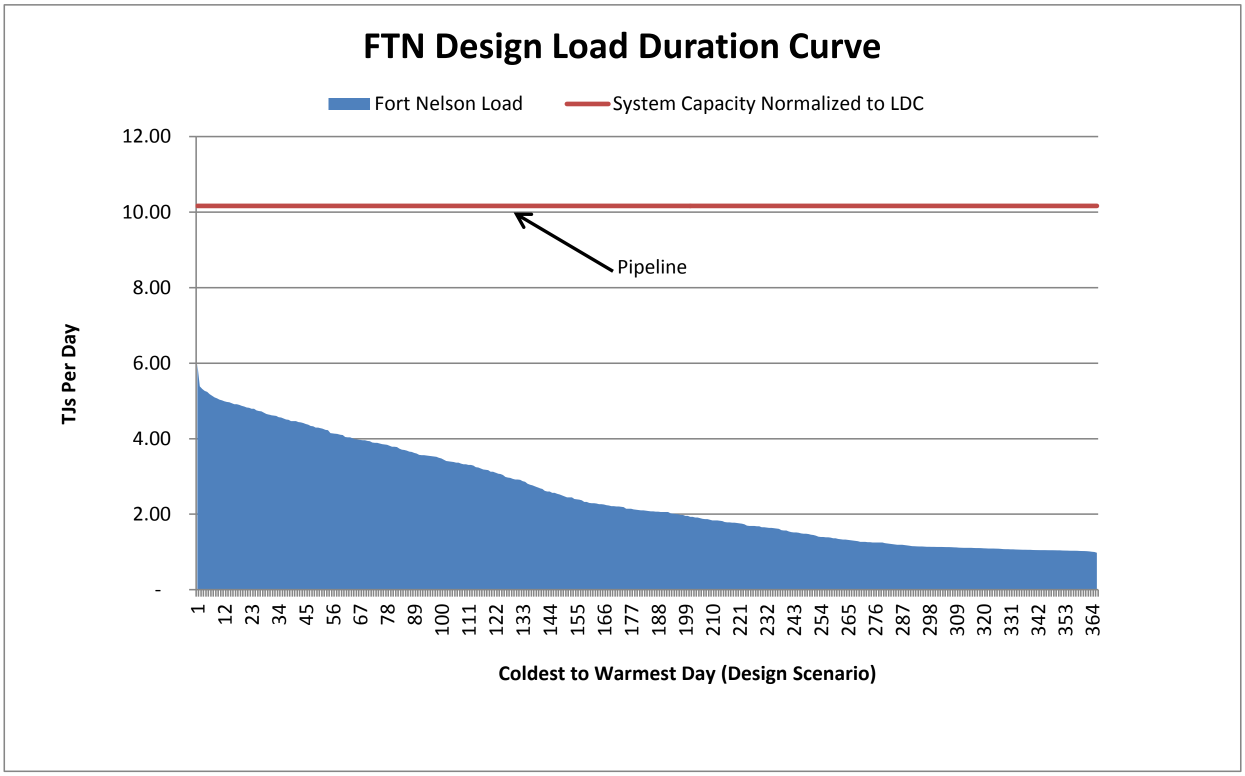
There are no changes to the FEVI load duration curve. The FEVI system capacity curve now reflects the availability of Mt. Hayes to meet system peak loads.

FEW



There are no changes to the FEW load duration curve. The system capacity curve now represents the daily average system capacity values instead of the instantaneous hourly system capacity values previously provided in the response to BCUC 1.153.1. The comparison of the daily average values between system capacity and load now provides a consistent assessment of all systems among the current utilities.

FEFN



There are no changes to the FEFN load duration curve. The system capacity curve now represents the daily average system capacity values instead of the instantaneous hourly system capacity values previously provided in the response to BCUC 1.153.1. Again, the comparison of the daily average values between system capacity and load now provides a consistent assessment of all systems among the current utilities.

33.2.1 Do FEU consider that the percentage of available system capacity differs between FEI, FEVI, FEW and FEFN? Please explain why or why not.

Response:

Yes, the FEU consider that the percentage of available System Capacity differs between FEI, FEVI, FEW and FEFN, just as it may differ from community to community within a service area or from neighbourhood to neighbourhood within a city. The percentage of system capacity in any location on the system is dependent upon several factors which can include:

- Year over year load change;
- The location on the system where the load change occurs;
- Changes in allowable maximum operating pressures of the pipe in service;
- System configuration - whether multiple pipes feed a given area or if an area is served by a single feed pipe; and
- The interdependence of assets used for multiple areas, such as the Mt. Hayes storage facility serving both FEVI and FEI or the Tilbury storage facility serving both the Lower Mainland and the Fraser Valley.

33.2.2 Please provide FEU's best estimate of the costs of the TGVI system capacity expansion referred to in BCUC 1.82.2.

Response:

The timing of the TGVI system capacity constraint referred to in BCUC 1.82.2 varies depending on the forecast scenarios. As stated on page 135 and 136 of the 2010 Long Term Resource Plan (LTRP), under the high forecast, the expansion could occur as early as 2017. Under the base forecast, the expansion could occur in 2021. Under the low forecast, the expansion could be delayed as far as 2027.

In the 2010 LTRP, three alternative solutions were described for addressing the approaching FEVI system capacity constraint. Each of these solutions has different cost implications.

The first alternative highlights the benefits of being able to manage system resources as a single service area having a common rate. This solution would be for the FEU's gas supply group to manage the allocation of the FEU's storage resources for the most cost effective benefit of all of the FEU's firm customers. The LTRP describes this alternative in terms of the current contractual arrangements for storage and send out between FEI and FEVI. The cost implications of this solution would stem from the potential need for FEI to acquire additional peak period system capacity to replace the Mt. Hayes resources that would be reallocated to FEVI. Pages 137 and 138 of the 2010 LTRP indicate that the FEI Coastal Transmission System has sufficient system capacity beyond 2035 as a result of commissioning the Mount Hayes facility. Some of this capacity could be utilized to serve Vancouver Island, likely making this the most cost effective solution, all things equal. While contractual agreements between FEI and FEVI can be amended under the current utility corporate structure, amalgamation and postage stamp rates would allow a more efficient approach to managing these resources for the benefit of both service areas. A complete study of the potential costs of this alternative has not been conducted to date and would be required in order to provide a proper cost estimate.

The second alternative as described in the 2010 LTRP is an infrastructure addition – the addition of a new compressor station in the Squamish area. A cost estimate of $24.2 million (P50 – 2007 direct costs) for this alternative was contained in the Mount Hayes CPCN Application submitted on June 5, 2007 (page 80).

The third option described in the 2010 LTRP involves the renewal of contractual arrangements between FEVI and BC Hydro for access to additional peaking capacity on the system. The cost implications of such an agreement are not currently available.

34.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.67.5, 1.67.6.1, 1.154.1, 1.152.2

Regional Variations - Customer Types/Growth

The FEU state in BCUC 1.67.5: "For example, FEI has a more diversified customer base compared to FEVI and FEW, who are dependent on a few industries such as ICP, pulp mills and tourism."

The FEU state in BCUC 1.67.6.1: "Amalgamation of FEW, whose exposure to the tourism industry is significantly higher than pre-amalgamation FEI's, will tend to increase FEI's exposure to negative events in the tourism industry."

The FEU provide in BCUC 1.154.1 a regional comparison of average annual growth in customers, which shows that for 2013 average annual customer growth is forecast at: FEV: 0.8%; FEVI: 2.5%; FEW: 0.7%; FEFN: 0.9%.

The FEU provide in BCUC 1.152.2 graphs showing the frequency distribution of normalized annual demand for residential customers in 2011 for FEI Mainland, FEVI, FEW and FEFN

34.1 Please explain the key reasons for regional variations in the normalized annual demand between FEI Mainland, FEVI, FEW and FEFN.

Response:

Please refer to the response to BCUC IR 1.158.1.

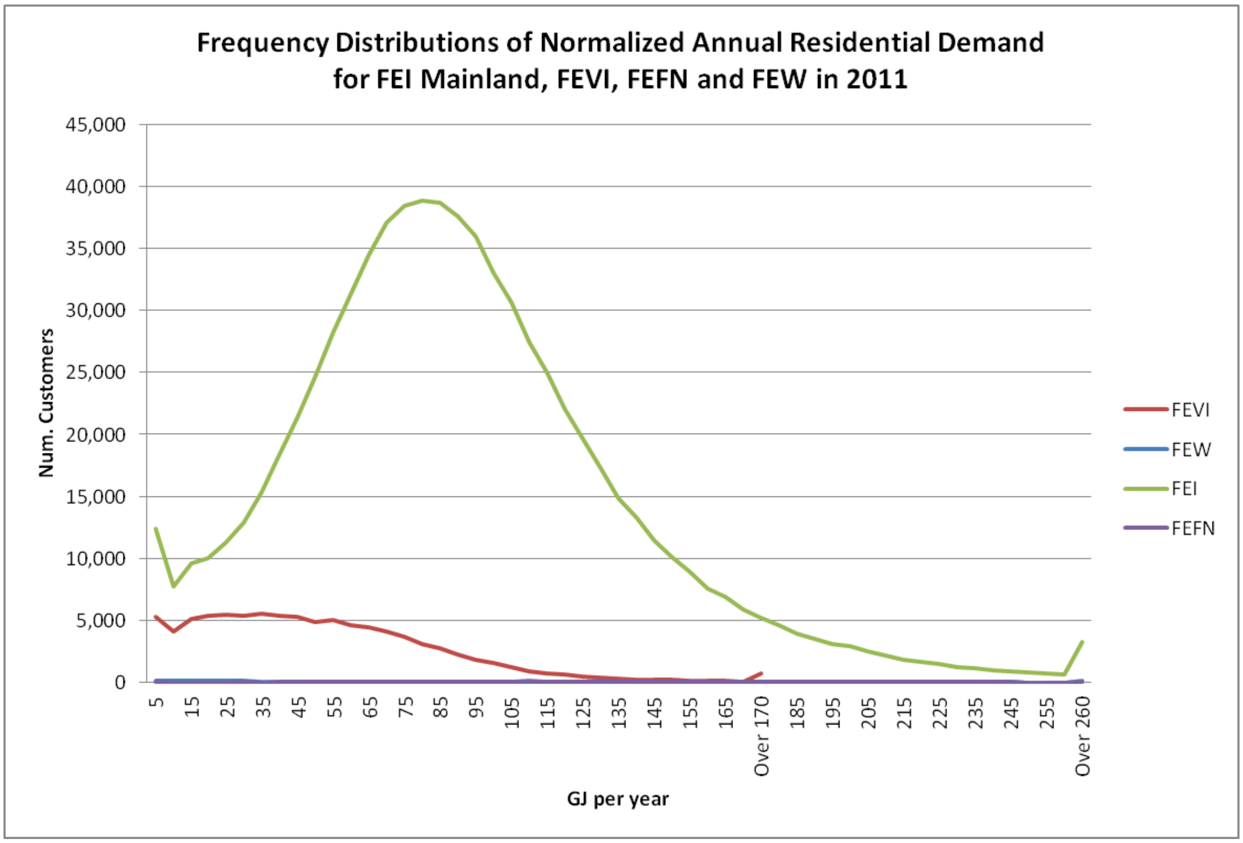
34.2 Do FEU agree that there is regional variation on residential customer consumption profiles and growth? If no, please explain why not.

Response:

The FEU agree that there are variations by region, community, and geographic area both within each of FEI, FEFN, FEVI and FEW, and between the utilities. The chart below summarizes the residential bill distribution data for 2011 presented in BCUC IR 1.52.1 and 1.52.2. The number of residential bills are presented instead of percentage of bills which allows a direct comparison of the bill distributions of FEI, FEVI, FEW and FEFN.

The size and diversity of customers in FEI is apparent compared to FEVI, FEW and FEFN. At every frequency interval there are more FEI customers than FEVI, FEFN and FEW customers combined. Note in the chart that the FEW and FEFN data appears relatively flat and is difficult to distinguish due to the low customer counts in those regions, relative to FEI.

For comparisons, the growth numbers are essentially the same for FEI, FEW and FEFN as represented in the response to BCUC IR 1.154.1. FEVI has a higher growth rate than the other three regions, but this is consistent with growth trends over the years, as also summarized in the response to BCUC IR 1.154.1.



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34.3 Please explain the reason for any differences in the proportion of (i) bypass and (ii) fixed price customers between FEI, FEFN, FEW and FEVI.

Response:

The FEU currently only have bypass agreements with 16 large customers in FEI due to their proximity to Spectra's Westcoast or TransCanada's Foothills major transmission pipeline systems. There are no bypass agreements with any customers in FEFN, FEVI or FEW. Therefore, differences in the proportion of bypass customers between FEI, FEFN, FEW, and FEVI are not meaningful.

Although customers have a fixed rate component to their bills, there is no rate schedule which has exclusively fixed rates. From a billing perspective, bypass customers come closest to the concept of fixed price customers, but as stated above there are no bypass (and hence fixed price) customers in FEW, FEVI or FEFN.

35.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.56.1, 1.147.3

Regional Variations - Price/Quality Trade-Off

The FEU state in BCUC 1.156.1: "[Municipal standards as to the quality of extensions (for example, use of concrete slurry compared to native fill)] can and do vary across the specific municipalities themselves and within the various regulatory entities."

The FEU state in BCUC 1.147.3: "In the case of FEI and FEFN, the delivery costs per kilometer of pipeline are low when compared to the other regions, as the systems are older relative to FEVI and FEW and therefore have been largely depreciated. Conversely, newer systems have higher delivery costs."

The FEU in BCUC 1.70.1 refer to FEW's "service area's commitment to reducing reliance on fossil fuels and commitment to renewable energy initiatives."

35.1 In general, are average municipal standards as to the quality of pipeline extensions similar in all regions (FEI, FEVI, FEFN, FEW)? In your response, please specifically state if average municipal standards in FEVI and FEW tend to be higher than FEI, and if average municipal standards for FEFN tend to be lower than FEI.

Response:

The FEU's standards to install pipelines are the same regardless of the Company or municipality. The FEU adhere to CSA Standard Z662 Oil and Gas Pipeline Systems as a benchmark for the physical construction and quality assurance for underground pipelines. Various municipalities in FEI and FEVI have additional local installation requirements as relates to restoration for asphalt road surfaces. The additional requirements are typically in place in established neighbourhoods where the FEU are attaching conversion services or conversion mains (i.e. an older home or street converting from oil, wood or propane to natural gas).

In this regard, the FEU experience a higher than average overall pipe installation cost in FEVI, although pockets of FEI (i.e. Vancouver) have comparable installation costs. In Victoria, for example, FEVI is obliged to submit a plan to the city in advance of construction not only for mains, but for individual service connections. In the Nanaimo region FEVI is required to submit third party pavement compaction testing for any excavation in a road allowance. In the Lower Mainland, some municipalities have put in place certain time restrictions for when work can be done as well as requirements for traffic plans.

Each municipality has similar and dissimilar concerns with utility installations and are moving towards addressing these concerns through various local requirements over and above the FEU's installation standards.

Municipalities are guarded as there are now many more independent contractors operating within their jurisdiction. These contractor's standards and repairs have in some cases become problematic. The difficulty in recovering costs from these companies to resolve these problems have forced the municipalities to become extremely diligent in the process of issuing permits, assessing permit fees for works to occur, and effecting permanent repairs. Although the FEU's work has not itself been an issue for municipalities, the FEU are being viewed in the same light as all the others working in the public road allowance, and our costs have increased in FEI, as well as FEVI as a result of this treatment.

To date FEW and FEFN have not had unusual municipal requirements imposed.

35.1.1 Do regional variations in municipal standards as to the quality of extension have an effect on average distribution costs in each region? Please explain why or why not.

Response:

Please refer to the response in BCUC IR 2.35.1.

Regional variations in Municipal Standards do have an effect on the installation costs. Zones that contain municipalities that have higher project costs will see an effect on the unit prices for that Zone. Vancouver Island municipalities, for example, have additional requirements for main and service installations related to paving, permitting, archeology and working around trees than their counterparts on the Mainland. These requirements do tend to increase the cost of installation.

To the extent that installation costs impact overall average distribution costs, regional variations in municipal standards would have a minor impact on the average. The average distribution costs in each region consist of a multitude of costs including transmission, supply, storage, operations, maintenance, financing, utility rate of return, etc.

The historical unit costs referred to above are used as a basis for the geo-price cost estimating methodology currently in place for the majority of mains and services projects. For those projects that fall outside the geo-price cost estimating methodology (i.e. exceptions to the norm such as larger diameter pipe, longer lengths, extraordinary conditions), these projects are manually estimated. Regional or municipal construction standards must be considered and included in the calculation of any estimated costs pertaining to work anticipated.

35.2 Please provide a table, comparing for the last three years, the following service indicators for FEI (separately for the Lower Mainland, Columbia and Inland service areas), FEFN, FEVI and FEFN. Please explain any significant variations.

- Response time to emergency calls
- Response time for answering service centre calls by a person
- Leaks per kilometer of distribution mains due to system deterioration
- Transmission system annual reportable incidents
- Number of third party distribution system damage incidents per 1000 housing starts.

Response:

The following table summarizes the FEU service indicators for the Lower Mainland, Columbia and Inland service areas as well as for FEFN, FEVI and FEW for the last three years. Within each service area there is a wide range for response times, leaks on mains and third party damage. Each municipality has its own set of variables (proximity to FEU musters, age of system, local construction activity, etc.) which impact the indicators.

	2009						2010						2011					
	Lower Mainland	Inland	Columbia	Fort Nelson	Vancouver Island	Whistler	Lower Mainland	Inland	Columbia	Fort Nelson	Vancouver Island	Whistler	Lower Mainland	Inland	Columbia	Fort Nelson	Vancouver Island	Whistler
Response time to emergency calls (minutes)	20.7	26.0	24.1	16.2	19.0	11.0	20.2	25.6	30.1	14.7	18.7	13.3	21.3	26.5	31.7	18.1	18.6	14.2
Response time for answering service centre calls by a person (%)	76.7	76.7	76.7	76.7	76.7	76.7	77.2	77.2	77.2	77.2	77.2	77.2	74.7	74.7	74.7	74.7	74.7	74.7
Leaks on distribution mains due to system deterioration	45	16	1	0	3	1	91	43	1	4	11	1	144	25	9	0	10	0
Transmission system annual reportable incidents	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of third party distribution system damage incidents	713	542	47	4	179	16	753	435	48	10	185	9	695	397	28	6	204	4

With regard to the "response time for answering service centre calls by a person", the FEU are unable to separate these by the geographical areas requested. The numbers provided are the province-wide response rates for these types of calls.

With regard to the "leaks per kilometer of distribution mains due to system deterioration", the absolute number of leaks on distribution mains has been provided as opposed to the ratio. The FEU are unable to go back to its gas main records at the end of 2009, 2010 and 2011 and provide segregation of the total kilometres of main by all of the geographical service areas requested. The increased number of leaks in 2010 and 2011 reflects a change in process for reporting and correcting leaks in comparison to 2009. (Reference: FEU 2012-2013 RRA, Exhibit B-6, response to BCOAPO IR 1.8.3)

With respect to the number of leaks, there are significantly more in the Lower Mainland and the Inland areas due to the size of the system and number of customers (service lines) in these areas. There are many other variables which impact the leak count in a service area. Age of the system and type of prevalent material (steel or polyethylene ("PE")) in use in the area are principal reasons why an area may have higher or lower numbers of leaks. In FEVI, for example, the system is relatively young and primarily PE which tends to yield lower leak frequencies. In FEW, the system was installed only very recently and leak experience is minimal. In areas of FEI such as Surrey and Kelowna where system growth has been more extensive and where PE pipe has been used (typically the norm in new installs today), leak frequencies are similarly lower.

With regard to the service indicator "number of third party distribution system damage incidents per 1,000 housing starts", this metric was changed to a directional indicator in 2004 and currently reads "number of third party distribution system damage incidents". The change was introduced and adopted as there was not a direct link between damages and housing starts.

35.3 Do FEU consider that there is a correlation between FEVI, FEW, FEFN and FEI embedded delivery costs per kilometer of pipeline and reliability of service received? Please explain why or why not.

Response:

The FEU do not fully understand the question. The standards for delivery and operations of the gas system across the FEU's service territory are consistent as is the reliability of service. Within segments of the system, due to age, location and other variables, more costs may be incurred for maintenance to ensure the same standard of reliability of service. However, the FEU do not see a direct correlation between embedded delivery costs per kilometer of pipeline and reliability of service received.

36.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.46.1.1, 1.17.1, 1.140.10

Combined Approach to Gas Supply

The FEU state in response to BCUC 1.46.1.1: "Cost savings or other benefits may be realized from an amalgamated gas portfolio over the longer term through further optimization of the resources in response to changing market conditions and availability of storage and pipeline transportation capacity. However, the cost savings or other benefits are not expected to be material in the immediate term as the management of the portfolios is already combined and the portfolios are already derived from a similar pool of resources. Furthermore, at this time, FEVI does not believe that these benefits would outweigh the impacts of reduced flexibility to manage the gas portfolios and any related price risk management activities in response to FEVI's unique circumstances."

The FEU state in BCUC 1.17.1: "the single most important item in an LRIC for FEU would be the long run incremental cost of gas which would be similar across FEI, FEVI, and FEW." (p. 73)

The FEU state in BCUC 1.140.10: "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. Sources of UAF include, but are not limited to, the following: system leakage ... lost gas ... measurement error.

36.1 As the commodity cost of gas is a pass through, would the LRIC of gas be the 'single most important item in an LRIC' for delivery rate design?

Response:

The FEU believe that the total cost of both gas and delivery should be included when considering an LRIC. Since most of the costs of the delivery system are fixed, the gas commodity becomes the primary (but not necessarily only) cost of the LRIC.

The FEU do not believe that the LRIC is a factor for determining the proposed delivery rates. If the FEU were to look at rate designs in the future that were not the traditional embedded cost-based rates, then LRIC might play a role but such non-traditional rates would need to look at the total cost of gas and delivery.

36.2 Please compare UAF volumes, as a percentage of total volumes, for FEI, FEVI, FEW and FEFN (using best estimates if accurate information is not available). Please explain any significant differences, including if there could be significant differences between the FEI, FEVI, FEW and FEFN in system leakage, lost gas and measurement error.

Response:

The following table provides the annual historical UAF as a percentage of the gas deliveries, by service area, for the previous five years; for rate setting purposes, the five year rolling average of the actual UAF percentages experienced is utilized as the forecast UAF percentage for the prospective period(s).

Annual Historical UAF as Percentage of Gas Deliveries for 2007-2011

	Year				
Service Area	**2007**	**2008**	**2009**	**2010**	**2011**
Lower Mainland (1)	0.03%	-0.20%	-0.16%	0.16%	0.69%
Inland	-0.45%	0.21%	-0.63%	0.12%	0.31%
Columbia	1.03%	0.16%	-0.62%	-0.45%	0.32%
Fort Nelson	0.47%	1.51%	0.37%	1.09%	-1.38%
Vancouver Island	1.94%	2.73%	1.14%	0.76%	1.62%
Whistler (2)					-0.21%

Notes: (1) Lower Mainland annual historical UAF data shown includes an adjustment related to an over accrual of gas deliveries identified in 2011 which, for UAF purposes, has been prorated over the prior ten-year period.

(2) The Whistler system was converted to natural gas during 2009. The 2011 data provides the initial, accurate natural gas UAF data. For rate setting purposes the five-year rolling average UAF for the Lower Mainland is utilized.

As discussed in the response to BCUC IR 1.140.10, 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. Although the FEU have various programs in place to help reduce the amount of UAF, UAF cannot be directly controlled by the utility and there is no mechanism in place to attempt to track UAF to its various causes.

The measurement error component, which includes the differences related to the measurement device accuracy tolerance of ± 1% and imprecisions in the allocations of consumption volumes to calendar periods for those customer classes having non-month end cycle based meter reading, is believed to be an important factor in the determination of the annual UAF percentages. For example, the negative percentages shown in the table above are the result of the measured volumes of gas deliveries to end use customers recorded in a given year, including gas used in operations, being greater than the measured volume of gas receipts during that year, and cannot be attributed to either system leakage or lost gas.

37.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.85.1, 1.74.4.4, 1.88.1, 1.87.1

Efficient Rate Design - Maturing Utility/Revenue Deferral Account

The FEU state in BCUC 1.85.1: "The FEU agree that one criterion for determining if a utility is a mature utility is whether growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities."

The FEU state in BCUC 1.74.4.4: "The FEU believe that maturing utilities, like FEVI and FEW, should be allowed greater flexibility in setting rates, including the acceptable range of [revenue: cost ratio] reasonableness."

The FEU state in BCUC 1.88.1: "FEVI is economic in its current state."

The FEU state in BCUC 1.87.1: "FEVI and FEW may consider non-traditional rate designs if postage stamp rates are not approved. Such rate designs may or may not be cost of service based, but in any event would need to allow the shareholder to earn a fair return on and of its investment. ... FEU does not believe that there is a need to set FEVI and FEW rates higher than cost of service at this time ..."

37.1 Do FEU consider that, for the purpose of determining if it would be appropriate to use a revenue deferral account for a maturing utility, the key criteria should be whether growth rates in customers, throughput and rate base have declined to levels that are in line with those experienced by mature utilities? Please explain why or why not.

Response:

The FEU consider that there are many factors in defining whether or not a utility is mature, as provided in the response to BCUC IR 1.85.1. As well, there may be many reasons to consider in establishing a deferral account, maturity level being only one of them. Such factors would need to be considered together as part of the determination of whether or not a utility is still maturing when looking at the appropriateness of a deferral account.

37.1.1 Do FEU consider that, if postage stamp rates are not approved, FEVI and FEW are sufficiently mature such that establishing a revenue deferral account would not be appropriate? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.86.1 regarding the maturity of FEVI and FEW. The FEU do not consider that the reason revenue deferral accounts are inappropriate at this time is solely on the basis of maturity level. There are many factors to consider in establishing a deferral account, maturity level being only one of them. As noted in the response to BCUC IR 1.87.1, FEVI and FEW would be cautious of the use of a revenue deferral account primarily because of the potential accumulation of a large revenue deficiency for future recovery from customers.

37.2 Do FEU consider that, if postage stamp rates are not approved, FEVI and FEW are not yet sufficiently mature to require revenue:cost ratios for each customer class to be within +/- 10%? Please explain why or why not, and discuss the criteria that should be used to determine when to put in place a transition plan to move revenue:cost ratios to within +/- 10 percent.

Response:

In the event that postage stamp rates are not approved, the FEU believe that FEVI's rate design could be rebalanced to allow for each customer class to be within +/- 10 percent. The earliest that the FEU would contemplate such an activity would be in 2014. However, the FEU believe that for FEW, no transition plan is required as the rate design today currently has a revenue:cost ratio of 1:1 and hence is already operating within a range of reasonableness of +/- 10 percent.

As FEVI and FEW are separate entities with their own unique circumstances, each utility must be discussed separately. The response will address FEVI first, followed by a discussion on FEW.

FEVI has been operating under a non-traditional rate design for the past several years whereby rates have been set above the cost of service with excess revenues contributing to the RSDA. The RSDA in turn will be used to offset expected rate increases required as a result of the loss of royalty revenues. The current Order (G-44-12) under which FEVI rates have been determined has set rates for a 2 year period that ends December 31st, 2013.

If amalgamation is not approved, in its next revenue requirement application for 2014 rates, FEVI will propose an appropriate mechanism to recover its costs from its customers. For example, if a rate increase is required, the FEVI may propose to utilize the RSDA to offset the increase. 2014 would also be the earliest time that the FEVI could consider rebalancing rates to within a range of reasonableness of +/- 10 percent. However, the FEU require time to assess the implications of doing so and then make a determination on whether this is appropriate. Therefore, while 2014 could be the earliest that the FEU would consider rebalancing FEVI's rates, it may not be the appropriate time to do so.

With respect to FEW, today, the utility has a cost of service based rate design, whereby the costs associated with the utility are fully recovered from all customers. As discussed in Section 3.4.2.2 of the Application, FEW utilizes only one rate schedule - the General Service Rate Schedule ("SGS"). This rate schedule serves all FEW customers from single family residences to large commercial customers such as large hotels. As the utility fully recovers its costs from the revenues it receives via SGS, the existing revenue:cost ratio is 1:1 and therefore within a +/- 10 percent range of reasonableness. Therefore, the FEU do not believe that criteria or a transition plan is required for FEW to move revenue:cost ratios to within +/- 10 percent.

37.3 Please describe the non-cost based rate designs which FEVI and FEW may consider if postage stamp rates are not approved, and the general market and regulatory environment which would result in those rate designs being considered viable options.

Response:

At this time the FEU have not done the relevant research and evaluation of appropriate rate designs they would consider if postage stamp rates are not approved. The FEU may consider non-traditional rate designs in any subsequent applications if necessary. While such designs may or may not directly rely on the embedded cost of service results, the FEU did not intend to imply that such rate designs would not be cost-based.

38.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.77.1.1, 1.78.2, 1.78.2.1

Efficient Rate Design - Whistler Conversion

BCUC 1.77.1.1 refers to the Commission Reasons for Decision on the 2010-2011 Whistler Revenue Requirements Application (C-138-10), where the Commission accepted FEW recovering conversion costs from its customers on the basis that "issues were widespread across customer classes, and that the policy change mitigated potential risk of load loss to FEW, which in turn would negatively impact rates to remaining customers."

The FEU state in BCUC 1.78.2: "FEVI (then TGVI) and FEW (then TGW) were the proponents of the applications that resulted in the conversion of the FEW system from propane to natural gas. ... While not all of the registered parties may have expressed specific opinions or support for all elements or aspects of the applications, the Commission took into consideration and gave weighting to all submissions by the participants in granting approval."

The FEU state in BCUC 1.78.2.1: "The current natural gas rates in FEW, although higher than elsewhere in the FEU's service territory, are lower than they would have been had the conversion not been undertaken. ... Whistler customers have not had an opportunity to enjoy rates at the same level as in other FEU service areas."

38.1 Please calculate the size of the fixed monthly surcharge for Whistler residential customers that would have been required to cover their share of the total conversion costs. Please explain all assumptions made in this calculation.

Response:

The fixed monthly surcharge would start upon amalgamation in 2014 and is estimated at $32.83 per customer. Alternatively, the surcharge is estimated at $1.462 /GJ in 2014). The surcharge would continue for an additional 15 years after 2014 as the approved amortization period is 20 years.

The assumptions in deriving the surcharge are the following:

1) There are two deferral accounts that captured the deferred conversion costs: (1) Appliance Conversion Planning Costs and (2) Direct Customer Appliance Conversion Cost. The embedded net mid-year rate base for these two accounts is forecast to be $6.8 million in 2014;

2) The annual cost of service from these deferral accounts is slightly greater than $1.0 million. The cost of service is comprised of deferral amortization of $421 thousand and income tax expense and earned return of approximately $600 thousand;
3) Capital structure and cost of capital are per the 2012 and 2013 FEU RRA compliance filing, dated May 1, 2012, for FEW, Section 7, Tab 7.3, Schedules 80 and 81 at Revised Rates. To determine the estimated 2014 charge, FEU has assumed that the capital structure and cost of capital remains the same as 2013;
4) Income Tax rate is 25%, Section 7, Tab 7.3, Schedules 31 and 32; and
5) Forecast average number of total FEW customers and sales volumes are 2,629 and 708.5 TJ in 2013; Section 7, Tab 7.3, Schedules 14 and 16. To determine the estimated 2014 charge, FEU has assumed that the forecast average customers and volume remains the same as 2013.

38.1.1 Do FEU consider that, should postage stamp rates be approved with the condition that FEW customers pay for their conversion costs, it would be more appropriate to recover these conversion costs through a fixed monthly charge rather than a variable energy charge? Please explain why or why not.

Response:

The FEU do not agree that upon amalgamation it would be appropriate for FEW customers to pay for the conversion costs incurred in 2009. The Commission did not order a similar treatment for the conversion costs FEI incurred for interior municipalities, such as Nelson, with the amalgamation or postage stamping of the Lower Mainland, Inland and Columbia service areas. As at December 31, 2011 the conversion costs still being recovered in FEI's postage stamp rates are net $347,000, the gross amount is $886,000. The approximate $7.5 million in FEW conversion cost relative to the amalgamated Rate Base, which is in excess of $3.5 billion, has a negligible impact on customers' postage stamp rates ($1.1 million / 162,502 TJ = $0.007/GJ).

In any event, if this was the condition of approval then, as a first step, postage stamp rates would have to be recalculated to exclude the impact of FEW conversion costs so that FEW customers were not double charged for this cost.

If a surcharge is to be applied, the FEU believe it would be appropriate that the surcharge is a variable charge per GJ for 2014 through 2029 because:

- The current recovery of conversion costs is through the volumetric delivery charge applied to all FEW customers; and,
- Charging a flat uniform monthly charge to all customers would result in a cross subsidy from residential customers to commercial customers. In replying to Commission Information Requests, FEW indicated that a typical residential customer took 14.5 hours to complete, whereas for commercial customers the range in time varied significantly from converting one heater in a warehouse to a major hotel with 500 appliances. For example, a hotel would require two to three days to complete the conversion of all of its appliances. (Terasen Gas (Whistler) Inc. 2010 – 2011 Revenue Requirements and Rates Application Response to BCUC IR No. 2.20.6, 2.20.16 and 2.20.17, submitted February 10, 2010).

Thus, in addition to reflecting the current cost recovery approach, a volumetric surcharge would more likely emulate how conversion costs were incurred for the various types of customers.

39.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.152.6, BCOAPO 1.6.1, CEC 1.4.1; Sapere 2011 Review of TLC pricing Method, pp. 1,2; Ofgem 2009 Discussion Paper on Energy Charges, p. 19

Efficient Rate Design – Fixed vs. Variable Charge

The FEU state in BCUC 1.152.6 that the percentage of customers consuming less than 50 GJs in 2011 was: FEI Mainland: 19%; FEVI: 57%; FEW: 45% and FEFN: 4%.

The FEU state in BCOAPO 1.6.1: "Customers face a consistent policy on service line extensions in that FEI, FEVI and FEW customers all have a service line cost allowance ("SLCA") of $1,535 for dwellings other than duplexes and $3,070 for duplexes."

FEU state in CEC 1.4.1: "The rationale for having the same basic charge in all service areas is similar to having common delivery, midstream and commodity rates; that is, fairness amongst all of FEU's customers. Further, the basic charge is intended to cover customer-related costs, such as meter reading, billing and customer service, which are performed on an integrated basis for the FEU and therefore costs do not differ across the various regions."

A March 15, 2011 report by the Sapere Research Group titled 'Review of The Lines Company's [TLC] Pricing Method' [a New Zealand Electricity Distributor] stated:[40]

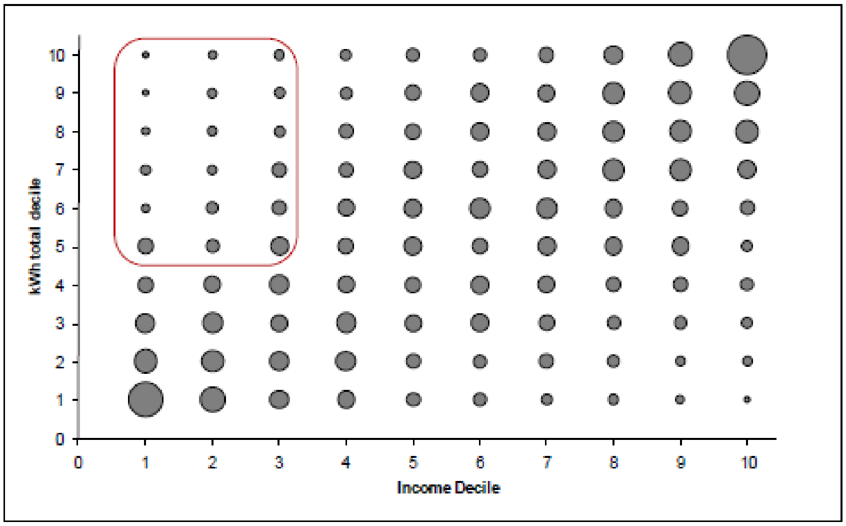
> "TLC's network footprint is challenging in a number of ways. It has one of the most sparse electricity footprints in the country, and a number of the residences and commercial customers operate on a seasonal basis (for instance ski related activity in the ski season only ...)" (page1)
>
> "The set up costs to provide even a small capacity service to any location are relatively high, and once in place the line assets have little value in another use (that is, they are sunk) ... These cost characteristics, and the desirability for the pricing structure to encourage efficient behaviour on the part of the supplier and customers, suggest a pricing structure with the following features:
>
> - That customers pay in terms of the capacity they require (and particularly at peak periods), rather than the throughput they use; ... (p. 2)

The UK regulator, Ofgem, issued a discussion paper in July 2009 titled "Can energy charges encourage energy efficiency?"[41] This included on page 19 a graph which

40 http://www.thelinescompany.co.nz/docs/Sapere%20Pricing%20Review%2015%20March%202011.pdf
41 http://www.ofgem.gov.uk/Sustainability/Documents1/Final%20discussion%20paper%2022%20July.pdf

mapped gas consumption across income groups. The diameter of the bubbles is proportional to the number of households, with Income Decile 1 being the lowest income group, and Income Decile 10 being the highest income group.

Figure 9: Gas consumption across income groups



Source: Ibid

39.1 Please describe the key principle(s) the FEU used which resulted in the proposed FEU (Amalco) residential fixed charge (for example, minimizing bill impacts, recovering sunk meter reading and billing costs, recovering incremental metering reading and billing costs, etc). Please state if this principle has been met for FEI, FEVI, FEW and FEFN customers in the postage stamp rate design.

Response:

The FEU are proposing to adopt FEI's rate structures and keep FEI's existing fixed charges, which have been reviewed by the Commission in several rate design proceedings (1993, 1996 and 2001). As summarized on page 179 of the Application in Table 9-1, the basic charge was postage stamped in the 1993 rate design proceeding and increased in the 1996 and 2001 proceedings. The level of the basic charge was set giving consideration to the multiple rate design principles in each of the proceedings including Fairness, Economic Efficiency, Competitiveness and Conservation. Please also refer to the response to BCUC IR 1.16.1 for an overview of the rate design principles compared across proceedings.

For example, in the 1993 rate design proceeding, the basic charge was postage stamped and set in part by considering the customer related costs resulting from the COSA. BC Gas had proposed to approximately double the basic charge to make it more aligned with customer related costs, but the Commission approved only a portion of the proposed increase due to the need to balance this objective with the principle of economic efficiency. The outcome was a basic charge level that was more in line with costs than the previous lower regional basic charges. The 1996 and 2001 rate design proceedings increased the postage stamp basic charge, bringing it further in line with customer related costs. For further details, the following references are provided:

1. Section 4 of the BCUC's Decision on BC Gas's 1993 Phase B Rate Design Application (Exhibit A2-1) provides an overview of the issue of the Basic Charge in that proceeding and the Commission's determination in that case.

2. Pages 4-5 of Appendix A to Order No. G-98-96 dated October 7, 1996 discusses the reasons why the Commission accepted the negotiated settlement of the basic charge in 1996. This Order is online at: http://www.bcuc.com/Documents/Orders/Orders96_2/G-98-96BCG.pdf.

3. Section 4 of BC Gas's 2001 Rate Design Application, Tab 5, pp. 5-6 (Exhibit A2-6) describes BC Gas's rate design proposal in 2001. The 2001 Negotiated Settlement Agreement approved by Order No. G-116-01 indicates the basic charge that was agreed upon and approved by the Commission.

By moving to FEI's basic charge, customers in the FEVI, FEW and FEFN service areas will see an increase in their basic charges.

In addition, beginning with the 2010 and 2011 RRA proceeding FEI began applying any approved revenue requirement rate increases to the volumetric delivery charges in order to improve energy efficiency awareness for customers. As stated at page 213 of the 2010-2011 FEI RRA:

> *"To support our Energy Efficiency and Conservation Program and to meet the evolving needs of our customers, we propose that the basic charge and administration fees be held at existing approved 2009 levels. As such, the proposed volumetric and demand based delivery rates have been adjusted to account for the revenue that would have been collected from the changes in the basic charge or administration fees in 2010 and 2011.*
>
> *Moving towards a larger volumetric component of the bill enhances the ability of our customers to experience benefits gained by reducing their usage through their participation in our EEC programs as well as through their overall energy efficiency awareness."*

Furthermore by adopting FEI's basic charge and flat delivery charge rate structures, FEFN will see the removal of its declining block rate structures which are inconsistent with energy conservation awareness.

As mentioned in the Application, the FEU anticipate some movement of customers as they adjust to the choices amongst the FEI rate classes as proposed in the Application. The FEU expect that a period of time from the implementation of common rates is required to evaluate the results of any such movement. Therefore, if amalgamation and the adoption of common rates is approved, the FEU intend to review the rate structures (including basic and variable charges), after seeing the effects of the migration of customers to new rate schedules or new service offerings.

39.1.1 Do FEU agree that an efficient rate design does not require that sunk customer related costs are recovered through a fixed charge? Please explain why or why not.

Response:

An efficient rate design would take into account the incremental costs, as discussed in the response to BCUC IR 2.33.1. It does not necessarily require that all sunk customer-related costs be recovered through a customer charge. However, incremental costs are not the only factor that should be considered when selecting an appropriate rate design.

The rate structure and level of rates that is ultimately approved by the Commission is an outcome of several inputs and balancing of various rate design objectives related to the perception of fairness, revenue stability, and rate stability, amongst others. Inputs into the Rate Design are costs measured in embedded cost of service allocation studies, regional and competitive pricing studies and other studies that may be done. In order to accomplish the goals of rate and revenue stability it may very well be necessary to set the Basic Charge at a rate that would not recover "sunk" customer-related costs, which is typical of gas and electric utilities in North America. However, the setting of the basic charge would be influenced by the level of the customer-related costs per customer by the various rate classes and would contribute to the recovery of those costs. The structure of rates is also influenced by the capability of the metering device to measure peak demand as well as total throughput. In the FEU, small volume customers such as residential and most commercial customers do not have metering devices that measure peak demand so that the rate structure for these customer classes only has a fixed Basic Charge and Volumetric Charges. For large volume users such as industrial customers in Rate Schedules 5, 25, 22, 22A and 22B the far more expensive measurement devices are able to measure peak demand along with total throughput and so the rate structure has a fixed Basic Charge and a Demand Charge along with Volumetric charges.

39.2 Please comment on whether higher residential fixed charges or minimum bills may be more appropriate for FEW and FEVI customers compared to FEI and FEFN customers to reflect the greater proportion of low use customers on their network. Please explain why or why not.

Response:

The FEU believe that setting higher basic charges or minimum bills for only the FEW and FEVI residential customers would not be appropriate as it would ignore the substantially higher number of FEI low volume customers. For example, the table below presents the number of customers for each of the four regions which shows the significant number of low volume (<50 GJ/yr) customers in FEI as compared with FEFN, FEW and FEVI.

Region	Total Residential Customers[42]	Percent < 50 GJ/yr	Low Consumption Residential Customers
FEI Mainland	776,109	19%	147,461
FEVI	96,682	57%	55,109
FEW	2,292	45%	1,031
FEFN	1,953	4%	78

As discussed in the response to BCUC IR 2.39.3, moving to the FEI basic charge ($0.389/day) will result in an increase to the basic charge for FEVI and FEW, which is currently $0.3450/day and $0.2464/day, respectively.

39.3 Do FEU consider that, assuming postage stamp rates are approved, an increase in the residential fixed charge, with a corresponding decrease in the

[42] Average residential customers as presented in the Application Schedule 7 of Appendices H-5, H-6, H-7, H-8 for FEI Mainland, FEVI, FEW and FEFN respectively.

energy charge, will disproportionately benefit FEFN and FEI customers compared to FEVI and FEW customers? Please explain why or why not.

Response:

No, the impact on each of the regions must be gauged in relation to the circumstances in each. In general, an increase to the basic charge with a corresponding decrease to the energy charge would tend to increase low consumption customers' bills and decrease high consumption customers' bills.

The FEU are not proposing to increase the residential basic charge to the approximately 775,000 FEI residential customers. By adopting FEI's rate structures for FEI Amalco, the basic charge will be increased to FEI's level for the current service areas FEFN, FEVI and FEW. The energy charge increase will be phased in for current FEI customers, thus mitigating the impact and moving the rate structures toward encouraging energy conservation awareness. For FEFN, the basic charge will be increased and the energy charge will be phased in over 15 years. This will improve energy conservation awareness, and will replace the current declining block structure in place. In the case of FEVI and FEW customers, they will experience an increase in their basic charges while the delivery charges will decrease, which will put in place Commission reviewed rate structures consistent with FEI, while dealing with the rate stability, vulnerability and revenue deficiency issues faced. As stated in the response to IR 2.39.1, based on multiple principles considered in developing FEI's rate structures, the FEU believe adopting a postage stamp rate will ultimately be the fairest approach for all the FEU's residential customers.

39.4 The Lines Company addressed the issue specific to their network of low use recreational properties (ski chalets) by recovering costs through fixed rather than variable charges. Do FEU consider that such an approach would also be appropriate for FEW? Please explain why or why not.

Response:

No, the FEU consider that, assuming FEW remains stand-alone, the approach used for low use recreational properties by The Lines Company would not be appropriate at this time for FEW whose customer base contains more than recreational properties such as ski chalets. In addition, FEW currently has only one rate which is applied across its diverse customer base (residential, small commercial and large commercial customers).

As summarized in the table below (from Appendix H-7 Schedule 7) a significant portion of FEW's sales come from large resort hotels in the LGS customer class whose consumption is more characteristic of a year round commercial customer. Further, as discussed in the Application Section 9.4.3, the LGS customers will be mapped to FEI Rate Schedules 2 and 3 resulting in an increase to the Basic Charges for the commercial customers (from the current $0.2464/day to $0.8161/day for Rate Schedule 2, and $4.3538/day for Rate Schedule 3).

Customer Class	SGS RES	SGS COM	LGS 1	LGS 2	LGS 3
Sales Volume (TJ)	244	85	145	116	119
Average No. of Customers	2,292	184	81	49	23

Other service areas within the FEU also have a significant number of recreational properties that enjoy the benefits of postage stamp rates today that the FEU are proposing FEW customers would adopt under FEI Amalco – for example in the Inland service area, the Okanagan has many cottage and lake communities as well as multiple resort ski hills.

The FEU intend to look at rate design in the future and will consider segmentation and other methods to develop appropriate rates by customer class. While the approach used by The Lines Company is interesting, a brief review shows that The Lines Company is quite different from FEW. Applying a rate concept from that utility would not be appropriate without additional review and analysis.

39.5 Please provide, separately for FEI, FEFN, FEVI and FEW, the annual incremental residential customer related costs (i.e. the costs which FEU would incur even if the customer had very low levels of consumption – for example, billing, metering, account maintenance etc).

Response:

The FEU have not done a long run incremental cost study for residential or other customers and believe this information would be more appropriate to consider in a future rate design proceeding when a more complete analysis can be conducted. The FEU believe it would be premature to consider changing the customer charge simply on the basis of incremental costs without a full consideration of the Bonbright principles, without a look at alternative customer charge levels, and without a full customer bill impact analysis by usage level. It is the intention of the FEU to fully consider any such changes in a subsequent application.

However, both the total embedded cost and the variable cost related to customers can be found in the COSA Model. While the total embedded costs include the depreciation and return associated with the customer-related portion of fixed costs, the variable costs include all O&M costs assigned as customer-related and include customer billing and accounting, meter reading, and customer service. Because it also includes distribution O&M and some admin & general expenses, it is greater than the minimum amount for an individual customer with low consumption. However, as meter reading is contained within the distribution O&M accounts, it is not possible to calculate just those minimum costs from the COSA.

The total unit embedded customer related costs in dollars per residential customer per year as presented in Schedule 7 of Appendices H-5, H-6, H-7, H-8 for FEI Mainland, FEVI, FEW and FEFN respectively are summarized in the table below. Also provided are the variable cost results associated with metering, marketing and customer accounting taken from the respective COSA results.

Region	Customer Related Cost ($ thousand)	Average customers	Customer Related Cost ($/customer/year)
Total Cost of Service Results			
FEI Mainland	$298,668	776,109	$385
FEVI	$42,129	96,682	$427
FEW	$2,109	2,292	$920
FEFN	$791	1,953	$405
Variable Cost Results			
FEI Mainland	$120,879	776,109	$156
FEVI	$14,378	96,682	$149
FEW	$409	2,292	$178
FEFN	$425	1,953	$217

The results show, with the exception of FEW, that the total customer related costs are similar across FEI, FEVI and FEFN. The higher customer related costs for FEW reflect the recent conversion of FEW from propane to natural gas, and will decline as the FEW system ages. When looking at the variable costs, the amounts are similar, with the exception of FEFN where costs are higher.

Further, the main extension test is designed to assess the incremental costs associated with connecting new customers. If the projected revenue for new customer additions does not cover the costs of customer connections, then a contribution in aid of construction would be assessed. Any increase to the fixed charges would have the effect of reducing the required contribution in aid for low consumption customers in the main extension test.

39.5.1 Please calculate the minimum level of consumption required by FEI, FEFN, FEVI and FEW residential customers (assuming amalgamation is not approved) to (i) offset incremental ongoing costs associated with that account, and (ii) offset incremental ongoing costs associated with that account plus contribute towards FEU's fixed costs an amount equal to one fifth of the contribution FEU makes to a new customer connection. Please redo this calculation assuming postage stamp rates are approved.

Response:

The FEU have provided the requested calculations in the tables below. The results show low minimum levels of consumption would be required for each region, whether regional rates or postage stamp rates are assumed. The exception is for FEFN, where the much lower rates lead to a significantly higher minimum level to cover the calculated costs.

While the analysis does provide some insight as to how well costs are covered by the existing customer charge, the FEU have not completed a thorough review of the issue at this time as discussed in the response to BCUC IR 2.39.5. This Application is not proposing any changes to FEI's basic customer charges or policies. The FEU plan to look at rate design issues in more depth in a future application and will provide an evaluation of various options related to the customer charge and policies at that time.

The following assumptions and inputs were used in the requested calculation:

- Variable customer related cost results associated with metering, marketing and customer accounting taken from the respective COSA results in Appendices H-5, H-6, H-7, H-8 for FEI Mainland, FEVI, FEW and FEFN respectively.
- The minimum level of consumption was calculated by subtracting from the variable customer related costs the annualized basic charge, and the result divided by the delivery charge.
- The basic and delivery charges are as approved effective January 1, 2013.
- The FEVI delivery charge was derived by subtracting the average cost of gas from the residential energy charge. ($14.325 – ($27,077,000/4528 TJ))
- The FEFN basic charge excludes the RSAM rider and cost of gas for the first 2 GJ, and the delivery charge excludes the RSAM rider and cost of gas from the 2013 approved forecast.

- The amount equal to one fifth of the contribution made to a new customer connection was calculated as one fifth of cost of service associated with the service line connection allowance of $1,535 assuming the approved return and capital structure.

(i) The minimum level of consumption required by residential customers to offset incremental ongoing costs associated with the account

Region	Variable Customer-Related Cost ($/customer)	Basic Charge $ / day	Delivery Charge $ /GJ	Minimum Level of Consumption (GJ/yr)
FEI - Mainland	$ 156	$ 0.3890	$ 3.790	4
FEVI	$ 149	$ 0.3450	$ 8.345	3
FEW	$ 178	$ 0.2464	$ 11.422	8
FEFN	$ 217	$ 0.3168	$ 2.461	41

(ii) The minimum level of consumption required by residential customers to offset incremental ongoing costs associated with the account, plus contribute towards fixed costs an amount equal to one fifth of the contribution made to a new customer connection.

Region	Variable Customer-Related Cost ($/customer)	Basic Charge $ / day	Delivery Charge $ /GJ	Minimum Level of Consumption (GJ/yr)
FEI - Mainland	$ 191	$ 0.3890	$ 3.790	13
FEVI	$ 181	$ 0.3450	$ 8.345	7
FEW	$ 209	$ 0.2464	$ 11.422	10
FEFN	$ 252	$ 0.3168	$ 2.461	55

The calculations are redone below assuming postage stamp rates are approved using the corresponding values from FEI Amalco.

(i) The minimum level of consumption required by residential customers to offset incremental ongoing costs associated with the account

Region	Variable Customer-Related Cost ($/customer)	Basic Charge $ / day	Delivery Charge $ /GJ	Minimum Level of Consumption (GJ/yr)
FEU	$ 167	$ 0.3890	$ 4.361	6

(ii) The minimum level of consumption required by residential customers to offset incremental ongoing costs associated with the account, plus contribute towards fixed costs an amount equal to one fifth of the contribution made to a new customer connection.

Region	Variable Customer-Related Cost ($/customer)	Basic Charge $ / day	Delivery Charge $ /GJ	Minimum Level of Consumption (GJ/yr)
FEU	$ 201	$ 0.3890	$ 4.361	14

39.6 Please determine the average end-point (i.e. assuming no phase-in) residential bill impact using <u>regional average</u> consumption data from approval of postage stamp rates for FEVI, FEI, FEFN and FEW customers.

<u>Response:</u>

The bill impacts requested are included as Appendix J-4 of the Application. These bill impacts provide annual bill impacts, or end-point impacts, based on typical consumption levels for each rate class in each of the service areas.

Additionally, the tables provided in the response to BCUC IR 1.93.3 provide this same information in the form of summary tables. These tables provide annual bill impacts for all service areas in both percentage and dollar terms.

39.6.1 Please redo the above analysis assuming postage stamping of FEI/FEVI/FEW; FEI/FEVI; and FEVI/FEW.

Response:

The common rates application involved a mapping methodology that transitioned all customers in FEVI, FEW and FEFN to FEI's rate classes based on consumption levels and rate class characteristics.

An amalgamated model for an FEVI and FEW amalgamation and postage stamping scenario would require a new mapping methodology, along with the creation of a new COSA model. More importantly, as discussed in the response to BCUC IRs 2.3.1 and 2.3.2, the option of amalgamating FEVI and FEW is not expected to be beneficial and the FEU would not proceed with such an amalgamation. In addition, a high level analysis of this option indicates a revenue deficiency of approximately $13 million, which translates to an average annual bill increase of approximately 6% for FEVI customers. Due to the substantial resources required, and the lack of benefits from this option, a new COSA model has not been created for the FEVI/FEW scenario.

In the following table, the residential bill impacts based on postage stamp rates for FEI, FEVI and FEW using regional consumption data and assuming no phase-in, are provided. These bill impacts are based on a high level analysis that does not include all inter-company adjustments and any potential changes in gas cost portfolios.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI, FEVI, & FEW	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,083.22	$55.25	5.4%
FEI - Inland	75	$838.84	$885.09	$46.25	5.5%
FEI - Columbia	80	$888.80	$934.62	$45.82	5.2%
FEVI	59	$965.45	$722.61	-$242.83	-25.2%
FEW	90	$1,653.66	$1,033.68	-$619.98	-37.5%

In the following table, the residential bill impacts based on postage stamp rates for FEI and FEVI using regional consumption data and assuming no phase-in are provided. These bill impacts are based on a high level analysis that does not include all inter-company adjustments and any potential changes in gas cost portfolios.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI, FEVI, & FEW	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,078.85	$50.88	4.9%
FEI - Inland	75	$838.84	$881.64	$42.80	5.1%
FEI - Columbia	80	$888.80	$930.94	$42.14	4.7%
FEVI	59	$965.45	$719.92	-$245.53	-25.4%

39.6.2 Please redo the above analysis (using regional average consumption data) assuming the proposed FEI (Amalco) residential fixed charge was instead set at (i) $1/day, and (ii) double the proposed fixed charge, with a corresponding decrease in the energy charge. Please state all assumptions used in this calculation.

Response:

The residential bill impacts based on approval of postage stamp rates for FEI, FEVI, FEW and FEFN, using regional consumption data and assuming no phase-in are provided in the tables below. These bill impacts are based on a high level analysis that does not include inter-company adjustments and any potential changes in gas cost portfolios.

The following table presents the analysis based on a fixed daily charge of $1, as described in Scenario (i) above:

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamated Rates with Basic Charge of $1/day	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,056.75	$28.78	2.8%
FEI - Inland	75	$838.84	$911.17	$72.33	8.6%
FEI - Columbia	80	$888.80	$947.58	$58.78	6.6%
FEVI	59	$965.45	$791.80	-$173.65	-18.0%
FEW	90	$1,653.66	$1,020.36	-$633.30	-38.3%
FEFN	140	$985.60	$1,384.31	$398.71	40.5%

The following table presents the analysis based on a fixed daily charge of $0.778, or double the fixed daily charge that has been proposed in the Application, and as described in Scenario (ii) above:

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamated Rates with Basic Charge of $0.778/day	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,065.91	$37.94	3.7%
FEI - Inland	75	$838.84	$901.33	$62.49	7.4%
FEI - Columbia	80	$888.80	$942.49	$53.69	6.0%
FEVI	59	$965.45	$766.38	-$199.06	-20.6%
FEW	90	$1,653.66	$1,024.77	-$628.89	-38.0%
FEFN	140	$985.60	$1,436.22	$450.62	45.7%

39.6.2.1 Please redo the above analysis assuming postage stamping of FEI/FEVI/FEW; FEI/FEVI; and FEVI/FEW.

Response:

As described in the response to IR 39.6.1, an amalgamated COSA model is not available for a scenario that involves amalgamating the FEVI and FEW service areas.

The bill impacts for amalgamated FEI/FEVI/FEW and FEI/FEVI based on the scenarios described in IR 39.6.2 are presented below.

Scenario (i)

The residential bill impacts based on postage stamp rates for FEI, FEVI and FEW, using regional consumption data, assuming no phase-in and increasing the fixed daily charge to $1 are provided in the table below. These bill impacts are based on a high level analysis that does not include inter-company adjustments and any potential changes in gas cost portfolios.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI, FEVI, & FEW	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,057.66	$29.69	2.9%
FEI - Inland	75	$838.84	$911.89	$73.05	8.7%
FEI - Columbia	80	$888.80	$948.33	$59.53	6.7%
FEVI	59	$965.45	$792.35	-$173.09	-17.9%
FEW	90	$1,653.66	$1,021.21	-$632.45	-38.2%

The residential bill impacts based on postage stamp rates for FEI and FEVI using regional consumption data, assuming no phase-in and increasing the fixed daily charge to $1 are provided in the table below.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI & FEVI	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,052.63	$24.66	2.4%
FEI - Inland	75	$838.84	$907.92	$69.08	8.2%
FEI - Columbia	80	$888.80	$944.10	$55.30	6.2%
FEVI	59	$965.45	$789.25	-$176.19	-18.2%

Scenario (ii)

The residential bill impacts based on postage stamp rates for FEI, FEVI and FEW, using regional consumption data, assuming no phase-in and increasing the fixed daily charge to $0.778, or twice the fixed charge proposed in the Application, are provided in the table below. These bill impacts are based on a high level analysis that does not include inter-company adjustments and any potential changes in gas cost portfolios.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI, FEVI, & FEW	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,066.95	$38.98	3.8%
FEI - Inland	75	$838.84	$902.15	$63.31	7.5%
FEI - Columbia	80	$888.80	$943.35	$54.55	6.1%
FEVI	59	$965.45	$767.01	-$198.43	-20.6%
FEW	90	$1,653.66	$1,025.74	-$627.92	-38.0%

The residential bill impacts based on postage stamp rates for FEI and FEVI using regional consumption data, assuming no phase-in and increasing the fixed daily charge to $0.778 are provided in the table below.

Service Area	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Postage Stamping of FEI & FEVI	Annual Bill Impact ($)	Annual Bill Impact (%)
FEI - Lower Mainland	95	$1,027.97	$1,061.97	$34.00	3.3%
FEI - Inland	75	$838.84	$898.23	$59.39	7.1%
FEI - Columbia	80	$888.80	$939.17	$50.37	5.7%
FEVI	59	$965.45	$763.95	-$201.50	-20.9%

39.7 Do FEU, in principle, support consideration of increasing the residential fixed charge? If no, please describe why not, including any regulatory or legal constraints. If yes, please propose the preferred level of fixed charge increase and recalculate the bill impacts for the above scenarios using the revised data.

Response:

No, the FEU in principle do not at this time support consideration of increasing the residential fixed charge over the level of the FEI basic charge in the postage stamp proposal. As discussed in the response to BCUC IR 2.39.1, FEVI, FEW and FEFN will already see an increase in their basic charges as a result of moving to the FEI basic charge. Increasing to the postage stamp basic charge in FEVI, FEW and FEFN will move the basic charge more in alignment with the recovery of customer related costs in each area. FEI's basic charge was reviewed in the 1993, 1996 and 2001 FEI rate design proceedings, and remains appropriate today. The FEU may review the basic charge in a future rate design proceeding considering the multiple principles involved.

39.7.1 Do FEU consider that increasing the fixed charge at a later date following approval of postage stamp rates could result in significant bill decreases for a large number of FEVI/FEW customers upon implementation of postage stamp rates, followed by potentially significant bill increases at a later date? Please explain why or why not, and if such an outcome could be consistent with rate stability.

Response:

As discussed in the response to BCUC IR 2.39.1, adopting the postage stamp basic charge will already result in an increase of the basic charge for FEVI, FEW and FEFN residential customers. The higher postage stamp basic charge will be more aligned with the recovery of customer related costs.

The extent of any bill increases to FEVI/FEW customers as a result of an increase to the fixed charge at a future date would depend on the size of the increase to the fixed charge and likely any other changes to the rate design. It may be possible for some customers (e.g., high energy users) to have a further bill decrease if there is a corresponding decrease to the variable charge as a result of an increase to the fixed charge. As in many rate designs, there will be some customers who experience bill increases, and some who experience bill decreases.

Potential significant increases in FEVI/FEWs customers' bills would depend on the assumptions made that would be incorporated into a future rate design proceeding before the Commission. The FEU would conduct market research, segmentation analysis and customer consultation that would all be factored into any rate design proposals at that time. The future proposals would give full consideration to multiple rate design principles including rate stability.

39.7.2 Do FEU consider that a significant increase in the fixed charge could assist in addressing competition concerns in FEVI and FEW? Please explain why or why not.

Response:

In the case that the amalgamation of FEVI and FEW with FEI and postage stamp rates are approved, the response to BCUC IR 2.39.7 discusses the increase in the FEVI/FEW basic charge and the better alignment with customer related costs resulting from the postage stamp proposal. The postage stamp proposal will also result in a decrease to the FEVI/FEW energy related charge.

However, as discussed in the BCUC IR 1.81 series, competitive concerns must consider multiple issues including:

- The higher installed capital costs associated with natural gas equipment as compared to electric equipment,
- Government policy with regard to GHG emissions such as the Carbon Tax, and
- The relative commodity price differential between natural gas and competing fuels.

Since the FEU consider the demand to be relatively inelastic, the FEU believe that a significant increase in the basic charge in itself would do little to address competition concerns in FEVI and FEW, and may for lower volume FEVI users (and those seeking to connect to the system) increase the competition concerns.

39.7.3 Do FEU consider it would be appropriate to also increase the fixed charge for FEI/FEFN customers (assuming postage stamp rates are approved), when the issue of a large number of low use customers relates primarily to FEVI and FEW regions?

Response:

The response to BCUC IR 2.39.2 shows that FEI has significantly more low use customers than the total number of low use customers in FEVI and FEW put together. Therefore the assumption in the question is invalid. There are low use customers throughout the FEU's customer base.

The FEU have outlined in the BCUC IR 2.39 series that they do not believe that it is appropriate to change the fixed charge at this time. Further, as discussed in the response to BCUC IR 2.39.1 the FEU believe that setting the fixed charge is based on the consideration of multiple other rate design principles in addition to the relative consumption level of customers.

39.7.4 Do FEU consider, for each of FEVI, FEW, FEFN and FEI, that an increase in the fixed charge to $1/day would increase or decrease consumption in each respective area? Please explain why, and if the emissions effects from any change are similar or different in all regions.

Response:

The impact of an increase in the basic charge on a customer's total bills will depend on a customer's usage but not on the region in which that customer is served, so on average no difference would be expected between areas. However, the FEU consider that such an increase in the basic charge with corresponding decrease in the variable delivery charge would be counter to energy efficiency pricing signals and awareness as discussed in the response to BCUC IR 2.39.1, and tend to decrease the incentive for customers to participate in energy efficiency measures. In the long run this could result in a reduced incentive to conserve and have an impact on emissions, all else being equal in each respective area.

Further, with such a proposed increase to the fixed charge, low usage customers in all regions would likely see an increase in their bills, and therefore may be incented to leave the system causing upward rate pressure on all customers. There may be a bigger impact in the regions where the basic charge is currently lower.

39.7.5 Do FEU consider, for each of FEVI, FEW, FEFN and FEI, that an increase in the fixed charge to $1/day would result in an energy charge which was closer to or further away from utility incremental costs to serve the customer (gas and delivery)? Please explain.

Response:

The FEU have not completed an incremental cost study at this point in time, and therefore cannot be certain whether or not an increase in the fixed charge to $1/day would result in an energy charge which is closer to or further away from the long-term incremental cost to serve. However, the FEU consider that all else equal an increase to the basic charge would result in a lower delivery charge and directionally would move closer to the utility's short-term incremental cost to serve. There would be no change to the gas commodity charge.

39.8 Do FEU consider that, if an analysis of consumption levels compared to income levels was performed (similar to that under taken by Ofgem in its July 2009 paper 'Can energy charges encourage energy efficiency'), the resulting graphs would vary between the different regions (FEVI, FEI, FEFN and FEI)? Please explain why or why not.

Response:

The FEU have not done an income versus consumption analysis. The FEU's considerations of what the results may be would only be speculation.

40.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-9, BCUC 1.93.3

Bill Impacts

The FEU in BCUC 1.93.3 include a table which shows regional bill impacts for each rate class, assuming postage stamp rates are approved without the proposed phase-in.

40.1 Please update the tables in BCUC 1.93.3 to reflect <u>regional</u> average consumption levels for each customer class.

<u>Response:</u>

The tables in BCUC IR 1.93.3 do in fact reflect regional average consumption levels for each rate class in each service area. The bill impacts are based on the consumption level for each rate class as detailed in the column titled "Consumption".

Additionally, Appendix J-4 of the Rate Design Application presents bill impacts that reflect the typical regional consumption level for each customer class in each service area, assuming postage stamp rates are approved without the proposed phase-in.

40.2 Please provide an explanation where delivery charge % increases for any one customer class are significantly higher or lower than those seen for other customers classes within the same region, such as the proposed 20.7 percent increase in delivery charge for RS4 – Seasonal, and the 14.5 percent delivery charge increase for RS22 – Large Industrial.

<u>Response:</u>

The delivery rate changes for Rate Schedules 4 and 22 (RS 4 and RS 22) have historically been based on the changes to the Rate Schedule 5/25 rates (RS 5/25), which results in percentage changes to the RS 4 and RS 22 that are different than the other rate schedules. That is, while a 9% increase may be applied to the RS 5/25 delivery rate, it is the dollar increase to the RS 5/25 delivery rate that is applied to the RS 4 and 22 rates. Since the volumetric delivery rates for both of these rate schedules are quite low in comparison to RS 5/25, the same dollar change applied to the RS 4 and RS 22 rates result in a larger percentage impact, all else equal.

However, the annual rate change is the more important indicator, and the tables in BCUC IR 1.93.3 highlight that the annual rate changes for RS 4 and RS 22 generally fall within a reasonable range.

40.2.1 Do FEU consider that Lower Mainland and Inland RS 4 and Lower Mainland RS 22 customers would experience rate shock if postage stamp rates are approved as proposed? Please explain why or why not.

Response:

No. As indicated in the table in the response to BCUC IR 1.93.2, RS 4 and RS 22 are expected to experience burner tip impacts of 6% or less if postage stamp rates are approved as proposed (with phase-in). This is a comparable to the burner tip impacts of other Mainland rate schedules.

40.2.2 Please estimate what typical bill increases in dollar terms would be for customers in these rate classes (using regional average consumption levels).

Response:

The FEU in the response to BCUC IR 1.93.3 did provide an estimate of the typical bill impact in dollar terms for each of the rate classes in each service area based on regional average consumption levels.

The response includes six tables for Lower Mainland, Inland, Columbia, FEVI, FEW and FEFN service areas. The last column of each table provides the annual bill impact in dollars and is based on the regional average consumption level.

40.2.3 Please explain why these rate classes see higher percentage increases as a percentage of the delivery charge than other rate classes.

Response:

Please refer to the response to BCUC IR 2.40.2.

40.2.4 Do FEU consider that, if postage stamp rates are approved, rate impacts for these customer classes should be phased-in? If no, please explain why not. If yes, please propose a phase-in approach.

Response:

Yes, the FEU proposed a 3 year phase-in approach in Section 8.4.1.3 of the Application for FEI. The phase-in process focuses on mitigating annual bill impacts as opposed to delivery rate impacts. In the case of Rate Schedule 4, although the delivery rate impact is relatively high at an increase of 20.7%, the annual bill impact is an increase of only 6.4% without the proposed phase-in, which is in line with the annual bill increases facing the other service areas. With the proposed phase-in, the burner tip impact is estimated at 5%. While the FEU do not believe that any further phase-in is required for these customers, as discussed in the other responses to information requests, the FEU are open to other phase-in proposals.

40.3 Do FEU consider that a higher level of overall net benefit would be required to support a move to/from postage stamp rates where the bill impacts are significant, compared to where bill impacts are minor? Please explain why or why not.

Response:

No, the nature of the factors that the Commission must consider are multi-faceted and do not lend themselves to quantification in the manner suggested by the question. In determining whether postage stamp rates for FEI Amalco are in the public interest, the Commission must weigh various types of factors together, which may or may not be quantifiable or directly comparable. For example, while bill impacts are relevant factors and can be quantified, they must be weighed against various other different kinds of factors, ranging from the financial savings to the benefits of rate stability and the benefits of ease of administration and simplicity. Thus, it is difficult to say what it would mean to require a "higher level of overall net benefit". Instead, the Commission must weigh all factors based on the evidence before it and make a determination regarding what is in the public interest.

41.0 Reference: Request for Common Rates

Exhibit B-3, Section 6.3.1, p. 114

Rate Impacts on FEVI Customers

"Common rates will provide FEVI and FEW customers with an immediate reduction in their natural gas rates and align them with the rest of the FEU service areas. All else equal, this will help FEVI and FEW retain customers and mitigate the potential for a declining customer base and lower throughput levels which would otherwise lead to further rate increases."

41.1 If the extension of postage stamp rates to FEVI is not approved by the Commission, how would FEVI address the issues associated with higher rates that it has identified, namely the retention of customers and declining throughput?

Response:

Regardless of whether or not postage stamp rates are approved, there are a number of actions that the FEU can take and are contemplating to address the issue of customer retention and declining throughput for FEVI and all the utilities. Some options include:

- Switch and Shrink Program Expansion – Initial indications are that the FEVI's Switch and Shrink program will successfully meet targets. Opportunities therefore exist to increase the scope and scale of the program for future years. If further success is realized this program could be expanded to the other service areas.

- Introduce a contribution in aid of construction ("CIAC") monthly finance option – as an option for customers to mitigate the upfront cost of attaching to the gas system, the FEU are at the beginning of investigating a monthly finance/fee option to pay for CIAC. This could be similar to the Centra Gas program pre Terasen Gas Inc. acquisition. This program would be designed to recover the cost of the CIAC over a period of time thereby helping to stimulate attachments.

- Increase sales and marketing efforts to move customers from oil and propane to gas – there are still a number of potential customers in the FEVI service area that are either on main or close to a main where the customer uses oil or propane. Increasing efforts in this area could lead to increasing load on the FEVI system. While there is not as significant a number of on main potential customers in FEI and FEW, the FEU are looking at the economics of ramping up these efforts as well.

- Increase LNG sales efforts – consistent with efforts in FEI, with the availability of Mt. Hayes, FEVI can increase load on the island via sales to both NGT customers and potentially more remote communities (for both power generation and distribution grid opportunities).

While these efforts may yield some increase in gas load and retention of customers, they do not address the rate disparity that exists across the FEU's service areas since these efforts, alone or in tandem will not have a significant short-term impact on FEVI rates. For this and the other reasons identified in the Application, amalgamation and postage stamp rates as proposed in this Application are the preferred option.

42.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-9, BCUC 96.1

Fort Nelson Large Commercial Bill Impacts

In response to the question: "Why have the FEU chosen to reduce the effective rates to RS 2.1 and RS 2.2 customers by approximately 20 % when the level of the Fort Nelson Phase-In Riders for all other Fort Nelson rates have been set so as to hold those rates constant?" FEU's partial response was:

"It was not the intention of the FEU to create a situation where individual customers within the Fort Nelson region experience increases or decreases in their annual bill as a result of this phase-in approach. As such, the FEU are investigating alternatives in the application of the rate rider to the approximately 35 customers in these three segments."

42.1 Have the FEU identified any alternative phase-in approaches for the RS2.1 and RS2.2 customers at this time?

Response:

As outlined in the Application, all customers in FEVI, FEW and FEFN have been mapped to Rate Schedules 1, 2 and 3. FEFN's RS 2.1, RS 2.2 and RS 25 customers were all mapped to FEI's Rate Schedule 3, and as a result an average phase-in rate rider was calculated for these three rate classes. This rider resulted in rate decreases for RS 2.1 and RS 2.2 customers, while the two transportation customers experienced rate increases.

However, prior to the proposed effective date for amalgamation of January 1, 2014, customers may choose to migrate to FEI's other rate schedules. It is anticipated that the two existing customers in FEFN's RS 25 (one of which is anticipated to terminate its contract in 2012) will transition to a transportation rate schedule such as FEI's Rate Schedule 23 or 25. This would substantially mitigate the forecast rate increase for these two FEFN customers.

Based on the probable migration of FEFN's RS 25 customers, a rate rider can be determined based on an average of the RS 2.1 and RS 2.2 mapped to FEI's Rate Schedule 3. This approach results in an annual bill increase of 1.49% for RS 2.1 customers, and an increase of 0.41% for RS 2.2 customers.

This approach results in minimal bill impacts for all of FEFN's customers in 2014, and ensures that the phase-in methodology is fair and equitable.

43.0 Reference: Delivery Rate Design – Affordability/Rate Shock

Exhibit B-9, BCUC 99.1

Impact to Fort Nelson Customers

BCUC 99.1 asked: "Under the current rate structure, with a separate rate base for the Fort Nelson service area, what are the stand-alone rates forecast to be in 15 years as a result of (i) either increases or further decreases in industrial load, (ii) forecast maintenance capital expenditures, and (iii) forecast declines in residential use per customer?"

As part of its response, the FEU provided the annual and the net present value of 15 years of residential bills under both the Common Rate with Phase-In, and the "Stand-Alone" scenario prescribed in the IR.

43.1 Please justify the determination of the discount rate used in the net present value calculation.

Response:

The FEU apply the after-tax weighted average cost of capital as standard practice in its net present value calculations. Thus, FEU have used the 2013 FEFN after tax weighted average cost of capital as the discount rate in the response to BCUC IR 1.99.1.

The Stand-Alone scenario included the impact of rebalancing the FEFN residential rate in 2014:

"In the absence of amalgamation and the implementation of common rates, it is likely that FEFN rates would be rebalanced to reflect a revenue to cost ratio of 90-110 [%]"

43.2 Please present the annual and net present value of 15 years of bills to customers taking service under RS 2.1 that reflects any rebalancing in 2014.

Response:

FEFN's Rate Schedule 2.1 customers would see a cumulative 32% increase in their rates by 2028 if rates were rebalanced to a revenue to cost ratio of 110% in 2014. While this impact has been analyzed in isolation below, the rebalancing of the revenue to cost ratio of FEFN's Rate Schedule 2.1 customers would result in rate impacts for other rate classes.

Consistent with other forecasts of this nature, for purposes of this response, the FEU have assumed an annual increase in delivery costs of approximately 2%, resulting in a cumulative bill increase for a Rate Schedule 2.1 customer in Fort Nelson of approximately 32% by 2028.

The following table presents the rebalanced rates for Rate Schedule 2.1 customers in Fort Nelson based on a rebalanced revenue to cost ratio of 110%:

Discount Rate	6.8%
Existing Annual Bill	$ 3,462.84

Rebalanced Annual Bill Impacts - RS 2.1				
	Annual Bill Impact (%)		*Approximate Annual Bill ($)*	
Year	***Annual***	***Cumulative***	***Total***	***NPV***
2014	4%	4%	$ 3,599	$ 3,370.3
2015	2%	6%	$ 3,671	$ 3,219.4
2016	2%	8%	$ 3,744	$ 3,075.2
2017	2%	10%	$ 3,819	$ 2,937.5
2018	2%	12%	$ 3,896	$ 2,806.0
2019	2%	14%	$ 3,973	$ 2,680.3
2020	2%	16%	$ 4,053	$ 2,560.3
2021	2%	18%	$ 4,134	$ 2,445.6
2022	2%	20%	$ 4,217	$ 2,336.1
2023	2%	22%	$ 4,301	$ 2,231.5
2024	2%	24%	$ 4,387	$ 2,131.6
2025	2%	26%	$ 4,475	$ 2,036.1
2026	2%	28%	$ 4,564	$ 1,944.9
2027	2%	30%	$ 4,656	$ 1,857.8
2028	2%	32%	$ 4,749	$ 1,774.6
			$ 62,236.8	$ 37,407.2

43.3 Please present the annual and net present value of 15 years of bills to customers taking service under RS 2.2 that reflects any rebalancing in 2014.

<u>Response:</u>

FEFN's 28 Rate Schedule 2.2 customers would see a decrease in their rates if rates were rebalanced to a revenue to cost ratio of 110% in 2014. While this impact has been analyzed in isolation below, the rebalancing of the revenue to cost ratio of FEFN's Rate Schedule 2.2 customers would result in rate impacts for other rate classes.

Consistent with other forecasts of this nature, for purposes of this response, the FEU have assumed an annual increase in delivery costs after 2014 of approximately 2%, resulting in a cumulative bill increase for a Rate Schedule 2.2 customer in Fort Nelson of approximately 14% by 2028.

The following table summarizes the annual and net present value of 15 years of rebalanced rates for Rate Schedule 2.2 customers:

Discount Rate	6.8%
Existing Annual Bill	$ 21,763.32

Rebalanced Annual Bill Impacts - RS 2.2				
	Annual Bill Impact (%)		*Approximate Annual Bill ($)*	
Year	***Annual***	***Cumulative***	***Total***	***NPV***
2014	-14%	-14%	$ 18,809	$ 17,614.6
2015	2%	-12%	$ 19,185	$ 16,825.8
2016	2%	-10%	$ 19,569	$ 16,072.3
2017	2%	-8%	$ 19,960	$ 15,352.6
2018	2%	-6%	$ 20,360	$ 14,665.1
2019	2%	-4%	$ 20,767	$ 14,008.4
2020	2%	-2%	$ 21,182	$ 13,381.1
2021	2%	0%	$ 21,606	$ 12,781.8
2022	2%	2%	$ 22,038	$ 12,209.5
2023	2%	4%	$ 22,479	$ 11,662.7
2024	2%	6%	$ 22,928	$ 11,140.4
2025	2%	8%	$ 23,387	$ 10,641.6
2026	2%	10%	$ 23,855	$ 10,165.0
2027	2%	12%	$ 24,332	$ 9,709.8
2028	2%	14%	$ 24,818	$ 9,275.0
			$ 325,275.5	$ 195,505.8

43.4 Please present the annual and net present value of 15 years of bills to customers taking service under RS 25 that reflects any rebalancing in 2014.

Response:

Both of FEFN's Rate Schedule 25 customers would see a decrease in their rates if rates were rebalanced to a revenue to cost ratio of 110% in 2014. While this impact has been analyzed in isolation below, the rebalancing of the revenue to cost ratio of FEFN's Rate Schedule 25 customers would result in rate impacts for other rate classes.

Consistent with other forecasts of this nature, for purposes of this response, the FEU have assumed an annual increase in delivery costs of approximately 2%, resulting in a cumulative bill increase for a Rate Schedule 25 customer in Fort Nelson of approximately 20% by 2028.

The following table summarizes the annual and net present value of 15 years of rebalanced rates for Rate Schedule 25 customers:

Discount Rate	6.8%
Existing Annual Bill	$ 18,565.83

Rebalanced Annual Bill Impacts - RS 25				
	Annual Bill Impact (%)		*Approximate Annual Bill ($)*	
Year	***Annual***	***Cumulative***	***Total***	***NPV***
2014	-8%	-8%	$ 17,070	$ 15,985.8
2015	2%	-6%	$ 17,411	$ 15,270.0
2016	2%	-4%	$ 17,760	$ 14,586.2
2017	2%	-2%	$ 18,115	$ 13,933.0
2018	2%	0%	$ 18,477	$ 13,309.0
2019	2%	2%	$ 18,847	$ 12,713.0
2020	2%	4%	$ 19,224	$ 12,143.7
2021	2%	6%	$ 19,608	$ 11,599.9
2022	2%	8%	$ 20,000	$ 11,080.5
2023	2%	10%	$ 20,400	$ 10,584.3
2024	2%	12%	$ 20,808	$ 10,110.3
2025	2%	14%	$ 21,224	$ 9,657.6
2026	2%	16%	$ 21,649	$ 9,225.1
2027	2%	18%	$ 22,082	$ 8,812.0
2028	2%	20%	$ 22,523	$ 8,417.4
			$ 295,197.8	$ 177,427.6

44.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.9.1, 1.104.5, 1.109.1, 1.9.1

Customer Preferences

The FEU state in BCUC 1.9.1: "... customer preferences to stay as a distinct or special area should not be one of the key evaluation criteria in evaluating the move to postage stamp rates."

BCUC 1.104.5 asked why customers were first asked by Vision Critical if they support common rates in principle, rather than, for example, a principle of cost based rates (customers who cost more paying more than customers who cost less). The FEU responded that both the existing rates and proposed common rates are cost-based rates.

BCUC 1.109.1 asked "If the FEU have previously confirmed that these [new] services offerings could be offered without amalgamation or common rates, could the FEU's presentation of benefits of common rates be seen as misleading to customers. If not, why not?" FEU responded "No . ... The communications used by the FEU did not at any point state that amalgamation was the only means of receiving these services."

The FEU state in BCUC 1.9.1: "The FEU are not aware of the reasons that Centra Gas withdrew its proposal to consolidate its Whistler and Port Alice Districts for rate making purposes in 1995."

44.1 Do FEU consider that customer preferences are a valid consideration in determining if benefits in the public interest would result from postage stamp rates? If no, please explain why not.

<u>Response:</u>

While the FEU respect the preferences of their customers and believe that they should be considered, it is not necessary to consider customer preferences to determine that postage stamp rates will result in benefits in the public interest. The FEU have identified the key benefits resulting from postage stamp rate design in Section 6 of the Application, which are independent of customer preferences. For example, the fact that postage stamp rates will result in more stable rates in the long-term for FEFN, FEVI and FEW customers is true regardless of customer preferences. Similarly, the cost savings and efficiencies that result from the proposed amalgamation and postage stamp rates will exist regardless of customer preferences.

Further, customer preferences may not be very useful in evaluating benefits if they are simply a "yes" or "no" to postage stamp rates. Rate design choices inevitably lead to different impacts to different customer groups, and each customer group will tend to prefer options where they believe they are getting a benefit regardless of other factors. Taking customer preferences as determinative would lead to a situation where no rate design is acceptable or rate design is determined by the majority.

More useful than simply preferences, are the perspectives that customers may bring to the potential benefits of postage stamp rates. Comments placed on the record in this proceeding by customers, for instance, speak to the benefits of lower rates of natural gas in FEVI. Other comments have opposed the postage stamp rate proposal for various reasons. These perspectives may be helpful in determining the nature of the benefits flowing from the postage stamp rate proposal.

44.2 Do FEU consider that, where a proposal results in bill increases, determining if the magnitude of the changes are acceptable does require consideration of customer preferences? Please explain why or why not.

Response:

In determining whether the magnitude of bill increases are acceptable, the Commission should consider all the relevant circumstances, including the reasons for the increase, the application of rate design principles, the benefits of the rate proposal, and any competing interests and customer preferences. However, consideration of customer preferences may be of limited value since customers generally do not prefer bill increases, even though the increases may be required or justified. Thus, whether bill increases are acceptable should not be reduced to a consideration of whether customers prefer them or not, but must be based on a consideration of the underlying reasons for the increase.

44.2.1 Is it FEU's position that the magnitude of changes resulting from the Application are acceptable to FEI customers? To FEFN customers? Please explain why or why not. Please explain why.

Response:

As discussed in the FEU's response to BCUC IR 1.101.1 and Section 10 of the Application, based on the results obtained from Market Research, Public Information Sessions, stakeholder meetings and Commercial & Industrial Customer surveys, FEI results are split evenly between support and opposition for customers paying the same rate for natural gas regardless of where they live, even after considering rate impacts. Based on these results, the magnitude of changes resulting from the extension of common rates appears to be acceptable to approximately half of FEI customers.

Market research, and feedback received from the FEFN public information session, the NRRC, the Chamber of Commerce and FEFN customers, all indicate that FEFN customers are opposed to this Application. As such, the magnitude of changes resulting from the Application do not appear acceptable to FEFN customers. As discussed in Section 10.3.1 of the Application however, while FEFN customers are not in favour of this Application, the NRRC supported the 15 year phase-in should common rates be approved by the Commission.

44.3 Do FEU agree that when Vision Critical first asked customers if they support postage stamp rates in principle (rather than, for example, a principle of regional cost-based rates) this question could be construed as leading, and if so could have influenced the results of the consultation? Please explain why or why not.

Response:

No, the FEU do not agree that the question is leading. A leading question is one that suggests the answer in the question. The question posed in the market research did not suggest the answer in the question and did not lead customers to make a certain response. Customers were free to respond as they wished to the questions posed.

The proposal before the Commission is for the extension of common rates across all the FEU's service areas, and as such, the purpose of the market research was to determine the level of support for common rates on a regional basis. With this purpose in mind, the question format and content focused on the FEU's proposed postage stamp rates.

Customers were asked whether they support common rates in principle prior to being shown the proposed bill impacts as it is important to understand the underlying level of support for postage stamp rates in isolation of bill impacts. By ordering the questions as it did, the market research was able to gauge support for postage stamp rates in principle and in the context of the consequent bill increases. In addition, as final customer rates may be altered through the regulatory process, it was necessary to gauge the level of support for common rates in isolation from rate impacts.

44.4 Please explain the purpose of presenting new service offerings as a benefit of amalgamation and postage stamp rates in your consultation with customers, when these service offerings can also be offered under the status quo? In your response, please state if the FEU consider that the approach taken could have influenced the results of the consultation, and explain why or why not.

Response:

With the current corporate structure in place, not all service offerings are available across the six service areas and entity specific proposals and approvals must be sought to extend any service offering currently available in FEI to FEVI, FEW or FEFN. With amalgamation and the adoption of common rates, this process would be simplified and accelerated thereby resulting in the expansion of new service offerings to the benefit of FEVI, FEW and FEFN customers.

The FEU do not believe that the approach taken influenced the results of the consultation as customers were informed that expanding these services to other areas was possible under the status quo, although would require a separate regulatory process. In consultation with stakeholders, the facilitation and acceleration of the expansion of service offerings was viewed as a benefit and as such the approach taken was valid. In addition, the expansion of service offerings, while a benefit for some customers, was not the main factor in determining support for this Application. As discussed in Section 10.5 of the Application, support for common rates is largely dependent on rate impact, not service offerings, and therefore the approach taken did not materially influence the results of the consultation.

44.5 Are FEU aware of whether customers in Centra Gas' Whistler and Port Alice Districts were generally supportive or not supportive of Centra Gas' proposal to consolidate those districts for rate making purposes in 1995? If yes, please explain.

Response:

The FEU are not aware of whether customers were generally supportive or not supportive of the Centra Gas proposal in 1995 to consolidate Whistler and Port Alice for ratemaking purposes.

45.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.11.2, 1.11.1; Exhibit A2-25, p.2

Distinct and Special Area

The FEU state in BCUC 1.11.2: "Distinctive characteristic considerations of unique and special areas might include economic development, sparsely settled regions, environmental and social considerations. It would also require that the area could be operated on a stand-alone basis and would not be part of a system that is planned for and operated on an integrated basis."

The FEU state in BCUC 1.11.1: "If an area was determined to be a distinct or special area for ratemaking

purposes, and a separate COSA could be established for that area with clearly defined assets and costs attributed to the area, then the revenue to cost ratio would be expected to be 100% for the assigned revenue requirements for the area as a whole (but not for each customer class) to ensure that a fair and reasonable return was provided for the distinct area. This would only be the case if the Commission determined that the area must be treated as a stand-alone utility in terms of costs and that the revenue requirements must be totally separated from the remaining portion of the utility costs."

The Commission, in a letter dated June 9, 2004 to Mr. Lekstrom (MLA, Peace River South) regarding Terasen Gas Inc. Rates and Costs for the District of Chetwynd (Exhibit A2-25), stated on page 2:

> "Terasen Gas, representatives of gas marketers, and Commission Staff will be discussing the issue of allocation of mid-stream costs during the remainder of 2004 with a view to adjusting the Midstream Cost Recovery Charge in rates effective January 1, 2005. These discussions will provide an opportunity to review whether Terasen can and should create a separate Midstream rate for communities north of Station 2 such as Chetwynd."

45.1 Please explain why the FEU consider that to be a distinct or special area for the purpose of Section 60(2) of the *Utilities Commission Act*, the area must be able to be operated on a stand-alone basis and would not be part of a system that is planned for and operated on an integrated basis?

<u>Response:</u>

The FEU did not state that to be a distinct or special area for purposes of section 60(2) of the UCA that the area must be operated on a stand-alone basis and would not be part of a system that is planned for and operated on an integrated basis. As quoted in the preamble, the FEU stated that "if the Commission determined that the area must be treated as a stand-alone utility in terms of costs and that the revenue requirements must be totally separated from the remaining portion of the utility costs," then the revenue-to cost ratio would be expected to be 100% for that area. Further, treating the utility as a stand-alone utility in terms of costs does not necessarily imply that it has to be planned for and operated on a stand-alone basis.

Section 60(2) of the UCA states that the Commission may take into account a distinct or special area "with a view to ensuring, so far as the Commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area." The Commission may take into account a distinct or special area and determine the extent to which it considers advisable the rate for that area should be "adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area."

However, the accuracy of rate base and resulting costs for the distinct or special area diminishes along with the amount of interconnectedness of the system because the common costs must be allocated among regions. The FEU therefore believe that a distinct or special area is appropriate only when the region is completely or is close to being a stand-alone system. Once that hurdle is passed, it would be necessary to consider other factors, such as the similarity of the service offered, the similarity of the customers and the ownership structure.

45.2 Please confirm that the Commission determining that "the area must be treated as a stand-alone utility in terms of costs and that the revenue requirements must be totally separated from the remaining portion of the utility costs" is consistent with the approach currently used for FEFN. If no, please explain.

Response:

FEFN currently has a separate revenue requirement that is regularly submitted for approval by the Commission. However, the costs included in the FEFN revenue requirement require a fair amount of allocation of both the rate base and operating costs to determine the amounts to include in the revenue requirement. While FEFN historically has been set up on a regional basis apart from rest of the FEI region, history alone should not be a criteria in determining a distinct or special area. As the FEU have grown through the acquisition process, it has become a more integrated utility in terms of facilities and operations. The FEU do not see any circumstances for the FEFN area that set it apart from other areas within FEI, FEVI or FEW that would require it to be continued to be treated as a distinct or special area.

45.3 In table form, please summarize the distinctive characteristics of FEI, FEVI, FEW and FEFN (to include, but not limited to, economic development, sparsely settled regions, environmental and social considerations) that could be affected by changes in gas delivery prices/rate design.

Response:

As stated in the FEU's response to BCUC IR 1.11.2, the FEU have not found any areas within the FEU's service areas that it considers to have the "distinctive characteristics" required in the Act.

Since there are no such distinctive characteristics to warrant separate COSAs for FEI, FEVI, FEW and FEFN, the FEU have not completed any other comprehensive studies that examine how this proposal would impact the economic well-being and/or social and economic considerations on a regional basis. The FEU did receive letters of support from Whistler and municipalities within FEVI that assert that this proposal will contribute to the overall economic health of the respective communities.

The FEU believe that there will always be a degree of varying characteristics within large geographical areas, such as FEI and FEVI. However, this does not necessarily warrant a regional approach in rate design. For example, some regions of FEI could be more similar to certain regions of FEVI, FEW or FEFN, in comparison to the rest of FEI. For example, from an annual income perspective, despite being neighbours, Regional District 9 - Fraser Valley has a more comparable average family income ($72,311)[43] to Regional District 35 - Central Okanagan ($75,130) than Greater Vancouver ($87,788). In a similar fashion, Regional District 31 – Squamish Lillooet, which also includes Whistler, has comparable income levels ($76,464) to the Fraser Valley. With regards to the FEVI service area, Regional District 29 – Sunshine Coast has an average family income of $70,358, which is much lower than Regional District 17 – Capital, where an average family income level is $84,032. As such, average income levels of customers in Victoria are more similar to the average income levels of customers in Greater Vancouver.

This variation is also present when examining types of housing and housing costs. While Whistler may have the reputation as a vacation destination, there are other areas within the

[43] All numbers included were obtained from the BC Stats Socio-Economic profiles, which can be located at http://www.bcstats.gov.bc.ca/StatisticsBySubject/SocialStatistics/SocioEconomicProfilesIndices/Profiles.aspx

Province such as Big White (Inland service area), Mount Washington (FEVI service area) and Fernie (Columbia service area) that have similar characteristics. In terms of housing costs, the Fraser Valley is comparable to the Capital region, which encompasses much of Southern Vancouver Island, as the percentage paying 30% or more of their income on housing costs is approximately 29%. Greater Vancouver on the other hand is substantially higher at 32.7%. However in the Northern Rockies, where Fort Nelson is located, this number substantially decreases to 14.5%.

The FEU believe that overall customer demographics are similar across the FEU's service areas with an expected level of variation.

45.4 Please explain the rationale for any changes to (or a decision not to change) the allocation of the Midstream rate for communities north of Station 2 since 2004. Please describe any changes made and the effect of those changes on communities north of Station 2 such as Chetwynd.

Response:

FEI provides natural gas service to the communities of Fort Nelson and Prophet River (located within the FEFN service area), and the communities of Chetwynd and Hudson's Hope (located within the Inland service area), and all of these communities are located north of Station 2. There have been no changes to the gas cost rate design methodologies for either the Fort Nelson or the Inland service areas since 2004.

While Fort Nelson is treated as a separate service area for establishing gas cost recovery rates, the Fort Nelson gas supply requirements are included within the FEI Annual Contracting Plan ("ACP") and an allocation of cost is used to determine the gas costs for the Fort Nelson service area. In 2004, FEI implemented the Essential Services Model ("ESM") for its gas supply portfolio to support the Customer Choice Program, with commodity unbundling marketer gas flow commencing November 1, 2004. In its ACP for the 2005/2006 gas contracting year, FEI reviewed the gas supply portfolio components required for, and the costs that would be allocated to, the Fort Nelson service area. With a view to continue to minimize Fort Nelson's exposure to price volatility, FEI made some minor adjustments to the FEFN portfolio resulting in a winter portfolio mix consisting of 1/3 storage, 1/3 hedged commodity, and 1/3 market-based commodity and a summer portfolio mix consisting of 1/2 hedged commodity and 1/2 market-based commodity. The FEFN gas supply portfolio today continues to reflect that general structure although the level of hedged commodity has fallen off with the suspension of the hedging program.

46.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.13.2.1, 1.147.4; UCA Section 60(3)

Remote Communities

The FEU state in BCUC 1.13.2.1: “No, the FEU do not consider that FEVI and FEW fit the criteria of remote communities.”

The FEU state in BCUC 1.147.4 that the number of customers per km of distribution pipe for 2011 were: FEI: 22; FEVI: 18; FEW: 19; and FEFN: 11.

Section 60 (3) of the *UCA* states “If the commission takes a special area into account under subsection (2) [distinct or special area] it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.”

46.1 Do FEU consider that FEFN fit the criteria of a remote community? Please explain why or why not.

Response

If the intent of the question is to ask whether Fort Nelson is the type of community that would fall under the Remote Communities Regulation (“RCR”) (Order-in-Council No. 509 dated June 25, 2007), the FEU do not consider that Fort Nelson fits the criteria of a remote community. In the first place the RCR does not provide a descriptive definition of what a remote community is, but rather provides a schedule of communities that are remote communities (and Fort Nelson is not on the list). The purpose of the RCR is to enable the designated remote communities to receive electric service from BC Hydro under existing postage stamp rate schedules (under either Zone 1 or Zone 2 rates depending on whether the community connects to the grid or not). Beyond not being a designated remote community, Fort Nelson has long established utility service for both electricity and natural gas. As far as electric service is concerned Fort Nelson is served by BC Hydro from a local gas-fired generating station and is also connected to the Alberta grid by a transmission line. Fort Nelson has an airport with regular jet service, a hospital, schools and other community services. Fort Nelson is a centre for oil and gas activity in BC’s far north. All of these elements set Fort Nelson apart from the much smaller and more remote communities that are on the RCR designated list of remote communities.

46.1.1 Do FEU agree that, for a rural remote community, electricity would generally be considered an essential service, while delivered natural gas would be considered optional (non-essential) services? If no, please explain why not.

Response:

Yes, the FEU agree that electric service to rural and remote areas would generally take precedence over natural gas service. Electricity is a more versatile energy source that can serve thermal energy needs, such as space and water heating, which can be served by natural gas, as well as many end uses that natural gas cannot serve, such as lights, appliances and computers.

47.0 Reference: Request for Common Rates

Order G-56-12, Appendix A, p. 4; BC Energy Plan, p. 39, Exhibit B-3, Section 6.8, p. 127; Exhibit B-9, BCUC 140.5, 158.8

Economic Development

The Commission, in the Reasons for Decision attached as Appendix A to Order G-56-12 on the BC Hydro Dawson Creek/Chetwynd Area Transmission Project, state on page 4:[44]

> "CAPP [Canadian Association of Petroleum Producers] identifies a practical point that, as members of the industry, they make plans based on the current Tariff. Indeed, Shell Canada (Shell) notes that it has moved beyond the planning and has considerable investment based on the current tariff, working on these plans for over three years. Shell relied on a "BCUC approved tariff [and] BCUC approved terms and conditions." It has completed a facility agreement and the security requirement. Air Liquide makes a distinct case that, as a non-natural gas producer, it has no choice but to seek electrical service from BC Hydro, and is relying on this service."

Policy Action No. 44 of the BC Energy Plan (page 39) states "Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America."

The FEU state in section 6.8 of the Application "Amalgamation and adoption of common rates is in line with provincial energy policy and the Provincial Government strategy on natural gas. ... to promote natural gas as a transportation fuel ... introducing a regulation under the Clean Energy Act to advance a proposed natural gas vehicle program."

The FEU state in the response to BCUC 1.40.5 "The FEU expect adopting a postage stamp rate structure will have no significant impact, positively or negatively, on the Provincial Government's efforts to promote natural gas as a transportation fuel."

The FEU state in BCUC 1.58.8 "... the FEU do not believe the approval of postage stamp rates within its service areas would provide a competitive advantage to bid a higher price over other investors to acquire new utility operations. In most acquisitions, an approved rate base already exists. The price paid would consider factors such as the existing rate base and approved cost of capital and future growth prospects to determine the price, not the assumption on extension of postage stamp rates."

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[44] http://www.bcuc.com/Documents/Proceedings/2012/DOC_30568_A-28_G-56-12_Reasons-Revised-Regulatory-Timetable.pdf

47.1 Please describe separately for FEI, FEVI, FEW and FEFN any BC economic developments impacts identified resulting from the proposal to move to postage stamp rates.

Response:

The FEU did not undertake any economic development impact studies in preparing the Application. As noted in Section 8 (Financial Review) of the Application, the proposal results in an economic benefit arising from the efficiencies achieved. While certain regions will achieve an economic benefit that is significant, such as FEVI and FEW, relative to a more modest increase in FEI, overall the regional economic impacts are not the basis for the Application.

47.1.1 Do FEU consider that there will be a net BC economic development benefit or disbenefit resulting from the proposal to move to postage stamp rates? Please explain why or why not.

Response:

The FEU believe there will be a benefit resulting from the proposal to move to postage stamp rates. However this benefit is difficult to quantify without a comprehensive economic impact analysis. The FEU do not believe that an economic impact analysis is necessary at this time as the proposal results in benefits for customers due to the expected efficiencies that will result in a net decrease in the overall cost of service. Regionally, the incremental savings in FEW and FEVI are more significant than the smaller increase for FEI, and as such the Companies predict that the economic development benefits will accrue mostly to FEVI and FEW customers.

47.2 If the Commission determined that postage stamp rates are 'more fair' than regional rates, do FEU agree that this would provide a competitive advantage to FEU compared to other investors in high cost and potentially uneconomic propane or natural gas utilities in BC? If no, please explain why not. Please include in your response whether this outcome would be consistent with Energy Plan Policy Action No. 44.

Response:

The FEU believe that a Commission determination that postage stamp rates are more fair than regional rates may provide advantages to the FEU or another large incumbent utility compared to other investors in high cost and potentially uneconomic propane or natural gas utilities in BC, but whether these advantages are significant would depend on the specific situation. For an incumbent utility the Commission would be involved in reviewing and approving both the acquisition transactions and any subsequent amalgamation / postage stamping request. The degree to which a utility is uncompetitive because it is high cost or uneconomic would be reflected in the purchase price and potentially in the rate base value that the acquiring utility would be allowed to use in establishing rates. Other investors may see greater value in other opportunities associated with an acquisition. For example, a non-BC based company Altagas was the successful bidder in the recent sale of PNG. Although the PNG – West division is a high cost utility, Altagas possibly saw enough value in the growth opportunities, such as for LNG export, that it made the high bid even though the opportunity for postage stamping was very limited.

The FEU do not believe that there is any connection between the types of public utility acquisition transactions contemplated in the question and Energy Plan Policy Action No. 44 (quoted below) which has to do with the regulatory (i.e. the Oil and Gas Commission) and fiscal (e.g. royalty rates) matters pertaining to the upstream oil and gas sector.

> *"44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America."*

47.3 Do FEU agree that promotion of natural gas as a transportation fuel should not be included as a benefit in the evaluation of this Application? If no, please explain why not.

Response:

The FEU clarify that amalgamation and postage stamp rates are important for the NGT initiative. In particular, postage stamp rates result in the following benefits that should be included in the evaluation of the Application.

- As stated in the response to BCUC IR 1.40.5, "prospective CNG customers within regions such as FEVI may benefit from common rate schedules." The benefit of this fact was not fully reflected in the FEU's response to BCUC IR 1.40.5. The existing higher delivery rates in FEVI and FEW are one important factor that makes it harder to develop the NGT market in these service territories. Under the proposed amalgamation, customers in FEVI and customers in FEW would have significantly lower delivery rates for natural gas for transportation uses. The reduced rates would improve the economics of adopting natural gas as a transportation fuel in these service territories, which are expected to help customers in these service areas make a decision to move to NGT by reducing one of the barriers that could be impeding their decision. For an example of the relative economics for NGT customers in FEI vs. FEW and FEVI, please see BCUC IR 2.55.1.

- Eliminating the significant economic disadvantage for CNG customers in FEW and FEVI would also help the FEU achieve the regional diversity goals with respect to the *Clean Energy Act Greenhouse Gas Reduction Regulation*.

- As noted in the response to BCUC IR 1.40.4, the expansion of NGT service offerings could be achieved through entity specific proposals and approvals. However, a benefit of amalgamation and the adoption of common rates would be in regulatory efficiency and an accelerated process of extending the NGT service offering to FEVI, FEW and FEFN customers.

On this basis there is a benefit from this Application with respect to the promotion of natural gas as a transportation fuel.

48.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.7.2.3, 1.93.6.1, 1.99.1

Rate Structure Stability

The FEU state in BCUC 1.7.2.3: "The proposed common rates across a combined entity will provide rate stability for the smaller service areas of FEVI, FEW and Fort Nelson (as discussed earlier in Section 6.3.2) by allowing a broader customer base to absorb any significant capital expenditures, customer or volume losses and declining use per customer without generating significant spikes in rates for any one service area."

The FEU state in BCUC 1.93.6.1, in response to a question asking if the FEU had considered phasing-in of rate decreases to FEVI and FEW in the context of conservation messages in the Energy Plan:

> *"No, FEU did not consider this option and alternative to postage stamp rates primarily because it does not address the issue of rate disparity amongst the entities."*

The FEU state in BCUC 1.99.1: "If all three [FEFN] scenarios materialize [decreases in industrial load, maintenance capital expenditures and declines in residential use per customer], the estimated impact to the average burner tip rate is a cumulative increase of approximately 20% by the fifteenth year. ...

The combined impact over the fifteen year period of the three scenarios and the rebalancing of rates is an approximate cumulative burner tip impact of 41% to Residential Fort Nelson customers. ...

The forecasted overall impact to a typical Residential Fort Nelson customer of amalgamation and implementation of common rates is an annual bill increase of approximately 54% in year 15."

48.1 Please confirm that FEFN residential customers would pay more under the proposal (54 per cent bill increase) even if the scenarios described in BCUC 1.99.1 and rate rebalancing were to occur (41 per cent bill increase). If no, please explain why not.

Response:

Confirmed, that the forecast impact to FEFN residential customers in Year 15 based on common rates is higher than the forecast impact in Year 15 if rates were rebalanced to a revenue to cost ratio of 90% combined with decreases in industrial load, maintenance capital expenditures and declines in residential use per customer as set out in BCUC IR 1.99.1.

However, on a net present value basis the common rate proposal is less costly than the sum total of the four scenarios, as demonstrated in the response to BCUC IR 1.99.1.

Additionally, if rates are rebalanced to a revenue to cost ratio of 100%, the total forecast impact in Year 15 of rebalancing as well as the three scenarios described above would be an increase to residential rates of approximately 55%. This is slightly higher than the forecast increase of 54% under the common rates proposal.

48.1.1 Does the 41 per cent cumulative burner tip impact to Residential FEFN customers assume existing FEFN COSA methodology or proposed FEI (Amalco) COSA methodology? If it assumes existing FEFN COSA methodology, please recalculate the bill impact assuming proposed FEI (Amalco) COSA methodology.

Response:

The 41 per cent cumulative burner tip impact is calculated based on existing FEFN COSA methodology. When rebalanced using the FEI Amalco COSA methodology, the results achieved are the same as under the legacy methodology.

48.2 Please calculate the forecasted overall impact to a typical commercial Fort Nelson customer in year 15 for the following scenarios: (i) all three scenarios referred to above in BCUC 1.99.1 materialise, (ii) all three scenarios referred to in BCUC 1.99.1 materialise and there is also rate rebalancing using FEFN existing COSA methodology, and (iii) all three scenarios referred to in BCUC 1.99.1 materialise and there is also rate rebalancing using FEI (Amalco) proposed COSA methodology.

Response:

The question does not indicate if the impacts are for FEFN's RS 2.1 or RS 2.2 customers. As there are commercial customers in both of these rate schedules, the impacts for both groups of customers are summarized below.

Scenario (i)

The impacts resulting from the loss of industrial load and maintenance capital expenditures reflect the average for all customers in Fort Nelson, and therefore the percentage change is the same for all customers. The impacts of the loss in industrial load and maintenance capital expenditures have been detailed in BCUC IR 1.99.1, and result in a forecast increase of 3.3% in the annual bill due to the loss of industrial volumes, and increase of 15% in the annual bill due to maintenance capital expenditures by Year 15.

The impact to RS 2.1 customers in Year 15 resulting from an annual decrease of 0.3% in consumption, or approximately 1.5 GJs per year is a 1.7% increase in the annual bill. The impact to RS 2.2 customers in Year 15 resulting from an annual decrease of 0.2% in consumption, or approximately 7.3 GJs per year is negligible to the annual bill.

The total percentage increases in the annual bills in Year 15 for each of these classes when adding these three impacts together is summarized in the table below.

	Loss of industrial load	Maintenance Captial Expenditure	Decline in Use Rates	Total Impact in Year 15
Rate Schedule 2.1	3.3%	14.9%	1.7%	19.9%
Rate Schedule 2.2	3.3%	14.9%	0.0%	18.2%

Scenario (ii)

As summarized in BCUC IRs 2.43.2 and 2.43.3, the impact of rebalancing RS 2.1 rates to a revenue to cost ratio of 110% would result in an increase of approximately 32% for an RS 2.1 customer, and an increase of 14% for an RS 2.2 customer by Year 15.

The total percentage increase in the annual bills in Year 15 for the three scenarios described in Scenario (i) combined with the impacts of rebalanced rates using FEFN's existing COSA methodology are summarized in the table below.

	Loss of industrial load	Maintenance Captial Expenditure	Decline in Use Rates	Rebalancing Impacts	Total Impact in Year 15
Rate Schedule 2.1	3.3%	14.9%	1.7%	32.0%	51.9%
Rate Schedule 2.2	3.3%	14.9%	0.0%	14.0%	32.2%

Scenario (iii)

Using the FEI Amalco methodology to determine FEFN's rates provides the same results as under FEFN's legacy methodology. Therefore, the bill impacts are the same as in Scenario (ii).

48.2.1 Please provide the average bill increase in year 15 for commercial customers under the postage stamp rate proposal.

Response:

Based on consumption levels, FEFN's commercial customers, Rate Schedules 2.1 and 2.2, were mapped to either FEI's Rate Schedule 2 or Rate Schedule 3. The average cumulative bill increase in Year 15 for these commercial customers is summarized in the table below:

Original Fort Nelson Rate Schedule	FEI Rate Schedule	Fort Nelson Average Bill Increase in Year 15
Rate Schedule 2.1	Rate Schedule 2	27.7%
Rate Schedule 2.1	Rate Schedule 3	24.6%
Rate Schedule 2.2	Rate Schedule 3	23.5%

49.0 Reference: Request for Common Rates

Commission Reasons for Decision to Order G-124-09, pp. 77, 80; Exhibit B-9, CEC 1.13.1, BCUC 1.157.1, 1.158.1

Low Income/Vulnerable Customers

Reasons for Decision to Order G-124-08 (BC Hydro Residential Inclining Block Rate Application) state:[45]

> "Terasen submits that it is sympathetic to the desire of BCOAPO to improve the energy security of low-income customers and notes that the RIB proposal results in favourable bill impacts for the vast majority of customers that BC Hydro has identified as low-income customers. Terasen further submits that even the minority of low-income customers that can expect to see higher bills under the RIB proposal needs to conserve only a modest amount of energy to offset bill impacts associated with the RIB rate structure." (p. 77)

> "With regard to differentiated rates for low-income residential customers, the Commission Panel has considered the extensive submissions of BCOAPO regarding differentiated rates but concurs with BC Hydro's evidence that the vast majority of BC Hydro's low-income customers will be better off under a simple two-step inclining block structure that is revenue neutral for the residential customer class than under the current flat rate structure." (p. 80)

The FEU state in CEC 1.13.4: "Income levels should not be used as a yardstick in determining rates as the income levels in British Columbia vary considerably."

The FEU include in BCUC 1.157.1 and 1.158.1 the following graphs:

[45] http://www.bcuc.com/Documents/Decisions/2008/DOC_19755_BCH-RIB-Decision-WEB.pdf

Figure: The Percentage of FEU Customers and of the General Population with Annual Income Less Than $20,000.

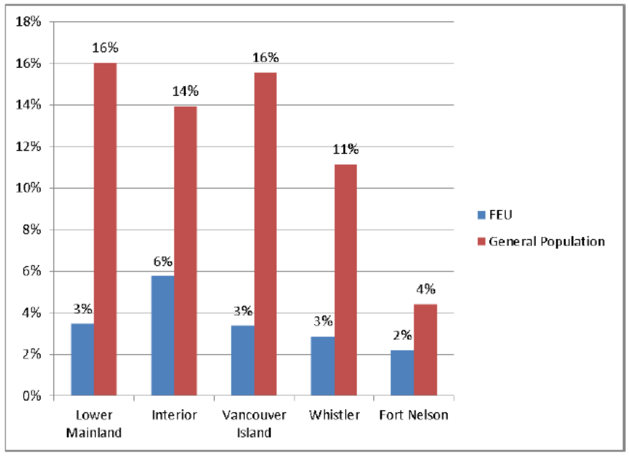
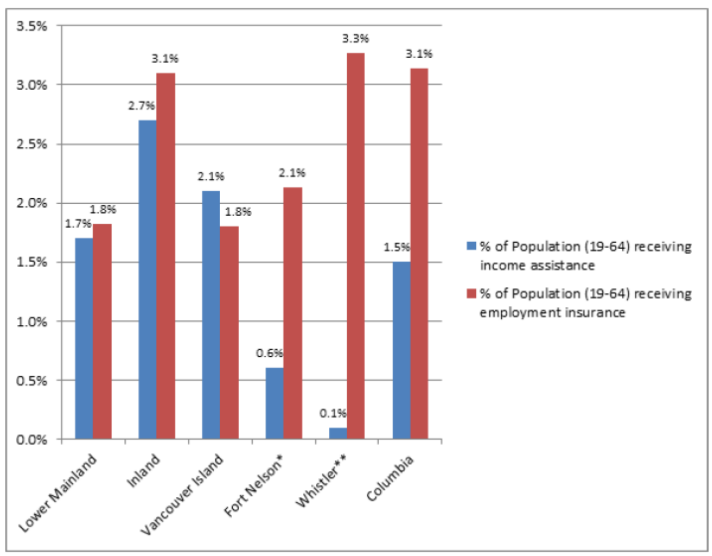


Figure: Proportion of the General Public Receiving Income Assistance and Receiving Employment Insurance Benefits.



* Northern Rockies Regional District
** Squamish-Lillooet Regional District

Figure: Median Householde Income of the FEU Customers and of the General Population by the FEU Service Area

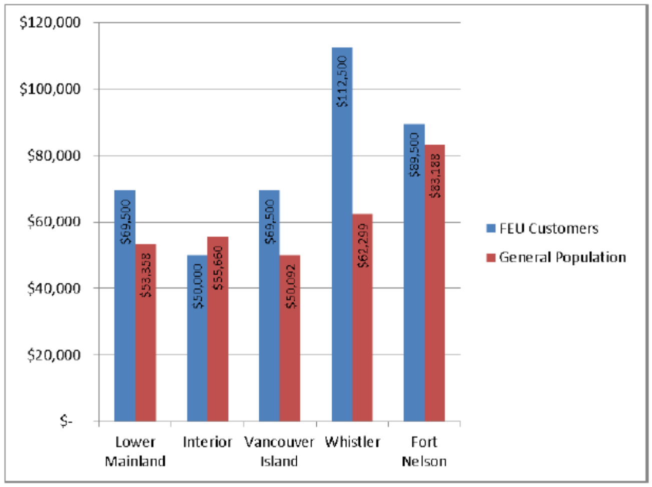


Figure 3: Primary Space Heating Fuel of FortisBC natural gas customers by Region (%)121

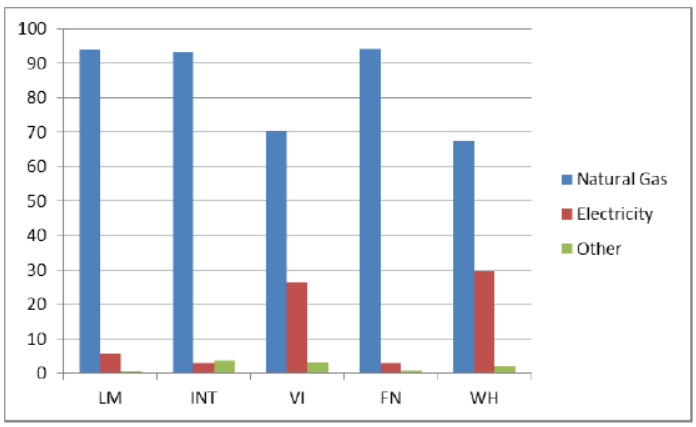
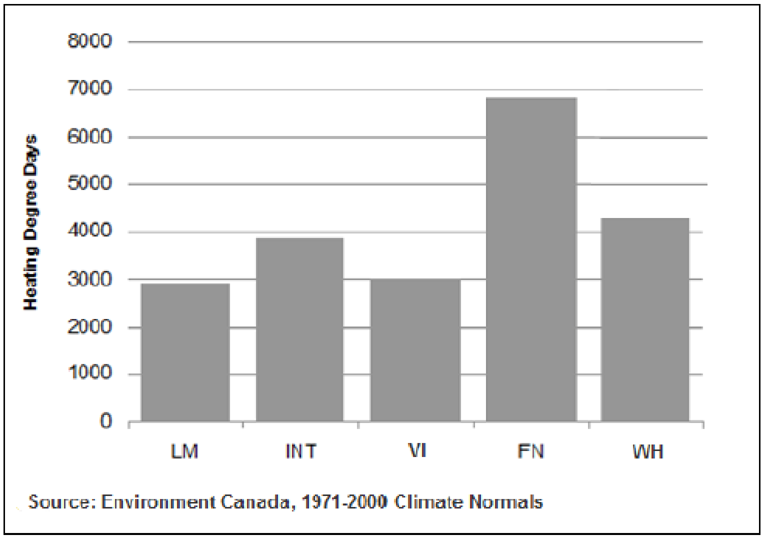


Figure 4: Typical Annual Heating Degree Days by Region122



49.1 Do FEU agree that whether a rate design change results in positive or negative overall impact on low income/vulnerable gas customers is a relevant consideration in determining if a rate proposal is in the public interest? If no, please explain why not.

Response:

The impact on low income/vulnerable gas customers may be one of many relevant considerations in terms of the public interest. It is not, however, a highly relevant consideration in this proceeding. Low income/vulnerable customers exist within all of the FEU's regions and the proposed rates result in a significant decrease to some low income/vulnerable customers and a relatively small, phased-in rate increase for other customers. This makes it extremely difficult to determine whether the postage stamping of rates will have a net positive or negative impact on low income/vulnerable customers.

49.2 Would FEU agree that postage stamping of FEW residential rates would result, on average, in overall bill decreases for higher income individuals and overall bill increases for lower income customers? If no, please explain why not.

Response:

The FEU do not agree that the postage stamping of FEW residential rates will result, on average, in overall bill decreases for higher income individuals and overall bill increases for lower income individuals.

Low income and high-income customers reside throughout all the FEU's service areas. Postage stamping of FEW residential rates will result in both low-income and high-income customers in the Whistler area receiving a material bill decrease. Similarly, all customers within FEI will experience a relatively minor bill increase. The bill impacts to all service areas resulting from postage stamp rates have been described in the Application and various IR responses. These bill impacts will be experienced by all customers of all income levels.

The FEU believe that it would be inconsistent with past practice to use income levels as a yardstick for determining rates, as the Commission has not set rates based on income levels in the past.

49.3 Do FEU consider that postage stamping of (i) FEVI and (ii) FEFN residential rates would result, on average, in overall bill decreases for higher incomes individuals and overall bill increases for lower income customers? If no, please explain why not.

Response:

The FEU assume that the IR is asking about the impact of the proposed postage stamp rates on FEVI and FEFN residential customers alone.

The FEU do not agree that the postage stamping of FEVI and FEFN residential rates will result, on average, in overall bill decreases for higher income individuals and overall bill increases for lower income individuals.

As indicated in the response to BCUC IR 2.49.2, low income and high-income customers reside throughout all the FEU's service areas. Therefore, postage stamping of FEVI and FEFN residential rates will result in both low-income and high-income customers in FEVI experiencing material decreases in their annual bills, while FEFN customers will experience material increases.

The bill impacts to all service areas resulting from postage stamp rates, as well as the mitigation strategy for FEFN customers, has been described in the Application and various IR responses. These bill impacts will be experienced by all customers of all income levels.

The FEU believe that it would be inconsistent with past practice to use income levels as a yardstick for determining rates, as the Commission has not set rates based on income levels in the past.

49.4 Do FEU consider that low-income residential FEFN customers need to conserve only a modest amount of gas in order to offset end-state bill impacts associated with the postage stamp rates proposal? Please explain why or why not.

Response:

The preamble to this IR references Terasen's comments regarding BC Hydro's Residential Inclining Block Rate Application ("RIB"). In the context of the RIB application, Terasen agreed that the minority of low-income customers would only need to conserve a modest amount of energy to offset the bill impacts associated with RIB.

In the case of FEFN residential customers, low-income or otherwise, the FEU recognize the large rate increases associated with the postage stamp rates proposal. FEFN residential customers would have to decrease their consumption by approximately 50 GJs or approximately 36%[46] to offset end state bill impacts associated with amalgamation and postage stamp rates.[47] The FEU do not consider a 50 GJ decrease in annual use as a modest amount and it is because of this that the FEU have investigated rate mitigation strategies for FEFN customers.

As a result of this analysis, the FEU have proposed a 15 year phase in strategy for FEFN customers. This strategy will help transition FEFN customers to amalgamated rates by delaying any impact of common rates for five years, and then phasing in the increase over the subsequent 10 years. This proposal would shield FEFN customers from sudden increases in

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[46] For comparison purposes, on a standalone basis, if the FEFN Residential R:C ratio was rebalanced to 90% it would require customers to decrease their annual consumption by 25 GJs or 17%, if rebalancing closer to 100% was required, it is likely that the annual consumption decrease would be close to the 50 GJs discussed in this response.

[47] Calculated as approximate Fort Nelson Residential customer annual bill increase (excluding phase-in rate rider) of $542 per year divided by effective Fort Nelson Residential burner tip rate of $10.91/GJ as provided in Appendix J-3

delivery rates, and would instead provide a smooth and gradual transition to common rates. While the FEU believe that the proposed phase in is appropriate, the FEU would be open to other rate mitigation options for FEFN customers.

49.4.1 Do FEU consider that low-income residential FEI customers need to conserve only a modest amount of gas in order to offset end-state bill impacts associated with the postage stamp rates proposal? Please explain why or why not.

Response:

A typical Lower Mainland FEI residential customer consuming 95 GJs annually would need to conserve approximately 5 GJs in order to offset the annual bill impact associated with postage stamp rates.[48] The FEU consider this to be a modest annual consumption decrease, as it translates to an approximate decrease of less than 0.5 GJs per month.

48 Please refer to Appendix J-4, Tab 1.1, page 1, annual bill impact of $53.99/ $11.389 /GJ effective rate = 4.74 GJs

50.0 Reference: Request for Common Rates

Exhibit B-3, Appendix G-5; Exhibit B-9, BCUC 1.80.1

Environment – Emissions vs. Economic Development Trade-Off

Section 2 of the *Clean Energy Act*, filed as Appendix G-5 of the Application, includes the following British Columbia energy objectives: ensure the authority's [BC Hydro's] rates remain among the most competitive of rates charges by public utilities in North America; reduce BC greenhouse gas emissions; and encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia.

The FEU state in BCUC 1.80.1: "The FEU generally agree with the statement [promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate] provided it is put in the right context. ... FEI's evidence provided during the [price risk management] proceedings was that maintaining competitiveness with electricity is not only in the best interests of FEI's customers, but it is also in the best interests of electricity consumers in the province. ... The FEU continue to believe that natural gas is the appropriate fuel to use in space and water heating applications and that government policy objectives can best be achieved in these energy end uses by using natural gas in combination with alternative energy solutions."

50.1 Please describe the 'right context' in which FEU would agree that 'promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate'. Please provide specific examples in your response.

Response:

The 'right context' in which the FEU would agree that 'promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate' would be circumstances in which using electricity advances government policy objectives more effectively than natural gas and is not detrimental to other policy objectives. This would clearly be the case for end uses where electricity is the only or the most practical energy form, such as lighting, appliances, computers and plug-in electronics. In the past natural gas used to be used for street lighting but going back to this use is an example of a program that would on balance be impractical and likely detrimental to current government policy objectives.

In situations where natural gas and electricity are competing energy sources, most often there are trade-offs that need to be weighed in determining whether electricity is better for meeting government policy objectives. Using electricity for space heating, for example, may reduce greenhouse gas emissions in that end use relative to natural gas, but it drives the need to acquire electricity at the higher marginal cost of new supply and drives the need for system reinforcements to deliver the electricity in the high use winter months. This would put pressure on electricity rates and on the objective of keeping electricity rates in BC among the lowest in North America. Further, at times the electricity to serve the space heating load may be imported from other jurisdictions where the electricity is produced from a fossil fuel. On the other hand, using natural gas (in combination with alternative energy sources) for space heating would help to alleviate the rate pressure and may free up electricity supply to serve markets such as electric plug-in vehicles that have a flatter demand profile throughout the year and may achieve greater GHG emission reductions in BC than simply using electricity to meet space heating needs. Large scale electrification initiatives in BC would also make it more difficult for BC to achieve energy objective (n) of being a net exporter of clean or renewable resources to benefit British Columbians and to help neighbouring jurisdictions reduce their GHG emissions.

The Province's recent implementation of a Natural Gas Strategy and an LNG Strategy signals a change in expectations for the role that natural gas should play in BC going into the future. While the full implications of these new policies are still to be determined, the FEU believe that the Companies' approach of promoting the efficient use of natural gas in BC (in combination with alternative energy solutions) is in the interests of all utility customers in the province, by providing solutions that are both cost effective and environmentally responsible.

50.2 Please explain how the FEU arrived at the position that 'natural gas is the appropriate fuel to use in space and water heating applications' and how this statement is consistent with the BC Energy Plan environmental objectives.

Response:

Natural gas is an important and cost-effective primary source of energy in BC that can be produced, stored and delivered reliably to customers when they need it and can be used very efficiently and effectively at the end use to provide the thermal energy that customers need. The FEU have been working extensively to promote energy conservation and efficiency among natural gas customers. The FEU expect to continue achieving improvements in the efficient use of natural gas that will assist in meeting the province's environmental objectives. In addition, incorporating alternative energy solutions, such as geoexchange, solar thermal and waste heat recovery, with natural gas backup along with building improvements into the energy mix will assist in meeting longer term environmental objectives.

Electricity on the other hand is a secondary energy source, produced around the world mainly from burning fossil fuels (coal, oil and natural gas) and smaller percentages by hydro generation, nuclear and renewable generation sources. British Columbia is exceptional in its electricity generation mix having a high percentage of hydro power and a relatively small percentage of fossil fuel-based generation. Once electricity is generated it cannot be stored (other than limited capability in batteries). Electrical generation capability can be stored in hydro reservoirs and fuel inventories but only certain types of electrical generation (such as hydro generation) can respond quickly to fluctuating changes in demand. Renewable electricity generation, such as wind and solar, tends to be very costly and not adequately reliable on its own, so back-up generation capability must also be installed to meet customer demand. Electricity generation and transmission have an environmental footprint of their own so electrification initiatives such as switching to electricity for space and water heating would have significant environmental impacts attached. In addition, new electrical generation is much more costly than the embedded electricity supply costs and electricity-based space heating would occur in winter months, which is already the highest use period for electricity consumption. Using electricity for space heating would take away from the supply available to achieve emission reductions in the transportation sector (electric plug-in vehicles) and from the supply available to export to other jurisdiction to offset higher emission electricity generation such as coal fired generation.

The Province's recent implementation of a Natural Gas Strategy and an LNG Strategy signal a change in expectations for the role that natural gas should play in the Province's economy going into the future. The FEU believe that making wise use of these provincial natural gas resources appropriately involves using natural gas efficiently within the province to serve the energy needs of consumers here. The FEU also believe that efficient local use of natural gas is in the interests of both natural gas and electricity consumers in BC.

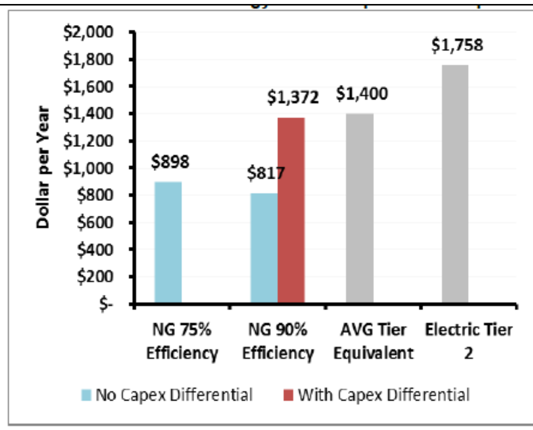
51.0 Reference: Request for Common Rates

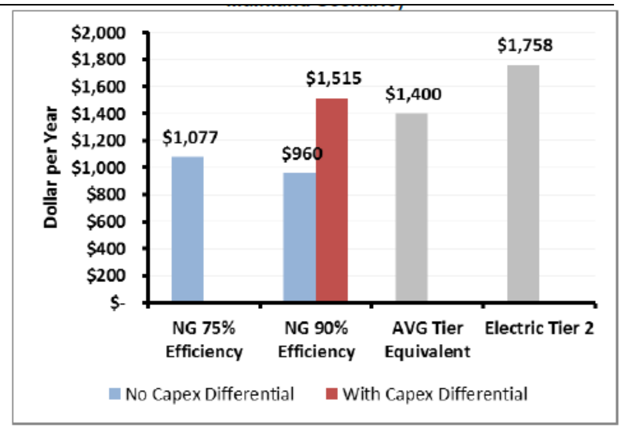
Exhibit B-9, BCUC 1.81.1.1, 1.81.2

Environment – Fuel Switching

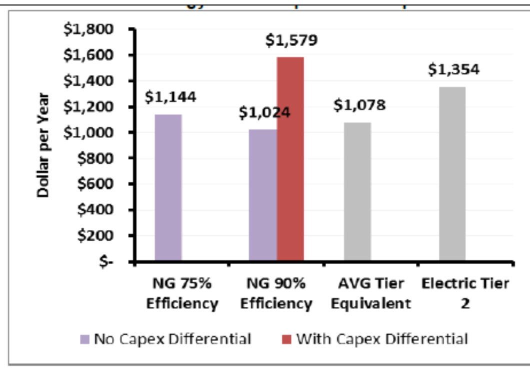
The FEU include in BCUC 1.81.1.1 and BCUC 1.81.2 the following regional energy cost comparison graphs for residential space and water heating:

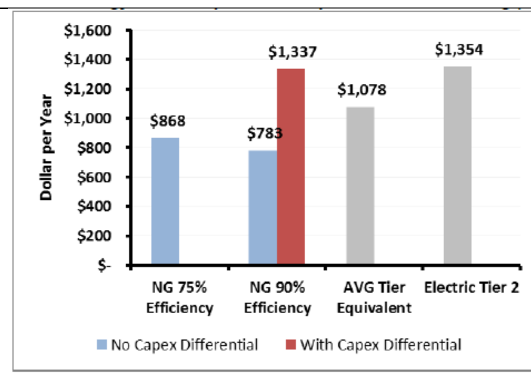
FEI (LM)



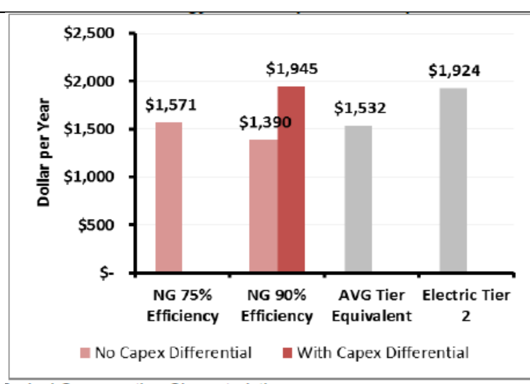


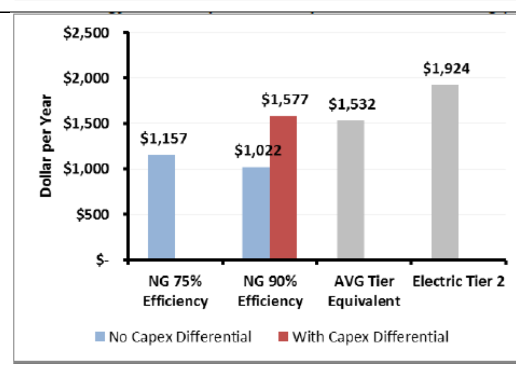
FEVI

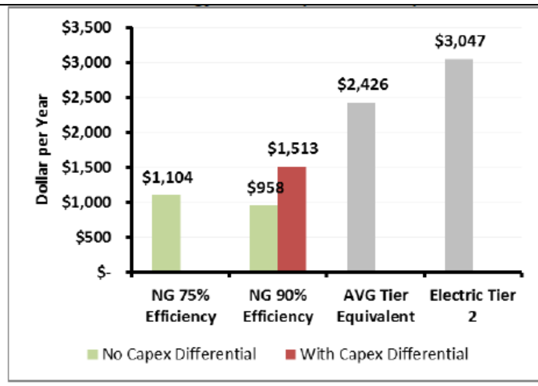
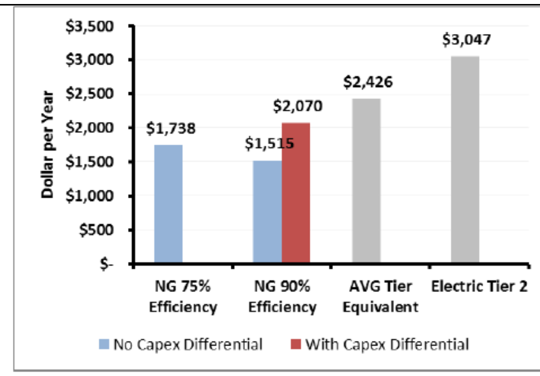




FEW





FEFN		

51.1 Please confirm that the graphs provided in response to BCUC 1.81.2 reflect end state postage stamp rates (i.e. after the phase-in). If not, please update the graphs accordingly.

Response:

Confirmed. The graphs provided in the response to BCUC 1.81.2 reflect the after phase-in end state postage stamp rates.

51.2 Using the graphs above, for FEI/FEVI/FEW and FEFN, please compare in a table the cost (delivery/year) of gas heat/hot water with electricity, under the following scenarios: (i) postage stamp rates not approved; (ii) postage stamp rates approved, but without any phase-in.

Response:

The following table is in the response to BCUC IRs 2.51.2 and 2.51.3.

Based on the graphs in the preamble of BCUC IR 2.51.0, the following table compares the costs of natural gas space heating and water heating with electricity under the requested scenarios. As requested in BCUC IR 2.51.3, the FEU assume 90 percent efficiency for gas and include the capex differential, and use the average tier equivalent for electricity.

	FEI (LML)		FEVI		FEW		FEFN	
	Common Rates Approved	Common Rates Not Approved	Common Rates Approved	Common Rates Not Approved	Common Rates Approved	Common Rates Not Approved	Common Rates Approved	Common Rates Not Approved
Annual Energy Consumption (Heat & Hot Water)								
Natural Gas @ 100% Efficiency (GJ/Yr)	*58*		*44*		*64*		*101*	
Electric Equivalent (Kwh)	*16435*		*12658*		*17979*		*28476*	
Annual Electric Energy Cost (Avg Tier Equivalent)	$1,400.29		$1,078.42		$1,531.77		$2,426.12	
Natural Gas @ 90% Efficiency (GJ/Yr)	*72*		*56*		*77*		*121*	
Annual Natural Gas Cost	$ 959.77	$ 816.87	$ 782.58	$ 1,024.45	$ 1,021.71	$ 1,389.80	$ 1,514.67	$ 957.86
Net Difference Between Electric and Gas Costs ($)	$ (440.52)	$ (583.42)	$ (295.84)	$ (53.97)	$ (510.06)	$ (141.97)	$ (911.45)	$ (1,468.26)
Net Difference Between Electric and Gas Costs (%)	-31%	-42%	-27%	-5%	-33%	-9%	-38%	-61%
Additional Capex Differential Per Year	*$554.86*		*$554.86*		*$554.86*		*$554.86*	
Total NG Cost Including Capex Differential	$ 1,514.63	$ 1,371.73	$ 1,337.44	$ 1,579.31	$ 1,576.57	$ 1,944.66	$ 2,069.53	$ 1,512.72
Net Difference Between Electric and Gas Costs ($)	$ 114.34	$ (28.56)	$ 259.02	$ 500.89	$ 44.80	$ 412.89	$ (356.59)	$ (913.40)
Net Difference Between Electric and Gas Costs (%)	8%	-2%	24%	46%	3%	27%	-15%	-38%
Natural Gas @ 75% Efficiency (GJ/Yr)	*82*		*64*		*89*		*141*	
Annual Natural Gas Cost	$ 1,077.08	$ 898.19	$ 868.11	$ 1,144.42	$ 1,156.69	$ 1,571.42	$ 1,737.69	$ 1,104.25
Net Difference Between Electric and Gas Costs ($)	$ (323.21)	$ (502.10)	$ (210.31)	$ 66.00	$ (375.08)	$ 39.65	$ (688.43)	$ (1,321.87)
Net Difference Between Electric and Gas Costs (%)	-23%	-36%	-20%	6%	-24%	3%	-28%	-54%

The assumptions used in the analysis are those used in BCUC IR 1.81.1 and are as follows:

Capital Cost Assumptions Applicable to All Service Areas *New Home Construction*	
Capital Cost for High Efficiency Furnace (90%) and ducting/Installation:	$7,000.00
Capital Cost of NG Water Heater and Installation	$1,400.00
Total Cost for Natural Gas High Efficiency Furnace and Water Heater	**$8,400.00**
Capital Cost for Electric Baseboards	$2,500.00
Capital Cost for Electric Water Heater and Installation	$ 975.00
Total Cost for Electric Baseboard and Water Heater	**$3,475.00**
Difference in upfront Capital Costs	**$4,925.00**
Interest Rate	6%
Measurable Life of Furnace (years)	18
Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 454.86**
NG Furnace Maintenance (per Year)	$ 100.00
Total Amount Needed to be Recovered Annually to Payoff Difference in Capital Cost	**$ 554.86***

* *This figure is divided by typical energy consumption for natural gas Space and Water Heating in the various service areas to derive the additional $/GJ required for natural gas customers to recover the difference in maintenance and upfront capital cost*

** *Natural gas capital and maintenance cost differential not applied to the 75% efficiency scenario since 90% efficiency furnaces are mandatory for new home construction*

Other assumptions in the analysis are as follows:

1. **Annual Electric Bill Assumptions:**
   - Average Step 1 / Step 2 rate - $0.0852/kWh applied to all kWh in the respective cases
   - Electric rates include the current BC Hydro 5% Rate Rider

2. **Annual Natural Gas Bill Assumptions:**
   - "Common Rates Not Approved" regional rates based on current natural gas rates for the respective Service Areas and includes Basic Charge and Carbon Tax @ $1.50/GJ
   - "Common Rates Approved" Proposed rates reflect end state postage stamp rates (ie. After the phase-in)

3. **Appliance Efficiency Assumptions:**
   - Electric space heating efficiency calculated @ 100% for Space Heating

- Natural gas space heating efficiency calculated at stated appliance efficiencies
- Water heater efficiencies: Natural Gas: 56%; Electric 90%

51.3 Please assume 90 percent efficiency for gas and include the capex differential, and use the average tier equivalent for electricity. Please also record in the table the net difference between the gas/electricity cost in all scenarios, in both dollar and percentage terms.

Response:

Please refer to the response to BCUC IR 2.51.2

51.3.1 Do FEU consider that the longer-term impacts of the postage stamp rates proposal may be different as gas prices and electricity prices change relative to each other (for example, FEVI may see an increase in customer switching to gas if electricity prices increase at a faster pace than gas)? Please explain why or why not.

Response:

The direct impact of the postage stamp rate proposal on the FEU's rates is not dependent on the price of electricity.

With respect to the competitiveness of natural gas against electricity as a result of the postage stamp rate proposal and the potential for fuel switching between natural gas and electricity, the FEU do not expect there to be a material change one way or the other. As indicated in Sections 4.1 and 6.8 of the Application, there are many determinants that inform customers' energy choices, not solely the price of competing energy forms, therefore, it is difficult to estimate what long-term impacts, if any, would occur if the relative prices of gas and electricity vary from those used in the BCUC IR 1.81 series charts.

51.4 Do FEU consider that for the purpose of evaluating the postage stamp rates proposal, it would be reasonable to assume that customer switching would likely be neutral overall? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.81.7.1. The FEU expect that the impact of the postage stamp rate proposal on overall natural gas usage in the province will be neutral or close to neutral. Any usage increase in FEVI and FEW resulting from lower natural gas rates (whether from fuel switching or increased usage by existing customers) may be more or less counterbalanced by the usage decreases in FEI and FEFN due to the rate increases in those areas.

Moreover, as indicated in Sections 4.1 and 6.8 of the Application, while amalgamation and common rates will improve natural gas prices in FEVI and FEW, the price of energy is only one of many determinants that inform customers' energy choices. Other factors include initial capital cost investment, perceptions about the green attributes of the fuel and space concerns with respect to appliance installations. Therefore, taking all these factors into account, the FEU do not expect any material fuel switching to take place from electricity to natural gas for space heating and hot water as a result of amalgamation and common rates.

52.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-3, Section 4.2, p. 73

Exhibit B-3, Section 6.8, p. 128

FEVI and FEW Customer Fuel Choice - Policy

On page 73 of the Application it states: "Because of these higher rates, the operating trends being experienced by the FEU (namely challenges in increasing total demand) pose more of a problem for FEVI and FEW than for FEI. Failing to address the rate discrepancies will make it more challenging for FEVI and FEW to increase their customer bases and retain existing customers."

On page 128 of the Application it states: "In the 2012-2013 RRA, Commission staff submitted several information requests about the impact of amalgamation and common rates on British Columbia's energy objectives. The FEU understand the root of these inquiries to be that reducing gas rates on Vancouver Island and in Whistler may make gas service more affordable relative to electricity, thus discouraging customers from switching to a lower GHG fuel source in British Columbia. Overall, the FEU expect the fuel switching between natural gas and electricity to not be sufficiently material one way or the other."

52.1 Please reconcile the FEU's position that failing to address the existing rate discrepancies will make it more challenging for FEVI and FEW to retain existing customers with the FEU's position, as stated on page 128 of the Application, that fuel switching between natural gas and electricity is not expected to be material "one way or the other."

Response:

As discussed in Sections 4.1 and 6.8 of the Application and in the responses to several IRs including BCUC IR 1.58.2, price point is one of many factors that affect customers' energy decisions and a net shift in customer preferences is often difficult to quantify. However, in line with economic theory, the FEU expect reducing the rates in FEVI and FEW will help to retain existing customers in the long run due to reduced constraints. Please refer to the response to BCUC IR 1.81.6 for further discussion around short run and long run elasticity considerations.

However, the FEU do not believe that improved ability to retain customers in the long run is in contradiction with the quoted text that fuel switching between natural gas and electricity is not expected to be material "one way or the other."

Even in the long run, where price elasticity of demand is more elastic, the FEU expect that barriers to fuel switching between electricity and natural gas will continue to exist for existing housing due to physical constraints. For example, the equipment adjustments necessary for residential customers to retrofit electric systems to natural gas systems are not likely to occur due to the physical limitation of the buildings - e.g. lack of ducting or hydronic systems. However similar limitations do not exist for customers who are considering making the switch from natural gas to electric, so a lower price for natural gas will help to retain existing natural gas customers. Switching from heating oil to natural gas switching is considered to be more likely in the similar pricing environment since a home using heating oil will generally be appropriately configured to accommodate natural gas heating equipment, thus the FEU expect the majority of fuel switching to happen from oil to natural gas in FEVI.

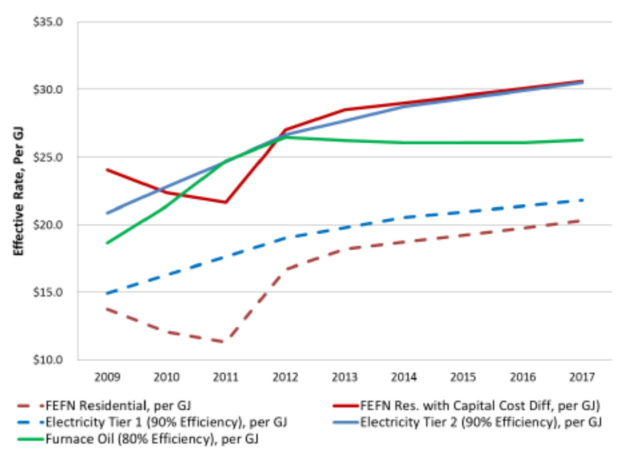
53.0 Reference: Delivery Rate Design – Efficient Rates

Exhibit B-9, BCUC 84.1, B-3-1, Appendix J-3

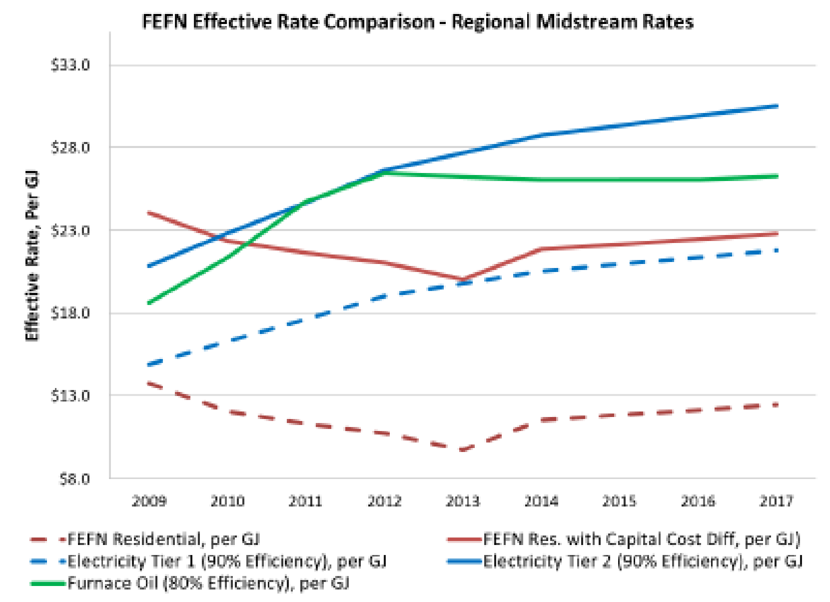
Competitiveness of Natural Gas with Respect to Electricity

The responses to BCUC 84.1 and 84.2 are charts reproduced below. Commission Staff understand that this analysis underpinning this chart is based on an annual consumption of 90 GJ, whereas the bill impacts to FEFN residential customers presented in Appendix J-3 of the Application are based on an annual consumption of 140 GJ. Commission Staff also understand that the comparison to electricity rates incorporates an efficiency factor of 90 percent. Nevertheless, Commission Staff are unable to reconcile the trend and magnitude of FEFN residential rate presented in these charts, with the expected rate increase in 2014 due to the implementation of postage stamps rates and excluding the FEFN phase-in rider.

The response to 84.1:



The response to 84.2:



53.1 Please confirm whether the historical and forecast FEFN residential effective rates correctly reflect the impact of the implementation of postage stamp rates in 2014 in the case of: (i) postage stamp midstream rates, and (ii) regional midstream rates.

Response:

Confirmed. Please note that the inclusion of carbon tax and the exclusion of rate riders in these two graphs will result in a variance from the impacts as provided in Appendix J-3.

To help clarify and reconcile with the rate impacts provided in Appendix J-3, the following tables provide the underlying effective rates embedded in the graphs provided in the responses to BCUC IR 1.84.1 and BCUC IR 1.84.2. The FEU have excluded carbon tax as well as recalculated based on 140 GJs for ease of comparison. As noted above, this analysis excludes rate riders and as such, the effective rates and annual bill impacts in the second table are slightly different than those provided in Appendix J-3.

FEFN, Residential Effective Rate @ 90 GJs per Year
As embedded in the Responses to BCUC IR 1.84.1 and BCUC IR 1.84.2

	2009	2010	2011	2012	2013	2014	2015	2016	2017
BCUC IR 1.84.1	13.8	12.1	11.3	10.7	9.7	12.9	13.3	13.6	14.0
Less: Carbon Tax	(0.7)	(1.0)	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
	13.01	11.07	10.08	9.24	8.24	11.43	11.77	12.13	12.49
BCUC IR 1.84.2	13.8	12.1	11.3	10.7	9.7	11.5	11.8	12.2	12.5
Carbon Tax	(0.7)	(1.0)	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
	13.01	11.07	10.08	9.24	8.24	10.05	10.35	10.66	10.98

2014 Increase, after carbon tax	
BCUC IR 1.84.1 (with postage stamp midstream)	39%
BCUC IR 1.84.2 (with regional midstream)	22%

FEFN, Residential Effective Rate @ 140 GJs per Year
As embedded in the Responses to BCUC IR 1.84.1 and BCUC IR 1.84.2, Recalculated at 140 GJs

	2009	2010	2011	2012	2013	2014	2015	2016	2017
BCUC IR 1.84.1 @ 140 GJs	12.6	11.1	10.4	9.9	8.9	12.4	12.7	13.0	13.4
Less: Carbon Tax	(0.7)	(1.0)	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
	11.89	10.10	9.14	8.37	7.44	10.87	11.19	11.53	11.88
BCUC IR 1.84.2 @ 140 GJs	12.6	11.1	10.4	9.9	8.9	11.0	11.3	11.6	11.9
Less: Carbon Tax	(0.7)	(1.0)	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)
	11.89	10.10	9.14	8.37	7.44	9.48	9.77	10.06	10.36

2014 Increase, after carbon tax	
BCUC IR 1.84.1 @ 140 GJs (with postage stamp midstream)	46%
BCUC IR 1.84.2 @ 140 GJs (with regional midstream)	27%

54.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.69.2.1

Other Service Offerings

The FEU state in BCUC 1.69.2.1: "As discussed in the Application and other IRs, amalgamation and the adoption of postage stamp rates is not a requirement to venture into new initiatives and amalgamation and the adoption of postage stamp rates will primarily facilitate and accelerate the process of extending Commission-approved service offerings. Consequently, while amalgamation and common rates will reduce the total regulatory burden by elimination of regulatory approval processes, amalgamation and common rates do not change the FEU's ability to venture into new initiatives and have no impact on FEI Amalco's long-term business risk compared to FEI pre-amalgamation. ... Amalgamation would have no impact on the ability of FEI to offer TES in the service areas of FEW and FEVI."

54.1 Do FEU agree that the only potential benefit related to other service offerings in an evaluation of postage stamp rates should be any changes in related administration and regulatory costs? If no, please explain.

Response:

The FEU do not agree that the changes in related administration and regulatory costs should be regarded as the only potential benefit related to other service offerings in an evaluation of postage stamp rates.

In addition to the benefit of regulatory and administrative cost savings of extending other service offerings via this Application, another benefit for customers is the expediency in timing for the extension of the service offerings to all customers. If amalgamation and common rates as proposed in this Application are approved, customers in FEW, FEVI and FEFN should be able to enjoy the service offerings currently only available in FEI in a much timelier manner than if entity specific proposals and approvals were required for the extension of each service offering.

54.1.1 Please estimate, on a NPV basis, any increase or decrease in administration and regulatory costs related to other service offerings which would result from approval of amalgamation and postage stamp rates. Please state all assumptions made. Please identify if the cost savings would be to the benefit of FEU's existing gas customers or to the benefit of customers of the new services.

Response:

This response addresses BCUC IR 2.54.1.1 and BCUC IR 2.54.1.2

The cost savings derived from the extension of other service offerings through this Application would be to the benefit of all the FEU's customers. It is difficult, however, for the FEU to quantify with any certainty what those cost savings would be. Administration and regulatory costs depend heavily on, and are not limited to, the Commission prescribed regulatory process (i.e. written process, oral hearing, etc.), the level of interested party intervention and the associated public notices requirement. As stated on page 123 of the Application, "to provide context, a major regulatory proceeding usually costs customers between $300 thousand to $1.5 million in incremental costs, in addition to internal labour devoted to the proceeding". Because these costs vary so significantly, the FEU are unable to forecast with any certainty what the administration and regulatory costs for extending these service offerings would be. Any estimate would be arbitrary and inaccurate in indicating any decreases in administration and regulatory costs resulting from the extension of other service offerings via this Application.

54.1.2 Please identify any differences in the estimated cost savings under the following amalgamation/ postage stamp rates scenarios: FEVI/FEW/FEI/FEFN; FEI/FEVI/FEW; FEI/FEVI; and FEVI/FEW.

Response:

Please refer to the response to BCUC IR 2.54.1.1.

54.2 Do FEU consider that CNG delivery rates in FEVI and FEW are uneconomic (i.e., net income from these potential customers would be higher if delivery rates were lower)? If yes, and postage stamp rates are not approved, do FEU plan to adjust these rates accordingly? Please explain why or why not.

Response:

The FEU interpret "CNG delivery rates" as being the complete cost of delivering CNG to the customer's vehicle. This consists of the following cost categories:

1. Commodity Rate
2. Delivery Rate
3. Fueling Station Rate

The business case regarding adoption of CNG vehicles is complex and involves many factors in addition to the delivery rate. For instance, the economics of a customer's fueling station rate vary widely depending on the customer's specific potential load. The FEU can therefore not categorically state whether the CNG delivery rate for FEVI and FEW is uneconomic.

It is clear, however, that the CNG delivery rates in FEVI and FEW are less economic than FEI's. As shown in the response to BCUC IR 2.55.1, there is a significant difference in the delivery rate component for customers located in FEI versus customers located in FEVI or FEW. Compared to the FEI case, customers in FEVI pay a premium of 16 cents per diesel litre equivalent for delivery and customers in FEW pay a premium of 36 cents per diesel litre equivalent (refer to the response to BCUC IR 2.55.1). These additional costs reduce the economic incentive to adopt CNG vehicles in the FEVI and FEW service territories.

At present there is no CNG load in FEVI or FEW. The higher delivery rates are one important factor that makes it harder to develop the NGT market in these service territories.

In the absence of approval of amalgamated rates, the FEU would consider alternatives, including assessing whether it was appropriate to adjust the rate and/or rate structure, to make CNG service in FEW or FEVI more economic.

55.0 Reference: Ancillary Benefits of Facilitating Consistent Access to Service Offerings

Exhibit B-3, Section 6.8, p. 128

Exhibit B-9, BCUC 40.0

NGT Service Extended to FEVI

"All things being equal, NGT initiatives, coupled with more affordable natural gas rates in FEVI and FEW service areas, will make natural gas more attractive as a fuel when compared to diesel and gasoline and will lead to the reduction of GHG emissions."

55.1 Please compare the CNG refueling price on a per litre of diesel equivalency basis, to the price of diesel and gasoline for period 2013 – 2018 under the following assumptions:

i. Assuming that CNG service was made available to FEVI customers beginning in 2013 and that postage stamp rates are extended to all Fortis service areas as proposed in the Application.

ii. Assuming that CNG service was made available to FEVI customers beginning in 2013 but that FEVI is not amalgamated with FEI and that FEVI maintains its own rates based on its cost of service.

Response:

CNG fueling station rates are determined on an individual station basis. Thus, without a particular fueling station to evaluate, the FEU are unable to respond to this question in detail.

In theory, however, because the CNG fueling station rate is calculated in accordance with Commission approved general terms and conditions (and it is assumed in this response that the same terms and conditions approved for FEI are approved for FEVI), the CNG fueling station rate in both scenarios would be comparable. However, the burner tip rate paid by CNG customers (i.e. delivery, cost of gas and the fueling station rate) would be lower in scenario (i) as compared to scenario (ii) as a result of the lower combined delivery and cost of gas in the amalgamated entity as compared to FEVI on a stand-alone basis.

To illustrate further, for a NGT customer who wished to use CNG for fueling vehicles, there are three components that need to be considered in developing the price per diesel litre equivalent as delivered into the vehicle. As indicated in BCUC IR 2.54.2, in the context of CNG the three components of "CNG delivery rates" consist of the following cost categories:

1. Commodity Rate

2. Delivery Rate

3. Fueling Station Rate

As discussed above, the fueling station rate with and without amalgamation would be determined by the customer's individual situation with respect to load and other factors that drive the calculation of the fueling station cost of service. Fueling station rates for customers in FEI, FEW and FEVI would be determined on the same basis other than the small difference in returns on rate base.

With respect to CNG Delivery rates as defined above, there are however substantial differences. To illustrate, consider a customer on each system that takes 20,000 GJ/year for NGT service:

- FEI Case - FEI's Delivery rate under Rate Schedule 25 works out to be approximately $1.74/GJ (assuming 20 vehicles and 20,000 annual GJ load)
- FEVI Case – Based on FEVI's High Load Factor rate, the FEVI rate works out to be $10.79/GJ for the same 20,000 GJ, including commodity. Excluding FEVI's proxy cost of gas of $5.069/GJ[49], the effective delivery charge is $5.721/GJ. That is a premium of about $4/GJ or about 16 cents per DLE versus the FEI case.
- FEW Case – Based on FEW rates, an annual load of 20,000 GJs works out to be approximately $14.935/GJ, but again that includes commodity. Excluding FEW's commodity cost of $4.029,[50] the effective delivery charge would be approximately $10.906/GJ. That is a premium of $9.20/GJ or about 36 cents per DLE versus the FEI case.

[49] Based on FEVI Gas Cost Proxy Calculations as included in Appendix J-7
[50] Based on FEW current gas cost as approved by BCUC Order No. G-29-12

56.0 Reference: Request for Common Rates

Exhibit B-9, BCUC 1.82.4, 1.82.5

Ability to Unwind if Conditions Change

The FEU state in BCUC 1.82.4 in response to a question asking whether a move to postage stamp rates would be easily reversible: "Should a situation arise where the FEU believed that postage stamp rates were no longer appropriate, it would be possible to move back to a regional rate structure, but the degree of ease to move to a regional rate structure would be dependent on a number of factors including ... the accounting methods and systems maintained ... how the utility is being operated ... IT system capability ... the nature and extent of regionalization of the system."

The FEU state in BCUC 1.82.5 "The FEU do not believe that the ability to dispose of part of its operations is a relevant consideration in determining the appropriateness of postage stamp rates."

56.1 Do FEU consider that if postage stamp rates are approved, bill impacts created by a move back to regional rates from postage stamp rates could be a key obstacle in moving back to regional rates? Please explain why or why not.

Response:

The FEU consider that bill impacts are one of several considerations (other considerations include, for example, the design of regions) in any move from postage stamp rates to regional rates. As the suggested move back to regional rates is hypothetical and it is unknown what the reasons for such a move would be or what the circumstances of FEI Amalco would be at the time, the FEU cannot judge what the bill impacts would be or whether bill impacts would be a key obstacle or not.

56.2 Do FEU consider that if postage stamp rates are approved, bill impacts which would result from divestiture of part of its business could be a key consideration in determining if divestiture would be in the public interest? Please explain why or why not, and specifically discuss a scenario of divestiture of FEVI or FEW after postage stamp rates have been implemented.

Response:

As the prospect of a divestiture of part of the FEU's business is entirely hypothetical, the FEU submit that the question is not relevant to the approvals sought in this Application.

Nevertheless, if subsequent to amalgamation being approved, FEI were to seek to divest part of its business, it would require approval under section 52 of the UCA, which states:

> *52 (1) Except for a disposition of its property in the ordinary course of business, a public utility must not, without first obtaining the commission's approval,*
>
> *(a) dispose of or encumber the whole or a part of its property, franchises, licences, permits, concessions, privileges or rights, or*
>
> *(b) by any means, direct or indirect, merge, amalgamate or consolidate in whole or in part its property, franchises, licences, permits, concessions, privileges or rights with those of another person.*
>
> *(2) The commission may give its approval under this section subject to conditions and requirements considered necessary or desirable in the public interest.*

In considering whether the divestiture would be in the public interest, the Commission would be concerned that the quality of service to customers should not be impaired and would consider any other impacts to customers. As part of this analysis, the Commission would likely consider bill impacts resulting from the divestiture.

With respect to a scenario in which postage stamp rates were approved and shortly afterward, the FEVI or FEW service area were divested from FEI Amalco, the likely bill impact would be a decrease in rates to FEI ratepayers as both of the divested service areas have a relatively higher rate base per customer on a standalone basis. The bill impacts to customers in the FEVI and FEW service areas would likely be an increase for the same reason. For either area, it would be important that rates in both areas reflect the appropriate allocation of costs so that rates remained cost-based after the divestiture.

57.0 Reference: Implementation of Common Rates

Exhibit B-9, BCUC 1.24.2, 1.91.5

No Rate Decrease

The FEU state in BCUC 1.24.2 in relation to a scenario where common rates are accepted but where FEVI and FEW customers, in all classes, do not see a decrease in rates: "... it is important to note that this scenario results in an over collection of revenue from the FEI and FEFN regions, relative to their cost of service. ... Based on this analysis, FEI does not believe it is appropriate to freeze FEVI and FEW rates while FEI and FEFN rates gradually increase."

BCUC 1.91.5 asked if the FEU agreed with the Commission's 1992 Reasons for Decision for BC Hydro's Rate Design Application which appeared to support a position that a substantial decline in rates to a particular customer class or large group within a class who are price sensitive would be inconsistent with Energy Plan Policy Action No. 4 to "Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation."

The FEU responded that they did "not agree that the conclusion is appropriately applied to this circumstance where different areas will see different rate changes" as "any consumption increases through lower rates on FEVI and FEW may be offset by similar aggregate consumption decreases in FEI and thus overall postage stamping will be more or less neutral."

57.1 Please confirm that, in the Commission's 1992 Reasons for Decision for BC Hydro's Rate Design Application, the concern stated was not whether there would be a net increase or decrease in consumption as a result of rate design changes, but whether there would be a substantial decline in rates to a particular group of customers. If no, please explain why not.

Response:

The FEU do not believe it is appropriate to characterize the Commission's determination in regard to the BC Hydro 1992 Rate Design Decision ("BCH 1992 RDA Decision"), as quoted in the preamble to the BCUC IR 1.91 series, as being concerned only about a substantial decline in rates to a particular group of customers and that increases or decreases in consumption were not relevant. It is important to consider the full context of the quote from the 1992 Decision.

The first part of the determination quoted from the BCH 1992 RDA Decision is as follows: "The Commission agrees that a substantial decline in rates to a particular customer class or large group within a class would not conform with the spirit of the Special Direction." The Special

Direction referred to is Special Direction No. 3 which is quoted in the BCH 1992 RDA Decision at page 4. The relevant portion of Special Direction No. 3 is as follows:

> *"**Conservation and Efficient Electricity Use***
> 1. *In setting BC Hydro electricity rates, the Commission shall ensure rate increases are smooth, stable and predictable and contribute to conservation and efficient electricity use by recognizing that electricity rates should gradually increase to meet the higher costs of new electricity supply.*
> 2. *The Commission shall further ensure that BC Hydro electricity rates remain fair, just and reasonable."*

In the 1992 RDA, BC Hydro was seeking to move from a declining block rate structure to a flat rate structure. The purpose was to move in the direction of conservation-based rates by changing the price signals for consumers to be more aligned with the fact that new electricity supply to meet demand growth was more costly than embedded power costs. In order to maintain class revenue neutrality in the proposed flat rate structure the initial block rate had to decrease and the trailing block rate had to increase. Lower volume electricity consumers were therefore going to experience a net rate (or bill) decrease. This was the context in which the Commission's determined that "a substantial decline in rates to a particular customer class or large group within a class would not conform with the spirit of the Special Direction". The existing declining block rates were conveying the signal to customers that using additional electricity was less costly for BC Hydro when it was actually driving higher costs. However, the rate decreases experienced by lower volume consumers under flat rates were found by the Commission to be inconsistent with the wording of the Special Direction that rate increases should be "smooth, stable and predictable" and "electricity rates should gradually increase to meet the higher costs of new electricity supply".

A second finding in the BCUC IR 1.91 series quote from the BCH 1992 RDA Decision is that "(t)he Commission does not believe that this precludes decreases in bills to customers who are unlikely to be price sensitive, especially if there are offsetting benefits." Customers that are not price sensitive do not change their energy consumption in response to price changes. The Commission therefore viewed the stipulations of the Special Direction as applying mainly to price sensitive customers that would increase their consumption when they experienced a bill decrease.

As the FEU have noted in several first round IR responses (BCUC IRs 1.81.6, 1.81.7, 1.91.5 and 1.91.5.1) natural gas consumption is relatively price insensitive so the concern about price decreases driving material consumption increases is not applicable. Further, the current circumstances for the marginal cost of natural gas are not the same as the situation faced by electricity when Special Direction No .3 came into effect. Therefore, the FEU do not believe the findings of the BC Hydro 1992 RDA Decision are of particular relevance in the current Application.

57.1.1 Do FEU consider that the proposed rate decreases in FEVI and FEW would be considered 'substantial' within the meaning of the Commission decision referred to above? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 2.57.1 for the FEU's reasons why the quoted aspects of the Commission Decision on the BC Hydro 1992 RDA are not applicable in the current Application.

What may be considered 'substantial' in terms of rate increases or decreases in a 1992 electricity Decision is quite different than the circumstances affecting natural gas rates. The commodity (and midstream) charges in FEI's natural gas rates have been separate from the delivery and basic charges since the mid-1990s. Natural gas customers have experienced several periods of high rate volatility driven primarily by natural gas market price volatility. For example, natural gas rates (and customer bills) doubled approximately between January 1, 1999 and January 1, 2001. More recently, FEI's customers have experienced an approximate 40% decrease in bills between mid-2008 and mid-2012 as natural gas commodity prices have softened significantly. While the current Application proposes one-time rate decreases for FEVI and FEW that are significant they are within the range of rate and bill variations experienced by natural gas customers due to market-based commodity price fluctuations.

57.2 Please explain why the FEU consider that the concept put forward in the Commission's 1992 Reasons for Decision for BC Hydro's Rate Design Application (a substantial decline in rates to a particular customer class or large group within a class who are price sensitive would be inconsistent with Energy Plan Policy Action No. 4) would apply to customer classes who see price increases/decreases depending on which class they are in, but not apply to customers who see price increases/decreases depending on which region they are in.

Response:

Please refer to the response to BCUC IR 2.57.1 for the FEU's reasons why the quoted aspects of the Commission Decision on the BC Hydro 1992 RDA are not applicable to the current Application.

57.2.1 If the Commission approves postage stamp rates, would FEU be supportive of phasing-in postage stamp rates such that FEVI and FEW do not see rate decreases, and FEI and FEFN rates are adjusted accordingly to ensure there is no net over-collection of revenue? Please explain why or why not.

Response:

No, the FEU would not be supportive of phasing-in postage stamp rates in the manner proposed by this question. Such a solution would result in the rate discrepancies that exist today across the service areas continuing for a significantly longer period of time as shown in the response to BCUC IR 1.24.2. The FEU do not believe the length of this delay in implementing postage stamp rates and its full benefits is reasonable.

Further, by holding FEVI and FEW rates at their current levels, it will be difficult to apply common rate classes across all the service areas, and would delay appropriate migration between classes (and/ or service offerings). This in turn will delay the ability to propose future rate design or rebalancing efforts for the combined service areas. The FEU are supportive of phasing in delivery rate changes; however, such a solution must address the rate discrepancy in a much more timely manner. Please refer to the response regarding phase-in options in BCUC IR 1.24.2 and discussed further in the response to BCUC IR 2.57.2.2.

57.2.2 Please describe an implementation plan which would meet the criteria of 'no substantial decline in rates for a particular FEVI or FEW customer class' if postage stamp rates were approved. Please show projected bill impacts for each customer class over time, using regional average consumption data.

Response:

Please refer to the response to BCUC IR 2.57.2.1. For the purposes of responding to this IR, the FEU believe that either a 3 year or a 5 year phase-in are appropriate implementation plans for FEVI and FEW customers upon approval of postage stamp rates.

FEU have expanded their Residential phase-in analysis from that shown in the response to BCUC IR 1.24.2 to include all rate schedules. This expansion results in a uniform transition to common rates for all customers, over both the three and five year periods. The FEU have calculated this phase-in approach on a total deficiency or surplus basis and then translated this to a delivery rate rider for each region. The FEU believe that it is appropriate to calculate the phase-in amount in this manner, rather than limiting the annual bill impacts to a certain percentage each year, because it reflects the revenue changes that are forecast upon transition to common rates, provides for a method of fairly allocating the transition amongst all customers, and takes away the potential for differences in the phase-in of the annual bill due to commodity fluctuations. As the delivery rate already reflects the common rate, this rider amount would be a credit on the bill for FEI customers (i.e. to reduce the bill) and a charge to FEVI and FEW customers (i.e. to increase the bill). The three year phase-in approach passes on one fourth of the impact in the beginning year so that rates are phased-in over three years, achieving common rates at the start of the fourth year. Similarly, the five year phase-in approach passes on one sixth of the impact in the beginning year so that rates are phased-in over a five year period, achieving common rates at the start of the sixth year.

If this approach is implemented, the FEU believe that it would still be appropriate to return the RSDA to FEI Mainland and FEFN customers as discussed in the Application. That is, a portion of the RSDA could be allocated to FEFN customers to finance the phase-in of common rates for the Fort Nelson region as proposed in the Application with the remaining balance in the RSDA allocated to Mainland customers. In this case, the FEU believe that the period over which the RSDA rate rider is provided to Mainland should be aligned with the period over which the transition to common rates occurs (i.e. three year or five year period), beginning in 2014.

Projected cumulative annual bill impacts for each customer class over the 3 and 5 year periods using regional average consumption data are provided in the tables below for FEI, FEVI and FEW. Please note that because the phase-in analysis in the response to BCUC IR 1.24.2 was limited to Residential customers there are variations from the impacts provided in that response to the revised impacts shown below. Please also note that this analysis does not include the impacts of the RSAM and MCRA rate riders or the RSDA rate rider discussed above.

Three Year Phase-In Analysis:

FEI- Three Year Phase-In	2014	2015	2016	2017
Lower Mainland				
Rate 1 - Residential	1.5%	2.8%	4.0%	5.3%
Rate 2 - Small Commercial	0.6%	1.7%	2.8%	3.8%
Rate 3 - Large Commercial	1.3%	2.2%	3.2%	4.1%
Rate 4 - Seasonal	4.2%	4.8%	5.5%	6.2%
Rate 5 - General Firm	1.5%	2.3%	3.1%	3.9%
Rate 6 - Natural Gas Vehicle	1.5%	2.7%	4.0%	5.2%
Rate 7 - General Interruptible Sales	1.5%	2.0%	2.5%	3.0%
Rate 22 - Large Volume Transportation (Non-bypass)	6.2%	8.9%	11.7%	14.5%
Rate 23 - Commercial Transportation	1.4%	3.8%	6.3%	8.7%
Rate 25 - General Firm Transportation (Non-bypass)	0.6%	3.2%	5.8%	8.4%
Rate 27 - General Interruptible Transportation	2.0%	4.5%	7.0%	9.5%
Inland				
Rate 1 - Residential	1.8%	3.0%	4.2%	5.5%
Rate 2 - Small Commercial	1.0%	2.0%	3.1%	4.1%
Rate 3 - Large Commercial	1.6%	2.6%	3.5%	4.5%
Rate 4 - Seasonal	4.8%	5.4%	6.1%	6.8%
Rate 5 - General Firm	2.0%	2.8%	3.6%	4.4%
Rate 6 - Natural Gas Vehicle	1.7%	2.9%	4.2%	5.5%
Rate 7 - General Interruptible Sales	1.6%	2.0%	2.4%	2.8%
Rate 23 - Commercial Transportation	1.5%	3.9%	6.4%	8.9%
Rate 25 - General Firm Transportation (Non-bypass)	0.8%	3.7%	6.5%	9.3%
Rate 27 - General Interruptible Transportation	2.0%	4.4%	6.9%	9.4%
Columbia				
Rate 1 - Residential	1.4%	2.6%	3.9%	5.1%
Rate 2 - Small Commercial	0.5%	1.6%	2.7%	3.8%
Rate 3 - Large Commercial	1.1%	2.1%	3.1%	4.0%
Rate 5 - General Firm	1.4%	2.1%	2.9%	3.7%
Rate 23 - Commercial Transportation	1.4%	3.9%	6.3%	8.7%
Rate 25 - General Firm Transportation (Non-bypass)	1.5%	4.0%	6.6%	9.1%
Rate 27 - General Interruptible Transportation	1.1%	2.4%	3.7%	5.1%

*Exclusive of RSAM, RSDA & MCRA Rider Impacts

FEVI- Three Year Phase-In	2014	2015	2016	2017
Rate 1 - Residential	-3.3%	-10.7%	-18.1%	-25.5%
Rate 2 - Small Commercial				
Rate 2 - AGS[1]	4.2%	-6.6%	-17.5%	-28.4%
Rate 2 - SCS1	-8.2%	-15.8%	-23.5%	-31.2%
Rate 2 - SCS2	-20.4%	-28.4%	-36.4%	-44.3%
Rate 2 - LCS1	-4.7%	-14.7%	-24.6%	-34.6%
Rate 3 - Large Commercial				
Rate 3 - AGS	-10.0%	-17.3%	-24.6%	-31.8%
Rate 3 - LCS2	-10.1%	-17.2%	-24.3%	-31.4%
Rate 3 - LCS3	-10.0%	-17.5%	-25.0%	-32.5%
Rate 3 - HLF[1]	23.0%	12.8%	2.6%	-7.6%
Rate 3 - ILF[1]	5.8%	-2.9%	-11.6%	-20.4%

*Exclusive of RSAM, RSDA & MCRA Rider Impacts

[1] Increase due to rate rider set on a weighted average basis with all other FEVI customers within rate schedule

Under this scenario, FEVI customers previously categorized as AGS, HLF and ILF may experience a rate increase as a result of the weighted average calculation of the rate rider, which is based on all FEVI customers within that rate schedule. If this particular phase-in plan was implemented, the FEU would determine an alternate approach for these particular customers, such as holding their rates flat until a decrease could occur. Further, these customers may opt into a different FEI Amalco rate schedule upon amalgamation which may negate this situation altogether.

FEW- Three Year Phase-In	2014	2015	2016	2017
Rate 1 - Residential	-5.2%	-15.4%	-25.7%	-36.0%
Rate 2 - Small Commercial				
Rate 2 - Commercial	-5.3%	-17.4%	-29.4%	-41.4%
Rate 2 - LCS1	-9.0%	-21.2%	-33.4%	-45.7%
Rate 3 - Large Commercial				
Rate 3 - LCS2	-10.5%	-23.2%	-35.9%	-48.6%
Rate 3 - LCS3	-12.3%	-25.0%	-37.7%	-50.3%

*Exclusive of RSAM, RSDA & MCRA Rider Impacts

Five Year Phase-In Analysis:

FEI- Five Year Phase-In	2014	2015	2016	2017	2018	2019
Lower Mainland						
Rate 1 - Residential	1.1%	1.9%	2.8%	3.6%	4.5%	5.3%
Rate 2 - Small Commercial	0.2%	1.0%	1.7%	2.4%	3.1%	3.8%
Rate 3 - Large Commercial	1.0%	1.6%	2.2%	2.9%	3.5%	4.1%
Rate 4 - Seasonal	4.0%	4.4%	4.8%	5.3%	5.7%	6.2%
Rate 5 - General Firm	1.3%	1.8%	2.3%	2.8%	3.4%	3.9%
Rate 6 - Natural Gas Vehicle	1.0%	1.9%	2.7%	3.5%	4.4%	5.2%
Rate 7 - General Interruptible Sales	1.3%	1.7%	2.0%	2.3%	2.7%	3.0%
Rate 22 - Large Volume Transportation (Non-bypass)	5.2%	7.1%	8.9%	10.8%	12.6%	14.5%
Rate 23 - Commercial Transportation	0.6%	2.2%	3.8%	5.5%	7.1%	8.7%
Rate 25 - General Firm Transportation (Non-bypass)[1]	-0.2%	1.5%	3.2%	5.0%	6.7%	8.4%
Rate 27 - General Interruptible Transportation	1.2%	2.8%	4.5%	6.2%	7.9%	9.5%
Inland						
Rate 1 - Residential	1.4%	2.2%	3.0%	3.8%	4.6%	5.5%
Rate 2 - Small Commercial	0.6%	1.3%	2.0%	2.7%	3.4%	4.1%
Rate 3 - Large Commercial	1.3%	1.9%	2.6%	3.2%	3.8%	4.5%
Rate 4 - Seasonal	4.5%	5.0%	5.4%	5.9%	6.4%	6.8%
Rate 5 - General Firm	1.7%	2.3%	2.8%	3.3%	3.8%	4.4%
Rate 6 - Natural Gas Vehicle	1.2%	2.1%	2.9%	3.8%	4.6%	5.5%
Rate 7 - General Interruptible Sales	1.4%	1.7%	2.0%	2.3%	2.5%	2.8%
Rate 23 - Commercial Transportation	0.6%	2.3%	3.9%	5.6%	7.2%	8.9%
Rate 25 - General Firm Transportation (Non-bypass)[1]	-0.1%	1.8%	3.7%	5.5%	7.4%	9.3%
Rate 27 - General Interruptible Transportation	1.1%	2.8%	4.4%	6.1%	7.7%	9.4%
Columbia						
Rate 1 - Residential	1.0%	1.8%	2.6%	3.5%	4.3%	5.1%
Rate 2 - Small Commercial	0.2%	0.9%	1.6%	2.3%	3.1%	3.8%
Rate 3 - Large Commercial	0.8%	1.5%	2.1%	2.7%	3.4%	4.0%
Rate 5 - General Firm	1.1%	1.6%	2.1%	2.6%	3.1%	3.7%
Rate 23 - Commercial Transportation	0.6%	2.2%	3.9%	5.5%	7.1%	8.7%
Rate 25 - General Firm Transportation (Non-bypass)	0.7%	2.3%	4.0%	5.7%	7.4%	9.1%
Rate 27 - General Interruptible Transportation	0.6%	1.5%	2.4%	3.3%	4.2%	5.1%

*Exclusive of RSDA, RSAM & MCRA Rider Impacts

[1] Minor decrease in year one due to rate rider set on a weighted average basis with RS 3

FEVI- Five Year Phase-In	2014	2015	2016	2017	2018	2019
Rate 1 - Residential	-0.8%	-5.8%	-10.7%	-15.6%	-20.6%	-25.5%
Rate 2 - Small Commercial						
Rate 2 - AGS[1]	7.9%	0.6%	-6.6%	-13.9%	-21.1%	-28.4%
Rate 2 - SCS1	-5.6%	-10.7%	-15.8%	-20.9%	-26.0%	-31.2%
Rate 2 - SCS2	-17.8%	-23.1%	-28.4%	-33.7%	-39.0%	-44.3%
Rate 2 - LCS1	-1.4%	-8.0%	-14.7%	-21.3%	-28.0%	-34.6%
Rate 3 - Large Commercial						
Rate 3 - AGS	-7.6%	-12.4%	-17.3%	-22.1%	-27.0%	-31.8%
Rate 3 - LCS2	-7.7%	-12.5%	-17.2%	-21.9%	-26.6%	-31.4%
Rate 3 - LCS3	-7.5%	-12.5%	-17.5%	-22.5%	-27.5%	-32.5%
Rate 3 - HLF[1]	26.3%	19.6%	12.8%	6.0%	-0.8%	-7.6%
Rate 3 - ILF[1]	8.8%	2.9%	-2.9%	-8.7%	-14.6%	-20.4%

*Exclusive of RSDA, RSAM & MCRA Rider Impacts

[1] Increase due to rate rider set on a weighted average basis with all other FEVI customers within rate schedule

Similar to the three year phase-in, FEVI customers previously categorized as AGS, HLF and ILF may experience a rate increase as a result of the weighted average calculation of the rate rider, which is based on all FEVI customers within that rate schedule. If this particular phase-in plan was implemented, the FEU would determine an alternate approach for these particular customers, such as holding their rates flat until a decrease could occur. Further, these customers may opt into a different FEI Amalco rate schedule upon amalgamation which may negate this situation altogether.

FEW- Five Year Phase-In	2014	2015	2016	2017	2018	2019
Rate 1 - Residential	-1.8%	-8.6%	-15.4%	-22.3%	-29.1%	-36.0%
Rate 2 - Small Commercial						
Rate 2 - Commercial	-1.3%	-9.3%	-17.4%	-25.4%	-33.4%	-41.4%
Rate 2 - LCS1	-4.9%	-13.0%	-21.2%	-29.3%	-37.5%	-45.7%
Rate 3 - Large Commercial						
Rate 3 - LCS2	-6.3%	-14.8%	-23.2%	-31.7%	-40.1%	-48.6%
Rate 3 - LCS3	-8.0%	-16.5%	-25.0%	-33.4%	-41.9%	-50.3%

*Exclusive of RSDA, RSAM & MCRA Rider Impacts

57.2.3 Please update the analysis above assuming postage stamp rates are only approved for (i) FEI/FEVI/FEW; (ii) FEI/FEVI; and (iii) FEVI/FEW.

Response:

Scenario (i)

Please refer to the tables provided in the response to BCUC IR 2.57.2.2 which are representative of scenario (i) FEI/FEVI/FEW. The annual bill impacts as provided in the response to BCUC IR 2.57.2.2 are considered to be representative because the exclusion of FEFN from amalgamation does not have a material impact on the amalgamated cost of service and correspondingly, does not have a material impact on the phase-in analysis.[51] Further, the FEU have assumed that under amalgamation and the implementation of common rates for all four companies, FEFN rates would be phased in as proposed in the Application and would not impact the phase-in scenario recommended in the response to BCUC IR 2.57.2.2. The exclusion of FEFN from amalgamation would however result in a larger credit RSDA rate rider for FEI Mainland customers, reducing the overall annual bills of FEI Mainland customers over the phase-in period.

Scenario (ii)

Please refer to the two tables below which reflect cumulative annual bill changes under the three and five year phase-ins as explained in the response to BCUC IR 2.57.2.2, but limited to the amalgamation of FEI/FEVI. Similar to scenario (i), the exclusion of FEW and FEFN from amalgamation does not have a material impact on the cost of service and the phase-in analysis due to the relative size of these entities in comparison to FEI Mainland and FEVI. Thus, the revised phase-in provides similar annual bill impacts to that shown in the response to BCUC IR 1.57.2.2 for FEI Mainland and FEVI customers.

Please note that this analysis is based on the high level analysis conducted for the response to BCUC IR 2.39.6.1 and as such, under this scenario the FEU do not have annual bill impacts to be able to provide a comprehensive phase-in analysis for each rate schedule; however, as noted above and demonstrated by the impact to Residential customers below, the results are similar to the results provided in the response to BCUC IR 2.57.2.2.

[51] The annual bill impact to a Lower Mainland Residential customer is approximately $1 per year lower under an FEI/FEVI/FEW amalgamation as compared to a FEI/FEVI/FEW/FEFN amalgamation.

Three Year Phase-In- Residential	2014	2015	2016	2017
Cumulative Annual Bill Change				
Lower Mainland Residential	1.6%	2.7%	3.9%	5.0%
Inland Residential	1.8%	2.9%	4.1%	5.2%
Columbia Residential	1.4%	2.6%	3.7%	4.8%
Vancouver Island Residential	-3.5%	-10.9%	-18.3%	-25.7%

*Exclusive of RSAM, RSDA & MCRA Rider Impacts

The table above reflects an annual bill change of approximately 1.1% per year, following the first year, for FEI Mainland customers and approximately 7.4% per year, following the first year, for FEVI customers.

Five Year Phase-In- Residential	2014	2015	2016	2017	2018	2019
Cumulative Annual Bill Change						
Lower Mainland Residential	1.2%	2.0%	2.7%	3.5%	4.2%	5.0%
Inland Residential	1.5%	2.2%	2.9%	3.7%	4.4%	5.2%
Columbia Residential	1.1%	1.8%	2.6%	3.3%	4.1%	4.8%
Vancouver Island Residential	-1.0%	-6.0%	-10.9%	-15.8%	-20.8%	-25.7%

*Exclusive of RSDA, RSAM & MCRA Rider Impacts

The table above reflects an annual bill change of approximately 0.8% per year for Lower Mainland customers, approximately 0.7% per year for Inland and Columbia customers and approximately 4.9% per year for FEVI customers, following the first year.

Scenario (iii)

For the reasons as described in the responses to BCUC IR 2.3.1, BCUC IR 2.3.2 and BCUC IR 2.39.6.1, a new COSA model has not been created for the FEVI/FEW scenario. In the absence of this model, the FEU are unable to provide a response for scenario (iii).

58.0 Reference: Implementation of Common Rates

Exhibit B-3, Section 9.8, p. 221; BCUC 1.1; Commission 2012 Delta School Decision

G-31-12, p. 21

Next Rate Design Application

The FEU state in Section 9.8 of the Application that if amalgamation and the adoption of common rates is approved, the FEU will review the cost allocation and customer segmentation in 2016.

Commission March 9, 2012 Delta School Decision (G-31-12) states on page 51:[52] "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."

58.1 If amalgamation and the adoption of postage stamp rates is approved, when would FEI (Amalco) plan to file a Rate Design Application which reviews cost allocation, customer segmentation and rate design?

Response:

The earliest that FEI Amalco would be in a position to file a Rate Design Application with a scope that includes a review of cost allocation methodologies, customer segmentation and rate structure design would be towards the end of 2016.

As discussed in Section 9.8 of the Application, the FEU believe that a two year period following the implementation of common rates is required to enable customer movement to occur.

Following that two year period, analysis and application development activities would occur.

58.2 If amalgamation and the adoption of postage stamp rates is not approved, when do FEI, FEVI, FEW, and FEFN plan to file a Rate Design Application which reviews cost allocation, customer segmentation, and rate design?

[52] http://www.bcuc.com/Documents/Decisions/2012/DOC_30039_03-09-2012-FEI_DeltaSD-37-Decision-WEB.pdf

Response:

If amalgamation and postage stamp rates are not approved, each of the entities will review their requirements and make a determination on when the appropriate time to file a Rate Design Application would be. Part of that determination would identify the scope of the Rate Design as not all elements of cost allocation, customer segmentation and rate structure may be deemed required. For example, it may be appropriate to only address rate rebalancing for FEFN which, based on the COSA Model filed in Appendix H-8, shows that residential customers are currently at a R:C ratio of 80 percent compared to commercial customers whose R:C ratios range from 116 to 129 percent. On the other hand, it may be appropriate to undertake a larger rate design scope for FEI that includes customer segmentation and rate structure analysis.

To complete a Rate Design Application that includes a review of cost allocation, customer segmentation and rate structure design, the FEU anticipate that a period of approximately two years would be required in order to conduct an extensive review of the data, customer requirements and other inputs that would be needed to fulfil the scope of such an application. A minimum of two years is appropriate in order to undertake the following key activities: 1) market research (surveys, focus groups, etc.) that may take approximately six months to complete; 2) development of a COSA model taking into account the various studies (including the market research results) which may also take six months to complete depending on the number of changes to the existing COSA Model; 3) Analysis of COSA Model results and subsequent COSA Model iterations that may take between three to six months; and, 4) Rate Design Application development that generally takes six months to complete.

The FEU believe that it may be possible to undertake a smaller scoped Rate Design Application that addresses one or two of the requirements within two years, e.g., rebalancing of rates could occur in a shorter timeframe than a review of cost allocation, customer segmentation and rate structure design.

59.0 Reference: Delivery Rate Design – Cost Based Rates

Exhibit B-9, BCUC 1.74.5.3, 1.76.1.1, 1.76.3

Acceptable Revenue to Cost Ratio

The FEU state in BCUC 1.74.5.3: "The exclusion of gas revenues and costs from total revenues and total cost of service would reflect inappropriate revenue to cost ratios, making it difficult to assess if rates for any customer class are reasonable and adequate to recover their allocated cost of service."

The FEU state in BCUC 1.76.1.1: "Tables 3-3, 3-5, 3-8 and 3-10 are based on the legacy COSA methodology that was followed for the individual companies. However, the FEU's Amalgamated results provided in Table 9-10 reflect a different COSA methodology that mainly adopts FEI's approved COSA methodology with a few modifications as outlined in the Table 9-5 (refer to page 196 of the Application)."

The FEU state in BCUC 1.76.3: "The numbers in the tables provided in the question above demonstrate that postage stamp rates as proposed in the Application bring FEI residential customers closer to unity (93.4 percent under FEI Amalco as compared to 92 percent under FEI) in terms of the resulting R:C Ratios. This means that there is less risk that FEI residential customers will see additional rate increases in future due to rate rebalancing."

59.1 What would the FEU consider to be a reasonable range of revenue-to-cost ratios if pass-through gas revenues and costs were excluded from the COSA Model? Please explain and provide supporting evidence.

Response:

The FEU believe that inclusion of gas revenues and costs in the COSA model to determine the revenue to cost ratios is necessary and appropriate to assess the rates for all rate classes. This is because the gas costs form a considerable part of the total cost of service (around 46% for the FEU). Therefore, even though the gas revenues and costs are pass-through in the COSA model, they do have an impact on the overall revenue to cost ratios, which are then used to assess whether rates are set at appropriate levels or not or if further rebalancing is required.

As mentioned in the response to BCUC IR 2.59.1.1, this is consistent with the standard industry practise. Also, this is consistent with FEI and FEVI previous rate design methodologies, which were thoroughly reviewed and approved by the Commission. Since FEI and FEVI have always included the gas costs and revenues from the COSA model to determine revenue to cost ratios for rate setting purposes, the FEU do not have a source for determining the appropriate range without gas costs. The range of reasonableness would need to be substantially larger;

however, the FEU cannot provide a comparable range of reasonableness in the event that gas revenues and costs were excluded from the COSA.

59.1.1 Do FEU consider that including pass-through gas revenues and costs from the COSA Model is standard industry practice in the gas industry? If yes, please provide supporting evidence.

Response:

COSA studies generally take into consideration all costs, including pass-through gas commodity costs, to determine the appropriate revenues required to recover those costs. The FEU have not undertaken a comprehensive survey of utilities to determine whether every utility includes pass-through gas revenues and costs in the COSA model. Based on EES' experience, however, the inclusion of gas costs would fall within standard industry practice in the gas industry. It is also consistent with what has been approved for FEI in the past and therefore, the FEU do not see any reason to suggest that the practise should be changed.

59.2 Please recalculate the COSA model under the Option F – the FEU's proposed solution - assuming that the commodity cost of gas is increased by 50 percent.

Response:

The following table provides a summary of the results for a case where the cost of gas (excluding midstream) for all customers is increased by 50% under the FEU's consolidated COSA. To ensure comparability in the Revenue to Cost ratios, the imputed cost of gas is included for Rate Schedules 23 and 25.

Rate Schedule	Revenues (adjusted to equal COS)	Cost of Service Margin	Total Cost of Gas	Total Utility Cost of Service
Rate 1 – Residential	$971,525	$509,719	$520,455	$1,030,173
Rate 2 – Small Commercial	$298,506	$109,009	$178,505	$287,514
Rate 6 – NGV	$642	$212	$371	$583
Rate 3 & 23	$286,943	$80,250	$189,603	$269,854
Rate 5 & 25	$139,710	$27,442	$101,963	$129,404

59.3 Please recalculate the COSA model under the Option F – the FEU's proposed solution - assuming that gas consumption is reduced across all customer classes by 20 percent.

Response:

The following table provides a summary of the results for a case where the gas consumption for all customers is decreased by 20% under the FEU's consolidated COSA. It was assumed that the average per unit cost of gas and midstream charges were unchanged as a result. To ensure comparability in the Revenue to Cost ratios, the imputed cost of gas is included for Rate Schedules 23 and 25.

A 20% reduction in consumption is very significant, is not likely to occur over a short time period, and would in fact take many years to occur. Even with this large of a reduction in consumption levels, the Revenue to Cost ratios are not substantially different, as pointed out in the response to BCUC 2.59.5. The Revenue to Cost ratios are a valid measure of interclass equity as they are relatively stable even in the event of changes in usage levels. In addition, the proposal for postage stamp rates without rate rebalancing is reasonable and allows for movement in usage levels without the need for further changes.

Rate Schedule	Revenues (adjusted to equal COS)	Cost of Service Margin	Total Cost of Gas	Total Utility Cost of Service
Rate 1 – Residential	$756,163	$509,719	$305,190	$814,910
Rate 2 – Small Commercial	$224,640	$109,009	$104,648	$213,658
Rate 6 – NGV	$475	$212	$204	$416
Rate 3 & 23	$206,481	$80,250	$109,121	$189,371
Rate 5 & 25	$95,394	$27,442	$57,615	$85,057

59.4 Please recalculate the COSA model under the Option F – the FEU's proposed solution - assuming that gas consumption of the Rate 3 customers only is reduced by 20 percent.

<u>Response:</u>

The following table provides a summary of the results for a case where the gas consumption for Rate Schedule 3 is decreased by 20% under the FEU's consolidated COSA. It was assumed that the average per unit cost of gas and midstream charges were unchanged as a result. To ensure comparability in the Revenue to Cost ratios, the imputed cost of gas is included for Rate Schedules 23 and 25.

Rate Schedule	Revenues (adjusted to equal COS)	Cost of Service Margin	Total Cost of Gas	Total Utility Cost of Service
Rate 1 – Residential	$834,375	$514,352	$374,276	$888,628
Rate 2 – Small Commercial	$250,744	$110,738	$128,338	$239,076
Rate 6 – NGV	$528	$213	$251	$464
Rate 3 & 23	$197,289	$73,309	$112,592	$185,901
Rate 5 & 25	$109,236	$28,006	$70,735	$98,741

59.5 Please present the results of the above three analyses in the following format:

Rate Schedule	As Filed	Commodity Cost of Gas Increased by 50%	Gas Consumption Reduced by 20%	Gas Consumption Reduced by 20% to Rate 3 Only
Rate 1 - Residential				
Rate 2 – Small Commercial				
Rate 6 - Seasonal				
Rate 3 & 23				
Rate 5 & 25				

Response:

The following table provides the resulting Revenue to Cost comparison for the cases requested. Note that even with the significant changes requested, the R:C ratios do not change substantially and for the most part are still within the proposed range of reasonableness. The proposed postage stamp rates can thus be considered relatively stable and would not need to change as a result of changes to the cost of gas or consumption levels.

Rate Schedule	As Filed	Commodity of Gas Increased by 50%	Gas Consumption Reduced by 20%	Gas Consumption Reduced by 20% to Rate 3 Only
Rate 1 – Residential	93.4%	94.3%	92.8%	93.9%
Rate 2 – Small Commercial	104.6%	103.8%	105.1%	104.9%
Rate 6 – NGV	112.7%	110.2%	114.3%	113.7%
Rate 3 & 23	107.9%	106.3%	109.0%	106.1%
Rate 5 & 25	110.4%	108.0%	112.2%	110.6%

59.6 Would the FEU consider increasing or decreasing the commodity or midstream rate of a particular customer class in order to carry out rate rebalancing?

Response:

No. The FEU would not change the commodity or midstream rates to achieve rate rebalancing. The commodity and midstream rates are set to equal the costs for each of those components separate from the delivery charge. Consistent with standard industry practice and previously approved rate design methodologies for FEI, the FEU believe that any rate rebalancing would occur only within the delivery charges.

59.7 Under the COSA method proposed by the FEU, would increasing consumption and/or increasing commodity or midstream costs have the same effect, directionally, as rate rebalancing?

Response:

Generally increasing the cost of gas would move Revenue to Cost ratios closer to 100%, while a decrease in the cost of gas would move Revenue to Cost ratios away from 100%. Similarly, as shown in the response to BCUC IR 2.59.5, increasing consumption would move Revenue to Cost ratios closer to 100%, while a decrease in consumption would move Revenue to Cost ratios away from 100%, providing that consumption levels do not impact the costs of providing service.

59.8 Under the COSA method proposed by the FEU, and to maintain an approach consistent across all rate groupings, should the transportation rate classes - Rate 23, Rate 25 and Rate 27 – be allocated costs and revenues in the amounts related to the commodity price of gas?

Response:

No. The transportation rate classes should not be allocated costs and revenues in the amounts related to the commodity price of gas. This is because the transport rate classes supply their own gas; therefore, they are excluded from the allocation of the total cost of gas that is used within the COSA. Further, because that total cost of gas includes only the amounts purchased to serve core customers, it cannot be allocated to the transport customers without assigning too few costs to the core classes. However, an imputed cost of gas can be added for the transport customers at the same average rate as for the core customers when calculating the revenues and costs used to generate the revenue to cost ratios. This allows the revenue to cost ratios to be compared on an equal basis for all customer classes.

59.9 From BCUC 1.76.1, please update Table 3-3, 3-5, 3-8, and 3-10 using proposed postage stamp rates to determine regional revenues, but leaving costs the same (i.e., regional costs using existing COSA methodology).

Response:

The following provides the requested tables. While it is possible to compare regional revenues under the proposed postage stamp rates to the regional costs under the existing COSA methodology, we do not believe that it is appropriate to compare revenues and costs developed under such different circumstances. The regional costs require certain transfers of costs between utilities to account for shared facilities and services that do not exist in the amalgamated case used to develop the postage stamp revenues. Further, the amalgamation of gas costs requires that all gas purchases and the midstream resources to transport that gas are applied equally to all customers, while the regional costs do not reflect that. Therefore, the FEU submit that the results are not meaningful or appropriate for determining rates.

Table 3-3: FEI with Postage Stamp Revenues vs. Regional Costs

Rate Schedule	R:C Ratio
Rate 1 – Residential	96%
Rate 2 – Small Commercial	107%
Rate 6 – Natural Gas Vehicle	129%
Rate 3 & 23 – Combined	116%
Rate 5 & 25 – Combined	119%

Table 3-5: FEFN with Postage Stamp Revenues vs. Regional Costs

Rate Schedule	R:C Ratio
Rate 1 – Residential	127%
Rate 2.1 – General Service 2.1	153%
Rate 2.2 – General Service 2.2	163%
Rate 25 – Firm Transportation Service	160%

Note that for FEFN this represents a case without a phase-in of the rates. We would expect that by the time the phase-in is complete, costs would have changed significantly and these numbers would be significantly different.

Table 3-8: FEVI with Postage Stamp Revenues vs. Regional Costs

Rate Schedule	R:C Ratio
RGS – Residential	59%
AGS – Apartment General Service	79%
SCS1 – Small Commercial 1	69%
SCS2 – Small Commercial 2	83%
LCS1 – Large Commercial Service 1	80%
LCS2 – Large Commercial Service 2	80%
LCS3 – Large Commercial Service 3	78%
High Load Factor	100%
Inverse Load Factor	117%

Table 3-10: FEW with Postage Stamp Revenues vs. Regional Costs

Rate Schedule	R:C Ratio
Residential	48%
Commercial	67%
LGS1 - Large General Service 1	65%
LGS2 - Large General Service 2	82%
LGS3 - Large General Service 3	59%

59.10 From BCUC 1.76.1, please update Table 9-10 using FEI COSA methodology, and Tables 3-3, 3-5, 3-8, and 3-10 using the new COSA methodology proposed for FEI Amalco. Please explain any significant differences.

Response:

The tables requested are provided below.

Table 9-10: FEU Amalgamated COSA with FEI Legacy Methodology

Rate Schedule	R:C Ratio
Rate 1 – Residential	92%
Rate 2 – Small Commercial	103%
Rate 6 – Natural Gas Vehicle	125%
Rate 3 & 23 – Combined	112%
Rate 5 & 25 – Combined	115%

Table 3-3: FEI Regional COSA with New Methodology

Rate Schedule	R:C Ratio
Rate 1 – Residential	93%
Rate 2 – Small Commercial	105%
Rate 6 – Natural Gas Vehicle	112%
Rate 3 & 23 – Combined	108%
Rate 5 & 25 – Combined	111%

Table 3-5: FEFN with Regional COSA with New Methodology

Rate Schedule	R:C Ratio
Rate 1 – Residential	95%
Rate 2 – Small Commercial	101%
Rate 3 – Large Commercial	109%

Table 3-8: FEVI with Regional COSA with New Methodology

Rate Schedule	R:C Ratio
Rate 1 – Residential	96%
Rate 2 – Small Commercial	102%
Rate 3 – Large Commercial	106%

Table 3-10: FEW with Regional COSA with New Methodology

Rate Schedule	R:C Ratio
Rate 1 – Residential	92%
Rate 2 – Small Commercial	104%
Rate 3 – Large Commercial	111%

59.10.1 Please calculate average $ and % bill impacts for each rate class assuming postage stamp rates are approved but changes to cost allocation methodology and a phase-in period are not. Please provide separate results for each of FEI, FEVI, FEW and FEFN customers and use regional consumption data.

Response:

The bill impacts, in both dollars and percentages, for each of the service areas based on regional consumption, are provided in the tables below. These bill impacts assume that postage stamp rates are approved but changes to the cost allocation methodology and a phase-in period are not.

The impacts are based on a COSA that uses the amalgamated revenue requirements and rate base. The differences in the methodology include not using the PLCC adjustment and using the customers weighted for meters rather than administration in allocating certain costs. The results required some rebalancing in costs to reduce rates for commercial customers and increase rates for residential customers.

While the COSA results under the "legacy" approach have been provided for comparative purposes, the FEU do not believe that the legacy methodology is appropriate to use going forward with postage stamp rates. When the minimum system was updated to reflect the 2" minimum main size currently in place, a greater proportion was classified as customer-related. Adding the PLCC reflected this larger main size and the amount of peak demand that could be served with the larger minimum size. The adjustment makes the results more comparable to the 25% customer/75% demand classification used in the 1991 COSA.

FEI - Lower Mainland	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
RS1 - Residential	95	$1,027.97	$1,094.92	$66.95	6.5%
RS2 - Small Commercial	300	$2,878.38	$2,986.92	$108.54	3.8%
RS3 - Large Commercial	2800	$23,433.04	$24,080.98	$647.94	2.8%
RS4 - Seasonal	5400	$34,919.52	$37,166.42	$2,246.90	6.4%
RS5 - General Firm	9700	$74,896.75	$77,241.93	$2,345.18	3.1%
RS6 - NGV	2900	$25,741.60	$23,712.86	-$2,028.74	-7.9%
RS7 - Interruptible	8100	$60,261.60	$62,214.58	$1,952.98	3.2%
RS22 - Large Industrial	467306	$467,348.26	$535,087.55	$67,739.29	14.5%
RS23 - Large Commercial	4100	$13,337.94	$15,699.50	$2,361.56	17.7%
RS25 - General Firm	19086	$43,973.11	$46,353.84	$2,380.73	5.4%
RS27 - Interruptible	53957	$78,024.98	$85,455.84	$7,430.86	9.5%

FEI - Inland	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
RS1 - Residential	95	$838.84	$894.33	$55.49	6.6%
RS2 - Small Commercial	300	$2,439.58	$2,538.78	$99.20	4.1%
RS3 - Large Commercial	2800	$21,797.44	$22,474.50	$677.06	3.1%
RS4 - Seasonal	5400	$57,686.82	$61,779.68	$4,092.86	7.1%
RS5 - General Firm	9700	$97,330.82	$100,802.55	$3,471.73	3.6%
RS6 - NGV	2900	$103,179.10	$95,032.78	-$8,146.32	-7.9%
RS7 - Interruptible	8100	$35,008.00	$36,068.43	$1,060.43	3.0%
RS23 - Large Commercial	4100	$14,920.14	$15,699.50	$779.36	5.2%
RS25 - General Firm	19086	$85,881.76	$91,034.40	$5,152.64	6.0%
RS27 - Interruptible	53957	$71,794.51	$78,529.46	$6,734.95	9.4%

FEI - Columbia	Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
RS1 - Residential	80	$888.80	$944.48	$55.68	6.3%
RS2 - Small Commercial	320	$3,052.96	$3,166.17	$113.21	3.7%
RS3 - Large Commercial	3300	$27,373.14	$28,097.19	$724.05	2.6%
RS5 - General Firm	9100	$70,950.20	$73,021.35	$2,071.15	2.9%
RS23 - Large Commercial	4200	$13,601.64	$14,298.09	$696.45	5.1%
RS25 - General Firm	30358	$71,297.63	$75,485.69	$4,188.06	5.9%
RS27 - Interruptible	7734	$21,031.78	$22,096.86	$1,065.08	5.1%

FEVI		Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
Amalgamated Rate Schedule	Original Rate Schedule					
RS1 - Residential	RGS	59	$965.45	$729.84	-$235.61	-24.4%
RS2 - Small Commercial	AGS	780	$10,130.94	$7,289.06	-$2,841.88	-28.1%
	SCS1	80	$1,473.68	$1,017.79	-$455.89	-30.9%
	SCS2	313	$5,546.19	$3,099.85	-$2,446.34	-44.1%
	LCS1	930	$13,147.62	$8,631.69	-$4,515.93	-34.3%
RS3 - Large Commercial	AGS	3990	$49,848.27	$33,639.54	-$16,208.73	-32.5%
	LCS2	2362	$30,251.19	$20,561.98	-$9,689.21	-32.0%
	LCS3	17694	$215,011.53	$143,715.62	-$71,295.91	-33.2%
	HLF	14025	$124,975.43	$114,244.73	-$10,730.70	-8.6%
	ILF	10183	$105,817.75	$83,384.22	-$22,433.53	-21.2%

FEW		Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
Amalgamated Rate Schedule	Original Rate Schedule					
RS1 - Residential	Residential	80	$1,653.66	$1,044.78	-$608.88	-36.8%
RS2 - Small Commercial	Commercial	260	$4,607.24	$2,628.41	-$1,978.83	-43.0%
	LCS1	1060	$18,506.44	$9,798.64	-$8,707.80	-47.1%
RS3 - Large Commercial	LCS2	2810	$48,910.94	$24,161.30	-$24,749.64	-50.6%
	LCS3	6200	$107,808.80	$51,391.15	-$56,417.65	-52.3%

FEFN		Annual Consumption	Annual Bill Based on 2013 RRA Rates	Annual Bill Based on Amalgamation with FEI Legacy Methodology	Annual Bill Impact ($)	Annual Bill Impact (%)
Amalgamated Rate Schedule	Original Rate Schedule					
RS1 - Residential	Rate 1	140	$985.60	$1,546.28	$560.68	56.9%
RS2 - Small Commercial	Rate 2.1	460	$3,462.84	$4,420.97	$958.12	27.7%
RS3 - Large Commercial	Rate 2.1	2624	$18,463.69	$22,667.27	$4,203.58	22.8%
	Rate 2.2	3100	$21,763.32	$26,490.70	$4,727.37	21.7%
	Rate 25	6890	$18,490.04	$56,475.76	$37,985.72	205.4%

59.11 Please list (in table form) the differences between the legacy COSA methodology for FEI, FEVI, FEW, and FEFN, and that proposed for FEI (Amalco). For each item on this list, please state if the methodology change generally acts to increase or decrease costs for each of the main customer classes.

Response:

Tables 9-5 and 9-6 in the Application show the differences between the legacy COSA methodology for FEI, FEVI, FEW, and FEFN, and that proposed for FEI Amalco in tabular form. These tables describe the updates to the 2001 FEI legacy COSA methodology used as a basis for the COSA study for FEI Amalco. These tables and the listed differences apply to FEVI, FEW and FEFN as well. While not truly changes in methodology, other factors differ between the FEVI, FEW and FEFN legacy COSA methodology and FEI Amalco methodology. For instance, the rate classes in legacy models reflect the current rates for FEVI, FEW and FEFN and the weighting factors and minimum system study reflect the results for each separate entity. The impact of these differences in terms of increase or decrease in costs for each of the main customer classes is discussed below.

- The addition of the weighting factor for customer administration and billing reduces costs to Rate Schedules 1 and 2 and increases costs to the other classes. The resulting R:C ratio is increased by less than 0.3% for Rate Schedule 1 and by roughly 2% for Rate Schedule 2. For the other classes, the R:C ratio would decrease by about 2% for Rate Schedules 3/23, by about 3% for Rate Schedules 5/25 and by roughly 12% for Rate Schedule 6.

- The addition of the PLCC reduces costs to Rate Schedule 1 and increases the costs to the other classes. The resulting R:C ratio is increased by roughly 1% for Rate Schedule 1 and decreased by roughly 1% for the other classes.

- For the minimum system study, the legacy COSA methodology used for FEI, FEVI, FEW and FEFN used a 2" minimum sized mains rather than the 1 ¼" size used in 1991 and FEVI's 2009 RDA. This had the impact of increasing costs to Rate Schedule 1. If the 2001 COSA results of 25% customer-related and 75% demand-related results were used for the FEI Amalco model, the result would be very similar to the 2" minimum sized mains and the PLCC combined.

The other changes did not impact the final costs assigned to the main customer classes.

59.11.1 If the proposed changes to methodology tend to favor one rate class over another, please state if this increases or reduces the need to rebalance rates for that customer class.

Response:

The proposed changes to the methodology reduce the need to rebalance rates among customer classes and are therefore favorable to all rate classes. If the changes were not adopted, the impacts discussed in BCUC 2.59.11 would apply. In that case, Rate Schedules 1 and 2 would still be within the 90-110% range. Rate Schedules 6, 3/23 and 5/25 would be above 110% and may need a small decrease in rates. These decreases would require a rate increase for Rate Schedule 1 in order to rebalance to 100% for the total utility, despite the fact that Rate Schedule 1 would be within the range of reasonableness.

59.12 Do FEU consider that a reduced need to rebalance rates should be considered a net benefit of the proposed COSA methodology changes? If yes, please explain why, and include in your response whether this could result in bias when evaluating alternative COSA methodologies.

Response:

The FEU do not consider that the need to rebalance rates is a benefit of the proposed changes. The amount of rebalancing required is a function of the methodology that was determined to be appropriate and was not a criteria in selecting the methodology.

60.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.28.1

Continuance of FEI/FEVI's Main Extension Test

The FEU response to BCUC IR 1.28.1 states: "FEI and FEVI's 2007 System Extension and Customer Connection Policies Review Application sought and received approval under section 61 of the UCA to establish the MX test as a rate schedule. The FEU are similarly asking for continuation and application of the FEI and FEVI approved MX Test (with the same established PI thresholds) to the FEI Amalco, and the discontinuance of the MX Test applied currently in Whistler under sections 59 to 61 of the UCA, as stated in section 2 h. of the Draft Order in Appendix K-2 of the Application. The FEU consider the reporting requirements to be part of the rate."

60.1 Please specify which sections of 59 to 61 of the UCA that FEU are applying under for the requested approval of reporting requirements relating to main extension test, particularly for reporting requirements changes or methodology variations in MX tests.

Response:

The FEU are applying under the same provisions of the UCA for all changes to rates sought in this Application, including the changes to FEI Amalco's main extension test.

Sections 59 to 61 of the UCA should be read together and therefore the FEU believe it is appropriate to refer to all these ratemaking sections together when considering what sections of the UCA it is applying under. While the FEU submit that further precision is not required, the FEU are seeking consent to amend FEI's main extension test pursuant to subsection 60(2) of the UCA. Subsections 60(1) and (2) of the UCA state:

(1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.

(2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.

Sections 59 and 60 make it clear that the Commission has the jurisdiction to set rates.

The Commission may hear applications to set rates or amend rate schedules pursuant to subsection 72(2) of the UCA, which states:

(2) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, requesting the commission to

(a) give a direction or approval which by law it may give, or

(b) approve, prohibit or require anything to which by any general or special Act, the commission's jurisdiction extends.

As stated in the response to BUCC IR 1.28.1, the definition of rate is very broad and includes "a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate". This definition is broad enough to capture reporting requirements and methodology variations. Reporting requirements and methodologies can be considered a rule or practice relating to a rate, for instance.

The Commission has previously approved main extensions, including reporting requirements and methodologies pursuant to applications made under section 61.

60.2 Are there any other applicable sections in the UCA that the FEU could be applying under for the requested approval of reporting requirements to main extension test, particularly for reporting requirement changes or methodology variations in MX tests?

Response:

Yes, the FEU could also apply under section 43(1)(b)(i) of the UCA. Section 43(1)(b)(i) states:

43 (1) A public utility must, for the purposes of this Act,

...

(b) provide to the Commission

(i) the information the Commission requires,

The FEU would also be applying under section 72(2) of the UCA, which states:

(2) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, requesting the commission to

(a) give a direction or approval which by law it may give, or

(b) approve, prohibit or require anything to which by any general or special Act, the commission's jurisdiction extends.

However, the Commission has previously approved main extension tests in response to applications made under section 61, which the FEU believe is appropriate.

61.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.29.1

Continuance of FEI/FEVI's Main Extension Test

The FEU response to BCUC IR 1.29.1 states: "From 2014 onwards, the Companies will continue using the same MX reporting methodology described above with the exception that pre-amalgamation main extensions will continue to be reported on in the manner as by the pre-amalgamation individual utilities (FEI and FEVI) whereas post-amalgamation main extensions will be reported on as a single entity (FEI Amalco). Specifically, this means that the 2009-2013 main extensions will continue to be reported on for the first five years of their existence segmented by FEI and FEVI random samples and top 5 mains whereas the 2014 and later mains will be reported on by the FEI Amalco entity."

61.1 On page 16 of the 2010 MX Report, dated June 1, 2011, FEI and FEVI indicated that the aggregate data for the 2010 main extensions was determined based on the following criteria:

- All main segments within the MX test that were installed after November 1, 2009.
- All completed main segments that were technically complete prior to October 31, 2010.

61.2 For the 2014 MX Report, what will be the aggregate data used for the 2014 main extensions? Would the 2014 main extensions data be based on all main segments within the MX test that are installed after November 1, 2013 and all completed main segments that are technically compete prior to October 31, 2014?

Response:

For simplicity and ease of administration, the Companies will include the main extensions installed from November 1, 2013, to December 31, 2013, in the reporting of the 2013 main extension population. This means that the 2013 main extension population will include mains completed between November 1, 2012, and December 31, 2013.

61.2.1 FEU's proposed Amalco rates go into effect January 1, 2014. How would the 2014 MX Report account for pre-amalgamation if some main extensions data is based on a timeframe between November 1, 2013 and December 31, 2013?

Response:

Please refer to the response to BCUC IR 2.61.2.

61.3 FEU's response to BCUC IR 1.29.1 regarding the 2014 MX Report on Random Samples & Top 5 Data states:

61.4 "The 5 highest cost main extensions:

- The FEI and FEVI populations for 2009-2013
- The 2014 FEI Amalco main population"

61.5 Please confirm that the 2014 MX Report will include the 5 highest cost main extensions for FEI and FEVI populations individually for 2009-2013, meaning that a total of 10 main extensions will be reported for both utilities each pre-amalgamation reporting year. If not confirmed, please explain otherwise.

Response:

Yes, the FEU confirm that the information will be provided as described above.

61.5.1 Post-amalgamation, please clarify whether the 2014 FEI Amalco main population will report on a total of 5 highest cost main extensions or a total of 10 highest cost main extensions.

Response:

The FEU are proposing to report on the 5 highest cost main extensions for the 2014 FEI Amalco main population.

61.5.2 Since pre-amalgamation MX reporting is on a total of 10 highest cost main extensions for FEI and FEVI combined, would it be appropriate for post-amalgamation MX reporting to also report a total of 10 highest cost main extensions? Why or why not?

<u>Response:</u>

Page 37 of the Commission's G-152-07 Decision referred to reporting on the top 5 highest cost main extension for each individual entity (i.e. FEI and FEVI). Since the FEU is proposing to have a single FEI Amalco entity post-amalgamation, it follows that the FEU would report on the top 5 highest cost FEI Amalco main extensions.

However, the FEU would not be averse to reporting on a total of the 10 highest cost main extensions if required.

62.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.30.2; BCUC IR 1.31.2

MX Test Background

The FEU response to BCUC IR 1.30.2 states: "In general, more main extensions in the existing FEVI and FEW areas will likely require a CIAC due to the proposed rate reductions whereas there will likely be slightly fewer main extensions in the existing FEI area that will require a CIAC due to the proposed rate increases. Overall, the FEU expect a minimal impact on net CIAC of the FEI Amalco entity." [emphasis added]

The FEU response to BCUC IR 1.31.2 state: "In section 7.4.2.3 of the Application, the FEU provide an analysis comparing PI values of the individual entities versus FEI Amalco. This analysis shows that FEVI and FEW customers PI values would decrease, FEI PI values would increase and, overall, amalgamation would have a minimal impact on PI values in aggregate. This means that more FEVI and FEW customers will be required to make a contribution to reach the requisite individual PI value of 0.8." [emphasis added]

62.1 Please quantify how many more main extensions (relative to total FEVI and FEW mains) in the existing FEVI and FEW areas will likely require a CIAC due to the proposed rate reductions? Please include any underlying assumptions and show calculations for FEVI and FEW separately.

Response:

Please refer to the response to BCUC IR 2.15.1.

62.1.1 Similarly, please quantify how many fewer main extensions (relative to total FEI mains) in the existing FEI area will require a CIAC due to the proposed rate increases? Please include any underlying assumptions and show calculations.

Response:

Please refer to the response to BCUC IR 2.15.1.

62.2 Please confirm that the current reporting requirements under the 2007 Decision with accompanying Orders G-152-07 and G-6-08 do not require FEI and FEVI to report on CIAC. If not confirmed, please specify.

Response:

The FEU confirm that Orders G-152-07 and G-6-08 do not require reporting on CIAC.

62.2.1 Post-amalgamation, should the FEU in the annual MX report include reporting on CIAC contributory mains to ensure adequate monitoring of main extensions that are close to the 0.8 individual PI threshold? Please explain.

Response:

As stated in BCUC IR 2.62.2, Orders G-152-07 and G-6-08 do not require reporting on CIAC. Thus, the FEU do not believe reporting on CIAC is necessary to ensure adequate monitoring of main extensions.

However, the Companies provided the number of FEI and FEVI customers that provided a CIAC in the 2010 MX Report at the request of the Commission Staff. The Companies could continue to provide this information in MX reports Post-amalgamation. The FEU could provide the number of FEI and FEVI customers that provided a CIAC for main extensions up to and including the 2013 data set. For post-amalgamation main extensions (i.e. 2014 onwards) the Companies could provide the number of FEI Amalco customers that provided a CIAC.

62.3 Post-amalgamation, please confirm whether the FEU are capable of including reporting on the total number of mains, total contributory mains and total CIAC amount by region or by service area. If not confirmed, please explain the changes in system capabilities pre-amalgamation and post-amalgamation, and the steps to enable capability of including reporting on the total number of mains, total contributory mains and total CIAC amount by region or by service area.

Response:

The FEU do have the internal data on the total number of mains, total contributory mains and total CIAC amount by location. However, the FEU currently do not have the information technology capabilities to extract the data for reporting purposes by region or service area as described below.

The FEU currently provide MX reporting to the Commission at a utility level (i.e. FEI and FEVI), not at an individual region or service area. The FEU believe that this utility level approach to MX reporting is appropriate and should continue post-amalgamation. This principle is reflected in the Company's proposal to report on main extensions at the FEI Amalco utility level.

If the FEU were to be directed to provide MX reporting at a regional or service area level, this would represent a change in current practice and would require additional effort to provide this level of detail. The exact nature of this effort is unknown at this time and would be dependent on the exact reporting requirements.

63.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.30.3

MX Test Attachments and Customer Use Forecast by Developers

The FEU response to BCUC IR 1.30.3 states: "As the developer does not have control over the usage rate of the end use customer, it is not reasonable for the developer to carry this risk, nor would it be reasonable to hold and end use customer to commitments for usage of specific appliances…. However, in certain instances where there is concern over the forecasts, a security deposit may be obtained from the developer which may be retained by the FEU, although this is very infrequent."

63.1 Please elaborate on who should bear the risk (e.g. all ratepayers, shareholder, developers, new customers, or existing customers), if the realized load is well below the customer attachment forecast and/or customer use forecast.

Response:

The response to BCUC IR 1.35.1 regarding the evaluation of the performance of main extensions also applies to the evaluation of the risk of a main extension. In particular, the performance and risk of main extensions should be examined in aggregate, not at an individual main extension level. This approach ensures that all main extension projects are treated equally, including both underperforming and over performing projects. In addition, since the MX Test approved by the Commission is a twenty year discounted cash flow ("DCF") model, the appropriate time frame to review the performance and risk of main extensions in aggregate should be at the end of twenty years. Variance year to year in forecast versus actual attachments and consumption is to be expected as a part of normal operations.

In general, any risk that the profitability index might not materialize as originally forecast over the twenty year DCF timeframe should be borne by existing customers. Since the FEU's existing customers receive the benefit of new customers that attach to the system, existing customers should also bear the associated risk.

As discussed in the response to BCUC IR 1.30.3, the builder/developer generally provides a good faith estimate of the future attachments and appliances to be installed in the main extension project. As the developer does not have control over the usage rate of the end use customer, it is not reasonable for the developer to carry this risk. Nor would it be reasonable to hold an end use customer to commitments for usage of specific appliances. Similarly, existing customers are able to change their load and usage profiles over time as a result of changing equipment or moving from one form of energy to another for a specific appliance (i.e.: electric stove to gas stove or vice versa). These existing customers are not penalized for changing their load profiles. On the contrary, through EEC, these customers are actually encouraged to use less than what they previously used. In this manner, is it inconsistent, and unequal from an intergenerational standpoint, to hold new customers/developers to a different standard than existing customers?

63.2 Please explain why the FEU only infrequently obtains a security deposit from a developer. In the response, please explain if this approach increases the risk of inefficient investment in infrastructure by FEU.

Response:

In most instances, it is not appropriate to obtain security from a builder/developer. As quoted above, the developer does not have control over the usage rate of the end use customer, so it is not reasonable for the developer to carry this risk. Placing risks on developers that they cannot control may unduly deter the efficient development of the system and the addition of load that increases throughput and lowers rates for all customers. As described in the responses to BCUC 1.30.2 and 1.30.3.1, the FEU rely on the knowledge and expertise of its Planning and Energy Solutions management team to evaluate forecasts from builder/developers. If there is a reason to be concerned about the forecast, then the FEU may require a security deposit. The FEU believe that its current systems address the risk of inefficient investment while not deterring efficient investment from taking place to the detriment of all customers.

As discussed in the response provided in BCUC IR 2.63.1, the performance and risk of inefficient investment in main extensions should be examined in aggregate, not at an individual main extension level. In addition, the appropriate time frame to review the performance and risk of main extensions in aggregate should be at the end of twenty years, consistent with the term of the MX Test DCF.

64.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.31.1; BCUC IR 1.29.1

MX Test Reporting by Region

The FEU response to BCUC IR 1.31.1 states: "Although it may be possible to report the MX by region, the Companies have not conducted a feasibility study to determine what internal capabilities would be required to report by region following amalgamation. As described in the response to BCUC IR 1.29.1, the Company is proposing to continue to report on pre-amalgamation main extensions for FEI and FEVI for the requisite five years. Post-2014, the Companies will be reporting on new main extensions from the single entity, FEI Amalco. This proposal is more efficient than continuing to report on the pre-amalgamation service areas."

For the 2014 MX Report, the FEU's response to BCUC IR 1.29.1 proposes that:

> "… the 2009-2013 main extension will continue to be reported on for the first five years of their existence segmented by FEI and FEVI random samples and top 5 mains whereas the 2014 and later mains will be reported on by the FEI Amalco entity."

64.1 Since FEU will already be reporting on pre-amalgamation 2009-2013 main extensions segmented by FEI and FEVI in the 2014 MX Report, what changes in system capabilities, if any, would be required to report on 2014 main extension by existing regions post-amalgamation?

Response:

The FEU currently report at the utility level (i.e. FEI and FEVI), not at a regional level. Please refer to the response to BCUC IR 2.62.3 for a discussion around the changes in capabilities to provide regional reporting.

64.1.1 Hypothetically, if Vancouver Island were a service area distinct from the Lower Mainland, Inland, Columbia, Whistler and Fort Nelson service areas, would FEU be capable of providing MX reporting post-amalgamation on the Vancouver Island service area? If not, what changes in system capabilities, if any, would be required post-amalgamation?

Response:

Please refer to the response to BCUC IR 2.64.1.

64.2 Do FEU consider that there is a risk that, should amalgamation and postage stamp rates be approved, FEU could determine through a feasibility study that it will be unable to report the MX by region? Please explain why or why not.

Response:

No. Please refer to the response to BCUC IRs 2.62.3 and 2.64.1.

64.2.1 Please explain the factors the FEU will consider in undertaking this feasibility study.

Response:

A feasibility study would only be considered in the event that there were changes in the reporting requirements from current practice. For example, as discussed in the response to BCUC IR 2.62.3, if the FEU were to be directed to provide MX reporting at a regional or service area level, this would represent a change in current practice and would require additional effort to provide this level of detail. The exact nature of this effort is unknown at this time and would be dependent on the exact reporting requirements.

65.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.32.3

Use of PI Inputs Reflecting FEI Amalco

The FEU response to BCUC IR 1.32.3 states: "For pre-amalgamation main extensions, the FEU propose to continue to use the original MX Test inputs from 2008-2013 when providing data for review by the Commission to ensure consistency."

65.1 Please confirm that the FEU are proposing to use the original MX Test inputs from 2008-2013 for each utility, including SI, Discount Rate, O&M, Property Tax, Variable Margin, and Fixed Margin, when providing data for review by the Commission to ensure consistency. If not confirmed, please explain otherwise.

Response:

Confirmed. The FEU will use the original MX Test inputs from 2008-2013 as described in the information request.

66.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.34.1

MX Reporting Regarding Performance by Service Areas

The FEU response to BCUC IR 1.34.1 states: "The proposed FEI Amalco MX reporting will continue to provide the Commission with the following data segmented geographically:

- Appliance use inputs for MX Test inputs segmented by Lower Mainland, Interior and Vancouver Island…
- Geo code pricing segmented by geography….

All other data presented in the MX Report relating to post-amalgamation main extensions will be reported on an amalgamated basis.

Please refer to the response to BCUC IRs 1.29.1 and 1.31.1 for a detailed description of the proposed MX Test reporting."

66.1 Please clarify whether the proposed FEI Amalco MX reporting, as described in FEU's responses to BCUC IR 1.29.1 and 1.31.1, for post-amalgamation main extensions, will allow the ability to differentiate performance (i.e. forecast and actual cost, forecast and actual attachments, forecast and actual consumption, ramp-up experience for early months of service, etc.) between different regions or different services areas. Please elaborate.

Response:

The proposed reporting by FEI Amalco will reflect MX tests performed based on the FEI Amalco common rates and the FEU will report on the performance of the FEI Amalco utility.

For a discussion of the ability to differentiate performance between different regions or different service areas please refer to the response to BCCUC IR 2.62.3.

67.0 Reference: MX Test

Exhibit B-9, BCUC IR 1.37.1.1

Use of Natural Gas per Customer – Vancouver Island

The FEUs response to BCUC IR 1.37.1.1 states: "One reason for declining use in FEVI is due to new residential customers attaching at use rates below the FEVI system average…"

Terasen Gas (Vancouver Island) Inc. (TGVI, now known as FEVI) Information Request (IR) response to BCUC 1.44.0 to the 2010-2011 Revenue Requirements and Rate Design Application submitted on August 28, 2009, Exhibit B-4, includes the following tables relating to actual annual consumption (June 1, 2006 to May 31, 2007) of 981 new services installed for TGI (now FEI) and TGVI (FEVI):

Company	Rate Class	Number of Customers	Actual Annual Consumption
TGI	Rate 1	623	58,192.7
TGI	Rate 2	66	38,453.8
TGI	Rate 3	2	2,548.0
TGI	Rate 23	1	10,564.1
TGVI	RGS	263	10,663.1
TGVI	SCS1	21	4,342.3
TGVI	SCS2	2	1,113.4
TGVI	LGS1	3	3,890.8

The same IR response above also provides the following table that illustrates the normalized annual consumption by rate class for the same set of FEVI customers included in the above table over the period 2006 to 2008:

		Normal Annual Cons(GJ)		
Rate Class	Number of Customers	June 1st 2006 to May 31st 2007	2007	2008
RGS	263	10,601.0	11,537.3	11,683.1
SCS1	21	4,307	5,043	4,941
SCS2	2	1,118	701	223
LGS1	3	3,878	3,583	3,021

67.1 In similar fashion as above, please provide an update for new services installed for FEVI in the 2009 cohort year by showing their consumption and use per customer in 2010-2011. Please complete the following table and make any adjustments as appropriate.

Line #	Use per Customer - New FEVI Customers - For 2009 Cohort Year					
			2010		2011	
1	Rate Class (a)	Number of New Customers (b)	Actual Annual Consumption (c)	Actual Use per Customer (d)	Actual Annual Consumption (e)	Actual Use per Customer (f)
2	RGS					
3	SCS1					
4	SCS2					
5	LGS1					

Response:

The following table displays the number of new customers in 2009 cohort year as well as their consumption and use per customer in 2010 and 2011. The actual annual consumption and use per customer are calculated based on the customers who had a full 365 days of billed consumption.

Use per Customer - New FEVI Customers -For 2009 Cohort Year					
		2010		2011	
Rate Class	Number of New Customers	Actual Annual Consumption (GJ)	Actual Use per Customer (GJ)	Actual Annual Consumption (GJ)	Actual Use per Customer (GJ)
RGS	2,785	80,598	30	87,676	39
SCS1	559	106,178	156	114,557	194
SCS2	-				
LGS1	-				

67.1.1 The FEU use the findings from its Residential End Use Studies to derive average use per appliance (FEU's response to BCUC IR 1.30.1). In light of the Residential End Use Studies, please indicate the types of appliances, and their respective average use per appliance, for new services installed for new FEVI customers.

Response:

The table below, originally provided in the 2010 MX annual report,[53] summarizes the annual average usage estimates by appliance type and region. The usage per appliance data is used in the MX Test to determine the projected delivery margin.

Appliance	2008 - 2010 (GJ/yr)	2011 (GJ/yr)		
	All Regions	Lower Mainland	Interior	Vancouver Island
Barbeque	3.1	3.1	3.1	3.1
Boiler	60.0	62.0	51.6	43.0
Clothes Dryer	4.0	4.2	3.6	3.4
Fireplace - Décor	15.8	18.3	15.9	16.1
Fireplace - Heating	16.8	21.4	19.8	19.7
Furnace (primary)	60.0	62.0	51.6	43.0
Furnace (secondary)	60.0	18.1	39.3	19.9
Hot Tub	17.9	19.5	19.5	19.5
Hot Water Tank	20.8	20.4	18.8	18.8
Pool	53.5	38.5	38.5	38.5
Range/Cooktop	8.5	5.6	5.1	4.7
Wall Heater	18.1	7.1	7.1	7.1

67.2 Please provide the FEVI system average use rates for residential customers since 2009.

Response:

Actual and normalized average use rates for residential customers for FEVI since 2009 are shown below.

FEVI	2009	2010	2011
Actual Average Use Rate (GJs)	56.6	50.8	56.2
Normalized Average Use Rate (GJs)	53.5	52.4	51.8

53 Submitted to the Commission on June 1, 2011

67.3 Do FEU consider that, based on information gathered to date, it is <u>more likely</u> that the most important driver for lower average residential consumption rates of FEVI customers compared to FEI customers is driven by (i) extensions to FEVI customers who do not have gas heat/hot water, or (ii) extensions to FEVI customers who have higher efficiency appliances, smaller size and/or better insulation than FEI customers? Please provide supporting evidence for the position taken.

<u>Response:</u>

The following table from the 2008 REUS study illustrates the difference in the penetration rates between FEVI and FEI by end use. FEI customers have higher penetration rates of 93% and 84% respectively for primary space heating and water heating compared to FEVI customers whose penetration rates are 71% and 76% respectively.

Table 1: FEI and FEVI penetration rate by end use

End Use	FEI Penetration (% presence)	FEVI Penetration (% presence)
Primary Space Heating	93%	71%
Water Heating	84%	76%

The higher penetration rate of space and water heating for FEI customers leads to higher UPCs.

The overall furnace efficiency is higher for FEVI compared to FEI regions as shown in Exhibit 5.25 from the 2008 REUS study. FEVI has the highest proportion of high efficiency furnaces (90% AFUE or higher) at 20.8% compared to 11.9% for LML (Lower Mainland).

Exhibit 5.25: Furnace Efficiency by Region including DK Responses (%)
Natural Gas or Piped Propane

Gas Furnace Efficiency	LM	INT	FN	TGVI
Unweighted base	360	587	123	277
Standard efficiency (less than 78% AFUE)	49.3	39.7	35	22.7
Mid-efficiency (78% to 85% AFUE)	24	35.1	37.4	41.4
High efficiency (90% AFUE or higher)	11.9	16.1	19.5	20.8
DK	14.9	9.1	8.1	15.1
Total	100	100	100	100

Totals may not sum due to rounding.

The 2008 REUS supports that the lower penetration rates for primary space heating and hot water in FEVI combined with higher efficiency appliances contribute to the lower average residential consumption rates for this region. However, the 2008 REUS does not conclude that penetration rates or appliance efficiency are the only factors determining lower usage, nor does the 2008 REUS suggest any ranking of significance on the usage for each of these factors. At this time, the FEU consider all potential factors that affect consumption collectively and is unable to determine statistical significance of each factor on an individual basis.

68.0 Reference: Proforma Rate Schedules

Exhibit B-3-1, Appendix B-3, Rate Schedule 1

Proposed Changes to Rate Schedules 1, 1U and 1X

The Basic Charge of Rate Schedule 1 includes the "Option A" surcharge applicable to Inland and Columbia service area customers whose primary space heating equipment was purchased and installed with the assistance of a promotional incentive. Option A was closed to new applicants in 1990. The proposed changes to the wording of Option A (replacing "Inland and Columbia" with "Mainland") suggest that this surcharge will be extended to applicable Lower Mainland customers as well.

68.1 Please confirm whether or not the promotional incentives referred to in Option A were provided to Inland and Columbia service area customers only.

Response:

Confirmed, the promotional incentives referred to in Option A were provided only to Inland and Columbia service area customers. The proposed changes to the wording of Option A do continue to note that "Option A is closed to new applicants effective September 1990", therefore there is no suggestion that this surcharge will be extended to applicable Lower Mainland customers as well, nor any new FEU customers in any service territories.

The proposed wording of Rate Schedule 1U suggests that the Customer Choice program will be extended only to customers in the "Mainland" area: "This Rate Schedule is available to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions,"

68.2 Please confirm whether the FEU intend to extend Customer Choice to all customers.

Response:

Under amalgamation and common rates, FEW, FEVI and FEFN will adopt FEI's rate structures and service offerings. FEI intends to extend the Customer Choice program to all existing and newly mapped Rate Schedule 1, 2, and 3 customers.

As indicated in Section 6.5.1 of the Application, the expansion of Customer Choice beyond the Lower Mainland, Inland and Columbia service areas would begin November 1, 2014 to allow time for proper customer education for the new areas. The FEU believe the specifics of the Customer Education Plan should be determined in a separate regulatory filing for the Customer Choice Program following a decision on amalgamation (refer to the response to BCUC IR 1.43.1 for full discussion). For this reason, Customer Choice will only be available to customers in the Mainland area upon amalgamation (January 1, 2014). The FEU will file an amendment to Rate Schedules 1U, 2U, and 3U to include the remaining customers at a later date, prior to when the program is available in other areas.

69.0 Reference: Proforma Rate Schedules

Exhibit B-3-1, Appendix B-3, Rate Schedules 5, 6, 6A, 6P, 7, 22, 23, and 25 through 27

Proposed Changes to Rate Schedules 5, 6, 6A, 6P, 7, 22, 23, and 25 through 27

69.1 Please confirm that service under Rate Schedules 5, 6, 6A and 6P, 7, 22, 23, and 25 through 27 will be extended to Fort Nelson customers.

<u>Response:</u>

Confirmed. Although FEFN customers were mapped to Rate Schedules 1, 2 and 3, they may elect to receive service under any of FEI's open rate schedules.

69.2 Why do the delivery related charges of the Rate Schedules listed above not include Rider 4 – the Phase in Rider applicable to Fort Nelson customers?

<u>Response:</u>

Please refer to Exhibit B-9-1, Attachment 110.1 filed on June 1, 2012 for the black-lined version of the FEU's GT&C's filed on June 1, 2012. These GT&C's include FEFN's phase-in rider, Rate Rider 4, as part of Rate Schedules 4, 5, 6, 7, 22, 23, 25, 26, and 27.

70.0 Reference: Rate Stabilization Deferral Account (RSDA) and the Fort Nelson Phase-In Rider

Exhibit B-3-1, Appendix J-1, Schedules 33 and 34

Continuity of Rider Amount for 2014 – 2028

Schedule 33 shows the RSDA continuity calculation for the period 2010 to 2016.

70.1 Why does the RSDA not continue to attract interest after 2013?

Response:

The RSDA should continue to attract interest after 2013. Schedule 33 showed a simplified calculation of the rider refund to customers based on the ending 2013 balance. A revised schedule including interest is provided in BCUC IR 2.70.2.

70.2 Does the inclusion of interest accrued over the period 2014 – 2016 have a material impact on the changes in rates of Mainland customers over the period 2014 to 2016?

Response:

Please refer to the revised Schedule 33 below which includes the impacts of including interest on the RSDA for 2014-2016. Note that the actual calculation of the 2014-2016 RSDA riders by the FEU will be updated to include the actual balance in the RSDA account at the end of 2012 and a revised projection for 2013 activity.

Line No.	Particulars	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Opening RSDA Balance, net of tax	(3,300)	(35,618)	(67,392)	(74,278)	(67,746)	(36,722)	(18,699)
2	Annual (Surplus)/ Deficiency	(44,743)	(41,533)	(6,389)	12,194	-	-	-
3	Add: Interest on Balance	(457)	(1,697)	(2,792)	(3,485)	(3,387)	(1,836)	(935)
4	Less: Allocation to Fort Nelson					18,886	-	-
5	Less: Rate Rider drawdown	-	-	-		25,867	25,867	25,867
6	Less: Tax	12,882	11,456	2,295	(2,177)	(10,341)	(6,008)	(6,233)
7	**Closing RSDA Balance, net of tax**	**(35,618)**	**(67,392)**	**(74,278)**	**(67,746)**	**(36,722)**	**(18,699)**	**0**
8								
9	Tax Rate	28.5%	26.5%	25.0%	25.0%	25.0%	25.0%	25.0%
10	**Closing RSDA Balance, before tax**	**(49,816)**	**(91,690)**	**(99,037)**	**(90,328)**	**(48,963)**	**(24,932)**	**0**

Line No.	Particulars	2014-2016 Allocated Revenue Deficiency ($000s)	2013 Mainland Sales Volume (TJs)	2014-2016 RSDA Rate Rider ($/GJ)
	(1)	(2)	(3)	(4)
1	**RSDA Rider Calculation**			
2				
3	Rate 1	$ (16,206)	69,816	$ (0.232)
4	Rate 2	$ (4,077)	23,332	$ (0.175)
5	Rate 4	$ (13)	185	$ (0.072)
6	Rate 6	$ (11)	56	$ (0.188)
7	Rate 22 Non-Bypass	$ (503)	11,504	$ (0.044)
8	Rate 3/23	$ (3,230)	24,000	$ (0.135)
9	Rate 5/25	$ (1,471)	14,579	$ (0.101)
10	Rate 7/27	$ (356)	5,819	$ (0.061)
11				
12	TOTAL	$ (25,867)	149,292	

The FEU have also provided an alternative table below based on the revised allocation amount needed for FEFN as discussed in BCUC IR 1.70.4. To summarize, with the inclusion of interest in the calculation of the FEFN riders, a smaller allocation is needed from the 2013 ending RSDA balance to provide FEFN customers with the same rate impacts as was provided in Schedule 34 of the Rate Design Application.

Line No.	Particulars	2010 Actual	2011 Projected	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Opening RSDA Balance, net of tax	(3,300)	(35,618)	(67,392)	(74,278)	(67,746)	(38,298)	(19,501)
2	Annual (Surplus)/ Deficiency	(44,743)	(41,533)	(6,389)	12,194	-	-	-
3	Add: Interest on Balance	(457)	(1,697)	(2,792)	(3,485)	(3,387)	(1,915)	(975)
4	Less: Allocation to Fort Nelson					15,674	-	-
5	Less: Rate Rider drawdown	-	-	-		26,977	26,977	26,977
6	Less: Tax	12,882	11,456	2,295	(2,177)	(9,816)	(6,266)	(6,501)
7	**Closing RSDA Balance, net of tax**	**(35,618)**	**(67,392)**	**(74,278)**	**(67,746)**	**(38,298)**	**(19,501)**	**0**
8								
9	Tax Rate	28.5%	26.5%	25.0%	25.0%	25.0%	25.0%	25.0%
10	**Closing RSDA Balance, before tax**	**(49,816)**	**(91,690)**	**(99,037)**	**(90,328)**	**(51,064)**	**(26,002)**	**0**

Line No.	Particulars	2014-2016 Allocated Revenue Deficiency ($000s)	2013 Mainland Sales Volume (TJs)	2014-2016 RSDA Rate Rider ($/GJ)
	(1)	(2)	(3)	(4)
1	**RSDA Rider Calculation**			
2				
3	Rate 1	$ (16,902)	69,816	$ (0.242)
4	Rate 2	$ (4,252)	23,332	$ (0.182)
5	Rate 4	$ (14)	185	$ (0.075)
6	Rate 6	$ (11)	56	$ (0.196)
7	Rate 22 Non-Bypass	$ (524)	11,504	$ (0.046)
8	Rate 3/23	$ (3,368)	24,000	$ (0.140)
9	Rate 5/25	$ (1,534)	14,579	$ (0.105)
10	Rate 7/27	$ (372)	5,819	$ (0.064)
11				
12	TOTAL	$ (26,977)	149,292	

The FEU are proposing to allocate $18,866 million of the Rate Stabilization Deferral Account (RSDA) balance to FEFN customers to phase in their rate increase resulting from extending postage stamp rates to all areas served by Fortis. This allocation is shown in year 2014 on Schedule 33. Its amortization through the FEFN Phase-in Rider is shown on Schedule 34

70.3 Why does the RSDA allocated to Fort Nelson not continue to attract interest after 2013?

Response:

The RSDA should continue to attract interest after 2013. Schedule 34 showed a simplified calculation of the rider refund to customers based on the ending 2013 balance. A revised schedule including interest is provided in BCUC IR 2.70.4.

70.4 Does the inclusion of interest accrued over the period 2014 – 2028 have a material impact on the proposed schedule of phasing in the rate increase resulting from extending postage stamp rates to Fort Nelson customers over the period 2014 to 2028?

Response:

The inclusion of interest accrued will have no impact on the proposed schedule of phasing in the rate increase to FEFN customers. The inclusion of interest will result in an equal reduction in the amount of RSDA that must be allocated to FEFN customers.

To clarify, with the inclusion of interest the FEU would only allocate $15.674 million of the RSDA to FEFN customers. The allocation of $15.674 million, in addition to the forecast interest of $3.212 million on these additions, would provide an equivalent $18.886 million to be returned to FEFN customers.

Please refer to the revised Schedule 34 below which separates out the interest component pertaining to the FEFN RSDA amount.

Line No.	Year	*Total Amount to be Returned to FN Customers*	*Total RSDA Interest*	*Rate 1 Rider ($/GJ)*	*Rate 2 Rider ($/GJ)*	*Rate 3 Rider ($/GJ)*
	(1)	(2)		(3)	(4)	(5)
1	2014	(1,427)	(561)	(3.869)	(2.082)	(3.110)
2	2015	(1,482)	(506)	(3.869)	(2.082)	(3.110)
3	2016	(1,538)	(450)	(3.869)	(2.082)	(3.110)
4	2017	(1,597)	(391)	(3.869)	(2.082)	(3.110)
5	2018	(1,658)	(330)	(3.869)	(2.082)	(3.110)
6	2019	(1,519)	(270)	(3.482)	(1.874)	(2.799)
7	2020	(1,374)	(216)	(3.095)	(1.666)	(2.488)
8	2021	(1,225)	(167)	(2.708)	(1.458)	(2.177)
9	2022	(1,068)	(125)	(2.321)	(1.249)	(1.866)
10	2023	(906)	(88)	(1.934)	(1.041)	(1.555)
11	2024	(738)	(57)	(1.547)	(0.833)	(1.244)
12	2025	(564)	(32)	(1.161)	(0.625)	(0.933)
13	2026	(383)	(15)	(0.774)	(0.416)	(0.622)
14	2027	(195)	(4)	(0.387)	(0.208)	(0.311)
15	2028	-	-	-	-	-
Total		(15,674)	(3,212)			

* Annual Rider may be subject to change based on volume forecast for each year and true-up for prior year volume variance

** Annual Rider to be determined based on the non-bypass volume forecast for each year and true-up for prior year volume variance

71.0 Reference: COSA Methodology

Exhibit B-9, BCUC 127.1; Exhibit B-9-1, Attachment 127.1, Schedule 5

FEI Amalco COSA Model with Amendments

Question 127.1 asked the FEU to incorporate a number of amendments into the FEI Amalco COSA, one of which was to "Classify all of the costs related to the Mt. Hayes LNG storage facility as energy-related."

From an examination of Schedule 5 of Attachment 127.1, it appears that the costs related to the Mt. Hayes LNG storage facility remain classified as demand-related.

71.1 Please confirm that the costs related to the Mt. Hayes LNG storage facility in fact remain classified as demand-related as reflected in the COSA schedules in Attachment 127.1.

Response:

Confirmed. Please refer to Attachment 71.1 for the updated schedules which incorporate the amendment to the COSA model to classify all of the costs related to Mt. Hayes LNG Storage facility as energy-related. For the purposes of this amendment, these costs are allocated to customers based on volumes.

Please note that the attached schedules also reflect all other changes as required in the response to BCUC IR 1.127.1.

72.0 Reference: COSA Schedules

Exhibit B-9, BCUC 142; BCUC 47.1.1

Postage Stamp vs. Regional Midstream Charges

In response to question 142.3, the FEU provided a table showing the midstream costs of each service area under postage stamp and regional midstream rate structures. In their response to 142.5, the FEU state: "The regional midstream costs presented on line B are a fair representation of the cost of midstream services assigned to each region under the current regionalized rate design models."

72.1 What are the total midstream costs payable by customers in the Fort Nelson area under the proposed postage stamp midstream rate design? In other words, what amount should appear in row 'E' under the 'FEFN' column of the table provided in response to question 142.3?

Response:

The total midstream costs allocated to, and payable by, FEFN customers under the postage stamp midstream option, and which relates to the amount that would appear in row "E" under the "FEFN" column of the table provided in the response to BCUC IR 1.142.3 is approximately $760 (in thousands).

The table below provides the composition of the total FEFN midstream costs to be recovered, by rate class, indicating that the postage stamp midstream rates continue to reflect the load factor differences between rate classes.

Fort Nelson Midstream Costs, By Rate Class, Under Postage Stamp Rates Option

	Rate 1	Rate 2	Rate 3	Total
Midstream Volumes *(TJ)*	274.3	193.3	119.4	587.0
Postage Stamp Midstream Charge *($/GJ)*	$ 1.384	$ 1.316	$ 1.055	
Total Allocated Midstream Costs *($000)*	$ 379.7	$ 254.3	$ 126.1	**$ 760.1**

In its response to question 47.1.1, the FEU state that: "FEI's diversified portfolio of resources has the ability to provide reliable service to all customers, including customers that are located in smaller and remote areas like FEFN."

72.2 Do the midstream costs provided in response to the previous question appropriately reflect the value provided to Fort Nelson customers by FEI's portfolio of resources?

Response:

Yes, the total FEFN midstream costs provided in the response to BCUC IR 2.72.1 appropriately reflect the value provided to FEFN customers. The total pool of midstream resources is optimized in order to serve customer demand on the system as a whole each day, including customers of FEFN.

Under postage stamp rates, the total costs of the resources in the midstream portfolio are allocated to all Sales customers on the system regardless of any particular customer's specific regional location within the FEU's service area. It should also be noted that for rate setting purposes the midstream costs are allocated to the various customer rate classes on a load factor adjusted volumetric basis, which appropriately reflects the demand each customer class places on the midstream resources required to meet their peak demand.

For additional information about this issue, please also refer to the responses to BCUC IRs 1.47.1, 1.47.2, 1.47.6, and 1.47.8.

72.3 What is the value to Fort Nelson customers of FEI's portfolio of resources?

Response:

Currently, FEI optimizes its pool of resources as a single portfolio on a total regional level that includes FEFN. As a result, FEFN customers already benefit from having their requirements included and managed as part of FEI's overall portfolio. For example, as discussed in the response to BCUC IR 1.47.1, the customers in Fort Nelson currently benefit from FEI's supplier relationships that allow for the contracting of a unique and flexible supply arrangement, and from the ability to manage intraday fluctuations via FEI's balancing agreement on Westcoast's T-North System.

For additional information about this topic, please also refer to page 36 of the Application and the responses to BCUC IRs 1.47.1, 1.47.2, 1.47.6, and 1.47.8.

73.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-3-1, Appendix B-3, p. D-5

Exhibit B-9-1 Response to BCUC IR 112.1, Attachment 110.1 p D-5

General Terms and Conditions

The FEU response to BCUC IR 112.1 states: "Upon further consideration, the FEU have decided to withdraw the proposed definitional change of "thermal energy" from this Application due to the pending resolution of the AES Inquiry. Depending on the outcome of that proceeding, FEI may seek a change to the definition in a separate proceeding."

In both Exhibit B-3-1 and Exhibit B-9-1 the same definition of Thermal Energy is included in both originally filled pro-forma GT&Cs and the GT&Cs filed as revised in response to BCUC IR 110.1

73.1 Please indicate why the definitional change was not reversed.

Response:

The GT&Cs included in Exhibit B-9-1 were incorrect. Please see Attachment 73.1 for the revised black-lined GT&Cs that show the definition of "Thermal Energy" has been changed back to the original definition, as follows:

*"**Thermal Energy** - Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source),and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision."*

74.0 Reference: Black-lined Proforma FEI Tariff with GT&Cs and Rate Schedules

Exhibit B-9-1 Response to BCUC IR 110.1, Attachment 110.1

General Terms and Conditions

74.1 Please provide a summary table showing each change made to the GT&Cs resulting from either errors, omission or other changes as identified in the responses to BCUC IR 110.1 and 118.1. Please include the GT&C page number where the revision was made, indicate that the revision has been completed and indicate the nature of the changes in the GT&Cs comparing the documents filed as part of Exhibit B-3-1 and Exhibit B-9-1.

<u>Response:</u>

In addition to the changes identified in the responses to BCUC IRs 1.110.1 and 1.118.1, the FEU have also identified the changes in the responses to BCUC IRs 1.115.1, 1.117.1, 1.122.1, and 1.124.1 with the intent to provide a more complete summary to the Commission.

IR No.	Page No. (Exhibit B-9-1 - Appendix B-3)	Revision Completed	Nature of Change
1.110.1	FEI GT&Cs Definitions - Page D-1	Complete	re-inserting "or the prorated daily equivalent charge - calculated on the basis of a 365.25-day year (to incorporate leap year), and rounded down to four decimal places" to the definition of Basic Charge
1.115.1	FEI GT&Cs Section 11 - Page A11-2	Complete	Daily charge corrected back to Monthly charge regarding Customer Requested Meter Relocation or Modifications
1.117.1	FEI GT&Cs Definitions - Page D-5	Complete	Withdraw proposed definitional change of "thermal energy"
1.118.1	RS 4 - Page R-4.17	Complete	Column Headers in Table of Charges amended in RS 4, 5, 6, 7, 22, 23, 25, 26, and 27; Inclusion of Rider 4: Phase-In Rider
	RS 5 - Page R-5.18	Complete	
	RS 6 - Page R-6.14	Complete	
	RS 7 - Page R-7.18	Complete	
	RS 22 - Pages R-22.28-29	Complete	
	RS 23 - Page R-23.30	Complete	
	RS 25 - Page R-25.30	Complete	
	RS 26 - Page R-26.32	Complete	
	RS 27 - Page R-27.24	Complete	
1.122.1	RS 7 - Page R-7.18	Complete	Basic Charge corrected back to Basic Charge per Month in RS 7
1.124.1	RS 22A - Page R-22A.11	Complete	Basic Charge corrected back to Basic Charge per Month in RS 22A, 22B and 23
	RS 22B - Page R-22B.5	Complete	
	RS 23 - Page R-23.30	Complete	

75.0 Reference: Unamortized Deferred Charges

Exhibit B-3, Section 8.2.1.2, p 153

Existing Deferral Accounts

The FEU Evidence states: "In the 2012-2013 RRA, the Companies proposed alignment of the amortization periods for similar deferral accounts. As outlined in Section 6.3 of the 2012-2013 RRA (Exhibit B-1), Whistler and Fort Nelson have proposed changes to the amortization periods for the Property Tax and Interest Variance accounts and Whistler has proposed changes to the amortization periods for the Revenue Stabilization Adjustment Mechanism ("RSAM") and the Tax Variance accounts to align with the Mainland amortization period for each of those accounts. If this proposal to align the treatment of deferral accounts is approved, all deferral accounts of a similar nature will be amortized over the same period and therefore, upon amalgamation, the balances of these accounts, as well as the corresponding amortization expense, are consolidated without adjustments required to FEI Amalco."

75.1 Please confirm that the proposal for alignment has been approved with reference to the recent RRA Decision and page reference?

Response:

The FEU confirm that the proposal for alignment has been approved through Commission Order No. G-44-12.

The changes to the Property Tax Variance, Interest Variance and Tax Variance accounts are summarized on Page 115 of the Decision as "…the FEU seek approval for modifications to various amortization periods for existing non-controllable deferral accounts within FEW and FEFN to standardize deferral account treatment with existing FEI policies." The approval is then provided on Page 116 with the Commission determination of "Accordingly, the Commission Panel approves the requested modifications to existing non-controllable deferral accounts." In addition, on page 116 of the Decision, the Commission agrees with the FEU "that the standardization of the FEU's deferral accounting policies simplifies and streamlines record keeping".

The change to the Revenue Stabilization Adjustment Mechanism account is summarized on Page 106 of the Decision as "The FEU request modifications to existing margin related deferral accounts in order to standardize treatment of these accounts within the FEU." The approval is then provided on Page 107 with the Commission determination of "The Commission Panel finds that the modifications to margin related deferral accounts are appropriate and in the interest of ratepayers and approves them as filed."

75.2 Please explain any differences from the approved tables provided in the most recent RRA Decision and that provided in Appendix J-1 Schedule 24 and Schedule 25 for the rate base deferral accounts.

Response:

The balances shown in Appendix J-1 reflect the addition of the September 12th RRA Evidentiary Update balances for FEI, FEVI and FEW, the FN amounts as approved through Commission Order G-177-11. An amalgamation adjustment for the elimination of the intercompany transaction between FEW and FEVI pertaining to the Whistler Pipeline, as discussed in Section 8.2.1.2 of the Rate Design Application, is also reflected.

The approved RRA deferral schedules were updated after the rate design application was filed to reflect the removal of the NGV incentives account which is now classified as a non-rate base deferral account, to update opening balances to reflect actual 2011 amounts, and to adjust forecasted amortization based on the revised opening balances for 2012 and 2013 accordingly. All of these changes would not be reflected in the deferral account balances shown in Appendix J-1 of the Rate Design Application.

76.0 Reference: Unamortized Deferred Charges

Exhibit B-3, Section 8.2.1.2, p 153 and 156

Existing Deferral Accounts

The FEU Evidence states: "With respect to the Margin Related deferral accounts recovered through rate riders and the commodity or midstream rates (Appendix J-1, Schedule 24, Lines 2 through 4), the FEU is proposing the following:

- To combine the closing balance in the existing Mainland, Fort Nelson and Whistler RSAM accounts (including interest) and to determine Rate Rider 5 based on the FEI Amalco harmonized rate schedules and volumes (FEI Amalco Rate Schedules 1, 1B, 1U, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23) when rate harmonization occurs. The projected credit RSAM rider of $0.026/GJ effective January 1, 2014 and applicable to FEI Amalco, is provided on Schedule 32 of Appendix J-1. The actual RSAM Rider that will be in place will be determined when rate harmonization occurs.

- To consolidate the December 31, 2013 balances in the FEVI GCVA and the FEFN GCRA gas cost deferral accounts, with the balances in the FEI and FEW Midstream Cost Reconciliation Accounts to form the FEI Amalco Midstream Cost Reconciliation Account, and to consolidate the December 31, 2013 balances in the FEI and FEW Commodity Cost Reconciliation Accounts to form the FEI Amalco Commodity Cost Reconciliation Account, both effective January 1, 2014. A discussion of the amalgamated cost of gas and the proposed allocation and recovery of costs as between Commodity and Midstream can be found in Section 9."

The FEU have also provided the Figure 8.1 on page 156 of the Application that shows the Pre-Amalgamation margin related deferral accounts and the post-Amalgamation/Common Rates margin related deferral accounts.

76.1 Please provide details of the mechanics of how the post-Amalgamation deferral accounts shown as CCRA, MCRA and RSAM in Figure 8-1 will function going forward.

Please include in your response the following information:

1. Ratebase exclusion and reasons for exclusion (if any),
2. Interest/AFUDC bearing and the period when interest accumulates and for how long,
3. Over what period is the account to be amortized,

4. When does the deferral account start collecting balances and when is the account forecast to cease collecting balances,
5. Why as well as when does the deferral account start amortizing and what is the anticipated amortization period (how long),
6. Estimated total amount to be deferred.

Response:

The FEU have provided the requested details below for each of the deferral accounts identified in Figure 8-1. To clarify, these accounts will each follow the same treatment as is currently approved through Commission Order G-44-12 for the 2012/2013 RRA. The same principles and mechanisms will be extended from the individual entity accounts to the amalgamated accounts.

RSAM

1. The entire balance is included in rate base on a forecast basis (no exclusions).
2. The RSAM account itself is non-interest or AFUDC bearing as the account is included in rate based on a forecast basis. As a result, any variance between the annual forecast and actual RSAM balances will be subject to deferred interest treatment which is consistent with the currently approved treatment.
3. This account is recovered from customers through a rate rider over three years. This account is designed to recover 1/3 of the cumulative RSAM deferral balance at the end of each year into the next year's rates (via a rate rider).
4. The deferral account would be available to collect balances immediately upon amalgamation and the use of this account would continue indefinitely.
5. The deferral account would start "amortizing" or recovering from customers immediately as it would be recovering the previous balances built up in the individual company RSAM accounts. Again, it would recover 1/3 of the cumulative RSAM deferral balance at the end of each year into the next year's rates (via a rate rider).
6. The FEU cannot forecast an amount to be deferred as the additions to this account are the result of variances in actual and forecast customer use.

CCRA

1. The entire balance is included in rate base on a forecast basis (no exclusions).
2. The CCRA account itself is non-interest or AFUDC bearing as the account is included in rate base on a forecast basis. As a result, any variance between the annual forecast and actual

CCRA balances will be subject to deferred interest treatment which is consistent with the currently approved treatment.

3. This account is recovered from customers over the prospective twelve month period each time the commodity rate is reset.
4. The deferral account would be available to collect balances immediately upon amalgamation and the use of this account would continue indefinitely.
5. The deferral account would start "amortizing" or recovering from customers immediately as it would be recovering the previous balances built up in the individual company CCRA accounts. Again, it would be recovered over the prospective twelve month period.
6. The FEU cannot forecast an amount to be deferred as the additions to this account are the result of changes in the actual commodity costs from the forecasted rate.

MCRA

1. The entire balance is included in rate base on a forecast basis (no exclusions).
2. The MCRA account itself is non-interest or AFUDC bearing as the account is included in rate base on a forecast basis. As a result, any variance between the annual forecast and actual MCRA balances will be subject to deferred interest treatment which is consistent with the currently approved treatment.
3. This account is designed to recover 1/3 of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates (via a rate rider).
4. The deferral account would be available to collect balances immediately upon amalgamation and the use of this account would continue indefinitely.
5. The deferral account would start "amortizing" or recovering from customers immediately as it would be recovering the previous balances built up in the individual company MCRA accounts. Again, it would recover 1/3 of the cumulative MCRA deferral balance at the end of each year into the next year's midstream rates (via a rate rider).
6. The FEU cannot forecast an amount to be deferred as the additions to this account are the result of midstream cost variances and volume-related variances due to differences between the forecast and actual consumption.

76.2 If the mechanics of the post-Amalgamation deferral accounts for the Margin related deferral accounts vary from that approved in the 2012 RRA Decision, please explain the differences and the reasons for each difference.

Response:

The mechanics of the post-Amalgamation deferral accounts for the Margin related deferral accounts will not vary from that approved in Order No. G-44-12 pertaining to the FEU's 2012 and 2013 Revenue Requirements Application.

77.0 Reference: Deferral Account Requests

Exhibit B-3, Section 8.2.1.2, p 154 – 157 Figure 8-1 and 8-3

Proposed Deferral Accounts

The FEU Evidence states: "Proposed changes to and discontinuances of Margin Related deferral accounts, as well as the request for new deferral accounts and the disposition of the RSDA, are outlined in Figure 8-1 and Table 8-3 below. Please note that Table 8-3 is limited to the deferral account changes required for amalgamation and postage stamp rates. All other deferral accounts, as provided in Schedules 24 and 25 of Appendix J-1, will continue as currently approved or proposed in the 2012-13 RRA, and require no change for the purpose of amalgamation and postage stamp rates."

77.1 Please provide details of the mechanics of how the proposed post-Amalgamation deferral accounts shown in Figure 8-3 will function going forward.

Please include in your response the following information:

1. Ratebase exclusion and reasons for exclusion (if any),
2. Interest/AFUDC bearing and the period when interest accumulates and for how long,
3. Over what period is the account to be amortized,
4. When does the deferral account start collecting balances and when is the account forecast to cease collecting balances,
5. Why as well as when does the deferral account start amortizing and what is the anticipated amortization period (how long),
6. Estimated total amount to be deferred.

Response:

The FEU have provided the requested details for each of the new deferral accounts identified in Table 8-3.

Amalgamation Costs Deferral Account

1. The entire balance is included in rate base, no exclusions.
2. This account would not bear interest or AFUDC because it is in rate base and will earn the allowed rate of return.

3. The amortization period for this account will be determined in the next Revenue Requirements proceeding.
4. The deferral account will start collecting balances as costs are incurred to effect the amalgamation. The expected date on which the account will cease to collect balances is December 31, 2014.
5. As noted above, the amortization period will be determined in the next Revenue Requirements proceeding. It is expected that this account will begin amortization in 2014.
6. As noted in Section 8.2.1.2, the FEU forecast gross additions of approximately $2.0 million for this account.

Company Use and Unaccounted for Gas Cost Variance Account

1. The entire balance is included in rate base (no exclusions).
2. This account would not bear interest or AFUDC since it is a rate base account.
3. The account would be amortized in rates over a one year period.
4. The deferral account could start collecting balances January 1, 2014 and would be ongoing.
5. Once a balance has accrued, the deferral account would start amortizing at the next point in time when delivery rates are reset. Again, it would be amortized over a one year period.
6. Consistent with other variance accounts, the FEU do not forecast an amount to be deferred as the account only captures variances between the actual company use and unaccounted for gas costs incurred and the forecast costs embedded in the amalgamated O&M expense.

Amalgamation and Rate Design Application Costs

1. The entire balance is non-rate base as the costs for this Application were not embedded within the approved 2012/2013 Revenue Requirement Application.
2. This account would earn AFUDC until the balance is added to rate base.
3. The amortization period for this account will be more appropriately determined in a future revenue requirement when recovery is sought from customers.
4. The deferral account has already begun collecting balances for this Application and it is forecast these costs will be incurred through 2013.
5. See point 3.

6. The FEU forecast gross additions of approximately $1.5 million for this account.

Fort Nelson Phase-In Rate Rider

1. The entire balance is non-rate base as it is simply an allocation of the existing RSDA balance within FEVI which is also a non-rate base deferral account.
2. This account would attract interest until the balance is fully returned to customers.
3. The account is to be returned to customers over 15 years.
4. The deferral account does not collect balances, but rather receives a one-time allocation from the existing FEVI RSDA account January 1, 2014.
5. The deferral account would start being returned to customers in 2014 to phase in the total amalgamation/postage stamp-related rate increase over 15 years.
6. The suggested amount needed in the deferral account to appropriately mitigate FEFN customers' rates is $18.9 million, including interest.

77.2 If the mechanics of the **Other Rate Base** post-Amalgamation deferral accounts vary from that approved in the 2012 RRA Decision, please explain the differences and the reasons for each difference.

Response:

The deferral accounts discussed in the response to BCUC IR 2.77.1 are all new deferral accounts and were, therefore, not considered or approved in the 2012 RRA Decision.

77.3 Please explain why Figure 8-3 the following description related to the Fort Nelson Phase-In Rate Rider Account, "Non-rate base account, attracting AFUDC. Rider mechanism as discussed in Section 8.2.1.2.4." where Section 8.2.1.2.4 does not exist? Where is Section 8.2.1.2.4 of the application? If the Section does not exist please provide a description of the Rider mechanism.

Response:

The Section referenced in Table 8-3 is referring to the discussion on the FEFN Phase-In Rate Rider Deferral Account included on Page 155 and embedded within Section 8.2.1.2 of the Rate Design Application. To clarify, as shown in the discussion on Page 155, the requested account would be a non-rate base account attracting <u>interest</u> and not attracting <u>AFUDC</u> as shown in Table 8-3.

77.4 Please explain why Figure 8-3 the following description related to the RSDA disposition states "December 31, 2013 balance in the non-rate base RSDA account returned to Mainland customers through a rate rider as discussed in Section 8.2.1.2.5.." where Section 8.2.1.2.5 does not exist? Where is Section 8.2.1.2.5 of the application? If the Section does not exist please provide a description of the RSDA disposition mechanism.

Response:

The section referenced in Table 8-3 is referring to the discussion on RSDA (Disposition) included on page 155 and embedded within Section 8.2.1.2 of the Application.

78.0 Reference: Special Agreements and Policies

Exhibit B-3-1, Appendix K-2, pp. 3-4; Appendix E-18-19

Draft Order – Special Agreements

In response to question 142.3, the FEU provided a table showing the midstream costs of each service area under postage stamp and regional midstream rate structures. In their response to 142.5, the FEU state: "The regional midstream costs presented on line B are a fair representation of the cost of midstream services assigned to each region under the current regionalized rate design models"

78.1 Please file a copy of the Storage and Delivery Agreement (SDA) between FEVI and FEI, and the Amending Agreement to the SDA, for Mount Hayes LNG service.

Response:

Please refer to Attachment 78.1 (FEVI's Tariff Supplement No.4).

78.2 Please confirm that the above agreements would be discontinued if the amalgamation and common rates option were to be approved.

Response:

Confirmed. See Draft Order, item 2.I.iv., where the FEU sought the discontinuance of "the Storage and Delivery Agreement (SDA) between FEVI and FEI, and the Amending Agreement to SDA, for the Mount Hayes LNG service."

78.3 Please file all of the existing agreements listed on in Appendix K-2, p. 3, section 2, g. (i&ii).

Response:

Please refer to Attachment 78.3a which contains the Transportation Service Agreement and Peaking Gas Management Services Agreement, as amended, between FEVI and the Vancouver Island Gas Joint Venture; and Attachment 78.3b which contains the Transportation Service Agreement between FEVI and British Columbia Hydro and Power Authority (BC Hydro); the Peaking Agreement, as amended, between FEVI and BC Hydro; and Capacity Assignment Agreement, as amended, between FEVI, FEI and BC Hydro (Tariff Supplements No. 1, 2 and 3 respectively).

78.3.1 Please file the blacklined version, showing all amendments made to all of the existing agreements requested in the question above.

Response:

The FEU cannot blackline amendments to these existing agreements at this time as no amendments have been agreed to. The FEU are in discussions with both the VIGJV and BC Hydro to amend the agreements if amalgamation is approved. While preliminary discussions have commenced with both parties, these discussions cannot be and will not be completed until a decision on this Application is made and certainty as to whether amalgamation will occur is determined. The FEU will file both amended agreements prior to January 1, 2014 for Commission approval if amalgamation is approved. As indicated in the Application (Exhibit B-3), page 135, footnote 171, the agreements and associated GT&Cs, including the Transmission Transportation Service Tariff, for BC Hydro and VIGJV will be filed once the agreements are signed.

79.0 Reference: Special Agreements and Policies

Exhibit B-9-1 Attachment 1.2

Shared Services Agreement – Proposed Form of Agreement for Amalco

In response to BCUC IR 1.3 the FEU have filed a blacklined version of the Shared Services agreement as proposed for an amalgamated entitly

On page 4 of the agreement the FEU have revised Section 3.1 to read as follows:

"~~TGI~~FEI agrees to pay to ~~Terasen~~FHI for the Services to be provided and for a proportionate share of the common expenses incurred by ~~Terasen~~FHI such as shareholder expenses and director compensation the amount of $~~9,022,000~~12,279,413 per annum on a take or-pay basis." [emphasis added]

79.1 Please explain the reason for the change from $9.022 million to $12.28. Please provide and explain the calculation used to derive the $12.28 million.

Response:

The $12.28 million is not a change as the "Shared Services Agreement - Proposed Form of Agreement for Amalco" is a new agreement with the new amalgamated entity. The new fee is simply the addition of the previously applied for and approved fees for each utility: FEI ($11.031 million); FEVI ($1.196 million); and FEW ($0.050 million). The individual amounts were applied for and approved for each company in the 2012-2013 Revenue Requirements application. There has not been any change in the services provided by either FHI or Fortis Inc. nor the fees charged in total. The difference between these amounts and the amount in the agreement is a mathematical error and has been updated in the agreement and blacklined corrected version provided in Attachment 79.1. The corrected amount of $12,277,400 has been incorporated into the agreement. A further blacklined change is included in Attachment 79.1 which addresses the response to BCUC IR 2.79.2.

79.2 Where in the application has the FEU indicated the reason for this change and has the FEU applied to the Commission to change the amount in the agreement?

Response:

Please refer to the response to BCUC IR 2.79.1.

On page SCA-1 of Schedule A – Description of Services the FEU have made the following additions as underlined:

SERVICES PROVIDED BY FORTIS INC. ("FORTIS") <u>WHICH BENEFIT FEI</u>

<u>In addition to the specific services described above, FEI receives the benefit of the expert advice and experience of Fortis executives.</u>

79.3 Why was this revision made?

<u>Response:</u>

This revision was made for consistency purposes to mirror the language used to describe the general governance and oversight services provided by FHI which language is contained in Schedule A under the heading "Services Provided by FHI" subheading "General Governance & Oversight Services" and which states "In addition to the services described below, FEI receives the benefit of the expert advice and experience of FHI executives…". Please also refer to the response to BCUC IR 2.79.1.

This change appears to be opinion and does not describe the services as intended

79.4 What would be the FEU position on deleting the additional language on page SCA-1?

<u>Response:</u>

The FEU would be willing to delete this additional language. It was added as clarification and does not represent new services to be provided. It is not integral to describing the services provided by Fortis Inc., as immediately following this statement there is a detailed list of the services provided by Fortis Inc.

80.0 Reference: Special Agreements and Policies

Exhibit B-9-1 Attachment 1.3

Transfer Pricing Policy and Code of Conduct

The FEU have filed the company's existing Transfer Pricing Policy (TPP) and Code of Conduct (COC) as requested in response to BCUC IR1 1.3.

80.1 Please review both the TPP and COC and indicate what revisions may be required for the proposed amalgamated entity and provide reasons for those revisions.

Response:

No revisions to the TPP or the COC are required for the proposed amalgamated entity because the amalgamation does not result in a change to the pricing of resources and services being provided to Non-Regulated Businesses ("NRBs") by the amalgamated entity under the TPP or a change in the use of utility resources for unregulated activities or the relationships between the amalgamated entity and NRBs under the COC. Additionally, the fees charged between FEI, FEVI and FEW were shared on a shared services model which allocated common resources based on customers, headcount or other similar allocators rather than the TPP.

80.2 Please provide a blacklined version of both the TPP and COC showing the proposed revisions.

Response:

There are no proposed revisions to the TPP or the COC.

Attachment 1.4

Date: 10/07/2012

FORTIS BC

PIPELINE SYSTEM MAP

Attachment 2.1

REFER TO LIVE SPREADSHEET

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 16.1

(Provided in electronic format only due to
document size and in order to conserve paper)

FORTISBC ENERGY INC.
FORT NELSON SERVICE AREA
GENERAL TERMS AND CONDITIONS

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Deleted: Stating Terms and Conditions and Rates for Gas Service

Deleted: in the Fort Nelson Service Area of British Columbia

Deleted: This Tariff is available for public inspection at:
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Deleted: Operations Centre
Deleted: 16705 Fraser Highway
Deleted: Surrey. B.C.
Deleted: V4N 0E8
Deleted: - and -
Deleted: FortisBC Energy Inc.
Deleted: Fort Nelson Service Area
Deleted: 3901 Nahanni Drive
Deleted: Fort Nelson, B.C.
Deleted: V0C 1R0
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i

BILLING

DISCONTINUANCE OF SERVICE AND REFUSAL OF SERVICE

LIABILITY AND INDEMNITY PROVISIONS

MISCELLANEOUS PROVISIONS

DIRECT PURCHASE AGREEMENTS

COMMODITY UNBUNDLING

BIOMETHANE RATE OFFERING

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Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Deleted: For definitions, please refer to the FortisBC Energy Tariff under the General Terms and Conditions section.¶

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Basic Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge – calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what FortisBC Energy will 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. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.

Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Commodity Unbundling Service	Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.
Conversion Factor	Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.
Customer	Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.
Day	Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.
Delivery Point	Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.
Delivery Pressure	Means the pressure of the Gas at the Delivery Point.
First Nations	Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.
Franchise Fees	Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations (i) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the *Indian Act*), (ii) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), or (iii) relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).

FortisBC Energy	Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number xxxxxxx.
FortisBC Energy System	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time for distribution services.
Gas	Means natural gas (including odorant added by FortisBC Energy) and propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
***General Terms & Conditions of* FortisBC Energy**	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.
Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.
Main	Means pipes used to carry Gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.
Meter Set	Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.

Midstream Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.
Month	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.
Municipal Operating Fees	Has the same meaning as Franchise Fees.
Other Service	Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.
Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Profitability Index	The revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time.
Rate Schedule	Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.

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Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.
Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.
Thermal Metering	Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.
Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.
Year	Means a period of 12 consecutive Months.
10^3m^3	Means 1,000 cubic metres.

Deleted: General Terms and Conditions¶
¶
For General Terms and Conditions of service for the Fort Nelson Service Area, please refer to the FortisBC Energy Tariff under the General Terms and Conditions section.

Areas Served by FortisBC Energy

These General Terms and Conditions of FortisBC Energy refer to the following areas served by FortisBC Energy: Mainland, Fort Nelson, Vancouver Island and Whistler.

Mainland Area Means the areas including, but not limited to, the following locations and surrounding areas of

Abbotsford	New Westminster
Anmore	North Vancouver City
Belcarra	North Vancouver Dist.
Burnaby	Pitt Meadows
Chilliwack	Port Coquitlam
Coquitlam	Port Moody
Delta	Richmond
Harrison Hot Springs	Squamish
Hope	Surrey
Kent	Vancouver
Langley City	West Vancouver
Langley District	White Rock
Maple Ridge	
Matsqui	
Mission	
Armstrong	Nelson
Ashcroft	Okanagan Falls
Bear Lake	Oliver
Cache Creek	100 Mile House
Castlegar	108 Mile House
Chase	150 Mile House
Chetwynd	Osoyoos
Christina Lake	Oyama
Clinton	Peachland
Coldstream	Penticton

Mainland Area (continued)

Collettville	Prince George
Craigmont	Princeton
Falkland	Quesnel
Ferguson Lake	Revelstoke
Fruitvale	Robson

Gibralter Mines
Grand Forks
Greenlake
Greenwood
Hedley

Hixon
Honeymoon Creek
Hudson's Hope
Kamloops
Kelowna

Keremeos
Lac La Hache
Lakeview Heights
Logan Lake
Lumby

MacKenzie
Merritt
Midway
Montrose
Naramata

Rossland
Salmo
Salmon Arm
Savona
Shelley

Sorrento
Spallumcheen
Summerland
Trail
Vernon

Warfield
Westbank
Westwold
Williams Lake
Winfield

Woodsdale

Cranbrook
Creston
Elkford
Fernie
Galloway

Jaffray
Kimberley
Sparwood
Yahk

Fort Nelson Area Means the areas including, but not limited to, the following locations and surrounding areas of

Fort Nelson
Prophet River

Vancouver Island and Whistler Areas

Means the areas including, but not limited to, the following locations and surrounding areas of

Campbell River
Central Saanich
Colwood
Comox
Courtenay

Cumberland
Duncan
Esquimalt
Gibsons
Highlands

Ladysmith
Langford
Lantzville
Metchosin
Nanaimo

North Cowichan
North Saanich
Oak Bay
Parksville
Pemberton

Port Alberni
Powell River
Qualicum Beach
Saanich
Sechelt

Sechelt Indian Band
Sidney
Sooke
Squamish
Sunshine Coast

Victoria
View Royal
Whistler

PART A

DISTRIBUTION SALES

and

SERVICE

1. Application Requirements

1.1 Requesting Services - A Person requesting FortisBC Energy

(a) to provide Gas Service,

(b) to provide a new Service Line,

(c) to re-activate an existing Service Line,

(d) to transfer an existing account,

(e) to change the type of Service provided, or

(f) to make alterations to an existing Service Line or Meter Set

must apply to FortisBC Energy at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 Required Documents - An applicant for

(a) Residential Service may be required to sign an application and a Service Agreement provided by FortisBC Energy,

(b) Commercial Service may be required to sign an application and a Service Agreement provided by FortisBC Energy, and

(c) Service on other Rate Schedules must sign the applicable Service Agreement provided by FortisBC Energy.

1.3 Separate Premises / Businesses - If an applicant is requesting Service from FortisBC Energy at more than one Premises, or for more than one separately operated business, the applicant will be considered a separate Customer for each of the Premises and businesses. For the purposes of this provision, FortisBC Energy will determine whether or not any building contains one or more Premises or any business is separately operated.

1.4 Required References - FortisBC Energy may require an applicant for Service to provide reference information and identification acceptable to FortisBC Energy.

1.5 Rental Premises - In the case of rental Premises, FortisBC Energy may

(a) require an owner of rental Premises or its agent who wishes FortisBC Energy to contract directly with a Tenant to enter into an agreement with FortisBC Energy defining the responsibilities of the owner or agent for payment for Service to the Premises,

(b) contract directly with the owner or agent of the rental Premises as a Customer of FortisBC Energy with respect to any or all Services to the Premises, or

(c) contract directly with each Tenant as a Customer of FortisBC Energy.

1.6 Refusal of Application - FortisBC Energy may refuse to accept an application for Service for any of the reasons listed in Section 23 (Discontinuance of Service and Refusal of Service).

2. Agreement to Provide Service

2.1 Service Agreement - The agreement for Service between a Customer and FortisBC Energy will be

(a) the oral or written application of the Customer which has been approved by FortisBC Energy and which is deemed to include the General Terms and Conditions, or

(b) a Service Agreement signed by the Customer.

2.2 Customer Status - A Person becomes a Customer of FortisBC Energy when FortisBC Energy

(a) approves the Person's application for Service, or

(b) provides Service to the Person.

A Person who is being provided Service by FortisBC Energy but who has not applied for Service shall be served in accordance with these General Terms and Conditions.

2.3 No Assignment / Transfer - A Customer may not transfer or assign an agreement for Service without the written consent of FortisBC Energy.

3. Conditions on Use of Service

3.1 Authorized Consumption - A Customer must not increase the maximum rate of consumption of Gas delivered to it by FortisBC Energy from that which may be consumed by the Customer under the applicable Rate Schedule nor significantly change its connected load without the written approval of FortisBC Energy, which approval will not be unreasonably withheld.

3.2 Unauthorized Sale / Supply / Use - Unless authorized in writing by FortisBC Energy, a Customer must not sell or supply Gas supplied to it by FortisBC Energy to other Persons or use Gas supplied to it by FortisBC Energy for any purpose other than as specified in the Service Agreement.

4. Rate Classification

4.1 Rate Classification - Subject to Section 4.2 (a) (Special Contracts and Tariff Supplements), Customers may be served under any Rate Schedule for which they meet the applicability criteria as set out in the appropriate Rate Schedule.

4.2 Special Contracts and Tariff Supplements - In exceptional circumstances, special contracts and tariff supplements may be negotiated between FortisBC Energy and the Customer and submitted for British Columbia Utilities Commission approval where

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that service to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the Customer on-system.

4.3 Periodic Review - FortisBC Energy may

(a) conduct periodic reviews of the quantity of Gas delivered and the rate of delivery of Gas to a Customer to determine which Rate Schedule applies to the Customer, and

(b) change the Customer's charge to the appropriate charge, or

(c) change the Customer to the appropriate Rate Schedule.

5. Application Fee and Charges

5.1 Application Fee - An applicant for Service must pay the applicable application fee set out in the Standard Fees and Charges Schedule.

5.2 Application Fee for Manifold Meters and Vertical Subdivisions - Where a new Service Line is required to serve more than one Customer at a Premises and the Service is provided with Gas meters connected to a meter manifold, the application fee for manifold meters set out in the Standard Fees and Charges Schedule will apply. Where a new Service Header is required to serve a Vertical Subdivision, the application fee set out in the Standard Fees and Charges Schedule will apply.

5.3 Waiver of Application Fee - The application fee

(a) will be waived by FortisBC Energy if Service to a Customer is reactivated after it was discontinued for any of the reasons described in Section 13.2 (Right to Restrict), and

(b) may be waived by FortisBC Energy if a Landlord requires Gas Service for a short period between the time a previous Tenant moves out and a new Tenant moves in.

5.4 Reactivation Charges - If

(a) Service is terminated

(i) at the request of a Customer, or

(ii) for any of the reasons described in Section 23 (Discontinuance of Service and Refusal of Service), or

(iii) to permit Customers to make alterations to their Premises, and

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year, the applicant for reactivation must pay the greater of

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

5.5 Identifying Load or Premises Served by Meter Sets - If a Customer requests FortisBC Energy to identify the Meter Set that serves the Premises and/or load after the Meter Set was installed, the Customer will pay the cost FortisBC Energy incurs in re-identifying the Meter Set where

(a) the Meter Set is found to be properly identified, or

(b) the Meter Set is found to be improperly identified as a result of Customer activity, including

(i) a change in the legal civic address of the Premises,

(ii) renovating or partitioning the Premises, or

(iii) rerouting Gas lines after the Delivery Point.

6. Security for Payment of Bills

6.1 Security for Payment of Bills - If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(a) be less than $50, and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Gas by the Customer or applicant.

6.2 Interest - FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. Subject to Section 6.5, if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed, and

(b) on a deposit held by FortisBC Energy in a form other than cash.

6.3 Refund of Deposit - When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

6.4 Unclaimed Refund - If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, becomes the absolute property of FortisBC Energy.

6.5 Application of Deposit - If a Customer's bill is not paid when due, FortisBC Energy may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC Energy applies the security deposit or calls on the equivalent form of security, FortisBC Energy may, under Section 23 (Discontinuance of Service and Refusal of Service), discontinue Service to the Customer for failure to pay for Service on time.

6.6 Replenish Security Deposit - If a Customer's security deposit or equivalent form of security is called upon by FortisBC Energy towards paying an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before FortisBC Energy will reconnect or continue Service to the Customer.

6.7 Failure to Pay - Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC Energy may, in FortisBC Energy's discretion, result in discontinuance or refusal of Service as set out in Section 23 (Discontinuance of Service and Refusal of Service).

7. Term of Service Agreement

7.1 Initial Term for Residential and Commercial Service - If a Customer is being provided Residential or Commercial Service, the initial term of the Service Agreement

(a) when a new Service Line is required will be one Year, or

(b) when a Main Extension is required will be for a period of time fixed by FortisBC Energy not exceeding the number of Years used to calculate the revenue in the Main Extension economic test used in Section 12 (Main Extensions).

7.2 Initial Term for Gas Service other than Residential or Commercial Service - If a Customer is being provided Gas Service other than Residential or Commercial Service, the initial term of the Service Agreement will be as specified in the Service Agreement or as specified in the appropriate Rate Schedule.

7.3 Transfer to Residential or Commercial Service - If a Customer is being provided Gas Service other than Residential or Commercial Service and transfers to Residential or Commercial Service, the initial term of the Service Agreement will be determined by the criteria set out in Section 7.1 (Initial Term for Residential and Commercial Service). A Customer may only transfer Service from one Rate Schedule to another Rate Schedule once a Year.

7.4 Renewal of Agreement - Unless

(a) the Service Agreement or the applicable Rate Schedule specifies otherwise,

(b) the Service Agreement is terminated under Section 8 (Termination of Service Agreement),

(c) a refund has been made under Section 9.2 (Refund of Charges), or

(d) the Service Agreement is for Seasonal Service,

the Service Agreement will be automatically renewed at the end of its initial term from Month to Month for Residential or Commercial Service, and from Year to Year for all other types of Gas Service.

8. Termination of Service Agreement

8.1 Termination by Customer - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC Energy at least 48 Hours notice.

8.2 Continuing Obligation - The Customer is responsible for, and must pay for, all Gas delivered to the Premises and is responsible for all damages to and loss of Meter Sets or other FortisBC Energy property on the Premises until the Service Agreement is terminated.

8.3 Effect of Termination - The Customer is not released from any previously existing obligations to FortisBC Energy under the Service Agreement by terminating the agreement.

8.4 Sealing Service Line - After receiving a termination notice for a Premises and after a reasonable period of time during which a new Customer has not applied for Gas Service at the Premises, FortisBC Energy may seal off the Service Line to the Premises.

8.5 Termination by FortisBC Energy - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC Energy may terminate the Service Agreement for any reason by giving the Customer at least 48 Hours written notice.

9. Delayed Consumption

9.1 Additional Charges - If a Customer has not consumed Gas

(a) within 2 Months after the installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the minimum charge for each billing period after that, and

(b) within one Year after installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the Customer the full cost of construction and installation of the Service Line and Meter Set less the total of the minimum charges billed to the Customer to that date.

9.2 Refund of Charges - If a Customer who has paid the charges for a Service Line under Section 9.1(b) (Additional Charges) consumes Gas in the second Year after installation of the Service Line, FortisBC Energy will refund to the Customer the payments made under Section 9.1(b) (Additional Charges). If a refund is made under Section 9.2 (Refund of Charges), the term of the Service Agreement will be one Year from the time the Customer begins consuming Gas.

10. Service Lines

10.1 Provided Installation - If FortisBC Energy's Main is adjacent to the Customer's Premises, FortisBC Energy

(a) will designate the location of the Service Lines on the Customer's Premises and determine the amount of space that must be left unobstructed around them,

(b) will install for Rate 1 and 2 Customers the Service Line from the Main to the Meter Set on the Customer's Premises at no additional cost to the Customer provided

(i) the Service Line follows the route which is the most suitable to FortisBC Energy,

(ii) the estimated direct cost of the Service Line does not exceed the Service Line Cost Allowance set out in the Standard Fees and Charges Schedule, and

(iii) the distance from the front of the Customer's building or machinery to the meter does not exceed 1.5 metres;

(c) will charge Rate 1 and 2 Customers for the estimated direct construction costs in excess of the Service Line Cost Allowance set out in the Standard Fees and Charges Schedule, and

(d) will perform an economic test for Rate 3 and larger Customers and for any Customers connecting to a Service Header including Vertical Subdivisions, and, when the Profitability Index of the test is less than 0.8, will charge the Customer a contribution sufficient to achieve a minimum Profitability Index of 0.8. The economic test will be discounted cash flow test, similar to the economic test for Main Extensions set out in Section 12.

10.2 Extended Installation - The Customer may make application to FortisBC Energy to extend the Service Line beyond that described in Section 10.1 (Provided Installation) part (b) (iii). Upon approval by FortisBC Energy and agreement for payment by the Customer of the additional costs, FortisBC Energy will extend the Service Line only if it is on the route approved by FortisBC Energy.

10.3 Customer Requested Routing - If

(a) FortisBC Energy's Main is adjacent to the Customer's Premises, and

(b) the Customer requests that its piping or Service Line enter its Premises at a different point of entry or follow a different route from the point or route designated by FortisBC Energy,

FortisBC Energy may charge the Customer for all additional costs as determined by FortisBC Energy to install the Service Line in accordance with the Customer's request.

10.4 Temporary Service - A Customer applying for Temporary Service must pay FortisBC Energy in advance for the costs which FortisBC Energy estimates it will incur in the installation and subsequent removal of the facilities necessary to supply Gas to the Customer.

10.5 Winter Construction - If an applicant or Customer applies for Service which requires construction when, in FortisBC Energy's opinion, frost conditions may exist, FortisBC Energy may postpone the required construction until the frost conditions no longer exist.

If FortisBC Energy carries out the construction, the applicant or Customer may be required to pay all costs in excess of the Service Line Cost Allowance which are incurred due to the frost conditions.

10.6 Additional Connections - If a Customer requests more than one Service Line to the Premises, on the same Rate Schedule, FortisBC Energy may install the additional Service Line and may charge the Customer the Application Fee set out in the Standard Fees and Charges Schedule, as well as the full cost (including overheads) for the Service Line installation. FortisBC Energy will bill the additional Service Line from a separate meter and account. If the additional Service Line is requested by a spouse, contractor, employee, agent or partner of the existing Customer, the same charges will apply.

10.7 Easement Required - If an intervening property is located between the Customer's Premises and FortisBC Energy's Main, the Customer is responsible for the costs of obtaining an easement in favour of FortisBC Energy and in a form specified by FortisBC Energy, for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying Gas to the Customer.

10.8 Ownership - FortisBC Energy owns the entire Service Line from the Main up to and including the Meter Set, whether it is located inside or outside the Customer's Premises. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.

10.9 Maintenance - FortisBC Energy will maintain the Service Line, subject to section 24.2 (Responsibility Before Delivery Point)..

10.10 Supply Cut Off - If the supply of Gas to a Customer's Premises is cut off for any reason, FortisBC Energy is not required to remove the Service Line from the Customer's property or Premises

10.11 Damage Notice - The Customer must advise FortisBC Energy immediately of any damage occurring to the Service Line.

10.12 Prohibition - A Customer must not construct any permanent structure over a Service Line or install any air intake openings or sources of ignition which contravene government regulations, codes or FortisBC Energy policies.

10.13 No Unauthorized Changes - No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other Persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line

(a) must be approved in writing by FortisBC Energy, and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer.

10.14 Site Preparation - The Customer will be responsible for all necessary site preparation including but not limited to clearing building materials, construction waste, equipment, soil and gravel piles over the proposed service line route to the standards established by FortisBC Energy. FortisBC Energy may recover any additional costs associated with delays or site visits necessitated by inadequate or substandard site preparation by the Customer.

11. Meter Sets & Metering

11.1 Installation - In order to bill the Customer for Gas delivered, FortisBC Energy will install one or more Meter Sets on the Customer's Premises. Unless approved by FortisBC Energy, all Meter Sets will be located outside the Customer's Premises at locations designated by FortisBC Energy.

11.2 Measurement - The quantity of Gas delivered to the Premises will be metered using apparatus approved by Consumer and Corporate Affairs Canada. The amount of Gas registered by the Meter Set during each billing period will be converted to Gigajoules in accordance with the *Electricity and Gas Inspection Act* and rounded to the nearest one-tenth of a Gigajoule.

11.3 Testing Meters - If a Customer applies for the testing of a Meter Set and

(a) the Meter Set is found to be recording incorrectly, the cost of removing, replacing and testing the meter will be borne by FortisBC Energy subject to Section 24.4 (Responsibility for Meter Set), and

(b) if the testing indicates that the Meter Set is recording correctly, as defined by the *Electricity and Gas Inspection Act*, the Customer must pay FortisBC Energy for the cost of removing, replacing and testing the Meter Set as set out in the Standard Fees and Charges Schedule.

11.4 Defective Meter Set - If a Meter Set ceases to register, FortisBC Energy will estimate the volume of Gas delivered to the Customer according to the procedures set out in Section 16.6 (Incorrect Register).

11.5 Protection of Equipment - The Customer must take reasonable care of and protect all Meter Sets and related equipment on the Customer's Premises. The Customer's responsibility for expense, risk and liability with respect to all Meter Sets and related equipment is set out in Section 24.4 (Responsibility for Meter Set).

11.6 No Unauthorized Changes - No Meter Sets or related equipment will be installed, connected, moved or disconnected except by FortisBC Energy's authorized employees, contractors or agents or by other Persons with FortisBC Energy's written permission.

11.7 Removal of Meter Set - At the termination of a Service Agreement, FortisBC Energy may disconnect or remove a Meter Set from the Premises if a new Customer is not expected to apply for Service for the Premises within a reasonable time.

11.8 Customer Requested Meter Relocation or Modifications - Any change in the location of a Meter Set or related equipment, or any modifications to the Meter Set, including automatic and/or remote meter reading

(a) must be approved by FortisBC Energy in writing, and

(b) will be made at the expense of the Customer if the change or modification is requested by the Customer or necessitated by the actions of the Customer. If any of the changes to the Meter Set or related equipment require FortisBC Energy to incur ongoing incremental operating and maintenance costs, FortisBC Energy may recover these costs from the Customer through a Monthly charge.

11.9 Meter Set Consolidations - A Customer who has more than one Meter Set at the same Premises or adjacent Premises may apply to FortisBC Energy to consolidate its Meter Sets. If FortisBC Energy approves the Customer's application, the Customer will be charged the value for all plant abandoned except for Meter Sets that are removed to facilitate Meter Set consolidations. In addition, the Customer will be charged FortisBC Energy's full costs, including overheads, for any abandonment, Meter Set removal and alteration downstream of the new Meter Set. If a new Service Line is required, FortisBC Energy will charge the Customer the Application Fee. In addition, the Customer will be required to sign a release waiving FortisBC Energy's liability for any damages should the Customer decide to re-use the abandoned plant downstream of the new Meter Set.

11.10 Delivery Pressure - The normal Delivery Pressure is 1.75 kPa. FortisBC Energy may charge Customers who require Delivery Pressure at other than the normal Delivery Pressure the additional costs associated with providing other than the normal Delivery Pressure.

11.11 Customer Requested Mobile Service - The Customer will be charged the cost of providing temporary mobile Gas Service if the request for such service is made by or brought on by the actions of the Customer.

12. Main Extensions

12.1 System Expansion - FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 Ownership - All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 Economic Test - All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension.

12.4 Revenue - The projected revenue to be used in the economic test will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions throughout the applicable areas served by FortisBC Energy have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

12.5 Costs - The total costs to be used in the economic test include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 Contributions in Aid of Construction - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 Contributions Paid by Connecting Customers - The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 Refund of Contributions - A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due,

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 Extensions to Contributory Extensions - When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 Security - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12A. Alternative Energy Extensions

12A.1 **System Expansion** - FortisBC Energy will make extensions to the FortisBC Energy System using technology that produces alternative energy, in accordance with the provisions of this section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below:

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of FortisBC Energy.

12A.3 **Cost of Service Model** - All applications by Customers for service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a customer will pay for the service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between FortisBC Energy and the Customer.

12A.4 **Projected Energy Consumption/Number of Customers** - The projected energy consumption and number of customers to be used in the cost of service model will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout all areas served by FortisBC Energy have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

12B. Vehicle Fuelling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling** – FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section of the General Terms and Conditions.

The CNG and LNG Services are described below:

CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and

(b) dispensing of compressed natural gas.

LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the service charge for which will be determined pursuant to Rate Schedule 16;

(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the customer's property. The ownership includes all components of the fueling station(s).

12B.3 **Cost of Service Recovery** - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4, where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.4 **Calculation of Cost of Service** – The total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fueling station;

(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer , escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and

(d) an allowance for overhead and marketing costs relating to developing NGV Fueling Station Agreements to be recovered from the Customer.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

12B.5 **Customer's Obligation at the Expiration of Initial Term of the Service Agreement** - If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

13. Interruption of Service

13.1 Regular Supply - FortisBC Energy will use its best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures.

13.2 Right to Restrict - FortisBC Energy may require any of its Customers, at all times or between specified Hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons:

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy,

(b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems,

(c) in order to comply with any legal requirements,

(d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems,

(e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage.

13.3 Notice - FortisBC Energy will, to the extent practicable, give notice of its requirements and removal of its requirements under Section 13.2 (Right to Restrict) to its Customers by

(a) newspaper, radio or television announcement, or

(b) notice in writing that is

(i) sent through the mail to the Customer's billing address,

(ii) left at the Premises where Gas is delivered,

(iii) served personally on a Customer, or

(iv) sent by facsimile or other electronic means to the Customer, or

(c) oral communication.

13.4 Failure to Comply - If, in the opinion of FortisBC Energy, a Customer has failed to comply with any requirement under Section 13.2 (Right to Restrict), FortisBC Energy may, after providing notice to the Customer in the manner specified in Section 13.3 (Notice), discontinue Service to the Customer.

14. Access to Premises and Equipment

14.1 Access to Premises - FortisBC Energy must have a right of entry to the Customer's Premises. The Customer must provide free access to its Premises at all reasonable times to FortisBC Energy's authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning Gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of Gas delivered to the Customer, or for any other related purpose which FortisBC Energy requires.

14.2 Access to Equipment - The Customer must provide clear access to FortisBC Energy's equipment. The equipment installed by FortisBC Energy on the Customer's Premises will remain the property of FortisBC Energy and may be removed by FortisBC Energy upon termination of Service.

15. Promotions and Incentives

15.1 Promotion of Gas Appliances - FortisBC Energy may promote, sell, rent, lease, or finance natural Gas vehicle equipment, Gas appliances and related accessories and services on a cash or finance plan basis and make reasonable charges for these Services.

16. Billing

16.1 Basis for Billing - FortisBC Energy will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in the General Terms and Conditions.

16.2 Meter Measurement - FortisBC Energy will measure the quantity of Gas delivered to a Customer using a Meter Set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 Multiple Meters - Gas Service to each Meter Set will be billed separately for Customers who have more than one Meter Set on their Premises.

16.4 Estimates - For billing purposes, FortisBC Energy may estimate the Customer's meter readings if, for any reason, FortisBC Energy does not obtain a meter reading.

16.5 Estimated Final Reading - If a Service Agreement is terminated under Section 8.1 (Termination by Customer), FortisBC Energy may estimate the final meter reading for final billing.

16.6 Incorrect Register - If any Meter Set has failed to measure the delivered quantity of Gas correctly, FortisBC Energy may estimate the meter reading for billing purposes, subject to Section 19 (Back-Billing).

16.7 Bills Issued - FortisBC Energy may bill a Customer as often as FortisBC Energy considers necessary but generally will bill on a Monthly basis.

16.8 Bill Due Dates - The Customer must pay FortisBC Energy's bill for Service on or before the due date shown on the bill which will be

(a) the first business Day after the twenty-first calendar Day following the billing date, or

(b) such other period as may be agreed upon by the Customer and FortisBC Energy.

16.9 Historical Billing Information - Customers who request historical billing information may be charged the cost of processing and providing the information.

17. Thermal Energy

17.1 All references to Gas shall be deemed to include a reference to Thermal Energy. For example, Gas Service shall be deemed to include the delivery of Thermal Energy through a Meter Set. Notwithstanding the foregoing, the meaning of Gas Distribution System shall be deemed not to include a hydronic heating system that delivers energy to Residential Customers but shall include the meters that measure the amount of energy by Residential Customers in a Vertical Subdivision.

18. Section Reserved for Future Use

19. Back-Billing

19.1 When Required - FortisBC Energy may, in the circumstances specified herein, charge, demand, collect or receive from its Customers in respect of a regulated Service rendered hereunder a greater or lesser compensation than that specified in the subsisting schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or an equal payment plan billing, such adjustments do not require back-billing treatment to be applied.

19.2 Definition - Back-billing means the rebilling by FortisBC Energy for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC Energy, and may result from the conduct of an inspection under provisions of the federal statute, the *Electricity and Gas Inspection Act* ("*EGI Act*"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) stopped meter

(b) metering equipment failure

(c) missing meter now found

(d) switched meters

(e) double metering

(f) incorrect meter connections

(g) incorrect use of any prescribed apparatus respecting the registration of a meter

(h) incorrect meter multiplier

(i) the application of an incorrect rate

(j) incorrect reading of meters or data processing

(k) tampering, fraud, theft or any other criminal act.

19.3 Application of Act - Whenever the dispute procedure of the *EGI Act* is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 Billing Basis - Where metering or billing errors occur and the dispute procedure under the *EGI Act* is not invoked, the consumption and demand will be based upon the records of FortisBC Energy for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC Energy. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

19.5 Tampering / Fraud - If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC Energy's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC Energy, then the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of Sections 19.8 (Under-Billing) to 19.11 (Changes in Occupancy), below, do not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by FortisBC Energy in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC Energy on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 Remedying Problem - In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

19.7 Over-billing - In every case of over-billing, FortisBC Energy will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to FortisBC Energy on a Monthly basis, will be paid to the Customer.

19.8 Under-billing - Subject to Section 19.5 (Tampering / Fraud), above, in every case of under-billing, FortisBC Energy will back-bill the Customer for the shorter of

(a) the duration of the error; or

(b) six Months for Residential or Commercial Service; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC Energy.

19.9 Terms of Repayment - Subject to Section 19.5 (Tampering / Fraud), above, in all cases of under-billing, FortisBC Energy will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 Disputed Back-bills - Subject to Section 19.5 (Tampering / Fraud), above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, FortisBC Energy will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and FortisBC Energy may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

19.11 Changes in Occupancy - Subject to Section 19.5 (Tampering / Fraud), above, back-billing in all instances where changes of occupancy have occurred, FortisBC Energy will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the applicable over or under billing will be cancelled.

20. Equal Payment Plan

20.1 Definitions - In this Section, "equal payment plan period" means a period of twelve consecutive Months commencing with a normal meter reading date at the Customer's Premises.

20.2 Application for Plan - A Customer may apply to FortisBC Energy by mail, by telephone, by facsimile or by other electronic means to pay fixed Monthly instalments for Gas delivered to the Customer during the equal payment plan period. Acceptance of the application will be subject to FortisBC Energy finding the Customer's credit to be satisfactory.

20.3 Monthly Instalments - FortisBC Energy will fix Monthly instalments for a Customer so that the total sum of all the instalments to be paid during the equal payment plan period will equal the total amount payable for the Gas which FortisBC Energy estimates the Customer will consume during the equal payment plan period.

20.4 Changes in Instalments - FortisBC Energy may, at any time, increase or decrease the amount of Monthly instalments payable by a Customer in light of new consumption information or changes to the Rate Schedules or the General Terms and Conditions.

20.5 End of Plan - Participation in the equal payment plan may be ended at any time

(a) by the Customer giving 5 Days' notice to FortisBC Energy, or

(b) by FortisBC Energy, without notice, if the Customer has not paid the Monthly instalments as required.

20.6 Payment Adjustment - At the earlier of the end of the equal payment plan period for a Customer or the end of the Customer's participation in the plan under Section 20.5 (End of Plan), FortisBC Energy will

(a) compare the amount which is payable by the Customer to FortisBC Energy for Gas actually consumed on the Customer's Premises from the beginning of the equal payment plan period to the sum of the Monthly instalments billed to the Customer from the beginning of the equal payment plan period, and

(b) pay to the Customer or credit to the Customer's account any excess amount or bill the Customer for any deficit amount payable.

21. Late Payment Charge

21.1 Late Payment Charge - If the amount due for Service or Service Related Charges on any bill has not been received in full by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, and the unpaid balance is $15 or more, FortisBC Energy may include in the next bill to the Customer the late payment charge specified in the Standard Fees and Charges Schedule.

21.2 Equal Payment Plan - If the Monthly instalment, Service Related Charges and payment adjustment as defined under Section 20.6 (Payment Adjustments) due from a Customer billed under the equal payment plan set out in Section 20 (Equal Payment Plan) have not been received by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, FortisBC Energy may include in the next bill to the Customer the late payment charge in accordance with Section 21.1 (Late Payment Charge) on the amount due.

22. Returned Cheque Charge

22.1 Dishonoured Cheque Charge - If a cheque received by FortisBC Energy from a Customer in payment of a bill is not honoured by the Customer's financial institution for any reason other than clerical error, FortisBC Energy may include a charge specified in the Standard Fees and Charges Schedule in the next bill to the Customer for processing the returned cheque whether or not the Service has been disconnected.

23. Discontinuance of Service and Refusal of Service

23.1 Discontinuance With Notice and Refusal Without Notice - FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons:

(a) the Customer has not fully paid FortisBC Energy's bill with respect to Services on or before the due date,

(b) the Customer or applicant has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it by the specified date,

(c) the Customer or applicant has failed to pay FortisBC Energy's bill in respect of another Premises on or before the due date,

(d) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC Energy's bill, security deposit, or required increase in the security deposit in respect of another Premises which was occupied by that occupant and the Customer at the same time,

(e) the Customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to FortisBC Energy,

(f) the Customer has failed to apply for Service, or

(g) the land or portion thereof on which FortisBC Energy's facilities are, or are proposed to be, located contains contamination which FortisBC Energy, acting reasonably, determines has adversely affected or has the potential to adversely affect FortisBC Energy's facilities, or the health or safety of its workers or which may cause FortisBC Energy to assume liability for clean up and other costs associated with the contamination. If FortisBC Energy, acting reasonably, determines that contamination is present it is the obligation of the occupant of the land to satisfy FortisBC Energy that the contamination does not have the potential to adversely affect FortisBC Energy or its workers. For the purposes of this Section, "contamination" means the presence in the soil, sediment or groundwater of special waste or another substance in quantities or concentrations exceeding criteria, standards or conditions established by the British Columbia Ministry of Environment, Lands and Parks or as prescribed by present and future laws, rules, regulations and orders of any other legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the environment.

23.2 Discontinuance or Refusal Without Notice - FortisBC Energy may discontinue without notice or refuse the supply of Gas or Service to a Customer for any of the following reasons:

(a) the Customer or applicant has failed to provide reference information and identification acceptable to FortisBC Energy, when applying for Service or at any subsequent time on request by FortisBC Energy,

(b) the Customer has defective pipe, appliances, or Gas fittings in the Premises,

(c) the Customer uses Gas in such a manner as in FortisBC Energy's opinion

(i) may lead to a dangerous situation, or

(ii) may cause undue or abnormal fluctuations in the Gas pressure in FortisBC Energy's Gas transmission or distribution system,

(d) the Customer fails to make modifications or additions to the Customer's equipment which have been required by FortisBC Energy in order to prevent the danger or to control the undue or abnormal fluctuations described under paragraph (c),

(e) the Customer breaches any of the terms and conditions upon which Service is provided to the Customer by FortisBC Energy,

(f) the Customer fraudulently misrepresents to FortisBC Energy its use of Gas or the volume delivered,

(g) the Customer vacates the Premises,

(h) the Customer's Service Agreement is terminated for any reason, or

(i) the Customer stops consuming Gas on the Premises.

23.3 Application to Former Tariffs - Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

Lower Mainland - Gas Tariff,

Inland - Gas Tariff B.C.E.C. No. 2,

Columbia - Gas Tariff B.C.U.C. No.1.

BC Gas Tariff

Terasen Gas Inc. Tariff

FortisBC Energy Inc. Gas Tariff

FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff

FortisBC Energy (Vancouver Island) Inc. Gas Tariff

FortisBC Energy (Whistler) Inc. Gas Tariff

24. Limitations on Liability

24.1 Responsibility for Delivery of Gas - FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by any Customer or any Person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport Gas, or provide Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents.

24.2 Responsibility Before Delivery Point - The Customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises, and

(b) FortisBC Energy-owned facilities serving the Customer's Premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible.

24.3 Responsibility After Delivery Point - The Customer is responsible for all expense, risk and liability with respect to the use or presence of Gas after it passes the Delivery Point.

24.4 Responsibility for Meter Set - The Customer is responsible for all expense, risk and liability with respect to all Meter Sets or related equipment at the Customer's Premises unless any loss or damage is

(a) directly attributable to the negligence of FortisBC Energy, its employees, contractors or agents, or

(b) caused by or resulting from a defect in the equipment. The Customer must prove that negligence or defect.

For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by FortisBC Energy in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service Line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such Service Line(s).

24.5 Customer Indemnification - The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Customer or any Person claiming by or through the Customer or any third party caused by or resulting from the use of Gas by the Customer or the presence of Gas in the Customer's Premises, or from the Customer or Customer's employees, contractors or agents damaging FortisBC Energy's facilities.

25. Miscellaneous Provisions

25.1 Taxes - The rates and charges specified in the applicable Rate Schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which FortisBC Energy may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the Customer.

25.2 Conflicting Terms and Conditions - Where anything in these General Terms and Conditions conflicts with special terms or conditions specified under an applicable Rate Schedule or Service Agreement, then the terms or conditions specified under the Rate Schedule or Service Agreement govern.

25.3 Authority of Agents of FortisBC Energy - No employee, contractor or agent of FortisBC Energy has authority to make any promise, agreement or representation not incorporated in these General Terms and Conditions or in a Service Agreement, and any such unauthorized promise, agreement or representation is not binding on FortisBC Energy.

25.4 Additions, Alterations and Amendments - The General Terms and Conditions, fees and charges, and Rate Schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by FortisBC Energy from time to time.

25.5 Headings - The headings of the Sections set forth in the General Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of the General Terms and Conditions.

26. Direct Purchase Agreements

26.1 Collection of Incremental Direct Purchase Costs - Where FortisBC Energy incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a Customer, agent, broker or marketer, FortisBC Energy may, subject to BCUC approval, collect those costs from the Customer, agent, broker or marketer. Such costs may include the costs of arranging, acquiring or transporting substitute Gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by FortisBC Energy. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

26.2 Direct Purchase Customers Returning to FortisBC Energy System Supply - Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy,

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply,

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer, and

(c) FortisBC Energy may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

27. Commodity Unbundling Service

27.1 In the event a Customer enters into a Gas supply contract with a Marketer for Commodity Unbundling Service under Rate Schedule 1U, 2U or 3U, the following terms and conditions will apply:

(a) The Customer must sign a Notice of Appointment of Marketer as notification to FortisBC Energy that the Marketer has the authority to do what is required with respect to the Customer's enrolment in Commodity Unbundling Service, including entering into the necessary Commodity Unbundling Service agreements and related Rate Schedules. Such Notice of Appointment of Marketer shall also authorize FortisBC Energy to share with the Marketer certain historical and ongoing consumption information and to verify the Commodity Cost Recovery Charge used to bill the Customer as directed by the Marketer.

(b) FortisBC Energy shall be entitled to rely solely on communications from the Marketer with respect to the enrolment of the Customer in Commodity Unbundling Service and with respect to the termination or expiry of any contract between the Customer and Marketer.

(c) FortisBC Energy will bill the Customer a Commodity Cost Recovery Charge according to the price indicated by the Marketer. Such price must be expressed as a single fixed price per Gigajoule in Canadian dollars. Such price shall not include amounts payable by the Customer to the Marketer for services other than the Gas commodity cost. The price may only be changed by Marketer no more than once per year on the anniversary of the Customers' enrolment in Commodity Unbundling Service with such Marketer. FortisBC Energy shall have no obligation to verify that the price communicated by the Marketer is the price agreed to between the Customer and the Marketer.

(d) FortisBC Energy will continue to bill the Customer as per the billing, payment, credit and collections policies set out in these General Terms and Conditions.

(e) The Customer shall make payment to FortisBC Energy based on the total charges on the bill and under no circumstances will payments be prorated between the various charges on the bill. Payments made by Customers to FortisBC Energy pursuant to the bills rendered by FortisBC Energy shall be made without any right of deduction or set-off and regardless of any rights or claims the Customers may have against the Marketer.

(f) Non-payment of any amounts designated as Commodity Cost Recovery Charge charged on the bill shall entitle FortisBC Energy to the same recourse as non-payment of any other FortisBC Energy service charges and may result in termination of service by FortisBC Energy in accordance with these General Terms and Conditions and any applicable Rate Schedules. In the event FortisBC Energy terminates the Customer's service, the subject Customer will be removed from the Commodity Unbundling Service. Should the Customer wish to re-enrol in Commodity Unbundling Service, the Customer will be required to re-apply for service with FortisBC Energy as per the then existing General Terms and Conditions and then be required to enrol as a new participant in order to be eligible for Commodity Unbundling Service.

(g) FortisBC Energy is not responsible for the terms of any of the Customer's contract(s) with the Marketer. Provision of Commodity Unbundling Service in no way makes FortisBC Energy liable for any obligation incurred by a Marketer vis-à-vis the Customer or third parties.

(h) In the event the British Columbia Utilities Commission issues an order to FortisBC Energy to return Customers to FortisBC Energy as supplier of last resort, the Customer will be returned with no notice to the FortisBC Energy standard system supply rate with no interruption of service upon the then applicable terms and conditions of FortisBC Energy system supply service. In the event there are incremental costs associated with returning the Customer to the standard system supply rate, these costs may be recovered by FortisBC Energy directly from the Customer.

(i) The Customer's enrolment in Commodity Unbundling Service shall be on a Premises specific basis.

28. Biomethane Service

28.1 Notional Gas - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 Biomethane Physical Delivery - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 Reduced Supply - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 Price Determination - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 Biomethane Customers - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 Enrolment - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Offering** - Biomethane Service is available in all areas served by FortisBC Energy except Revelstoke

(e) **Moving** - If a Customer registered for Biomethane Service moves to a new Premises within the areas served by FortisBC Energy described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a FortisBC Energy conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy conventional Gas Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

Standard Fees and Charges Schedule

Application Fee

Existing Installation	\$25.00
New Installation	\$25.00
New Installation - Manifold Meters	\$25.00 per meter
New Installation - Vertical Subdivision	\$25.00 per meter

Service Line Cost Allowance

Other than a duplex	\$1,535.00
Duplex	\$3,070.00

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	\$20.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	\$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

Rate Schedule 1: Residential Service

Available This Rate Schedule is available to all Customers served by FortisBC Energy Fort Nelson Service Area provided adequate capacity exists in FortisBC Energy's system.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. This Rate Schedule is also applicable to thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source) and measured by a thermal meter for one premise of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed for hydronic heating.

Deleted: RATE CLASSIFICATION AND RATES

Deleted: Domestic Service

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Deleted: (a) Availability

Deleted: To firm gas supplied at One (1) point of delivery and through One (1) meter for use in approved appliances for all residential uses in single-family residences, separately metered single-family apartments or common areas serving strata lot owners of residential condominium complexes.

Deleted: Option A is applicable to any customer qualifying for Domestic Service where the primary space heating equipment utilized on the premises was purchased and installed with the assistance of a promotional incentive provided by Company. Subsequent to providing the promotional incentive, Option A is applicable:

Deleted: <#>for a term of 120 Months,¶
<#>¶
<#>to all gas bills with a billing period of approximately 30 days.¶

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Deleted: Option B is applicable to any customer qualifying for Domestic Service where the primary space heating equipment utilized on the premises was not purchased and installed with the assistance of a promotional incentive provided by Company.

*Option A: Where the customer's primary space heating equipment utilized on the premises was purchased and installed with the assistance of a promotional incentive provided by the Company:

R

R

$ 0.0407 times the amount of the promotional incentive divided by $100.

Effective September 30, 1990, Option A is closed to customers who have not availed themselves of the promotional incentive prior to that date.

Table of Charges

	Fort Nelson Service Area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X***
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

Deleted: (b) **Monthly Rate**

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Deleted: Minimum daily charge to include ¶

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Deleted: on a daily basis

Deleted: $0.5469[1] plus $0.0391

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Deleted: promotional incentive

Deleted: divided by $100.

Deleted: Next 28 Gigajoules in any month . @ $5.952[1] per Gigajoule¶
Excess of 30 Gigajoules in any month @ $5.882[1] per Gigajoule

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	Fort Nelson Service Area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation** – Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider** – Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

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Deleted: Option B: Where the customer's primary space heating equipment utilized on the premises was not purchased and installed with the assistance of a promotional incentive provided by the Company:¶
¶
Minimum daily charge to include ¶
<object>the first 2 Gigajoules/month prorated¶
on a daily basis $0.5469[1]¶
<object>¶
Next 28 Gigajoules in any month @ $5.952[1] per Gigajoule¶
Excess of 30 Gigajoules in any month @ $5.882[1] per Gigajoule¶
¶
¶

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

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Commodity Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Rider 9 (Reserved for future use.)

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. Fort Nelson Service Area have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. Fort Nelson Service Area will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.

Franchise Fee Charge - Except for the Option A surcharge, a Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge, any charge under Option A and the Franchise Fee Charge.

Deleted: Notes:¶
¶
1. Rate includes the Revenue Stabilization Adjustment Amount applicable to Fort Nelson Service Area Rate 1 Customers. For the period January 1, 2012 to December 31, 2012, the Revenue Stabilization Adjustment Amount is a credit of $0.011 per Gigajoule.¶

Deleted: FortisBC Energy Inc. Fort Nelson Service Area Tariff¶
General Terms and Conditions¶

Deleted: General Service¶
(a) Availability¶
Available to all consumers.¶
¶
(b) Monthly Rate¶
General Service¶
Rate 2.1: Applicable to customers who have consumed less than 6,000 Gigajoules in the twelve months ended with the most recent October billing.¶
¶
Minimum daily service charge¶
<object>to include the first 2 Gigajoules/month prorated¶
on a daily basis $1.1521[1]¶
<object>¶
Next 298 Gigajoules in any month @ $6.252[1] per Gigajoule¶
Excess of 300 Gigajoules in any month @ $6.166[1] per Gigajoule¶
¶
Rate 2.2: Applicable to customers who have consumed a quantity of gas equal to or greater than 6,000 Gigajoules in the twelve months ended with the most recent October billing.¶
¶
Minimum monthly service charge¶
<object>to include the first 2 Gigajoules/month prorated¶
on a daily basis $1.1521[1]¶
<object><object>¶
Next 298 Gigajoules in any month @ $6.252[1] per Gigajoule¶
Excess of 300 Gigajoules in any month @ $6.166[1] per Gigajoule¶
¶
With respect to customers who do not have a twelve-month consumption record, the Company shall assign the applicable rate based on a mutually agreed upon annual volume forecast.¶

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¶
1. Rate includes the Revenue Stabilization Adjustment Amount applicable to Fort Nelson Service Area Rate 2.1 and 2.2 Customers. For the period January 1, 2012 to December 31, 2012, the Revenue Stabilization Adjustment Amount is a credit of $0.011 per Gigajoule.

Deleted: Order No.: G-27-12 Issued By: Diane Roy, Director, Regulatory Affairs¶
¶
Effective Date: April 1, 2012¶
¶
BCUC Secretary: Original signed by Alanna Gillis Fourth Revision of Page 2

Rate Schedule 2: Small Commercial Service

Available

This Rate Schedule is available in all areas served by FortisBC Energy provided, adequate capacity exists in FortisBC Energy's System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

Table of Charges

	Fort Nelson Area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

	Fort Nelson Area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. Fort Nelson Service Area have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. Fort Nelson Service Area will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.

Deleted: Natural Gas Vehicle Fuel Service¶
Rate 2.3 Applicable to firm gas supplied for the purpose of being further compressed and dispensed as fuel to operate vehicles.¶
¶
<object><object>Minimum monthly service charge¶
to include the first 2 Gigajoules . $35.19¶
<object>¶
Next 298 Gigajoules in any month @ $7.003 per Gigajoule¶
Excess of . 300 Gigajoules in any month @ $6.915 per Gigajoule¶
¶
¶
The Company may make a promotional grant of up to $1,700 per vehicle towards the vehicle conversion costs of retail customers using public refuelling facilities within the Company's service area. The amount of each grant shall not exceed the four (4) year projected net revenue from each vehicle.¶
¶

Deleted: FortisBC Energy Inc. Fort Nelson Service Area Tariff
General Terms and Conditions

Deleted: Compression/Dispensing Service
Rate 2.4: In addition to gas service rendered and charged for under Rate 2.3, Company may provide on-site compression and refuelling services at rates which are fully compensatory and filed, as required, with the British Columbia Utilities Commission.

(c) General Conditions

Except for Compression/Dispensing Service - Rate 2.4, service under Rates 2.1 to 2.3 is available on a monthly contract which shall continue from month to month thereafter until either party shall give to the other party at least ten (10) days prior to the expiration of any such month a written notice of desire to terminate the same, whereupon at the expiration of such month, it shall cease and terminate.

Contract for Compression/Dispensing Service - Rate 2.4 shall be for a period of not less than five (5) years with no seasonal or temporary disconnection of service.

Contract shall be automatically extended from year to year thereafter unless cancelled by either the Company or the Buyer in accordance with the terms of the Service Agreement.

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Effective Date: April 1, 2012

BCUC Secretary: Original signed by Alanna Gillis Fourth Revision of Page 2.1

(i)

Deleted: FortisBC Energy Inc. Fort Nelson Service Area Tariff¶
General Terms and Conditions¶

Deleted: Industrial Service¶
(a) Availability¶
For industrial use only. To firm gas, no portion of which shall be re-sold, supplied at one point of delivery and through one meter.¶
¶
It may be supplied to tenants of the consumer on the consumer's premises through the consumer's system. Consumers under this rate may be restricted by the Company to a total of 790 GJ per day, at the discretion of the Company.¶
¶
(b) Monthly Rate¶
Rate 3.1: Applicable to customers with forecasted consumption for the ensuing calendar year of a quantity of gas less than 96,000 Gigajoules.¶
¶
<#>Delivery Charge per Gigajoule¶
¶
First 20 Gigajoules in any month @ $2.910¶
Next 260 Gigajoules in any month @ $2.690¶
Excess over 280 Gigajoules in any month @ $2.174¶
<object>¶
<#>Gas Cost Recovery Charge per Gigajoule @ $ 3.553¶
¶
<#>Minimum Monthly Delivery Charge $ 1,826.00¶
¶
<#>Rider 5 per Gigajoule $ (0.011)¶
¶
Rate 3.2: Applicable to customers with forecasted consumption for the ensuing calendar year of a quantity of gas equal to or in excess of 96,000 Gigajoules, but less than 360,000 Gigajoules.¶
¶
<#>Delivery Charge per Gigajoule¶
¶
First 20 Gigajoules in any month @ $2.910¶
Next 260 Gigajoules in any month @ $2.690¶
Excess over 280 Gigajoules in any month @ $2.174¶
<object>¶
<#>Gas Cost Recovery Charge per Gigajoule @ $ 3.553¶
¶
<#>Minimum Monthly Delivery Charge $ 1,826.00¶
¶
Rider 5 per Gigajoule $ (0.011)

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Effective Date: April 1, 2012¶
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BCUC Secretary:

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(i)

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General Terms and Conditions¶

Deleted: Rate 3.3: Applicable to customers with forecasted consumption for the ensuing calendar year of a quantity of gas equal to or in excess of 360,000 Gigajoules.¶
¶
<#>Delivery Charge per Gigajoule¶
¶
First 20 Gigajoules in any month @ $2.910¶
Next 260 Gigajoules in any month @ $2.690¶
Excess over 280 Gigajoules in any month @ $2.174¶
<object>¶
<#>Gas Cost Recovery Charge per Gigajoule @ $ 3.553¶
¶
<#>Minimum Monthly Delivery Charge $ 1,826.00¶
¶
<#>Rider 5 per Gigajoule $ (0.011)¶
¶
Delivery Margin Related Rider¶
¶
Rider 5 Revenue Stabilization Adjustment Charge - Applicable to Fort Nelson Service Area Rate 3.1, 3.2 and 3.3 Customers for the period January 1, 2012 to December 31, 2012.¶
¶
Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. Fort Nelson Service Area have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. Fort Nelson Service Area will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.¶
(c) General Conditions¶
<#>This classification and rate is available only on an annual contract, which shall continue from year to year thereafter until either party shall give to the other party at least thirty (30) days prior to the expiration of any such year a written notice of desire to terminate the same, whereupon at the expiration of such year, it shall cease and terminate.¶
¶
<#>No equipment which has been served with gas under this rate shall be served with gas under any other rate, during any calendar year while the customer's agreement for service under this rate is in force, without the permission of the Company.¶
¶
No equipment which has been served with gas under this rate shall be served with gas under any other rate, during any calendar year whil ...

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Effective Date: April 1, 2012¶
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BCUC Secretary: Original signed by Alanna Gillis Fourth Revision of Page 3.1¶

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Rate Schedule 25

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FORT NELSON SERVICE AREA¶
¶
¶
RATE SCHEDULE 25¶
GENERAL FIRM TRANSPORTATION¶
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TABLE OF CONTENTS¶
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Section Page¶
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Notes:¶
<object>1. Station 2 Daily Price means the Westcoast Station 2 Daily Midpoint Price as set out in Gas Daily's Daily Price Survey for Gas delivered to Westcoast Station 2 in Canadian dollars per Gigajoule.

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¶
Effective Date: March 1, 2011¶
¶
BCUC Secretary: *Original signed by E.M. Hamilton* Original Page 4.

Rate Schedule 3: Large Commercial Service

Available

This Rate Schedule is available to all Customers served by FortisBC Energy provided, adequate capacity exists in FortisBC Energy's System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

Table of Charges

	Fort Nelson Area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

	Fort Nelson Area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. Fort Nelson Service Area have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. Fort Nelson Service Area will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved. C

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Deleted: FortisBC Energy Inc. Fort Nelson Service Area Tariff¶
Rate Schedule 25¶

Deleted: GENERAL FIRM TRANSPORTATION AGREEMENT¶
¶
This Agreement is dated the ____ day of ____________, 20__, between FortisBC Energy Inc. ("FortisBC Energy") and ______________________________________ (the "Shipper").¶
¶
WHEREAS:¶
¶
A. FortisBC Energy owns and operates the FortisBC Energy System; and¶
¶
B. The Shipper has requested that FortisBC Energy arrange for the transportation of Gas on a firm basis through the FortisBC Energy System to ______________________ located in or near ________________________ in the Province of British Columbia in accordance with Rate Schedule 25.¶
¶
¶
NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the terms, conditions and limitations contained herein, the parties agree as follows:¶
¶
<#>Specific Information¶
¶
Daily Transportation Quantity (DTQ): ______________ Gigajoules per day ¶
¶
Customer Agent and/or Group, if applicable: ______________________________¶
¶
Commencement Date: ______________________________¶
¶
Expiry Date: ______________________________¶
(only specify an expiry date if term of Transportation Agreement is not to automatically continue from year to year as set out in section 9.2 of Rate Schedule 25 or if Shipper is not End-User)¶
¶
End-User: ______________________________¶
(insert name of End-User only if it differs from name of Shipper)¶
¶
Delivery Point: ______________________________¶
¶
Gauge pressure at the Delivery Point: ______________________________¶
¶
Interconnection Point: The point at (______ km-post _______) where the Transporter's pipeline system in British Columbia interconnects with the FortisBC Energy Syste ...

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Effective Date: March 1, 2011¶
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BCUC Secretary: *Original signed by E.M. Hamilton* Original Page 4.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
GENERAL TERMS AND CONDITIONS

Deleted: GAS TARIFF

Deleted: Standard Terms and Conditions and Rates for Gas Service

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¶
Effective Date: March 1, 2011¶
¶
BCUC Secretary: *Original signed by E.M. Hamilton* Original Frontispiece

Deleted: Tariff

Deleted: This Tariff is available for public inspection at:

FortisBC Energy Operations Centre
16705 Fraser Highway
Surrey, B.C.
V4N 0E8

- and -

FortisBC Energy (Vancouver Island) Inc.
320 Garbally Road
Victoria, B.C.
V8T 2K1

The Tariff is also available for inspection on-line at the FortisBC Energy website at www.fortisbc.com.

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Effective Date: March 1, 2011

BCUC Secretary: *Original signed by E.M. Hamilton* Original Page i

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Section **Page**

PART B TRANSMISSION TRANSPORTATION SERVICE B i

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PART A

DISTRIBUTION SALES

SERVICE

Definitions

In these Terms and Conditions:

(a) **Basic Charge** - Means a fixed charge required to be paid by a Customer or Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge - calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places. C/N

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(b) **Biogas -** Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.

(c) **Biomethane -** Means Biogas purified or upgraded to pipeline quality gas.

(d) **Biomethane Service** - Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales C/N

(e) **British Columbia Utilities Commission** - Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to C

(i) any commission that is a successor to such commission, and

(ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia

(f) **Carbon Offsets** - Means what FortisBC Energy will 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. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.

(g) **Commercial Service** - Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations. C

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(h) **Commodity Cost Recovery Charge** - Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

(i) **Commodity Unbundling Service** - Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.

(j) **Customer** - Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy. C

(k) **Day** - Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement. C

(l) **Delivery Point** - Means the outlet of the Meter Set unless otherwise specified in the Service Agreement. C

(m) **Delivery Pressure** - Means the pressure of the Gas at the Delivery Point. C

(n) **First Nations** - Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.

(o) **Franchise Fees** - Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations

i. for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the Indian Act),

ii. relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the Indian Act), or

iii. relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the Indian Act).

(p) **FortisBC Energy** - Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number xxxxxxx. C

(q) **FortisBC Energy System** - Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time for distribution services

(r) **Gas** - Means natural gas (including odorant added by FortisBC Energy) and propane. C

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(s) **Gas Service** - Means the delivery of Gas through a Meter Set.

General Terms & Conditions of FortisBC Energy - Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.

(t) **Gigajoule** - Means a measure of energy equal to one billion joules used for billing purposes.

(u) **Heat Content** - Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).

(v) **Hour** - Means any consecutive 60 minute period.

(w) **Landlord** - Means a Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.

(x) **Main** - Means pipes used to carry Gas for general or collective use for the purposes of distribution.

(y) **Main Extension** - Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.

(z) **Marketer** - Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.

(aa) **Meter Set** - Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.

(bb) **Midstream Cost Recovery Charge** - Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

(cc) **Month** - Means a period of time, for billing purposes, of 27 to 34 consecutive Days.

(dd) **Municipal Operating Fees -** Has the same meaning as Franchise Fees.

(ee) **Other Service -** Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.

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Formatted: List Paragraph, No bullets or numbering (ff) **Other Service Charges -** Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.

(gg) **Person** - Means a natural person, partnership, corporation, society, unincorporated entity or body public. C

(hh) **Premises** - Means a building, a separate unit of a building, or machinery together with the surrounding land. C

(ii) **Profitability Index** - Means the revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time. C

(jj) **Rate Schedule** - Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service. C

(kk) **Residential Service** - Means firm Gas Service provided to the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments. C

(ll) **Rider** - Means an additional charge or credit attached to a rate.

(mm) **Seasonal Service** - Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st. C

(nn) **Service** - Means the provision of Gas Service or other service by FortisBC Energy. C

(oo) **Service Agreement** - Means an agreement between FortisBC Energy and a Customer for the provision of Service. C

(pp) **Service Header** - Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main. C

(qq) **Service Line** - Means the portion of the pipeline used for the transporting of Gas from FortisBC Energy's Main distribution pipeline to the inlet of the Meter Set. In the case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises. C

(rr) **Service Related Charges** - Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges. C

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(tt) **Tenant** - Means a Person who has the temporary use and occupation of real property owned by another Person. C

(uu) **Thermal Energy** - Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.

(vv) **Thermal Metering** - Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.

(ww) **Vertical Subdivision** - Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor. C

(xx) **Year** - Means a period of 12 consecutive Months. C

(yy) **10^3m^3** - Means **1,000 cubic metres.**

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Areas Served by FortisBC Energy

These General Terms and Conditions of FortisBC Energy refer to the following areas served by FortisBC Energy: Mainland, Fort Nelson, Vancouver Island and Whistler.

Mainland Area Means the areas including, but not limited to, the following locations and surrounding areas of

Abbotsford
Anmore
Belcarra
Burnaby
Chilliwack

Coquitlam
Delta
Harrison Hot Springs
Hope
Kent

Langley City
Langley District
Maple Ridge
Matsqui
Mission

New Westminster
North Vancouver City
North Vancouver Dist.
Pitt Meadows
Port Coquitlam

Port Moody
Richmond
Squamish
Surrey
Vancouver

West Vancouver
White Rock

Armstrong
Ashcroft
Bear Lake
Cache Creek
Castlegar

Chase
Chetwynd
Christina Lake
Clinton
Coldstream

Nelson
Okanagan Falls
Oliver
100 Mile House
108 Mile House

150 Mile House
Osoyoos
Oyama
Peachland
Penticton

Mainland Area (continued)

Collettville
Craigmont
Falkland
Ferguson Lake
Fruitvale

Gibralter Mines
Grand Forks
Greenlake
Greenwood
Hedley

Hixon
Honeymoon Creek
Hudson's Hope
Kamloops
Kelowna

Keremeos
Lac La Hache
Lakeview Heights
Logan Lake
Lumby

MacKenzie
Merritt
Midway
Montrose
Naramata

Prince George
Princeton
Quesnel
Revelstoke
Robson

Rossland
Salmo
Salmon Arm
Savona
Shelley

Sorrento
Spallumcheen
Summerland
Trail
Vernon

Warfield
Westbank
Westwold
Williams Lake
Winfield

Woodsdale

Cranbrook
Creston
Elkford
Fernie
Galloway

Jaffray
Kimberley
Sparwood
Yahk

Fort Nelson Area

Means the areas including, but not limited to, the following locations and surrounding areas of

Fort Nelson
Prophet River

Vancouver Island and Whistler Areas

Means the areas including, but not limited to, the following locations and surrounding areas of

Campbell River
Central Saanich
Colwood
Comox
Courtenay

Cumberland
Duncan
Esquimalt
Gibsons
Highlands

Ladysmith
Langford
Lantzville
Metchosin
Nanaimo

North Cowichan
North Saanich
Oak Bay
Parksville
Pemberton

Port Alberni
Powell River
Qualicum Beach
Saanich
Sechelt

Sechelt Indian Band
Sidney
Sooke
Squamish
Sunshine Coast

Victoria
View Royal
Whistler

1. Application Requirements

1.1 **Requesting Services** - A Person requesting FortisBC Energy

(a) to provide Gas Service,

(b) to provide a new Service Line,

(c) to re-activate an existing Service Line,

(d) to transfer an existing account,

(e) to change the type of Service provided, or

(f) to make alterations to an existing Service Line or Meter Set

must apply to FortisBC Energy at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 **Required Documents** - An applicant for

(a) Residential Service may be required to sign an application and a Service Agreement provided by FortisBC Energy,

(b) Commercial Service may be required to sign an application and a Service Agreement provided by FortisBC Energy, and

(c) Service on other Rate Schedules must sign the applicable Service Agreement provided by FortisBC Energy.

1.3 **Separate Premises / Businesses** - If an applicant is requesting Service from FortisBC Energy at more than one Premises, or for more than one separately operated business, the applicant will be considered a separate Customer for each of the Premises and businesses. For the purposes of this provision, FortisBC Energy will determine whether or not any building contains one or more Premises or any business is separately operated.

1.4 **Required References** - FortisBC Energy may require an applicant for Service to provide reference information and identification acceptable to FortisBC Energy.

1.5 **Rental Premises** - In the case of rental Premises, FortisBC Energy may

(a) require an owner of rental Premises or its agent who wishes FortisBC Energy to contract directly with a Tenant to enter into an agreement with FortisBC Energy defining the responsibilities of the owner or agent for payment for Service to the Premises,

(b) contract directly with the owner or agent of the rental Premises as a Customer of FortisBC Energy with respect to any or all Services to the Premises, or

(c) contract directly with each Tenant as a Customer of FortisBC Energy.

1.6 **Refusal of Application** - FortisBC Energy may refuse to accept an application for Service for any of the reasons listed in Section 21 (Discontinuance of Service and Refusal of Service).

2. Agreement to Provide Service

2.1 **Service Agreement** - The agreement for Service between a Customer and FortisBC Energy will be

(a) the oral or written application of the Customer which has been approved by FortisBC Energy and which is deemed to include the Standard Terms and Conditions, or

(b) a Service Agreement signed by the Customer.

2.2 **Customer Status** - A Person becomes a Customer of FortisBC Energy when FortisBC Energy

(a) approves the Person's application for Service, or

(b) provides Service to the Person.

A Person who is being provided Service by FortisBC Energy but who has not applied for Service shall be served in accordance with these Standard Terms and Conditions.

2.3 **No Assignment / Transfer** - A Customer may not transfer or assign an agreement for Service without the written consent of FortisBC Energy.

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3. Conditions on Use of Service

3.1 **Authorized Consumption** - A Customer must not increase the maximum rate of consumption of Gas delivered to it by FortisBC Energy from that which may be consumed by the Customer under the applicable Rate Schedule nor significantly change its connected load without the written approval of FortisBC Energy, which approval will not be unreasonably withheld.

3.2 **Unauthorized Sale / Supply / Use** - Unless authorized in writing by FortisBC Energy, a Customer must not sell or supply Gas supplied to it by FortisBC Energy to other Persons or use Gas supplied to it by FortisBC Energy for any purpose other than as specified in the Service Agreement.

4. Rate Classification

4.1 **Rate Classification** - Subject to Section 4.2 (a) (Special Contracts and Tariff Supplements), Customers may be served under any Rate Schedule for which they meet the applicability criteria as set out in the appropriate Rate Schedule.

4.2 **Special Contracts and Tariff Supplements** - In exceptional circumstances, special contracts and tariff supplements may be negotiated between FortisBC Energy and the Customer and submitted for British Columbia Utilities Commission approval where

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that Service to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the Customer on-system.

4.3 **Periodic Review** - FortisBC Energy may

(a) conduct periodic reviews of the quantity of Gas delivered and the rate of delivery of Gas to a Customer to determine which Rate Schedule applies to the Customer, and

(b) change the Customer's charge to the appropriate charge, or

(c) change the Customer to the appropriate Rate Schedule.

5. Application and Service Line Installation Fees and Charges

5.1 **Application Fee** - An applicant for Service must pay the applicable Application Fee set out in the Special Rate Schedule.

5.2 **Application Fee for Manifold Meters and Vertical Subdivisions** - Where a new Service Line is required to serve more than one Customer at a Premises and the Service is provided with Gas meters connected to a meter manifold, the Application Fee for manifold meters set out in the Special Rate Schedule will apply. Where a new Service Header is required to serve a Vertical Subdivision, the Application Fee set out in the Special Rate Schedule will apply.

5.3 **Waiver of Application Fee** - The Application Fee

(a) will be waived by FortisBC Energy if Service to a Customer is reactivated after it was discontinued for any of the reasons described in Section 13.2 (Right to Restrict); and

(b) may be waived by FortisBC Energy if a Landlord requires Gas Service for a short period between the time a previous Tenant moves out and a new Tenant moves in.

5.4 **Reactivation Charges** - If

(a) Service is terminated

(i) at the request of a Customer, or

(ii) for any of the reasons described in Section 21 (Discontinuance of Service and Refusal of Service), or

(iii) to permit Customers to make alterations to their Premises, and

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year, the applicant for reactivation must pay the greater of

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

5.5 **Identifying Load or Premises Served by Meter Sets** - If a Customer requests FortisBC Energy to identify the Meter Set that serves the Premises and/or load after the Meter Set was installed, the Customer will pay the cost FortisBC Energy incurs in re-identifying the Meter Set where

(a) the Meter Set is found to be properly identified, or

(b) the Meter Set is found to be improperly identified as a result of Customer activity, including

(i) a change in the legal civic address of the Premises,

(ii) renovating or partitioning the Premises, or

(iii) rerouting Gas lines after the delivery point.

6. Security for Payment of Bills

6.1 **Security for Payment of Bills** - If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(a) be less than $50, and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive months consumption of Gas by the Customer or applicant.

6.2 **Interest** - FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Special Rate Schedule. Subject to Section 6.5, if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed, and

(b) on a deposit held by FortisBC Energy in a form other than cash.

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6.3 **Refund on Deposit** - When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

6.4 **Unclaimed Refund** - If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, becomes the absolute property of FortisBC Energy.

6.5 **Application of Deposit** - If a Customer's bill is not paid when due, FortisBC Energy may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC Energy applies the security deposit or calls on the equivalent form of security, FortisBC Energy may, under Section 21 (Discontinuance of Service and Refusal of Service), discontinue Service to the Customer for failure to pay for Service on time.

6.6 **Replenish Security Deposit** - If a Customer's security deposit or equivalent form of security is called upon by FortisBC Energy towards paying an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before FortisBC Energy will reconnect or continue Service to the Customer.

6.7 **Failure to Pay** - Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC Energy may, in FortisBC Energy's discretion, result in discontinuance or refusal of Service as set out in Section 21 (Discontinuance of Service and Refusal of Service).

7. Term of Service Agreement

7.1 **Initial Term for Residential and Commercial Service** - If a Customer is being provided Residential or Commercial Service, the initial term of the Service Agreement

(a) when a new Service Line is required will be one Year, or

(b) when a Main Extension is required will be for a period of time fixed by FortisBC Energy not exceeding the number of Years used to calculate the revenue in the Main Extension economic test used in Section 12 (Main Extensions).

7.2 **Initial Term for Gas Service Other than Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service, the initial term of the Service Agreement will be as specified in the Service Agreement or as specified in the appropriate Rate Schedule.

7.3 **Transfer to Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service and transfers to Residential or Commercial Service, the initial term of the Service Agreement will be determined by the criteria set out in Section 7.1 (Initial Term for Residential and Commercial Service). A Customer may only transfer Service from one Rate Schedule to another Rate Schedule once a Year.

7.4 **Renewal of Agreement** - Unless

(a) the Service Agreement or the applicable Rate Schedule specifies otherwise,

(b) the Service Agreement is terminated under Section 8 (Termination of Service Agreement),

(c) a refund has been made under Section 9.2 (Refund of Charges), or

(d) the Service Agreement is for Seasonal Service,

the Service Agreement will be automatically renewed at the end of its initial term from Month to Month for Residential or Commercial Service, and from Year to Year for all other types of Gas Service.

8. Termination of Service Agreement

8.1 **Termination by Customer** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC Energy at least 48 Hours notice.

8.2 **Continuing Obligation** - The Customer is responsible for, and must pay for, all Gas delivered to the Premises and is responsible for all damages to and loss of Meter Sets or other FortisBC Energy property on the Premises until the Service Agreement is terminated.

8.3 **Effect of Termination** - The Customer is not released from any previously existing obligations to FortisBC Energy under the Service Agreement by terminating the agreement.

8.4 **Sealing Service Line** - After receiving a termination notice for a Premises and after a reasonable period of time during which a new Customer has not applied for Gas Service at the Premises, FortisBC Energy may seal off the Service Line to the Premises.

8.5 **Termination by FortisBC Energy** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC Energy may terminate the Service Agreement for any reason by giving the Customer at least 48 Hours notice.

9. Delayed Consumption

9.1 **Additional Charges** - If a Customer has not consumed Gas

(a) within 2 Months after the installation of the Service Line to the Customer's Premises, FortisBC Energy may change the minimum charge for each billing period after that, and

(b) within one Year after installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the Customer the full cost of construction and installation of the Service Line and Meter Set less the total of the minimum charges billed to the Customer to that date.

9.2 **Refund of Charges** - If a Customer who has paid the charges for a Service Line under Section 9.1(b) (Additional Charges) consumes Gas in the second Year after installation of the Service Line, FortisBC Energy will refund to the Customer the payments made under Section 9.1(b) (Additional Charges). If a refund is made under Section 9.2 (Refund of Charges), the term of the Service Agreement will be one Year from the time of the Customer begins consuming Gas.

10. Service Lines

10.1 **Provided Installation** - If FortisBC Energy's Main is adjacent to the Customer's Premises, FortisBC Energy

(a) will designate the location of the Service Lines on the Customer's Premises and determine the amount of space that must be left unobstructed around them;

(b) will install for Residential General Service Rate No. 1, Small Commercial Service Rate No. 1, and Small Commercial Service Rate No. 2 Customers the Service Line from the Main to the Meter Set on the Customer's Premises at no additional cost to the Customer provided

(i) the Service Line follows the route which is the most suitable to FortisBC Energy,

(ii) the estimated direct cost of the Service Line does not exceed the Service Line Cost Allowance set out in the Special Rate Schedule, and

(iii) the distance from the front of the Customer's building or machinery to the meter does not exceed 1.5 metres;

(c) will charge Residential General Service Rate No. 1, Small Commercial Service Rate No. 1, and Small Commercial Service Rate No. 2 Customers for the estimated direct construction costs in excess of the Service Line Cost Allowance set out in the Special Rate Schedule; and

(d) will perform an economic test for Large Commercial Service Rate No. 1, Large Commercial Service Rate No. 2, Large Commercial Service Rate No. 3 and larger Customers and for any Customers connecting to a Service Header including Vertical Subdivisions, and, when the Profitability Index is less than 0.8, will charge the Customer a contribution sufficient to achieve a minimum Profitability Index of 0.8. The economic test will be discounted cash flow test, similar to the economic test for Main Extensions set out in Section 12.

10.2 **Extended Installation** - The Customer may make application to FortisBC Energy to extend the Service Line beyond that described in Section 10.1 (Provided Installation) (b) (iii). Upon approval by FortisBC Energy and agreement for payment by the Customer of the additional costs, FortisBC Energy will extend the Service Line only if it is on the route approved by FortisBC Energy.

10.3 **Customer Requested Routing** - If

(a) FortisBC Energy's Main is adjacent to the Customer's Premises, and

(b) the Customer requests that its piping or Service Line enter its Premises at a different point of entry or follow a different route from the point or route designated by FortisBC Energy,

FortisBC Energy may charge the Customer for all additional costs as determined by FortisBC Energy to install the Service Line in accordance with the Customer's request.

10.4 **Temporary Service** - A Customer applying for Temporary Service must pay FortisBC Energy in advance for the costs which FortisBC Energy estimates it will incur in the installation and subsequent removal of the facilities necessary to supply Gas to the Customer.

10.5 **Winter Construction** - If an applicant or Customer applies for Service which requires construction when, in FortisBC Energy's opinion, frost conditions may exist, FortisBC Energy may postpone the required construction until the frost conditions no longer exist.

If FortisBC Energy carries out the construction, the applicant or Customer may be required to pay all costs in excess of the Service Line Cost Allowance which are incurred due to the frost conditions.

10.6 **Additional Connections** - If a Customer requests more than one service connection to the Premises, on the same Rate Schedule, FortisBC Energy may install the additional Service Line and may charge the Customer the Application Fee set out in the Special Rate Schedule, as well as the full cost (including overheads) for the Service Line installation. FortisBC Energy will bill the additional Service Connection from a separate meter and account. If the additional Service Connection is requested by a spouse, contractor, employee, agent or partner of the existing Customer, the same charges will apply.

10.7 **Easements and Right-of-Way** - If the Customer is not the owner of the Premises or there is intervening property between the Premises and FortisBC Energy's Mains, the Customer shall obtain for FortisBC Energy from the proper owner, in a form satisfactory to FortisBC Energy, the necessary consent or easement in writing for the installation and maintenance in said Premises and in or about such intervening property, of all necessary facilities for supplying Gas. FortisBC Energy reserves the right to acquire rights-of-way if deemed desirable by FortisBC Energy. The Customer is responsible for the costs of obtaining an easement in favour of FortisBC Energy and in a form specified by FortisBC Energy for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying Gas to the Customer.

10.8 **Ownership** - FortisBC Energy owns the entire Service Line from the Main up to and including the Meter Set, whether it is located inside or outside the Customer's Premises.

10.9 **Maintenance** - FortisBC Energy will maintain the Service Line.

10.10 **Supply Cut Off** - If the supply of Gas to a Customer's Premises is cut off for any reason, FortisBC Energy is not required to remove the Service Line from the Customer's property or Premises.

10.11 **Damage Notice** - The Customer must advise FortisBC Energy immediately of any damage occurring to the Service Line.

10.12 **Prohibition** - A Customer must not construct any permanent structure over a Service Line or install any air intake openings or sources of ignition which contravene government regulations, codes or FortisBC Energy's policies.

10.13 **No Unauthorized Changes** - No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line

(a) must be approved in writing by FortisBC Energy, and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer.

10.14 **Site Preparation** - The Customer will be responsible for all necessary site preparation including but not limited to clearing building materials, construction waste, equipment, soil and gravel piles over the proposed service line route to the standards established by FortisBC Energy. FortisBC Energy may recover any additional costs associated with delays or site visits necessitated by inadequate or substandard site preparation by the Customer.

11. Meter Sets and Metering

11.1 **Installation** - In order to bill the Customer for Gas delivered, FortisBC Energy will install one or more Meter Sets on the Customer's Premises. Unless approved by FortisBC Energy, all Meter Sets will be located outside the Customer's Premises at locations designated by FortisBC Energy.

11.2 **Measurement** - The quantity of Gas delivered to the Premises will be metered using apparatus approved by Customer and Corporate Affairs Canada. The amount of Gas registered by the Meter Set during each billing period will be converted to Gigajoules in accordance with the *Electricity and Gas Inspection Act* and rounded to the nearest one-tenth of a Gigajoule.

11.3 **Testing Meters** - If a Customer applies for the testing of a Meter Set and

(a) the Meter Set is found to be recording incorrectly, the cost of removing, replacing and testing the meter will be borne by FortisBC Energy subject to Section 22.4 (Responsibility for Meter Set), and

(b) if the testing indicates that the Meter Set is recording correctly, as defined by the *Electricity and Gas Inspection Act*, the Customer must pay FortisBC Energy for the cost of removing, replacing and testing the Meter Set as set out in the Special Rate Schedule.

11.4 **Defective Meter Set** - If a Meter Set ceases to register, FortisBC Energy will estimate the volume of Gas delivered to the Customer according to the procedures set out in Section 16.6 (Incorrect Register).

11.5 **Protection of Equipment** - The Customer must take reasonable care of and protect all Meter Sets and related equipment on the Customer's Premises. The Customer's responsibility for expense, risk and liability with respect to all Meter Sets and related equipment is set out in Section 22.4 (Responsibility for Meter Set).

11.6 **No Unauthorized Changes** - No Meter Sets or related equipment will be installed, connected, moved or disconnected except by FortisBC Energy's authorized employees, contractors or agents or by other Persons with FortisBC Energy's written permission.

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11.7 **Removal of Meter Set** - As the termination of a Service Agreement, FortisBC Energy may disconnect or remove a Meter Set from the Premises if a new Customer is not expected to apply to Service for the Premises within a reasonable time.

11.8 **Customer Requested Meter Relocation or Modifications** - Any change in the location of a Meter Set or related equipment, or any modifications to the Meter Set, including automatic and/or remote meter reading

(a) must be approved by FortisBC Energy in writing, and

(b) will be made at the expense of the Customer if the change or modification is requested by the Customer or necessitated by the actions of the Customer. If any of the changes to the Meter Set or related equipment require FortisBC Energy to incur ongoing incremental operating and maintenance costs, FortisBC Energy may recover these costs from the Customer through a Monthly charge.

11.9 **Meter Set Consolidations** - A Customer who has more than one Meter Set at the same Premises or adjacent Premises may apply to FortisBC Energy to consolidate its Meter Sets. If FortisBC Energy approves the Customer's application, the Customer will be charged the value for all plant abandoned except for Meter Sets that are removed to facilitate Meter Set consolidations. In addition, the Customer will be charged FortisBC Energy's full costs, including overheads, for any abandonment, Meter Set removal and alteration downstream of the new Meter Set. If a new Service Line is required, FortisBC Energy will charge the Customer the Application Fee. In addition, the Customer will be required to sign a release waiving FortisBC Energy's liability for any damages should the Customer decide to re-use the abandoned plant downstream of the new Meter Set.

11.10 **Delivery Pressure** - The normal Delivery Pressure is 1.75 kPa. FortisBC Energy may charge Customers who require Delivery Pressure at other than the normal Delivery Pressure the additional costs associated with providing other than the normal Delivery Pressure.

11.11 **Customer Requested Mobile Service** - The Customer will be charged the cost of providing temporary mobile Gas Service if the request for such Service is made by or brought on by the actions of the Customer.

12. Main Extensions

12.1 **System Expansion** - FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 **Ownership** - All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 **Economic Test** - All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual Main Extension.

12.4 **Revenue** - The projected revenue to be used in the economic test will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star® rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

12.5 **Costs** - The total costs to be used in the economic test include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 **Contributions in Aid of Construction** - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 **Contributions Paid by Connecting Customers** - The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the Main Extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension contribution agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

12.8 **Refund of Contributions** - A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due,

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 **Extensions to Contributory Extensions** - When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security** - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12A. Alternative Energy Extensions

12A.1 **System Expansion** - FortisBC Energy will make extensions to the FortisBC Energy system using technology that produces alternative energy, in accordance with the provisions of this Section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below.

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the suns rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and Customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of FortisBC Energy.

12A.3 **Cost of Service Model** - All applications by Customers for Service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a Customer will pay for the Service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between FortisBC Energy and the Customer.

12A.4 **Projected Energy Consumption / Number of Customers** - The projected energy consumption and number of Customers to be used in the cost of service model will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the revenue projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout Vancouver Island have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

12B. Vehicle Fuelling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling –** FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section of the General Terms and Conditions.

The CNG and LNG Services are described below:

CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and

(b) dispensing of compressed natural gas.

LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the service charge for which will be determined pursuant to Rate Schedule 16;

(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the customer's property. The ownership includes all components of the fueling station(s).

12B.3 **Cost of Service Recovery** - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4, where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.4 **Calculation of Cost of Service –** The total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fueling station;

(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer , escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and

(d) an allowance for overhead and marketing costs relating to developing NGV Fueling Station Agreements to be recovered from the Customer.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

12B.5 **Customer's Obligation at the Expiration of Initial Term of the Service Agreement** - If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

13. Interruption of Service

13.1 **Regular Supply** - FortisBC Energy will use its best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures.

13.2 **Right to Restrict** - FortisBC Energy may require any of its Customers, at all times or between specified Hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy,

(b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems,

(c) in order to comply with any legal requirements,

(d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems,

(e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage.

13.3 **Notice** - FortisBC Energy will, to the extent practicable, give notice of its requirements and removal of its requirements under Section 13.2 (Right to Restrict) to its Customers by

(a) newspaper, radio or television announcement, or

(b) notice in writing that is

(i) sent through the mail to the Customer's billing address,

(ii) left at the Premises where Gas is delivered,

(iii) served personally on a Customer, or

(iv) sent by facsimile or other electronic means to the Customer, or

(c) oral communication.

13.4 **Failure to Comply** - If, in the opinion of FortisBC Energy, a Customer has failed to comply with any requirement under Section 13.2 (Right to Restrict), FortisBC Energy may, after providing notice to the Customer in the manner specified in Section 13.3 (Notice), discontinue Service to the Customer.

14. Access to Premises and Equipment

14.1 **Access to Premises** - FortisBC Energy must have a right of entry to the Customer's Premises. The Customer must provide free access to its Premises at all reasonable times to FortisBC Energy's authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning Gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of Gas delivered to the Customer, or for any other related purpose which FortisBC Energy requires.

14.2 **Access to Equipment** - The Customer must provide clear access to FortisBC Energy's equipment. The equipment installed by FortisBC Energy on the Customer's Premises will remain the property of FortisBC Energy and may be removed by FortisBC Energy upon termination of Service.

15. Promotions and Incentives

15.1 **Promotion of Gas Appliances** - FortisBC Energy may promote, sell, rent, lease, or finance natural Gas vehicle equipment, Gas appliances and related accessories and Services on a cash or finance plan basis and make reasonable charges for these Services.

16. Billing

16.1 **Basis for Billing** - FortisBC Energy will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in the Standard Terms and Conditions.

16.2 **Meter Measurement** - FortisBC Energy will measure the quantity of Gas delivered to a Customer using a Meter Set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 **Multiple Meters** - Gas Service to each Meter Set will be billed separately for Customers who have more than one Meter Set on their Premises.

16.4 **Estimates** - For billing purposes, FortisBC Energy may estimate the Customer's meter readings if, for any reason, FortisBC Energy does not obtain a meter reading.

16.5 **Estimated Final Reading** - If a Service Agreement is terminated under Section 8.1 (Termination by Customer), FortisBC Energy may estimate the final meter reading for final billing.

16.6 **Incorrect Register** - If any Meter Set has failed to measure the delivered quantity of Gas correctly, FortisBC Energy may estimate the meter reading for billing purposes, subject to Section 17 (Back-Billing).

16.7 **Bills Issued** - FortisBC Energy may bill a Customer as often as FortisBC Energy considers necessary but generally will bill on a Monthly basis.

16.8 **Bill Due Dates** - The Customer must pay FortisBC Energy's bill for Service on or before the due date shown on the bill which will be

(a) the first business Day after the twenty-first calendar Day following the billing date, or

(b) such other period as may be agreed upon by the Customer and FortisBC Energy.

16.9 **Historical Billing Information** - Customers who request historical billing information may be charged the cost of processing and providing the information.

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17. Thermal Energy

17.1 All references to Gas shall be deemed to include a reference to Thermal Energy. For example, Gas Service shall be deemed to include the delivery of Thermal Energy through a Meter Set. Notwithstanding the foregoing, the meaning of Gas Distribution System shall be deemed not to include a hydronic heating system that delivers energy to Residential Customers but shall include the meters that measure the amount of energy by Residential Customers in a Vertical Subdivision.

18. Section Reserved for Future Use

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19. Back-Billing

19.1 **When Required** - FortisBC Energy may, in the circumstances specified herein, charge, demand, collect or receive from its Customers in respect of a regulated Service rendered hereunder a greater or lesser compensation than that specified in the subsisting schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or an equal payment plan billing, such adjustments do not require back-billing treatment to be applied.

19.2 **Definition** - Back-billing means the rebilling by FortisBC Energy for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC Energy, and may result from the conduct of an inspection under provisions of the federal statute, the *Electricity and Gas Inspection Act*. The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) stopped meter

(b) metering equipment failure

(c) missing meter now found

(d) switched meters

(e) double metering

(f) incorrect meter connections

(g) incorrect use of any prescribed apparatus respecting the registration of a meter

(h) incorrect meter multiplier

(i) the application of an incorrect rate

(j) incorrect reading of meters or data processing

(k) tampering, fraud, theft or any other criminal act.

19.3 **Application of Act** - Whenever the dispute procedure of the *Electricity and Gas Inspection Act* is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 **Billing Basis** - Where metering or billing errors occur and the dispute procedure under the *Electricity and Gas Inspection Act* is not invoked, the consumption and demand will be based upon the records of FortisBC Energy for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC Energy. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

19.5 **Tampering / Fraud** - If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC Energy's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC Energy, then the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of Sections 19.8 (Under-Billing) to 19.11 (Changes in Occupancy), below, do not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by FortisBC Energy in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC Energy on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 **Remedying Problem** - In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

19.7 **Over-Billing** - In every case of over-billing, FortisBC Energy will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to FortisBC Energy on a Monthly basis, will be paid to the Customer.

19.8 **Under-Billing** - Subject to Section 19.5 (Tampering / Fraud), above, in every case of under-billing, FortisBC Energy will back-bill the Customer for the shorter of

(a) the duration of the error; or

(b) six Months for Residential or Commercial Service; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC Energy.

19.9 **Terms of Repayment** - Subject to Section 19.5 (Tampering / Fraud), above, in all cases of under-billing, FortisBC Energy will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 **Disputed Back-Bills** - Subject to Section 19.5 (Tampering / Fraud), above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, FortisBC Energy will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and FortisBC Energy may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

19.11 **Changes in Occupancy** - Subject to Section 19.5 (Tampering / Fraud), above, back-billing in all instances where changes of occupancy have occurred, FortisBC Energy will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the applicable over or under billing will be cancelled.

20. Equal Payment Plan

20.1 **Definitions** - In this Section, "equal payment plan period" means a period of twelve consecutive Months commencing with a normal meter reading date at the Customer's Premises.

20.2 **Application for Plan** - A Customer may apply to FortisBC Energy by mail, by telephone, by facsimile or by other electronic means to pay fixed Monthly instalments for Gas delivered to the Customer during the equal payment plan period. Acceptance of the application will be subject to FortisBC Energy finding the Customer's credit to be satisfactory.

20.3 **Monthly Instalments** - FortisBC Energy will fix Monthly instalments for a Customer so that the total sum of all the instalments to be paid during the equal payment plan period will equal the total amount payable for the Gas which FortisBC Energy estimates the Customer will consume during the equal payment plan period.

20.4 **Changes in Instalments** - FortisBC Energy may, at any time, increase or decrease the amount of Monthly instalments payable by a Customer in light of new consumption information or changes to the Rate Schedules or the Standard Terms and Conditions.

20.5 **End of Plan** - Participation in the equal payment plan may be ended at any time

(a) by the Customer giving 5 Days' notice to FortisBC Energy, or

(b) by FortisBC Energy, without notice, if the Customer has not paid the Monthly instalments as required.

20.6 **Payment Adjustment** - At the earlier of the end of the equal payment plan period for a Customer or the end of the Customer's participation in the plan under Section 18.5 (End of Plan), FortisBC Energy will

(a) compare the amount which is payable by the Customer to FortisBC Energy for Gas actually consumed on the Customer's Premises from the beginning of the equal payment plan period to the sum of the Monthly instalments billed to the Customer from the beginning of the equal payment plan period, and

(b) pay to the Customer or credit to the Customer's account any excess amount or bill the Customer for any deficit amount payable.

21. Late Payment Charge

21.1 **Late Payment Charge** - If the amount due for Service or Service Related Charges on any bill has not been received in full by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, and the unpaid balance is $15 or more, FortisBC Energy may include in the next bill to the Customer the late payment charge specified in the Special Rate Schedule.

21.2 **Equal Payment Plan** - If the Monthly instalment, Service Related Charges and payment adjustment as defined under Section 20.6 (Payment Adjustment) due from a Customer billed under the equal payment plan set out in Section 18 (Equal Payment Plan) have not been received by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, FortisBC Energy may include in the next bill to the Customer the late payment charge in accordance with Section 21.1 (Late Payment Charge) on the amount due.

22. Returned Cheque Charge

22.1 **Dishonoured Cheque Charge** - If a cheque received by FortisBC Energy from a Customer in payment of a bill is not honoured by the Customer's financial institution for any reason other than clerical error, FortisBC Energy may include a charge specified in the Special Rate Schedule in the next bill to the Customer for processing the returned cheque whether or not the Service has been disconnected.

23. Discontinuance of Service and Refusal of Service

23.1 **Discontinuance With Notice and Refusal Without Notice** - FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons:

(a) the Customer has not fully paid FortisBC Energy's bill with respect to Services on or before the due date,

(b) the Customer or applicant has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it by the specified date,

(c) the Customer or applicant has failed to pay FortisBC Energy's bill in respect of another Premises on or before the due date,

(d) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC Energy's bill, security deposit, or required increase in the security deposit in respect of another Premises which was occupied by that occupant and the Customer at the same time,

(e) the Customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to FortisBC Energy,

(f) the Customer has failed to apply for Service, or

(g) the land or portion thereof on which FortisBC Energy's facilities are, or are proposed to be, located contains contamination which FortisBC Energy, acting reasonably, determines has adversely affected or has the potential to adversely effect FortisBC Energy's facilities, or the health or safety of its workers or which may cause FortisBC Energy to assume liability for clean up and other costs associated with the contamination. If FortisBC Energy, acting reasonably, determines that contamination is present it is the obligation of the occupant of the land to satisfy FortisBC Energy that the contamination does not have the potential to adversely affect FortisBC Energy or its workers. For the purposes of this Section, "contamination" means the presence in the soil, sediment or groundwater of special waste or another substance in quantities or concentrations exceeding criteria, standards or conditions established by the British Columbia Ministry of Environment or as prescribed by present and future laws, rules, regulations and orders of any other legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the environment.

23.2 **Discontinuance or Refusal Without Notice** - FortisBC Energy may discontinue without notice or refuse the supply of Gas or Service to a Customer for any of the following reasons:

(a) the Customer or applicant has failed to provide reference information and identification acceptable to FortisBC Energy, when applying for Service or at any subsequent time on request by FortisBC Energy,

(b) the Customer has defective pipe, appliances, or Gas fittings in the Premises,

(c) the Customer uses Gas in such a manner as in FortisBC Energy's opinion

(i) may lead to a dangerous situation, or

(ii) may cause undue or abnormal fluctuations in the Gas pressure in FortisBC Energy's Gas transmission or distribution system,

(d) the Customer fails to make modifications or additions to the Customer's equipment which have been required by FortisBC Energy in order to prevent the danger or to control the undue or abnormal fluctuations described under paragraph (c),

(e) the Customer breaches any of the terms and conditions upon which Service is provided to the Customer by FortisBC Energy,

(f) the Customer fraudulently misrepresents to FortisBC Energy its use of Gas or the volume delivered,

(g) the Customer vacates the Premises,

(h) the Customer's Service Agreement is terminated for any reason, or

(i) the Customer stops consuming Gas on the Premises.

23.3 **Application to Former Tariffs** - Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

Lower Mainland - Gas Tariff,

Inland - Gas Tariff B.C.E.C. No. 2,

Columbia - Gas Tariff B.C.U.C. No.1.

BC Gas Tariff

Terasen Gas Inc. Tariff

FortisBC Energy Inc. Gas Tariff

FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff

FortisBC Energy (Vancouver Island) Inc. Gas Tariff

FortisBC Energy (Whistler) Inc. Gas Tariff

24. Limitations on Liability

24.1 **Responsibility for Delivery of Gas** - FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by any Customer or any Person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport Gas, or provide Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents.

24.2 **Responsibility Before Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises, and

(b) FortisBC Energy-owned facilities serving the Customer's Premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible.

24.3 **Responsibility After Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to the use or presence of Gas after it passes the Delivery Point.

24.4 **Responsibility for Meter Set** - The Customer is responsible for all expense, risk and liability with respect to all Meter Sets or related equipment at the Customer's Premises unless any loss or damage is

(a) directly attributable to the negligence of FortisBC Energy, its employees, contractors or agents, or

(b) caused by or resulting from a defect in the equipment.

The Customer must prove that negligence or defect. For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by FortisBC Energy in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service Line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such Service Line(s).

24.5 **Customer Indemnification** - The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Customer or any Person claiming by or through the Customer or any third party caused by or resulting from the use of Gas by the Customer or the presence of Gas in the Customer's Premises, or from the Customer or Customer's employees, contractors or agents damaging FortisBC Energy's facilities.

25. Miscellaneous Provisions

25.1 **Taxes** - The rates and charges specified in the applicable Rate Schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which FortisBC Energy may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the Customer.

25.2 **Conflicting Terms and Conditions** - Where anything in these Standard Terms and Conditions conflicts with special terms or conditions specified under an applicable Rate Schedule or Service Agreement, then the terms or conditions specified under the Rate Schedule or Service Agreement govern.

25.3 **Authority of Agents of FortisBC Energy** - No employee, contractor or agent of FortisBC Energy has authority to make any promise, agreement or representation not incorporated in these Standard Terms and Conditions or in a Service Agreement, and any such unauthorized promise, agreement or representation is not binding on FortisBC Energy.

25.4 **Additions, Alterations and Amendments** - The Standard Terms and Conditions, fees and charges, and Rate Schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by FortisBC Energy from time to time.

25.5 **Headings** - The headings of the Sections set forth in the Standard Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of the Standard Terms and Conditions.

26. Direct Purchase Agreements

26.1 **Collection of Incremental Direct Purchase Costs** - Where FortisBC Energy incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a Customer, agent, broker or marketer, FortisBC Energy may, subject to BCUC approval, collect those costs from the Customer, agent, broker or marketer. Such costs may include the costs of arranging, acquiring or transporting substitute Gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by FortisBC Energy. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

26.2 **Direct Purchase Customers Returning to FortisBC Energy System Supply** - Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy,

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply,

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer, and

(c) FortisBC Energy may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

27. Commodity Unbundling Service

27.1 In the event a Customer enters into a Gas supply contract with a Marketer for Commodity Unbundling Service under Rate Schedule 1U, 2U or 3U, the following terms and conditions will apply:

(a) The Customer must sign a Notice of Appointment of Marketer as notification to FortisBC Energy that the Marketer has the authority to do what is required with respect to the Customer's enrolment in Commodity Unbundling Service, including entering into the necessary Commodity Unbundling Service agreements and related Rate Schedules. Such Notice of Appointment of Marketer shall also authorize FortisBC Energy to share with the Marketer certain historical and ongoing consumption information and to verify the Commodity Cost Recovery Charge used to bill the Customer as directed by the Marketer.

(b) FortisBC Energy shall be entitled to rely solely on communications from the Marketer with respect to the enrolment of the Customer in Commodity Unbundling Service and with respect to the termination or expiry of any contract between the Customer and Marketer.

(c) FortisBC Energy will bill the Customer a Commodity Cost Recovery Charge according to the price indicated by the Marketer. Such price must be expressed as a single fixed price per Gigajoule in Canadian dollars. Such price shall not include amounts payable by the Customer to the Marketer for services other than the Gas commodity cost. The price may only be changed by Marketer no more than once per year on the anniversary of the Customers' enrolment in Commodity Unbundling Service with such Marketer. FortisBC Energy shall have no obligation to verify that the price communicated by the Marketer is the price agreed to between the Customer and the Marketer.

(d) FortisBC Energy will continue to bill the Customer as per the billing, payment, credit and collections policies set out in these General Terms and Conditions.

(e) The Customer shall make payment to FortisBC Energy based on the total charges on the bill and under no circumstances will payments be prorated between the various charges on the bill. Payments made by Customers to FortisBC Energy pursuant to the bills rendered by FortisBC Energy shall be made without any right of deduction or set-off and regardless of any rights or claims the Customers may have against the Marketer.

(f) Non-payment of any amounts designated as Commodity Cost Recovery Charge charged on the bill shall entitle FortisBC Energy to the same recourse as non-payment of any other FortisBC Energy service charges and may result in termination of service by FortisBC Energy in accordance with these General Terms and Conditions and any applicable Rate Schedules. In the event FortisBC Energy terminates the Customer's service, the subject Customer will be removed from the Commodity Unbundling Service. Should the Customer wish to re-enrol in Commodity Unbundling Service, the Customer will be required to re-apply for service with FortisBC Energy as per the then existing General Terms and Conditions and then be required to enrol as a new participant in order to be eligible for Commodity Unbundling Service.

(g) FortisBC Energy is not responsible for the terms of any of the Customer's contract(s) with the Marketer. Provision of Commodity Unbundling Service in no way makes FortisBC Energy liable for any obligation incurred by a Marketer vis-à-vis the Customer or third parties.

(h) In the event the British Columbia Utilities Commission issues an order to FortisBC Energy to return Customers to FortisBC Energy as supplier of last resort, the Customer will be returned with no notice to the FortisBC Energy standard system supply rate with no interruption of service upon the then applicable terms and conditions of FortisBC Energy system supply service. In the event there are incremental costs associated with returning the Customer to the standard system supply rate, these costs may be recovered by FortisBC Energy directly from the Customer.

(i) The Customer's enrolment in Commodity Unbundling Service shall be on a Premises specific basis.

28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Offering** - Biomethane Service is available in all areas served by FortisBC Energy except Revelstoke

(e) **Moving** - If a Customer registered for Biomethane Service moves to a new Premises within the areas served by FortisBC Energy described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a FortisBC Energy conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy conventional Gas Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

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PART B

TRANSMISSION TRANSPORTATION

SERVICE

1. Definitions and Interpretation

1.1 Except where the context otherwise requires, the following terms when used in this tariff or in a Service Agreement shall have the following meanings:

(a) **Authorized Quantity** - means the quantity of Gas, in gigajoules, authorized by FEVI for delivery to Shipper at the Delivery Points on any Day pursuant to Section 3.3 or Section 3.5.

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

(c) **Business Day** - means any day, excluding Saturdays, Sundays and statutory holidays.

(d) **Commodity Toll** - means, in respect of any Firm Transportation Service or Interruptible Transportation Service, the commodity toll, expressed in dollars per gigajoule, specified for that service in the applicable Service Agreement.

(e) **Contract Demand** - means the maximum quantity of Gas that FEVI is obligated to deliver on any Day pursuant to a Service Agreement providing for Firm Transportation Service.

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

(g) **Curtailment Notice** - means a notice given by FEVI to Shipper under Section 2.4 limiting the quantities of Gas which may be delivered to Shipper at one or more of the Delivery Points on any Day.

(h) **Day** - means a period of 24 consecutive hours beginning and ending at 0800 PST.

(i) **DST** - means Pacific Daylight Savings Time.

(j) **Delivered Quantity** - means in respect of any Day the total quantity of Gas, in gigajoules, delivered to Shipper at the Delivery Points.

(k) **Delivery Point** - means the point immediately downstream of the outlet flange of FEVI's meter installed at each point where the FEVI System connects with the facilities of Shipper as specified for each Shipper in the applicable Service Agreement.

(l) **Demand Toll** - means, in respect of any Firm Transportation Service, the demand toll, expressed in dollars per gigajoule of Contract Demand per Day specified for that service in the applicable Service Agreement.

(m) **FEI** - means FortisBC Energy Inc.

(n) **FEI System** - means the FEI gas pipeline and distribution system extending from a point of connection with the Westcoast System near Huntingdon, British Columbia to a point of connection with the FEVI System in Coquitlam, British Columbia.

(o) **FEVI** - shall mean FortisBC Energy (Vancouver Island) Inc.

(p) **FEVI System** - means the gas transmission pipeline and related facilities owned and operated by FEVI, extending from a point of connection with the FEI System in Coquitlam, British Columbia to various Delivery Points on the Sunshine Coast and Vancouver Island.

(q) **Firm Transportation Service** - means the obligation of FEVI to provide Gas transportation service without interruption or curtailment.

(r) **Force Majeure** - has the meaning ascribed to it in Section 15.2.

(s) **Gas** - means the residue remaining after natural gas has been subjected to any or all of the following permissible processes:

(i) the removal of any constituent parts other than methane, and the removal of methane to such extent as is necessary in removing other constituents;

(ii) the compression, regulation, cooling, cleaning or any other chemical or physical process to such extent as may be required in production, gathering, transmission, storage, removal from storage and delivery, provided that no diluents such as air or nitrogen are added; and

(iii) the addition of odorant by FEI.

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

(u) **gigajoule or GJ** - means 1,000,000,000 joules.

(v) **Interruptible Toll** - means, in respect of any Interruptible Transportation Service, the interruptible toll, expressed in dollars per gigajoule, specified for that service in the applicable Service Agreement.

(w) **Interruptible Transportation Service** - means, subject to the availability of capacity on the FEVI System, the obligation of FEVI to provide Gas transportation service at Shipper's request which is subject to curtailment or interruption.

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

(y) **megajoule or MJ** - means 1,000,000 joules.

(z) **Month** - means the period of time commencing at 0800 PST on the first Day of any month and ending at 0800 PST on the first Day of the next succeeding month.

(aa) **Monthly Imbalance** - means in respect of Shipper, that quantity of Gas specified in a monthly system operations report provided to Shipper by FEVI pursuant to Section 5.1.

(bb) **PST** - means Pacific Standard Time.

(cc) **Party or Parties** - means, with respect to a Service Agreement, FEVI and/or Shipper.

(dd) **Peaking Gas Management Agreement** - means an agreement between two or more Shippers providing for the reallocation of deliveries of Gas to one or more of such Shippers.

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

(ff) **petajoule or PJ** - means 1,000,000 gigajoules.

(gg) **Planned Maintenance** - means any maintenance, repairs, improvements, expansion or other work performed on the FEVI System which is undertaken by FEVI after giving at least 14 days notice of such work to Shipper.

(hh) **Prime Rate** - means the rate of interest per annum established and reported by the Bank of Montreal to the Bank of Canada from time to time as a reference rate of interest for the determination of interest rates that it charges to customers of varying degrees of creditworthiness in Canada for Canadian dollar loans made by it in Canada and designated by it as its "Prime Rate", as to which a certificate of the manager or acting manager of the main branch of the Bank of Montreal in Vancouver, British Columbia shall (in the absence of manifest error) be conclusive evidence.

(ii) **Receipt Point** - means the points where the FEI System connects with other pipelines at Huntingdon, British Columbia.

(jj) **Receipt Quantity** - means in respect of any Day the total quantity of Gas, in gigajoules, delivered by Shipper to FEVI at the Receipt Point.

(kk) **Service Agreement** - means a gas transportation service agreement under which FEVI provides Firm Transportation Service and/or Interruptible Transportation Service to Shipper.

(ll) **Shipper** - means any person who enters into a Service Agreement with FEVI.

(mm) **System Gas** - means that quantity of Gas which FEVI requires:

(i) for fuel and other operating uses and for lost and unaccounted for Gas incurred in the operation and maintenance of the FEVI System, other than the Gas cost of which is capitalized as part of the cost of a pipeline construction or repair project; and

(ii) for any allowance for compressor fuel and for lost and unaccounted for Gas which FEVI is required to supply to FEI pursuant to the Wheeling Agreement.

(nn) **Tariff** - means Part B of FEVI's Tariff concerning gas transportation service, as amended or supplemented from time to time and accepted for filing by the BCUC.

(oo) **Westcoast** - means Westcoast Energy Inc.

(pp) **Westcoast General Terms and Conditions** - means Westcoast's General Terms and Conditions – Service, as approved by or filed with the National Energy Board and in effect from time to time.

(qq) **Westcoast System** - means the gas gathering, processing and transportation facilities owned by Westcoast within British Columbia, Alberta, the Yukon and the Northwest Territories.

(rr) **Wheeling Agreement** - means the agreement dated July 3, 1989 between FEI and FEVI, as amended from time to time and accepted for filing by the BCUC.

(ss) **Year** - means a period of 12 consecutive Months beginning at 0800 PST on January 1 and ending at 0800 PST on the next succeeding January 1.

(tt) **10^3m^3** - means 1,000 cubic metres of gas.

1.2 In Service Agreements and this Tariff words importing the singular shall include the plural, and vice versa, and words importing the masculine gender shall include the feminine gender, and vice versa, and words importing persons shall include firms and corporations, and vice versa.

1.3 Any words or phrases that are not defined in this Tariff or in a Service Agreement and that have a generally accepted meaning in the custom usage of the natural gas industry in western Canada shall have that meaning in this Tariff and in a Service Agreement.

1.4 The division of Service Agreements and this Tariff into Sections, the provision of an index and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of Service Agreements or this Tariff.

1.5 Service Agreements and this Tariff shall be construed in accordance with the laws of the Province of British Columbia and the laws of Canada applicable therein and Service Agreements shall be treated in all respects as contracts made, entered into and to be wholly performed in British Columbia by parties domiciled and resident therein.

1.6 Where a provision of a Service Agreement or this Tariff confers a discretion or decision making power on one or more of the parties to a Service Agreement, such provisions shall be interpreted, unless otherwise expressly stated therein, as requiring the discretion or decision making power to be exercised reasonably.

2. Service

2.1 Subject to the provisions of the applicable Service Agreement and this Tariff, FEVI shall, on each Day in the term of a Service Agreement providing for Firm Transportation Service, transport and deliver to Shipper at the Delivery Points that quantity of Gas, not exceeding the Contract Demand, which Shipper delivers to FEVI at the Receipt Point in conformity with the quality specifications set out in Section 10.1 on each such Day.

2.2 Subject to the provisions of the applicable Service Agreement and this Tariff and subject to the availability of capacity on the FEVI System, FEVI shall, on each Day in the term of a Service Agreement providing for Interruptible Transportation Service, transport and deliver to Shipper at the Delivery Points that quantity of Gas which Shipper delivers to FEVI at the Receipt Point in conformity with the quality specifications set out in Section 10.1 on each such Day.

2.3 FEVI will authorize Firm Transportation Service and Interruptible Transportation Service on each Day in the following priority and sequence:

(a) Firm Transportation Service shall be given the first priority, provided that if FEVI determines that the capacity available on the FEVI System or any part thereof on any Day to serve all Shippers requesting Firm Transportation Service will not be sufficient to permit FEVI to authorize all of the Firm Transportation Service requested for that day, FEVI will allocate the available capacity to such Shippers pro rata on the basis of Contract Demand; and

(b) Interruptible Transportation Service shall be given second priority, provided that if FEVI determines that the capacity available on the FEVI System or any part thereof on any Day to serve all Shippers requesting that service will not be sufficient to permit FEVI to authorize all of the Interruptible Transportation Service requested for that Day, FEVI will allocate the available capacity to such Shippers pro rata on the basis of the quantities of Interruptible Transportation Service requested by such Shippers for that Day.

2.4 If at any time after FEVI has authorized Firm Transportation Service and Interruptible Transportation Service for any Day pursuant to Section 3.3 or Section 3.5, FEVI determines that capacity on the FEVI System or any part thereof is not sufficient to allow FEVI to satisfy all or some of the Firm Transportation Service and the Interruptible Transportation Service authorized for that Day, FEVI will curtail or interrupt service for the balance of the Day in the following priority or sequence:

(a) FEVI will first curtail or interrupt Interruptible Transportation Service pro rata on the basis of the quantities of Gas authorized for delivery on that Day under that service at the affected Delivery Points; and

(b) FEVI will then curtail or interrupt Firm Transportation Service pro rata on the basis of Contract Demand at the affected Delivery Points.

FEVI shall, at least two hours prior to the effective time of the curtailment, give a Curtailment Notice to Shipper specifying the curtailment or interruption of Firm Transportation Service and Interruptible Transportation Service at one or more of the Delivery Points and the anticipated duration of the curtailment.

2.5 Shipper shall monitor the deliveries of Gas each Day at the Delivery Points and shall promptly upon receipt of a Curtailment Notice reduce the quantities of Gas taken by Shipper at the affected Delivery Points so as to comply with quantities, prescribed in a Curtailment Notice.

2.6 FEVI shall give at least 14 Days notice to Shipper of any Planned Maintenance, which notice shall specify the duration of any anticipated effect on the ability to deliver Gas at any of the Delivery Points, and shall, to the extent operating conditions on the FEVI System permit, provide all Shippers with the opportunity, pro rata on the basis of Contract Demand, to deliver additional Gas into FEVI's line pack to offset any reduction in deliveries occasioned by the Planned Maintenance.

2.7 Shipper shall take delivery of Gas at each of the Delivery Points as nearly as practicable at a uniform hourly rate of flow.

2.8 FEVI shall, to the extent reasonably practicable, schedule Planned Maintenance so as to minimize the interference with Gas deliveries to Shipper and to avoid periods of anticipated peak Gas requirements.

2.9 Shipper and FEVI shall cooperate with each other in order to optimize the delivery of Gas through, and the operation of, the FEVI System.

2.10 It is recognized by Shipper that FEVI must operate the FEVI System so as to maintain the operating stability, security and safety of the FEVI System. Shipper will comply with all reasonable requests made by FEVI to reduce or otherwise regulate the delivery of Gas to Shipper at the Delivery Points or to increase or decrease the delivery of Gas to FEVI at the Receipt Point when so advised by FEVI that such action is necessary to maintain the operating stability, security or safety of the FEVI System.

2.11 Subject to Section 2.12, FEVI shall operate and maintain the FEVI System in accordance with engineering and operating practices and procedures customarily applied in the natural gas industry in western Canada.

2.12 FEVI retains the full and exclusive right to operate the FEVI System in a manner which, in FEVI's sole discretion, is consistent with operating conditions and obligations as they may exist from time to time.

3. Nominations, Authorized Quantities and Deliveries of Gas

3.1 Shipper shall on each day prior to 0815 PST or DST, whichever is in effect on that day, or prior to such other time as may be agreed to in writing by Shipper and FEVI, provide FEVI by fax with a nomination schedule, in a form acceptable to FEVI, setting out for the next succeeding Day:

(a) the quantities of Gas, in gigajoules, that Shipper desires to take at each of the Delivery Points;

(b) the allowance for System Gas, based upon the percentage requirements specified monthly by FEVI;

(c) the quantity of Gas required to correct any imbalance between the Delivery Quantity and the Receipt Quantity for any preceding Day or Days;

(d) the sources of supply of the Gas to be delivered by Shipper at the Receipt Point, and the priority as between those sources; and

(e) the quantity of Gas, if any, to be reallocated by Shipper pursuant to a Peaking Gas Management Agreement.

3.2 If, in respect of any Day, Shipper fails to provide FEVI with a nomination schedule in accordance with Section 3.1, the nomination schedule last provided by Shipper shall constitute Shipper's nomination schedule for that Day.

3.3 FEVI shall, within one hour of receiving confirmation from FEI as to the quantities of Gas authorized for delivery from Shipper's supply sources to FEVI at the Receipt Point on the next succeeding Day, provide Shipper by fax with a schedule setting out for the next succeeding Day:

(a) the total quantity of Gas to be delivered from Shippers supply sources to FEVI at the Receipt Point;

(b) the allowance for System Gas to be delivered to FEVI;

(c) the adjustment required to correct any system imbalances; and

(d) the Authorized Quantity to be delivered by FEVI to Shipper.

If FEVI does not receive confirmation from FEI respecting the quantities of Gas authorized for delivery at the Receipt Point on the next succeeding Day prior to the close of business on any Day, FEVI shall, as soon as reasonably practicable but in any event on the next day by 0800 PST or DST, whichever is in effect on that day, provide Shipper by fax with the schedule required pursuant to this Section.

3.4 FEVI shall on each Day provide Shipper with a schedule setting out the capacity available on the FEVI System to deliver Gas to each of the Delivery Points on the next succeeding Day.

3.5 Shipper may on each day by 0815 PST or DST, whichever is in effect on that Day, or prior to such other time as may be agreed to in writing by Shipper and FEVI, provide FEVI with a revised nomination schedule for that Day, in a form acceptable to FEVI, setting out for that Day the information required pursuant to Section 3.1. FEVI shall, giving priority to the quantities of Gas previously authorized in accordance with Section 3.3 and subject to the availability of capacity at the applicable Delivery Points and the receipt of confirmation from FEI as provided in this Section, authorize the revised nominations in the priority and sequence specified in Section 2.3. FEVI shall request FEI to change the quantities authorized for delivery from Shipper's supply sources to FEVI at the Receipt Point for that Day to reflect the revised nomination given by Shipper pursuant to this Section. If FEI confirms to FEVI that the quantities of Gas authorized for delivery from Shipper's supply sources at the Receipt Point have been changed to reflect Shipper's revised nomination, FEVI shall, within one hour of receiving such confirmation, provide Shipper with a revised schedule for that Day setting out the information specified in Section 3.3. If such confirmation is not given to FEVI by FEI by 1200 PST or DST, whichever is in effect on that Day, FEVI shall by fax notify Shipper that the schedule previously provided for that Day pursuant to Section 3.3 remains in effect.

3.6 FEVI shall not be required to authorize or to deliver to Shipper at any Delivery Point a quantity of Gas which exceeds the design capacity of FEVI's metering and related facilities at any such Delivery Point.

3.7 Shipper shall give written notice to FEVI setting out the name, title, telephone and fax numbers of the Person designated by Shipper to receive Curtailment Notices, schedules and monthly system operations reports under Sections 2.4, 3.3, 3.4 and 5.1. FEVI shall give written notice to Shipper setting out the name, title, telephone and fax numbers of the Person designated by FEVI to receive nominations and revised nominations under Sections 3.3 and 3.5.

3.8 Where Shipper and FEVI agree to do so in writing, the nomination and other schedules to be provided by Shipper and FEVI pursuant to Sections 3.1, 3.3 and 3.5, and the monthly service operations reports to be provided by FEVI in accordance with Article 5 may be delivered by one Party to the other by means of a computerized system of communication rather than by fax.

3.9 If Westcoast, FEI or any other company operating a pipeline which transports Gas for delivery through the FEVI System changes its Gas nomination and authorization procedures, FEVI shall make such amendments to this Tariff as FEVI and all Shippers agree are appropriate to reflect such changed procedures.

4. Receipt and Delivery Temperature and Pressure

4.1 Gas delivered to FEVI at the Receipt Point shall meet or exceed the minimum, and shall not exceed the maximum, delivery pressure and temperature standards specified in the Westcoast General Terms and Conditions.

4.2 Gas delivered by FEVI to Shipper at the Delivery Points shall be delivered at the pressure and temperature specified in the applicable Service Agreement.

5. Monthly Imbalances and Unauthorized Overruns

5.1 FEVI shall, within ten Days of the end of each Month, provide Shipper by fax with a monthly service operations report for the Month, which report shall set out:

(a) the Receipt Quantity for each Day in the Month;

(b) the Delivered Quantity for each Delivery Point for each Day in the Month;

(c) the quantity of Gas reallocated to or by Shipper on each Day in the Month pursuant to a Peaking Gas Management Agreement;

(d) the required allowance for System Gas as determined for the Month in accordance with Section 6.3; and

(e) the resulting Monthly Imbalance.

5.2 Shipper shall correct the Monthly Imbalance specified in the monthly service operations report provided to Shipper in accordance with Section 5.1 in a manner acceptable to FEVI during the Month in which such report was received by Shipper or in such other Month as may be acceptable to FEVI.

5.3 If Shipper fails to correct the Monthly Imbalance as required pursuant to Section 5.2, FEVI may, after giving notice to Shipper, correct the Monthly Imbalance by:

(a) increasing or reducing Gas deliveries to Shipper at the Delivery Points; or

(b) purchasing Gas to make up any shortfall in the Receipt Quantities for the preceding Month.

If FEVI purchases Gas to make up any such shortfall, Shipper shall pay FEVI for such Gas an amount equal to 150 percent of the amount, reflective of current market conditions, paid by FEVI to acquire and take delivery of such Gas at the Receipt Point. Amounts payable by Shipper pursuant to this Section shall be included in the statement delivered by FEVI pursuant to Section 8.1 for the Month in which FEVI purchased such Gas.

5.4 The balancing provisions in Sections 5.1, 5.2 and 5.3 are designed to provide Shipper and FEVI with reasonable flexibility in operating their respective facilities. If, at any time during the term of a Service Agreement, those provisions are found to be unworkable by the Parties or if, at any such time, one Party determines that the other is abusing the flexibility provided, the Parties agree to renegotiate those provisions to achieve their intended result.

5.5 If on any Day Shipper takes Gas at one or more of the Delivery Points in excess of the quantity of Gas specified for any such Delivery Point in a Curtailment Notice, Shipper shall, in addition to any other amounts payable in respect of the transportation and delivery of that Gas, pay to FEVI:

(a) in respect of that portion of the aggregate excess between 105 percent and up to and including 110 percent of the aggregate quantities specified in the Curtailment Notice, an amount per gigajoule equal to ten times the Demand Toll; and

(b) in respect of that portion of the aggregate excess which exceeds 110 percent of the aggregate quantities specified in the Curtailment Notice, an amount per gigajoule equal to twenty times the Demand Toll.

No amount shall be payable by Shipper in accordance with this Section in respect of any Gas delivered to Shipper prior to the time at which a Curtailment Notice became effective in accordance with Section 2.4.

5.6 FEVI shall waive the payment of the amounts required to be paid by Shipper pursuant to Section 5.4 where the excess takes by Shipper did not contribute to FEVI's failure to deliver the quantities of Gas authorized for delivery during the period of curtailment to the other Shippers on the FEVI System or did not otherwise adversely affect the operations of the FEVI System.

6. Tolls

6.1 Shipper shall pay to FEVI in respect of Firm Transportation Service provided by FEVI to Shipper pursuant to a Service Agreement in each Month the tolls for that Firm Transportation Service specified in the applicable Service Agreement.

6.2 Shipper shall pay to FEVI in respect of Interruptible Transportation Service provided by FEVI to Shipper pursuant to a Service Agreement in each Month the tolls for that Interruptible Transportation Service specified in the applicable Service Agreement.

6.3 In addition to the tolls payable pursuant to Section 6.1 or Section 6.2 and any other amounts payable by Shipper in accordance with this Tariff, Shipper shall in respect of each Month deliver to FEVI at the Receipt Point an allowance for System Gas equal to that quantity of Gas, in gigajoules, which is the sum of:

(a) that percentage, specified in the Wheeling Agreement, of the aggregate of the Receipt Volumes for the Month;

(b) the quantity of System Gas, other than fuel for line heaters at meter stations, incurred in the operation of the FEVI System for the Month multiplied by the ratio, the numerator of which is the total of the Delivered Quantities received by Shipper in the Month and the denominator of which is the total quantities of Gas delivered at all the Delivery Points in the Month; and

(c) the quantity of fuel incurred in the operation of line heaters at the meter stations at the Delivery Points where Gas is delivered to Shipper in accordance with a Service Agreement, determined in accordance with Section 6.4.

6.4 Where Gas is delivered to two or more Shippers at any Delivery Point, the quantity of fuel for line heaters at meter stations to be delivered by each Shipper to FEVI for such Delivery Point for any Month shall be that quantity determined by multiplying the line heater fuel consumed at such Delivery Point by the ratio, the numerator of which is the total of the Delivered Quantities received by such Shipper in the Month at that Delivery Point and the denominator of which is the total quantities of Gas delivered in the Month at that Delivery Point.

7. Demand Toll Credits

7.1 If for any reason FEVI is unable or fails to deliver at the Delivery Points on any Day the total quality of Gas, up to the Contract Demand that Shipper has in good faith requested FEVI to deliver under a Service Agreement providing for Firm Transportation Service, then, in respect of such Day, a credit in an amount equal to the product obtained by multiplying the Demand Toll by the difference between the quantity of Gas so requested and the quantity of Gas delivered by FEVI shall be applied to the monthly bill rendered by FEVI pursuant to Article 8, but no such credit shall be given if such inability to deliver by FEVI resulted from:

(a) the inability or failure of Shipper for any reason, including Force Majeure, to deliver Gas in conformity with the quality specifications set out in Section 10.1 to FEVI at the Receipt Point;

(b) the inability or failure of Shipper for any reason, including Force Majeure, to take delivery of Gas at any of the Delivery Points; or

(c) any act or omission of Shipper, including the taking of Gas from the FEVI System at any of the Delivery Points in excess of the Authorized Quantity.

8. Statements and Payments

8.1 FEVI shall, within 15 Days following the end of each Month, deliver to Shipper a statement setting out the quantities of Gas delivered to Shipper at the Delivery Points during such Month and the amount payable by Shipper for all services provided by FEVI to Shipper during the Month. Where actual quantities of Gas are not available, estimates may be used and adjusted in a subsequent Month when actual quantities become available. Any statement delivered pursuant to this Section shall be deemed to have been delivered on the Day on which it is received by the Shipper.

8.2 Shipper shall, within ten Days of the receipt of the statement for any Month pursuant to Section 8.1 or within 25 Days following the end of such Month, whichever is the later, pay the amount specified therein in Canadian funds to FEVI at its principal office in Vancouver, British Columbia. If Shipper fails to make such payment, or any portion thereof, when due, interest thereon shall accrue at a rate equal to the Prime Rate in effect on the date such payment was due plus:

(a) 2% from the date when such payment was due for the first 30 Days that such payment remains unpaid, and 5% thereafter until the same is paid where Shipper has not, during the immediately preceding six Month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due until the same is paid where Shipper has, during the immediately preceding six Month period, failed to make any payment when due hereunder.

8.3 If any error is discovered in a statement rendered by FEVI pursuant to Section 8.1, such error shall be corrected by an adjustment in a subsequent statement rendered by FEVI within 30 Days of the discovery of the error; provided, however, that no adjustment shall be made for any error in a statement which is discovered more than 24 Months after the receipt of that statement by Shipper.

8.4 Each Party shall have the right at reasonable times to examine the books, records and charts of the other Party to the extent necessary to verify the accuracy of any statement, charge or computation made under or pursuant to the provisions of a Service Agreement and this Tariff.

9. Letter of Credit

9.1 In order to secure the prompt and orderly payment of the amounts to be paid by Shipper under a Service Agreement, FEVI may require Shipper to provide, and at all times maintain, an irrevocable letter of credit in favour of FEVI issued by a financial institution acceptable to FEVI in an amount equal to the maximum amount payable by Shipper under a Service Agreement for up to 184 Days of service. Where FEVI requires Shipper to provide a letter of credit and Shipper is able to provide alternative security acceptable to FEVI, FEVI will accept such security in lieu of a letter of credit.

9.2 FEVI may in any Month draw on the letter of credit in an amount necessary to satisfy the amount due for the previous Month when Shipper has not paid such amount within the time and in the manner provided in Section 8.2.

9.3 Where FEVI requires Shipper to provide and maintain a letter of credit pursuant to Section 9.1, such letter of credit, or any replacement thereof, shall have a term equal of the lesser of:

(a) one Year; or

(b) the period ending one Month after the last Month in the term of the Service Agreement.

9.4 Shipper shall, within 120 Days of the end of each fiscal Year included in the term of a Service Agreement, provide FEVI with a copy of Shipper's audited financial statements (unless FEVI agrees to accept unaudited financial statements) for each such fiscal Year and shall, if so requested in writing by FEVI, provide FEVI within 60 Days of the end of any of the first three quarters of any such fiscal Year, interim financial statements for any such quarter.

10. Gas Quality

10.1 Gas delivered by Shipper to FEVI at the Receipt Point shall meet or exceed the minimum, and not exceed the maximum quality specifications specified in the Westcoast General Terms and Conditions. Whenever the Gas offered for delivery to FEVI at the Receipt Point fails to conform with the quality specifications set out in the Westcoast General Terms and Conditions, FEVI may, without prejudice to any other rights it may have, refuse to take delivery of such Gas in which case:

(a) FEVI shall give notice of such refusal to Shipper setting forth the reasons therefor; and

(b) FEVI shall, as soon as practicable, accept deliveries of Gas at the Receipt Point after the failure to conform has been remedied and notice thereof has been given to FEVI.

10.2 Gas delivered by FEVI to Shipper at the Delivery Points shall conform to the specifications set out in the Wheeling Agreement for Gas delivered by FEI to FEVI. Whenever the Gas delivered by FEVI to Shipper at any of the Delivery Points fails to conform with any of the specifications referred to in this Section, Shipper may, without prejudice to any other rights it may have, refuse to take delivery of such Gas, in which case:

(a) Shipper shall give notice of such refusal to FEVI setting forth the reasons therefor; and

(b) Shipper shall, as soon as practicable, accept deliveries of Gas at the Delivery Points after the failure to conform has been remedied and notice thereof has been given to Shipper.

11. Measurement

11.1 The unit of volume of Gas for all purposes hereunder shall be one cubic metre at an absolute pressure of 101.325 kilopascals and at a temperature of 15 degrees centigrade.

11.2 The provisions of Section 11.3 shall apply to the measurement of all Gas delivered by Shipper to FEVI at the Receipt Point, and the provisions of Sections 11.4 to 11.8 shall apply to the measurement of all Gas delivered by FEVI to Shipper at the Delivery Points.

11.3 All Gas delivered by Shipper to FEVI at the Receipt Point shall be measured as to volume, quality, heat content and heating value by Westcoast at the meters installed, operated and maintained by Westcoast at the Receipt Point or at such other instruments installed, operated and maintained by Westcoast to determine such measurements in respect of Gas delivered at the Receipt Point. Such measurements shall be made in accordance with the standards, procedures and specification set out in Westcoast's General Terms and Conditions, and such measurements and all other quality and heating value measurements as made by Westcoast shall be final and binding upon the Parties and utilized for all purposes of a Service Agreement.

11.4 The volume of Gas delivered by FEVI to Shipper at the Delivery Points shall be measured and computed on a daily basis by FEVI in accordance with the requirements established under the *Gas Inspection Act* with respect to orifice, positive displacement, turbine and rotary meters.

11.5 Corrections shall be made on a daily basis for the deviation from Boyle's Law at the pressure and temperature at which the Gas is metered. To determine the factors for such corrections, a quantitative analysis of the Gas will be made by FEVI or obtained from FEI at reasonable intervals and such factors will be obtained from data contained in the American Gas Association Manual for Determination of Supercompressibility Factors for Natural Gas – Par Research Project NX19 of December 1962, as published by the American Gas Association, or any subsequent revisions thereto acceptable to both Shipper and FEVI or directed for use pursuant to the *Gas Inspection Act*. If positive displacement or turbine meters are used, the supercompressibility factor shall be squared.

11.6 The relative density of the Gas delivered by FEVI to Shipper at the Delivery Points shall be determined by FEVI from time to time utilizing the method prescribed in the American Gas Association Publication 2529 and samples of Gas taken from points on the FEVI System or the FEI System where the sample or samples of Gas taken are representative of the Gas delivered through the pipeline system.

11.7 The flowing temperature of Gas in the meters installed and operated by FEVI shall be determined by means of temperature devices installed and operated in accordance with the requirements established under the *Gas Inspection Act*.

11.8 The atmospheric pressure at the actual altitude of each of the Delivery Points shall be calculated in accordance with the requirements established under the *Gas Inspection Act*.

11.9 The volumes of Gas delivered by Shipper to FEVI at the Receipt Point on each Day, and the volumes of Gas delivered by FEVI to Shipper at the Delivery Points on each Day shall be converted to energy units by multiplying the volume of Gas so delivered by the heat content of each cubic metre of Gas in accordance with then procedures established under the *Gas Inspection Act*. The heat content of the Gas delivered at the Delivery Points shall be measured by FEI for Gas delivered from the FEI System into the FEVI System.

12. Measurement Equipment

12.1 FEVI shall install, maintain and operate suitable metering and other equipment complying with the requirements established under the *Gas Inspection Act* and necessary to measure the volume, temperature and pressure of all Gas delivered at the Delivery Points, and shall calibrate and adjust such meters and other equipment and change the charts as required.

12.2 Shipper shall have access to such meters and other equipment during reasonable hours, and shall be entitled to be present at the time of any installing, testing, cleaning, changing, repairing, inspecting, calibrating or adjusting done to or in connection with the meters and other measuring equipment installed and maintained by FEVI at the Delivery Points, and shall be given reasonable notice in order that it can be present.

12.3 Shipper may install, maintain and operate at its own expense check measuring equipment at the Delivery Points, for the purpose of checking FEVI's meters and other measuring equipment.

12.4 Each Party shall through testing verify the accuracy of its meters and other measuring equipment at the Delivery Points at least every two Months or at such other intervals as may be agreed to by the Parties, and whenever requested by the other Party. If, upon a requested verification, a meter or other measuring equipment is found to be registering correctly, subject to an inaccuracy not exceeding two percent, the cost of such verification shall be charged to and be borne by the Party requesting the same: otherwise, the cost of all such requested verifications shall be borne by the other Party. If, upon any test, a meter or other measuring equipment is found to be inaccurate by not more than two percent, previous readings of such equipment shall be considered correct in computing deliveries of Gas at the Delivery Points, but such equipment shall be adjusted at once to record accurately. If, upon any test, any meter or other measuring equipment is found to be inaccurate by more than two percent, then any previous readings of such equipment shall be corrected to zero error for any period which is known or can be agreed upon, but if the period is not known or cannot be agreed upon, such correction shall be for a period covering the last half of the time elapsed since the date of the last test.

12.5 If a meter or other measuring equipment is out of service or out of repair so that the quantity of Gas delivered cannot be correctly determined by the reading thereof, the Gas delivered during the period of such meter or other measuring equipment is out of service or out of repair shall be estimated on the basis of the best available data, using the first of the following methods which is feasible:

(a) by using the registration of any check measuring equipment installed and operated by Shipper, provided such equipment is registering accurately;

(b) by correcting the error if the percentage of error can be ascertained by calibration, test or mathematical calculations; or

(c) by estimating the quantities of Gas delivered to Shipper utilizing deliveries during prior periods of similar conditions when the meter or other measuring equipment was registering accurately.

12.6 Each Party shall cause to be preserved for a period of at least two Years, all test data, charts and other records of Gas measurement. Either Party desiring to preserve any records for a longer period may require the other Party to deliver to it such records, which shall thereafter be retained at the sole expense of the Party desiring those records.

13. Possession and Control of Gas and Liabilities

13.1 FEVI shall be deemed to be in possession and control of, and responsible for all Gas received by it at the Receipt Point until such Gas is delivered by it to Shipper at the Delivery Points as if it were the owner thereof, and shall have the right at all times to commingle such Gas with other Gas in the FEVI System. Nothing in this Section shall be interpreted to effect an actual transfer of title or ownership of a Shipper's Gas to FEVI while such Gas is in FEVI's possession and control.

13.2 Each Party assumes full responsibility and liability for the maintenance and operation of its respective properties, facilities and equipment, and shall indemnify and save harmless the other Party from all liability and expense an account of any and all damages, claims or actions, including injury to or death of persons, arising from any act, accident, event or omission in connection with the construction, installation, presence, maintenance and operation of the property, facilities and equipment of the indemnifying Party, or in connection with Gas deemed to be in possession and control of the indemnifying Party.

13.3 If FEVI curtails or interrupts service in accordance with this Tariff, Shipper's sole and exclusive remedy against FEVI shall, except as otherwise provided in a Service Agreement, be the recovery of Demand Toll Credits pursuant to and in accordance with Article 7.

13.4 In no event shall either Shipper or FEVI be liable to the other for any indirect, special or consequential loss, damage, cost or expense whatsoever, whether based on breach of contract, negligence, strict liability or otherwise including, without limitation, loss of profits or revenues, cost of capital, loss or damages for failure to receive or deliver Gas, cost of lost, purchased or replacement Gas, cancellation or permits or certificates, and the termination of contracts.

14. Representations and Acknowledgments

14.1 FEVI represents and warrants to Shipper that:

(a) it has full right, power and authority to enter into a Service Agreement with Shipper; and

(b) it has obtained all certificates, licenses, permits and authorizations necessary for the operation of the FEVI System.

14.2 Shipper represents and warrants to FEVI that:

(a) it has full right, power and authority to enter into a Service Agreement, and that all Gas delivered to FEVI thereunder at the Receipt Point shall be free from all liens and adverse claims; and

(b) as of the Day on which services are first provided by FEVI under a Service Agreement, Shipper shall have obtained all necessary authorizations, permits, licenses, certificates and agreements required by it for the receipt, transportation and delivery of Gas by FEVI in accordance with a Service Agreement.

14.3 Shipper acknowledges to FEVI that, as between Shipper and FEVI, Shipper is solely responsible for acquiring under contract sufficient Gas supplies or reserves, and sufficient gathering, processing and transportation capacity required to deliver to the Receipt Point the quantities of Gas to be transported and delivered by FEVI pursuant to a Service Agreement, and for obtaining all governmental authorizations and approvals required in connection therewith.

15. Force Majeure

15.1 Subject to the other provisions of this Article, if either Shipper or FEVI is unable by reason of Force Majeure to perform in whole or in part any obligation or covenant imposed pursuant to a Service Agreement, with the exception of unpaid financial obligations, such failure shall be deemed not to be a breach of such obligation or covenant and the obligations of both Parties under the Service Agreement shall be suspended to the extent necessary during the continuation of any inability so caused by such Force Majeure.

15.2 As used in Part B of this Tariff, the term "Force Majeure" means any event or occurrence not within the control of the Party claiming Force Majeure and which by the exercise of reasonable diligence such Party is unable to prevent or overcome, including, without limiting the generality of the foregoing, any acts of God, including lighting, earthquakes, storms, washouts, landslides, fires, epidemics and floods; strikes, lockouts or other industrial disturbances; acts of the Queen's or public enemies, sabotage, wars, blockades, insurrections, riots or civil disturbances; fires, explosions, breakages of or accidents to machinery or lines of pipe; hydrate obstructions of lines of pipe; the laws, orders, rules, regulations, acts or restraints of any court or governmental or regulatory authority; and pipeline repairs. For the purposes of this Article, a Party is deemed to have control over the actions or omissions of those Persons to which it, its agents, contractors or employees have delegated, assigned or subcontracted its obligations and responsibilities.

15.3 Neither Party shall be entitled to the benefit of Section 15.1 under any of the following circumstances:

(a) to the extent that the failure was caused by the negligence of the Party claiming Force Majeure;

(b) to the extent that the failure was caused by the Party claiming Force Majeure having failed to diligently attempt to remedy the condition by taking all reasonable acts and to resume the performance of such covenants and obligations or to resume making nominations with reasonable dispatch;

(c) if the failure was caused by lack of funds or is in respect of the monthly payments due hereunder;

(d) to the extent such failure was caused by the failure of Shipper's Gas supply or by the failure of Westcoast or any other pipeline to transport and deliver Gas to Shipper at the Receipt Point;

(e) to the extent the failure was caused by Shipper's inability for any reason to resell Gas to its customers in its service areas; or

(f) to the extent the failure was caused by the inability of Shipper for any reason to obtain materials and supplies required in its industrial or commercial operations or to market the products produced in those operations.

16. Notices

16.1 Any notice, other than a Curtailment Notice, which shall or may be given hereunder shall, unless otherwise specified herein, be in writing and delivered or sent by fax or courier to such Party's address, as specified in a Service Agreement, or at such other address as either Party shall designate by written notice. Any notice delivered or sent by fax or courier shall be deemed to have been received by the addressee on the Business Day on which it was so delivered or sent or, if delivered or sent on a day other than Business Day, on the next following Business Day.

17. Miscellaneous

17.1 No waiver by either Party of any default by the other in the performance of any of the provisions of a Service Agreement shall operate or be construed as a waiver of any other or future default or defaults, whether if a like or a different character.

17.2 A Service Agreement may be assigned in whole or in part by Shipper if Shipper has first obtained the prior written consent of FEVI, which consent shall not be unreasonably withheld.

17.3 A Service Agreement shall enure to the benefit of and be binding upon the Parties thereto and their respective successors and permitted assigns.

17.4 Nothing herein contained shall prevent either of the Parties from pledging, charging or mortgaging its rights under a Service Agreement as security for its indebtedness or obligations without the consent of the other Party. Any Person who has acquired a security interest in a Service Agreement as security for the indebtedness or obligations of either Party may, without the consent of the other Party, assign the Service Agreement to another Person in connection with the enforcement of the security interest.

17.5 A Service Agreement together with this Tariff incorporated therein by reference constitutes the entire agreement between the Parties and supersedes all previous agreements, understandings, negotiations and representations between the Parties.

17.6 No amendments or variation of a Service Agreement shall be effective and binding upon the Parties unless such amendment or variation is set forth in writing and duly executed by the Parties thereto.

17.7 A Service Agreement and the rights and obligations of the Parties thereunder are subject to all present and future valid laws, regulations, rules, orders and directives of any legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the Parties or the subject matter of the Service Agreement.

17.8 Notwithstanding the termination of a Service Agreement, the provisions of Article 13 respecting liabilities and indemnities which have accrued prior to the date of termination, the provisions of Article 8 respecting statements, payments, correction of errors and the examination of records and the provisions of Article 5 respecting the correction of Monthly Imbalances shall survive the termination of the Service Agreement. The Parties shall use reasonable efforts to make all adjustments and to settle all accounts which are outstanding between the Parties as of the date of termination as soon as possible.

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PART C

RATE SCHEDULES

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Standard Fees and Charges Schedule

Deleted: The following charges apply to special services and circumstances as set out in the Terms and Conditions. These charges are subject to revision based on FortisBC Energy's cost of providing such services:

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Application Fee

Existing Installation	$25.00
New Installation	$25.00
New Installation – Manifold Meters	$25.00 per meter
New Installation – Vertical Subdivision	$25.00 per meter

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Service Line Cost Allowance

Other than a duplex	$1,535.00
Duplex	$3,070.00

Deleted: 3.

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	$20.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

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Metering Related Charges

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Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

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Rate Schedule 1: Residential Service

Deleted: RESIDENTIAL GENERAL SERVICE RATE NO. 1 (RGS-1)

Available

This Rate Schedule is available to all Customers served by FortisBC Energy provided adequate capacity exists in FortisBC Energy's system.

Deleted: In communities where Customers are served from distribution systems connected to the Vancouver Island Natural Gas Pipeline.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. This Rate Schedule is also applicable to thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source) and measured by a thermal meter for one premise of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed for hydronic heating.

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Energy Charge per GJ $14.325
Minimum Monthly Charge $10.50

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Table of Charges

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	Vancouver Island Area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X***
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

	Vancouver Island Area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

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Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation** – Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider** – Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Rider 9 (Reserved for future use.)

Franchise Fee Charge - Except for the Option A surcharge, a Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

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Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers have been established as interim rates, effective January 1, 2012. Final determination of rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved. C

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Rate Schedules¶

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Deleted: To Gas supplied to users served under Residential General Service Rate No. 1 (RGS-1) at one point of delivery through one meter.

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Deleted: Annual energy consumption must equal or exceed 20 GJ per Year. This optional rate rider is available to RGS-1 Customers. Customers choosing Rate Rider A will have their customer contribution requirement arising from attaching a load of less than 53 GJ reduced by $472. Rider A is not available to reduce contribution amounts required for reasons other than the attachment of loads less than 53 GJ.

Deleted: In the event that the required contribution minus $472 is less than zero, no Customer contribution will apply. In no event will the selection of Rate Rider A result in a payment from FortisBC Energy to a Customer for the difference between $472 and the contribution payable.

Deleted: Customers taking the optional rider must choose to do so at the time of application for Service.

Deleted: Rider A is not available to Customers requesting Service to a newly constructed residence or residence under construction, except where the Customer requesting Service is to be the owner occupying the residence. Rider A is not available to builders at residences constructed for resale upon completion.

Deleted: Rider A is not available to Customers requesting Service to a residence or building which is to be leased or rented to Tenants.

Deleted: Rider A is available to owner occupants only.

Deleted: In the event that a Customer increases annual load to 53 GJ, Rate Rider A will no longer be payable.¶
¶

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Rate Schedules¶

Deleted: In the event that a Customer increases annual load, within two Years of taking Service, to a level less than or equal to 53 GJ, but more than the load contracted for at the time Service was first extended, and if requested by the Customer, a portion of any Customer contribution previously paid may be refunded to the Customer to reflect the increased load.

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Deleted: Monthly Charge $5.00

Deleted: Effective January 1, 2006, Optional Rate Rider A – Service Line Charge is closed to new Customers.

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Effective Date: March 1, 2011¶
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BCUC Secretary: *Original signed by E.M. Hamilton* Original Page C-2.1¶

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SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1) Rate Schedule 2: Small Commercial Service

Available

This Rate Schedule is available in all areas served by FortisBC Energy provided adequate capacity exists in FortisBC Energy's System.

Deleted: In communities where Customers are served from distribution systems connected to the Vancouver Island Natural Gas Pipeline.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

Deleted: To Gas supplied to commercial users at one point of delivery through one meter.

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Deleted: Basic Daily Charge $0.3105

Deleted: Energy Charge per GJ . $16.940

Deleted: Minimum Monthly Charge $9.45

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Table of Charges

	Vancouver Island area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

	Vancouver Island area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

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Rate Rider D (Reserved for future use.)

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Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

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Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers have been established as interim rates, effective January 1, 2012. Final determination of rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved. C

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Available¶
¶
In communities where Customers are served from distribution systems connected to the Vancouver Island Natural Gas Pipeline.¶
¶
¶
Applicable¶
¶
To Gas supplied commercial users at one point of delivery through one meter.¶
¶
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Conditions¶
¶
Annual energy consumption must equal or exceed 200 GJ per Year. If the annual consumption is less than 200 GJ, the Customer will be reclassified to the appropriate Service rate.¶
¶
¶
Rates¶
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Basic Daily Charge $1.1016¶
Energy Charge per GJ . $16.455¶
Minimum Monthly Charge $33.53¶
¶
¶
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Notes:¶
Rate Rider D . (Reserved for future use.)¶
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Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers have been established as interim rates, effective January 1, 2012. Final determination of rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved.¶
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LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)¶
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Effective Date: January 1, 2012¶
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BCUC Secretary: . *Original signed by Alanna Gillis* . First Revision of Page C-9

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LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2) Rate Schedule 3: Large Commercial Service

Available

In communities where Customers are served from distribution systems connected to the Vancouver Island Natural Gas Pipeline. This Rate Schedule is available to all Customers served by FortisBC Energy provided adequate capacity exists in FortisBC Energy's System.

Applicable

To Gas supplied commercial users at one point of delivery through one meter. This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

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Annual energy consumption must equal or exceed 2,000 GJ per Year. If the annual consumption is less than 2,000 GJ, the Customer will be reclassified to the appropriate Service rate.¶

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Basic Daily Charge $3.2138¶
Energy Charge per GJ $12.311¶
Minimum Monthly Charge $97.82¶

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Table of Charges

	Vancouver Island area
Delivery Margin Related Charges	
1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

	Vancouver Island area
Commodity Related Charges	
6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

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Rate Rider D (Reserved for future use.)

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers have been established as interim rates, effective January 1, 2012. Final determination of rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved. C

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LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)¶
¶
Available¶
¶
In communities where Customers are served from distribution systems connected to the Vancouver Island Natural Gas Pipeline.¶
¶
¶
Applicable¶
¶
To Gas supplied commercial users at one point of delivery through one meter.¶
¶
¶
Conditions¶
¶
Annual energy consumption must equal or exceed 6,000 GJ per Year. If the annual consumption is less than 6,000 GJ, the Customer will be reclassified to the appropriate Service rate.¶
¶
¶
Rates¶
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Basic Daily Charge $6.6205¶
Energy Charge per GJ $12.015¶
Minimum Monthly Charge $201.51¶
¶
¶
¶
Notes:¶
Rate Rider D (Reserved for future use.)¶
¶
¶
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Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers have been established as interim rates, effective January 1, 2012. Final determination of rates for FortisBC Energy (Vancouver Island) Inc. Core Market sales and transportation customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent rates approved.¶
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LARGE COMMERCIAL SERVICE RATE NO. 13 (LCS-13)¶
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FORTISBC ENERGY (WHISTLER) INC.
GENERAL TERMS AND CONDITIONS

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Table of Contents¶

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¶
FortisBC Energy Operations Centre¶
16705 Fraser Highway¶
Surrey, B.C.¶
V4N 0E8¶
¶
- and -¶
¶
FortisBC Energy (Whistler) Inc.¶
8021 Mons Road¶
Whistler, B.C.¶
V0N 1B8¶
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The Tariff is also available for inspection on-line at the FortisBC Energy website at www.fortisbc.com.

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Effective Date: March 1, 2011¶
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Definitions

Unless the context indicates otherwise, in these Terms and Conditions and Rate Schedules, the following words have the following meanings:

(a) **Basic Charge** - Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge - calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places. C/N

(b) **Biogas -** Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.

(c) **Biomethane -** Means Biogas purified or upgraded to pipeline quality gas.

(d) **Biomethane Service** - Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales

(e) **British Columbia Utilities Commission** - Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to C

(i) any commission that is a successor to such commission, and

(ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia.

(f) **Carbon Offsets** - Means what FortisBC Energy will 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. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.

(g) **Commercial Service** - Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations. C

(h) **Commodity Cost Recovery Charge** - Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

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(i) **Commodity Unbundling Service** - Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.

(j) **Customer** - Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy. C

(k) **Day** - Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service. C

(l) **Delivery Point** - Means the outlet of the Meter Set unless otherwise specified in the Service Agreement. C

(m) **Delivery Pressure** - Means the pressure of the Gas at the Delivery Point. C

First Nations - Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.

(n) **Franchise Fees** - Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations

i. for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the Indian Act),

ii. relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the Indian Act), or

iii. relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the Indian Act).

(o) **FortisBC Energy** - Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number xxxxxxx. C

(p) **FortisBC Energy System** - Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time for distribution services

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(q) **Gas** - Means natural gas (including odorant added by FortisBC Energy) and propane. C

(r) **Gas Service** - Means the delivery of Gas through a Meter Set. C

(s) **General Terms & Conditions of FortisBC Energy** - Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.

(t) **Gigajoule** - Means a measure of energy equal to one billion joules used for billing purposes. C

(u) **Heat Content** - Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3). C

(v) **Hour** - Means any consecutive 60 minute period. C

(w) **Landlord** - Means a Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner. C

(x) **Main** - Means pipes used to carry Gas for general or collective use for the purposes of distribution. C

(y) **Main Extension** - Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property. C

(z) **Marketer** - Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.

(aa) **Meter Set** - Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping. C

(bb) **Midstream Cost Recovery Charge** - Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

(cc) **Month** - Means a period of time, for billing purposes, of 27 to 34 consecutive Days. C

(dd) **Municipal Operating Fees** - Has the same meaning as Franchise Fees.

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(ee) **Other Service -** Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.

(ff) **Other Service Charges -** Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.

(gg) **Person** - Means a natural person, partnership, corporation, society, unincorporated entity or body public. C

(hh) **Premises** - Means a building, a separate unit of a building, or machinery together with the surrounding land. C

(ii) **Profitability Index** - Means the revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time. C

(jj) **Rate Schedule** - Means a schedule attached to and forming part of this Tariff, which sets out the changes for Service and certain other related terms and conditions for a class of Service. C

(kk) **Residential Service** - Mean firm Gas Service provided to the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments. C

(ll) **Rider** - Means an additional charge or credit attached to a rate.

(mm) **Seasonal Service** - Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st. C

(nn) **Service** - Means the provision of Gas Service or other service by FortisBC Energy. C

(oo) **Service Agreement** - Means an agreement between FortisBC Energy and a Customer for the provision of Service. C

(pp) **Service Header** - Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main. C

(qq) **Service Line** - Means the portion of the pipeline used for the transporting of Gas from FortisBC Energy's Main distribution pipeline to the inlet of the Meter Set. In the case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the C

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(rr) Consumer's individual Premises, but not within the Customer's individual Premises.

(ss) **Service Related Charges** - Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges. C

(tt) **Temporary Service** - Means the provision of Service for what FortisBC Energy determines will be a limited period of time. C

(uu) **Tenant** - Means a Person who has the temporary use and occupation of real property owned by another Person. C

(vv) **Thermal Energy** - Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.

(ww) **Thermal Metering** - Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.

(xx) **Vertical Subdivision** - Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor. C

(yy) **Year** - Means a period of 12 consecutive Months. C

(zz) **10^3m^3** - Means **1,000 cubic metres.**

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Areas Served by FortisBC Energy

These General Terms and Conditions of FortisBC Energy refer to the following areas served by FortisBC Energy: Mainland, Fort Nelson, Vancouver Island and Whistler.

Mainland Area Means the areas including, but not limited to, the following locations and surrounding areas of

Abbotsford	New Westminster
Anmore	North Vancouver City
Belcarra	North Vancouver Dist.
Burnaby	Pitt Meadows
Chilliwack	Port Coquitlam
Coquitlam	Port Moody
Delta	Richmond
Harrison Hot Springs	Squamish
Hope	Surrey
Kent	Vancouver
Langley City	West Vancouver
Langley District	White Rock
Maple Ridge	
Matsqui	
Mission	
Armstrong	Nelson
Ashcroft	Okanagan Falls
Bear Lake	Oliver
Cache Creek	100 Mile House
Castlegar	108 Mile House
Chase	150 Mile House
Chetwynd	Osoyoos
Christina Lake	Oyama
Clinton	Peachland
Coldstream	Penticton

Mainland Area (continued)

Collettville
Craigmont
Falkland
Ferguson Lake
Fruitvale

Gibralter Mines
Grand Forks
Greenlake
Greenwood
Hedley

Hixon
Honeymoon Creek
Hudson's Hope
Kamloops
Kelowna

Keremeos
Lac La Hache
Lakeview Heights
Logan Lake
Lumby

MacKenzie
Merritt
Midway
Montrose
Naramata

Prince George
Princeton
Quesnel
Revelstoke
Robson

Rossland
Salmo
Salmon Arm
Savona
Shelley

Sorrento
Spallumcheen
Summerland
Trail
Vernon

Warfield
Westbank
Westwold
Williams Lake
Winfield

Woodsdale

Cranbrook
Creston
Elkford
Fernie
Galloway

Jaffray
Kimberley
Sparwood
Yahk

Fort Nelson Area Means the areas including, but not limited to, the following locations and surrounding areas of

Fort Nelson
Prophet River

Vancouver Island and Whistler Areas Means the areas including, but not limited to, the following locations and surrounding areas of

Campbell River
Central Saanich
Colwood
Comox
Courtenay

Cumberland
Duncan
Esquimalt
Gibsons
Highlands

Ladysmith
Langford
Lantzville
Metchosin
Nanaimo

North Cowichan
North Saanich
Oak Bay
Parksville
Pemberton

Port Alberni
Powell River
Qualicum Beach
Saanich
Sechelt

Sechelt Indian Band
Sidney
Sooke
Squamish
Sunshine Coast

Victoria
View Royal
Whistler

PART A

DISTRIBUTION SALES

and

SERVICE

1. Application Requirements

1.1 **Requesting Services** - A Person requesting FortisBC Energy

(a) to provide Gas Service,

(b) to provide a new Service Line,

(c) to re-activate an existing Service Line,

(d) to transfer an existing account,

(e) to change the type of Service provided, or

(f) to make alterations to an existing Service Line or Meter Set

must apply to FortisBC Energy at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 **Required Documents** - An applicant for

(a) Residential Service may be required to sign an application and a Service Agreement provided by FortisBC Energy,

(b) Commercial Service may be required to sign an application and a Service Agreement provided by FortisBC Energy, and

(c) Service on other Rate Schedules must sign the applicable Service Agreement provided by FortisBC Energy.

1.3 **Separate Premises / Businesses** - If an applicant is requesting Service from FortisBC Energy at more than one Premises, or for more than one separately operated business, the applicant will be considered a separate Customer for each of the Premises and businesses. For the purposes of this provision, FortisBC Energy will determine whether or not any building contains one or more Premises or any business is separately operated.

1.4 **Required References** - FortisBC Energy may require an applicant for Service to provide reference information and identification acceptable to FortisBC Energy.

1.5 **Rental Premises** - In the case of rental Premises, FortisBC Energy may

(a) require an owner of rental Premises or its agent who wishes FortisBC Energy to contract directly with a Tenant to enter into an agreement with FortisBC Energy defining the responsibilities of the owner or agent for payment for Service to the Premises,

(b) contract directly with the owner or agent of the rental Premises as a Customer of FortisBC Energy with respect to any or all Services to the Premises, or

(c) contract directly with each Tenant as a Customer of FortisBC Energy.

1.6 **Refusal of Application** - FortisBC Energy may refuse to accept an application for Service for any of the reasons listed in Section 21 (Discontinuance of Service and Refusal of Service).

2. Agreement to Provide Service

2.1 **Service Agreement** - The agreement for Service between a Customer and FortisBC Energy will be

(a) the oral or written application of the Customer which has been approved by FortisBC Energy and which is deemed to include the Terms and Conditions, or

(b) a Service Agreement signed by the Customer.

2.2 **Customer Status** - A Person becomes a Customer of FortisBC Energy when FortisBC Energy

(a) approves the Person's application for Service, or

(b) provides Service to the Person.

A Person who is being provided Service by FortisBC Energy but who has not applied for Service shall be served in accordance with these Terms and Conditions.

2.3 **No Assignment / Transfer** - A Customer may not transfer or assign an agreement for Service without the written consent of FortisBC Energy.

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3. Conditions on Use of Service

3.1 **Authorized Consumption** - A Customer must not increase the maximum rate of consumption of Gas delivered to it by FortisBC Energy from that which may be consumed by the Customer under the applicable Rate Schedule nor significantly change its connected load without the written approval of FortisBC Energy, which approval will not be unreasonably withheld.

3.2 **Unauthorized Sale / Supply / Use** - Unless authorized in writing by FortisBC Energy, a Customer must not sell or supply Gas supplied to it by FortisBC Energy to other Persons or use Gas supplied to it by FortisBC Energy for any purpose other than as specified in the Service Agreement.

4. Rate Classification

4.1 **Rate Classification** - Subject to Section 4.2 (a) (Special Contracts and Tariff Supplements), Customers may be served under any Rate Schedule for which they meet the applicability criteria as set out in the appropriate Rate Schedule

4.2 **Special Contracts and Tariff Supplements** - In exceptional circumstances, special contracts and tariff supplements may be negotiated between FortisBC Energy and the Customer and submitted for British Columbia Utilities Commission approval where

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that Service to the Customer is economic, or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the Customer on-system.

4.3 **Periodic Review** - FortisBC Energy may

(a) conduct periodic reviews of the quantity of Gas delivered and the rate of delivery of Gas to a Customer to determine which Rate Schedule applies to the Customer; and

(b) change the Customer's charge to the appropriate charge, or

(c) change the Customer to the appropriate Rate Schedule.

5. Application Fee and Charges

5.1 **Application Fee** - An applicant for Service must pay the applicable Application Fee set out in the Special Rate Schedule.

5.2 **Application Fee for Manifold Meters and Vertical Subdivisions** - Where a new Service Line is required to serve more than one Customer at a Premises and the Service is provided with Gas meters connected to a meter manifold, the Application fee for manifold meters set out in the Special Rate Schedule will apply. Where a new Service Header is required to service a Vertical Subdivision, the Application Fee set out in the Special Rate Schedule will apply.

5.3 **Waiver of Application Fee** - The Application Fee

(a) will be waived by FortisBC Energy if Service to a Customer is reactivated after it was discontinued for any of the reasons described in Section 13.2 (Right to Restrict), and

(b) may be waived by FortisBC Energy if a Landlord requires Gas Service for a short period between the time a previous Tenant moves out and a new Tenant moves in.

5.4 **Reactivation Charges** - If

(a) Service is terminated

(i) at the request of a Customer, or

(ii) for any of the reasons described in Section 21 (Discontinuance of Service and Refusal of Service), or

(iii) to permit Customers to make alterations to their Premises, and

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year, the applicant for reactivation must pay the greater of

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

5.5 **Identifying Load or Premises Served by Meter Sets** - If a Customer requests FortisBC Energy to identify the Meter Set that serves the Premises and/or load after the Meter Set was installed, the Customer will pay the cost FortisBC Energy incurs in re-identifying the Meter Set where

(a) the Meter Set is found to be properly identified, or

(b) the Meter Set is found to be improperly identified as a result of Customer activity including

(i) a change in the legal civic address of the Premises,

(ii) renovating or partitioning the Premises, or

(iii) rerouting Gas lines after the delivery point.

6. Security for Payment of Bills

6.1 **Security for Payment of Bills** - If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(a) be less than $50, and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive months consumption of Gas by the Customer or applicant.

6.2 **Interest** - FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Special Rate Schedule. Subject to Section 6.5, if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed, and

(b) on a deposit held by FortisBC Energy in a form other than cash.

6.3 **Refund on Deposit** - When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

6.4 **Unclaimed Refund** - If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, becomes the absolute property of FortisBC Energy.

6.5 **Application of Deposit** - If a Customer's bill is not paid when due, FortisBC Energy may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC Energy applies the security deposit or calls on the equivalent form of security, FortisBC Energy may, under Section 21 (Discontinuance of Service and Refusal of Service), discontinue service to the Customer for failure to pay for Service on time.

6.6 **Replenish Security Deposit** - If a Customer's security deposit or equivalent form of security is called upon by FortisBC Energy towards paying an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before FortisBC Energy will reconnect or continue Service to the Customer.

6.7 **Failure to Pay** - Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC Energy may, in FortisBC Energy's discretion, result in discontinuance or refusal of Service as set out in Section 21 (Discontinuance of Service and Refusal of Service).

7. Term of Service Agreement

7.1 **Initial Term for Residential and Commercial Service** - If a Customer is being provided Residential or Commercial Service, the initial term of the Service Agreement

(a) when a new Service Line is required will be one Year, or

(b) when a Main Extension is required will be for a period of time fixed by FortisBC Energy not exceeding the number of Years used to calculate the revenue in the Main Extension economic test used in Section 12 (Main Extensions).

7.2 **Initial Term for Gas Service other than Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service, the initial term of the Service Agreement will be as specified in the Service Agreement or as specified in the appropriate Rate Schedule.

7.3 **Transfer to Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service and transfers to Residential or Commercial Service, the initial term of the Service Agreement will be determined by the criteria set out in Section 7.1 (Initial Term for Residential and Commercial Service). A Customer may only transfer Service from one Rate Schedule to another Rate Schedule once a Year.

7.4 **Renewal of Agreement** - Unless

(a) the Service Agreement or the applicable Rate Schedule specifies otherwise,

(b) the Service Agreement is terminated under Section 8 (Termination of Service Agreement),

(c) a refund has been made under Section 9.2 (Refund of Charges), or

(d) the Service Agreement is for Seasonal Service,

the Service Agreement will be automatically renewed at the end of its initial term from Month to Month for Residential or Commercial Service, and from Year to Year for all other types of Gas Service.

8. Termination of Service Agreement

8.1 **Termination by Customer** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC Energy at least 48 Hours notice.

8.2 **Continuing Obligation** - The Customer is responsible for, and must pay for, all Gas delivered to the Premises and is responsible for all damages to and loss of Meter Sets or other FortisBC Energy property on the Premises until the Service Agreement is terminated.

8.3 **Effect of Termination** - The Customer is not released from any previously existing obligations to FortisBC Energy under the Service Agreement by terminating the agreement.

8.4 **Sealing Service Line** - After receiving a termination notice for a Premises and after a reasonable period of time during which a new Customer has not applied for Gas Service at the Premises, FortisBC Energy may seal off the Service Line to the Premises.

8.5 **Termination by FortisBC Energy** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC Energy may terminate the Service Agreement for any reason by giving the Customer at least 48 Hours notice.

9. Delayed Consumption

9.1 **Additional Charges** - If a Customer has not consumed Gas

(a) within 2 Months after the installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the minimum charge for each billing period after that, and

(b) within one Year after installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the Customer the full cost of construction and installation of the Service Line and Meter Set less the total of the minimum charges billed to the Customer to that date.

9.2 **Refund of Charges** - If a Customer who has paid the charges for a Service Line under Section 9.1 (b) (Additional Charges) consumes Gas in the second year after installation of the Service Line, FortisBC Energy will refund to the Customer the payments made under Section 9.1 (b) (Additional Charges). If a refund is made under Section 9.2 (Refund of Charges), the term of the Service Agreement will be one Year from the time the Customer begins consuming Gas.

10. Service Lines

10.1 **Provided Installation** - If FortisBC Energy's Main is adjacent to the Customer's Premises, FortisBC Energy

(a) will designate the location of the Service Lines on the Customer's Premises and determine the amount of space that must be left unobstructed around them;

(b) will install for Residential Service the Service Line from the Main to the Meter Set on the Customer's Premises at no additional cost to the Customer provided

(i) the Service Line follows the route which is the most suitable to FortisBC Energy,

(ii) the estimated direct cost of the Service Line does not exceed the Service Line Cost Allowance set out in the Special Rate Schedule, and

(iii) the distance from the front of the Customer's building or machinery to the meter does not exceed 1.5 metres;

(c) will charge Residential Service Customers for the estimated direct construction costs in excess of the Service Line Cost Allowance set out in the Special Rate Schedule; and

(d) will perform an economic test for Residential Service and larger Customers and for any Customers connecting to a Service Header including Vertical Subdivisions, and, when the Profitability Index is less than 1.0, will charge the Customer a contribution sufficient to achieve a minimum Profitability Index of 1.0. The economic test will be discounted cash flow test, similar to the economic test for Main Extensions set out in Section 12.

10.2 **Extended Installation** - The Customer may make application to FortisBC Energy to extend the Service Line beyond that described in Section 10.1 (Provided Installation) (b) (iii). Upon approval by FortisBC Energy and agreement for payment by the Customer of the additional costs, FortisBC Energy will extend the Service Line only if it is on the route approved by FortisBC Energy.

10.3 **Customer Requested Routing** - If

(a) FortisBC Energy's Main is adjacent to the Customer's Premises, and

(b) the Customer requests that its piping or Service Line enter its Premises at a different point of entry or follow a different route from the point or route designated by FortisBC Energy,

FortisBC Energy may charge the Customer for all additional costs as determined by FortisBC Energy to install the Service Line in accordance with the Customer's request.

10.4 **Temporary Service** - A Customer applying for Temporary Service must pay FortisBC Energy in advance for the costs which FortisBC Energy estimates it will incur in the installation and subsequent removal of the facilities necessary to supply Gas to the Customer.

10.5 **Winter Construction** - If an applicant or Customer applies for Service which requires construction when, in FortisBC Energy's opinion, frost conditions may exist, FortisBC Energy may postpone the required construction until the frost conditions no longer exist.

If FortisBC Energy carries out the construction, the applicant or Customer may be required to pay all costs in excess of the Service Line Cost Allowance which are incurred due to the frost conditions.

10.6 **Additional Connections** - If a Customer requests more than one Service connection to the Premises, on the same Rate Schedule, FortisBC Energy may install the additional Service Line and may charge the Customer the Application Fee set out in the Special Rate Schedule, as well as the full cost (including overheads) for the Service Line installation. FortisBC Energy will bill the additional Service Connection from a separate meter and account. If the additional Service Connection is requested by a spouse, contractor, employee, agent or partner of the existing Customer, the same charges will apply.

10.7 **Easements & Right-of-Way** - If the Customer is not the owner of the Premises or there is intervening property between the Premises and FortisBC Energy's Mains, the Customer shall obtain for FortisBC Energy from the proper owner, in a form satisfactory to FortisBC Energy, the necessary consent or easement in writing for the installation and maintenance in said Premises and in or about such intervening property, of all necessary facilities for supplying Gas. FortisBC Energy reserves the right to acquire rights-of-way if deemed desirable by FortisBC Energy. The Customer is responsible for the costs of obtaining an easement in favour of FortisBC Energy and in a form specified by FortisBC Energy for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying Gas to the Customer.

10.8 **Ownership** - FortisBC Energy owns the entire Service Line from the Main up to and including the Meter Set, whether it is located inside or outside the Customer's Premises.

10.9 **Maintenance** - FortisBC Energy will maintain the Service Line.

10.10 **Supply Cut Off** - If the supply of Gas to a Customer's Premises is cut off for any reason FortisBC Energy is not required to remove the Service Line from the Customer's property of Premises.

10.11 **Damage Notice** - The Customer must advise FortisBC Energy immediately of any damage occurring to the Service Line.

10.12 **Prohibition** - A Customer must not construct any permanent structure over a Service Line or install any air intake openings or sources of ignition which contravene government regulations, codes or FortisBC Energy's policies.

10.13 **No Unauthorized Changes** - No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line

(a) must be approved in writing by FortisBC Energy, and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer.

10.14 **Site Preparation** - The Customer will be responsible for all necessary site preparation including but not limited to clearing building materials, construction waste, equipment, soil and gravel piles over the proposed service line route to the standards established by FortisBC Energy. FortisBC Energy may recover any additional costs associated with delays or site visits necessitated by inadequate or substandard site preparation by the Customer.

11. Meter Sets and Metering

11.1 **Installation** - In order to bill the Customer for Gas delivered, FortisBC Energy will install one or more Meter Sets on the Customer's Premises. Unless approved by FortisBC Energy, all Meter Sets will be located outside the Customer's Premises at locations designated by FortisBC Energy.

11.2 **Measurement** - The quantity of Gas delivered to the Premises will be metered using apparatus approved by Customer and Corporate Affairs Canada. The amount of Gas registered by the Meter Set during each billing period will be converted to Gigajoules in accordance with the *Electricity and Gas Inspection Act* and rounded to the nearest one-tenth of a Gigajoule.

11.3 **Testing Meters** - If a Customer applies for the testing of a Meter Set and

(a) the Meter Set is found to be recording incorrectly, the cost of removing, replacing and testing the meter will be borne by FortisBC Energy subject to Section 22.4 (Responsibility for Meter Set), and

(b) if the testing indicates that the Meter Set is recording correctly, as defined by the *Electricity and Gas Inspection Act*, the Customer must pay FortisBC Energy for the cost of removing, replacing and testing the Meter Set as set out in the Special Rate Schedule.

11.4 **Defective Meter Set** - If a Meter Set ceases to register, FortisBC Energy will estimate the volume of Gas delivered to the Customer according to the procedures set out in Section 16.6 (Incorrect Register).

11.5 **Protection of Equipment** - The Customer must take reasonable care of and protect all Meter Sets and related equipment on the Customer's Premises. The Customer's responsibility for expense, risk and liability with respect to all Meter Sets and related equipment is set out in Section 22.4 (Responsibility for Meter Set).

11.6 **No Unauthorized Changes** - No Meter Sets or related equipment will be installed, connected, moved or disconnected except by FortisBC Energy's authorized employees, contractors or agents or by other Persons with FortisBC Energy's written permission.

11.7 **Removal of Meter Set** - As the termination of a Service Agreement, FortisBC Energy may disconnect or remove a Meter Set from the Premises if a new Customer is not expected to apply to Service for the Premises within a reasonable time.

11.8 **Customer Requested Meter Relocation or Modifications** - Any change in the location of a Meter Set or related equipment, or any modifications to the Meter Set, including automatic and/or remote meter reading

(a) must be approved by FortisBC Energy in writing, and

(b) will be made at the expense of the Customer if the change or modification is requested by the Customer or necessitated by the actions of the Customer. If any of the changes to the Meter Set or related equipment require FortisBC Energy to incur ongoing incremental operating and maintenance costs, FortisBC Energy may recover these costs from the Customer through a Monthly charge.

11.9 **Meter Set Consolidations** - A Customer who has more than one Meter Set at the same Premises or adjacent Premises may apply to FortisBC Energy to consolidate its Meter Sets. If FortisBC Energy approves the Customer's application, the Customer will be charged the value for all plant abandoned except for Meter Sets that are removed to facilitate Meter Set consolidations. In addition, the Customer will be charged FortisBC Energy's full costs, including overheads, for any abandonment, Meter Set removal and alteration downstream of the new Meter Set. If a new Service Line is required, FortisBC Energy will charge the Customer the Application Fee. In addition, the Customer will be required to sign a release waiving FortisBC Energy's liability for any damages should the Customer decide to re-use the abandoned plant downstream of the new Meter Set.

11.10 **Delivery Pressure** - The normal Delivery Pressure is 1.75 kPa. FortisBC Energy may charge Customers who require Delivery Pressure at other than the normal Delivery Pressure the additional costs associated with providing other than the normal Delivery Pressure.

11.11 **Customer Requested Mobile Service** - The Customer will be charged the cost of providing temporary mobile Gas Service if the request for such Service is made by or brought on by the actions of the Customer.

12. Main Extensions

12.1 **System Expansion** - FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 **Ownership** - All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 **Economic Test** - All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 1.0 or greater for an individual Main Extension.

12.4 **Revenue** - The projected revenue to be used in the economic test will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star® rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

12.5 **Costs** - The total costs to be used in the economic test include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 **Contributions in Aid of Construction** - If the economic test results indicate a Profitability Index of less than 1.0, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 **Contributions Paid by Connecting Customers** - The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the Main Extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension contribution agreement for initial contributions. Customers will be billed a contribution amount after the Main Extension is built.

12.8 **Refund of Contributions** - A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due,

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 **Extensions to Contributory Extensions** - When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security** - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

12A. Alternative Energy Extensions

12A.1 **System Expansion** - FortisBC Energy will make extensions to the FortisBC Energy System using technology that produces alternative energy, in accordance with the provisions of this section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below:

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of FortisBC Energy.

12A.3 **Cost of Service Model** - All applications by Customers for service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a customer will pay for the service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between FortisBC Energy and the Customer.

12A.4 **Projected Energy Consumption/Number of Customers** - The projected energy consumption and number of customers to be used in the cost of service model will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout all areas served by FortisBC Energy have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

12B. Vehicle Fuelling Stations

12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling –** FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section of the General Terms and Conditions.

The CNG and LNG Services are described below:

CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and

(b) dispensing of compressed natural gas.

LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the service charge for which will be determined pursuant to Rate Schedule 16;

(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the customer's property. The ownership includes all components of the fueling station(s).

12B.3 **Cost of Service Recovery** - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4, where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.4 **Calculation of Cost of Service –** The total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fueling station;

(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer , escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and

(d) an allowance for overhead and marketing costs relating to developing NGV Fueling Station Agreements to be recovered from the Customer.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

12B.5 **Customer's Obligation at the Expiration of Initial Term of the Service Agreement** - If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

13. Interruption of Service

13.1 **Regular Supply** - FortisBC Energy will use its best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures.

13.2 **Right to Restrict** - FortisBC Energy may require any of its Customers, at all times or between specified Hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy,

(b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems,

(c) in order to comply with any legal requirements,

(d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems,

(e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage.

13.3 **Notice** - FortisBC Energy will, to the extent practicable, give notice of its requirements and removal of its requirements under Section 13.2 (Right to Restrict) to its Customers by

(a) newspaper, radio or television announcement, or

(b) notice in writing that is

(i) sent through the mail to the Customer's billing address,

(ii) left at the Premises where Gas is delivered,

(iii) served personally on a Customer, or

(iv) sent by facsimile or other electronic means to the Customer, or

(c) oral communication.

13.4 **Failure to Comply** - If, in the opinion of FortisBC Energy, a Customer has failed to comply with any requirement under Section 13.2 (Right to Restrict), FortisBC Energy may, after providing notice to the Customer in the manner specified in Section 13.3 (Notice), discontinue Service to the Customer.

14. Access to Premises and Equipment

14.1 **Access to Premises** - FortisBC Energy must have a right of entry to the Customer's Premises. The Customer must provide free access to its Premises at all reasonable times to FortisBC Energy's authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning Gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of Gas delivered to the Customer, or for any other related purpose which FortisBC Energy requires.

14.2 **Access to Equipment** - The Customer must provide clear access to FortisBC Energy's equipment. The equipment installed by FortisBC Energy on the Customer's Premises will remain the property of FortisBC Energy and may be removed by FortisBC Energy upon termination of Service.

15. Promotions and Incentives

15.1 **Promotion of Gas Appliances** - FortisBC Energy may promote, sell, rent, lease, or finance natural Gas vehicle equipment, Gas appliances and related accessories and Services on a cash or finance plan basis and make reasonable charges for these Services.

16. Billing

16.1 **Basis for Billing** - FortisBC Energy will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in the Terms and Conditions.

16.2 **Meter Measurement** - FortisBC Energy will measure the quantity of Gas delivered to a Customer using a Meter Set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 **Multiple Meters** - Gas Service to each Meter Set will be billed separately for Customers who have more than one Meter Set on their Premises.

16.4 **Estimates** - For billing purposes, FortisBC Energy may estimate the Customer's meter readings if, for any reason, FortisBC Energy does not obtain a meter reading.

16.5 **Estimated Final Reading** - If a Service Agreement is terminated under Section 8.1 (Termination by Customer), FortisBC Energy may estimate the final meter reading for final billing.

16.6 **Incorrect Register** - If any Meter Set has failed to measure the delivered quantity of Gas correctly, FortisBC Energy may estimate the meter reading for billing purposes, subject to Section 17 (Back-Billing).

16.7 **Bills Issued** - FortisBC Energy may bill a Customer as often as FortisBC Energy considers necessary but generally will bill on a Monthly basis.

16.8 **Bill Due Dates** - The Customer must pay FortisBC Energy's bill for Service on or before the due date shown on the bill which will be

(a) the first business Day after the twenty-first calendar Day following the billing date, or

(b) such other period as may be agreed upon by the Customer and FortisBC Energy.

16.9 **Historical Billing Information** - Customers who request historical billing information may be charged the cost of processing and providing the information.

17. Thermal Energy

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17.1 All references to Gas shall be deemed to include a reference to Thermal Energy. For example, Gas Service shall be deemed to include the delivery of Thermal Energy through a Meter Set. Notwithstanding the foregoing, the meaning of Gas Distribution System shall be deemed not to include a hydronic heating system that delivers energy to Residential Customers but shall include the meters that measure the amount of energy by Residential Customers in a Vertical Subdivision.

18. Section Reserved for Future Use

19. Back Billing

19.1 **When Required** - FortisBC Energy may, in the circumstances specified herein, charge, demand, collect or receive from its Customers in respect of a regulated Service rendered hereunder a greater or lesser compensation than that specified in the subsisting schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or an equal payment plan billing, such adjustments do not require back-billing treatment to be applied.

19.2 **Definition** - Back-billing means the re-billing by FortisBC Energy for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC Energy, and may result from the conduct of an inspection under provisions of the federal statute, the *Electricity and Gas Inspection Act* ("EGI Act"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) stopped meter

(b) metering equipment failure

(c) missing meter now found

(d) switched meters

(e) double metering

(f) incorrect meter connections

(g) incorrect use of any prescribed apparatus respecting the registration of a meter

(h) incorrect meter multiplier

(i) the application of an incorrect rate

(j) incorrect reading of meters or data processing

(k) tampering, fraud, theft or any other criminal act

19.3 **Application of Act** - Whenever the dispute procedure of the EGI Act is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 **Billing Basis** - Where metering or billing errors occur and the dispute procedure under EGI Act is not invoked, the consumption and demand will be based upon the records of FortisBC Energy for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC Energy. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

19.5 **Tampering / Fraud** - If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC Energy's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC Energy, then the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of Section 17.8 (Under-Billing) to 17.11 (Changes in Occupancy) below, do not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by FortisBC Energy in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC Energy on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 **Remedying Problem** - In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

19.7 **Over-billing** - In every case of over-billing, FortisBC Energy will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to FortisBC Energy on a monthly basis, will be paid to the Customer.

19.8 **Under-billing** - Subject to Section 17.5 (Tampering / Fraud) above, in every case of under-billing, FortisBC Energy will back-bill the Customer for the shorter of:

(a) the duration of the error; or

(b) six Months for Residential or Commercial Service; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC Energy.

19.9 **Terms of Repayment** - Subject to Section 17.5 (Tampering / Fraud) above, in all cases of under-billing, FortisBC Energy will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 **Disputed Back-Bills** - Subject to Section 17.5 (Tampering / Fraud) above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, FortisBC Energy will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and FortisBC Energy may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

19.11 **Changes in Occupancy** - Subject to Section 17.5 (Tampering / Fraud) above, back-billing in all instances where changes of occupancy have occurred, FortisBC Energy will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the applicable over or under billing will be cancelled.

20. Equal Payment Plan

20.1 **Definitions** - In this Section, "equal payment plan period" means a period of twelve consecutive Months commencing with a normal meter reading date at the Customer's Premises.

20.2 **Application for Plan** - A Customer may apply to FortisBC Energy by mail, by telephone, by facsimile or by other electronic means to pay fixed Monthly instalments for Gas delivered to the Customer during the equal payment plan period. Acceptance of the application will be subject to FortisBC Energy finding the Customer's credit to be satisfactory.

20.3 **Monthly Instalments** - FortisBC Energy will fix Monthly instalments for a Customer so that the total sum of all the instalments to be paid during the equal payment plan period will equal the total amount payable for the Gas which FortisBC Energy estimates the Customer will consume during the equal payment plan period.

20.4 **Changes in Instalments** - FortisBC Energy may, at any time, increase or decrease the amount of the Monthly instalments payable by the Customer in light of new consumption information or changes to the Rate Schedules or the Terms and Conditions.

20.5 **End of Plan** - Participation in the equal payment plan may be ended at any time

(a) by the Customer giving 5 Days' notice to FortisBC Energy, or

(b) by FortisBC Energy, without notice, if the Customer has not paid the Monthly instalments as required.

20.6 **Payment Adjustment** - At the earlier of the end of the equal payment plan period for a Customer or the end of the Customer's participation in the plan under Section 18.5 (End of Plan), FortisBC Energy will

(a) compare the amount which is payable by the Customer to FortisBC Energy for Gas actually consumed on the Customer's Premises from the beginning of the equal payment plan period to the sum of the Monthly instalments billed to the Customer from the beginning of the equal payment plan period, and

(b) pay to the Customer or credit to the Customer's account any excess amount or bill the Customer for any deficit amount payable.

21. Late Payment Charge

21.1 **Late Payment Charge** - If the amount due for Service or Service Related Charges on any bill has not been received in full by FortisBC Energy on or before the due date specified on the bill, and the unpaid balance is $15 or more, FortisBC Energy may include in the next bill to the Customer the late payment charge specified in the Special Rate Schedule.

21.2 **Equal Payment Plan** - If the Monthly instalment, Service Related Charges and payment adjustment as defined under Section 18.6 (Payment Adjustment) due from a Customer billed under the equal payment plan set out in Section 18 (Equal Payment Plan) have not been received by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, FortisBC Energy may include in the next bill to the Customer the late payment charge in accordance with Section 19.1 (Late Payment Charge) on the amount due.

22. Returned Cheque Charge

22.1 **Dishonoured Cheque Charge** - If a cheque received by FortisBC Energy from a Customer in payment of a bill is not honoured by the Customer's financial institution for any reason other than clerical error, FortisBC Energy may include a charge specified in the Special Rate Schedule in the next bill to the Customer for processing the returned cheque whether or not the Service has been disconnected.

23. Discontinuance of Service and Refusal of Service

23.1 **Discontinuance With Notice and Refusal Without Notice** - FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons:

(a) the Customer has not fully paid FortisBC Energy's bill with respect to Services on or before the due date,

(b) the Customer or applicant has failed to pay any required security deposit equivalent form of security, or post a guarantee or required increase in it by the specified date,

(c) the Customer or applicant has failed to pay FortisBC Energy's bill in respect of another Premises on or before the due date,

(d) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC Energy's bill, security deposit, or required increase in the security deposit in respect of another Premises which was occupied by that occupant and the Customer at the same time,

(e) the Customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to FortisBC Energy,

(f) the Customer has failed to apply for Service, or

(g) the land or portion thereof on which FortisBC Energy's facilities are, or are proposed to be, located contains contamination which FortisBC Energy, acting reasonably, determines has adversely affected or has the potential to adversely effect FortisBC Energy's facilities, or the health or safety of its workers or which may cause FortisBC Energy to assume liability for clean up and other costs associated with the contamination. If FortisBC Energy, acting reasonably, determines that contamination is present it is the obligation of the occupant of the land to satisfy FortisBC Energy that the contamination does not have the potential to adversely affect FortisBC Energy or its workers. For the purposes of this Section, "contamination" means the presence in the soil, sediment or groundwater of special waste or another substance in quantities or concentrations exceeding criteria, standards or conditions established by the British Columbia Ministry of Environment or as prescribed by present and future laws, rules, regulations and orders of any other legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the environment.

23.2 **Discontinuance or Refusal Without Notice** - FortisBC Energy may discontinue without notice or refuse the supply of Gas or Service to a Customer for any of the following reasons:

(a) the Customer or applicant has failed to provide reference information and identification acceptable to FortisBC Energy, when applying for Service or at any subsequent time on request by FortisBC Energy,

(b) the Customer has defective pipe appliances, or Gas fittings in the Premises,

(c) the Customer uses Gas in such a manner as in FortisBC Energy's opinion

(i) may lead to a dangerous situation, or

(ii) may cause undue or abnormal fluctuations in the Gas pressure in FortisBC Energy's Gas transmission or distribution system,

(d) the Customer fails to make modifications or additions to the Customer's equipment which have been required by FortisBC Energy in order to prevent the danger or to control the undue or abnormal fluctuations described under paragraph (c),

(e) the Customer breaches any of the terms and conditions upon which Service is provided to the Customer by FortisBC Energy,

(f) the Customer fraudulently misrepresents to FortisBC Energy its use of Gas or the volume delivered,

(g) the Customer vacates the Premises,

(h) the Customer's Service Agreement is terminated for any reason, or

(i) the Customer stops consuming Gas on the Premises.

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23.3 **Application to Former Tariffs** - Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

Lower Mainland - Gas Tariff,

Inland - Gas Tariff B.C.E.C. No. 2,

Columbia - Gas Tariff B.C.U.C. No.1.

BC Gas Tariff

Terasen Gas Inc. Tariff

FortisBC Energy Inc. Gas Tariff

FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff

FortisBC Energy (Vancouver Island) Inc. Gas Tariff

FortisBC Energy (Whistler) Inc. Gas Tariff

24. Limitations on Liability

24.1 **Responsibility for Delivery of Gas** - FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by any Customer or any Person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport Gas, or provide Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents.

24.2 **Responsibility Before Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises, and

(b) FortisBC Energy -owned facilities serving the Customer's Premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible.

24.3 **Responsibility After Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to the use or presence of Gas after it passes the Delivery Point.

24.4 **Responsibility for Meter Set** - The Customer is responsible for all expense, risk and liability with respect to all Meter Sets or related equipment at the Customer's Premises unless any loss or damage is

(a) directly attributable to the negligence of FortisBC Energy, its employees, contractors or agents, or

(b) caused by or resulting from a defect in the equipment.

The Customer must prove that negligence or defect. For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by FortisBC Energy in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service Line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such Service Line(s).

24.5 **Customer Indemnification** - The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Customer or any Person claiming by or through the Customer or any third party caused by or resulting from the use of Gas by the Customer or the presence of Gas in the Customer's Premises, or from the Customer or Customer's employees, contractors or agents damaging FortisBC Energy's facilities.

25. Miscellaneous Provisions

25.1 **Taxes** - The rates and charges specified in the applicable Rate Schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which FortisBC Energy may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the Customer.

25.2 **Conflicting Terms and Conditions** - Where anything in these Terms and Conditions conflicts with special terms or conditions specified under an applicable Rate Schedule or Service Agreement, then the terms or conditions specified under the Rate Schedule or Service Agreement govern.

25.3 **Authority of Agents of FortisBC Energy** - No employee, contractor or agent of FortisBC Energy has authority to make any promise, agreement or representation not incorporated in these Terms and Conditions or in a Service Agreement, and any such unauthorized promise, agreement or representation is not binding on FortisBC Energy.

25.4 **Additions, Alterations and Amendments** - The Terms and Conditions, fees and charges, and Rate Schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by FortisBC Energy from time to time.

25.5 **Headings** - The headings of the Sections set forth in the Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of the Terms and Conditions.

26. Direct Purchase Agreements

26.1 **Collection of Incremental Direct Purchase Costs** - Where FortisBC Energy incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a Customer, agent, broker or marketer, FortisBC Energy may, subject to BCUC approval, collect those costs from the Customer, agent, broker or marketer. Such costs may include the costs of arranging, acquiring or transporting substitute Gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by FortisBC Energy. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

26.2 **Direct Purchase Customers Returning to FortisBC Energy System Supply** - Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy,

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply,

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer, and

(c) FortisBC Energy may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

27. Commodity Unbundling Service

27.1 In the event a Customer enters into a Gas supply contract with a Marketer for Commodity Unbundling Service under Rate Schedule 1U, 2U or 3U, the following terms and conditions will apply:

(a) The Customer must sign a Notice of Appointment of Marketer as notification to FortisBC Energy that the Marketer has the authority to do what is required with respect to the Customer's enrolment in Commodity Unbundling Service, including entering into the necessary Commodity Unbundling Service agreements and related Rate Schedules. Such Notice of Appointment of Marketer shall also authorize FortisBC Energy to share with the Marketer certain historical and ongoing consumption information and to verify the Commodity Cost Recovery Charge used to bill the Customer as directed by the Marketer.

(b) FortisBC Energy shall be entitled to rely solely on communications from the Marketer with respect to the enrolment of the Customer in Commodity Unbundling Service and with respect to the termination or expiry of any contract between the Customer and Marketer.

(c) FortisBC Energy will bill the Customer a Commodity Cost Recovery Charge according to the price indicated by the Marketer. Such price must be expressed as a single fixed price per Gigajoule in Canadian dollars. Such price shall not include amounts payable by the Customer to the Marketer for services other than the Gas commodity cost. The price may only be changed by Marketer no more than once per year on the anniversary of the Customers' enrolment in Commodity Unbundling Service with such Marketer. FortisBC Energy shall have no obligation to verify that the price communicated by the Marketer is the price agreed to between the Customer and the Marketer.

(d) FortisBC Energy will continue to bill the Customer as per the billing, payment, credit and collections policies set out in these General Terms and Conditions.

(e) The Customer shall make payment to FortisBC Energy based on the total charges on the bill and under no circumstances will payments be prorated between the various charges on the bill. Payments made by Customers to FortisBC Energy pursuant to the bills rendered by FortisBC Energy shall be made without any right of deduction or set-off and regardless of any rights or claims the Customers may have against the Marketer.

(f) Non-payment of any amounts designated as Commodity Cost Recovery Charge charged on the bill shall entitle FortisBC Energy to the same recourse as non-payment of any other FortisBC Energy service charges and may result in termination of service by FortisBC Energy in accordance with these General Terms and Conditions and any applicable Rate Schedules. In the event FortisBC Energy terminates the Customer's service, the subject Customer will be removed from the Commodity Unbundling Service. Should the Customer wish to re-enrol in Commodity Unbundling Service, the Customer will be required to re-apply for service with FortisBC Energy as per the then existing General Terms and Conditions and then be required to enrol as a new participant in order to be eligible for Commodity Unbundling Service.

(g) FortisBC Energy is not responsible for the terms of any of the Customer's contract(s) with the Marketer. Provision of Commodity Unbundling Service in no way makes FortisBC Energy liable for any obligation incurred by a Marketer vis-à-vis the Customer or third parties.

(h) In the event the British Columbia Utilities Commission issues an order to FortisBC Energy to return Customers to FortisBC Energy as supplier of last resort, the Customer will be returned with no notice to the FortisBC Energy standard system supply rate with no interruption of service upon the then applicable terms and conditions of FortisBC Energy system supply service. In the event there are incremental costs associated with returning the Customer to the standard system supply rate, these costs may be recovered by FortisBC Energy directly from the Customer.

(i) The Customer's enrolment in Commodity Unbundling Service shall be on a Premises specific basis.

28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Offering** - Biomethane Service is available in all areas served by FortisBC Energy except Revelstoke

(e) **Moving** - If a Customer registered for Biomethane Service moves to a new Premises within the areas served by FortisBC Energy described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a FortisBC Energy conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy conventional Gas Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

Standard Fees and Charges Schedule

Application Fee

Existing Installation	$25.00
New Installation	$25.00
New Installation – Manifold Meters	$25.00 per meter
New Installation – Vertical Subdivision	$25.00 per meter

Service Line Cost Allowance

Other than a duplex	$1,535.00
Duplex	$3,070.00

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	$20.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

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Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	$50.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

Rate Schedule 1: Residential Service

Available

This Rate Schedule is available to all Customers served by FortisBC Energy provided adequate capacity exists in FortisBC Energy's system.

Applicable

This Rate Schedule is applicable to firm Gas supplied at one Premise for use in approved appliances for all residential applications in single-family residences, separately metered single-family townhouses, rowhouses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments. This Rate Schedule is also applicable to thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source) and measured by a thermal meter for one premise of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed for hydronic heating.

R

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Deleted: In the Resort Municipality of Whistler where Customers are serviced from a direct extension of the existing distribution system.

Deleted: To Gas supplied to Customers at one point of delivery through one meter.

Deleted: Rates

Deleted: Basic Charge per Day $0.2464¶
¶
Delivery Charge per GJ $10.979¶
¶
Rider 5 (RSAM) $0.524¶

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Gas Cost Recovery Charge per GJ $4.029¶
¶
Minimum Monthly Charge $7.50

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Table of Charges

Whistler Area

Delivery Margin Related Charges

1. **Basic Charge** per Day	**$ X***
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

Commodity Related Charges

6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

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Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for all FortisBC Energy (Whistler) Inc. customers have been established as interim, approved effective January 1, 2012. Final determination for all FortisBC Energy (Whistler) Inc. customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation** – Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider** – Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

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Commodity Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Rider 9 (Reserved for future use.)

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Franchise Fee Charge - Except for the Option A surcharge, a Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above charges) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge, any charge under Option A and the Franchise Fee Charge.

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Gas Tariff

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Deleted: To Gas supplied to Customers at one point of delivery through one meter.

Deleted: Conditions

Deleted: Rate Rider A is applicable to all Customers served under the General Service Rate Tariff (SGS). Rate Rider A serves to recover increased Gas costs accumulated in the Gas Cost Deferral Account.

Deleted: Rate Rider A is to be applied in addition to the approved rates beginning July 1, 2001.

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A

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Deleted: Order No.: G-177-11/G196-11 Issued By: Diane Roy, Director, Regulatory Affairs¶
¶
Effective Date: January 1, 2012¶
¶
BCUC Secretary: *Original signed by Alanna Gillis* Third Revision of Page 36

Deleted: RATE RIDER B
RECOVERY OF JULY TO DECEMBER 2009 APPROVED RETURN ON EQUITY AND CAPITAL STRUCTURE

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Deleted: To Gas supplied to Customers at one point of delivery through one meter.

Deleted: Conditions

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Rate Schedule 2: Small Commercial Service

Available

This Rate Schedule is available in all areas served by FortisBC Energy provided, adequate capacity exists in FortisBC Energy's System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of less than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

Table of Charges

Whistler area

Delivery Margin Related Charges

1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

Whistler area

Commodity Related Charges

6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. all non-bypass customers have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. non-bypass customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.

Rate Schedule 3: Large Commercial Service

Available

This Rate Schedule is available to all Customers served by FortisBC Energy provided, adequate capacity exists in FortisBC Energy's System.

Applicable

This Rate Schedule is applicable to Customers with a normalized annual consumption at one Premises of greater than 2,000 Gigajoules of firm Gas, for use in approved appliances in commercial, institutional or small industrial operations.

Table of Charges

Whistler area

Delivery Margin Related Charges

1. **Basic Charge** per Day	**$ X**
2. Delivery Charge per Gigajoule	$ X
3. Rider 2 per Gigajoule	$ X
4. Rider 4 per Gigajoule	$ X
5. Rider 5 per Gigajoule	$ X
Subtotal of per Gigajoule **Delivery** Margin Related Charges	**$ X**

Whistler area

Commodity Related Charges

6. Midstream Cost Recovery Charge per Gigajoule	$ X
7. Rider 6 per Gigajoule	$ X
Subtotal of per Gigajoule **Midstream** Cost Recovery Related Charges	**$ X**
8. **Cost of Gas** (Commodity Cost Recovery Charge) per Gigajoule	**$ X**

Delivery Margin Related Riders

Rider 2 **Rate Stabilization Deferral Account Allocation –** Applicable to all Customers in locations listed under the Mainland area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 3 (Reserved for future use.)

Rider 4 **Phase In Rider –** Applicable to all Customers listed under the Fort Nelson area in the Definitions of the General Terms and Conditions for the Year ending December 31, 2014.

Rider 5 **Revenue Stabilization Adjustment Charge** - Applicable to all Customers served by FortisBC Energy for the Year ending December 31, 2014.

Commodity Cost Recovery Charge Related Riders

Rider 1 **Propane Surcharge** - Applicable to all Customers located in the City of Revelstoke and surrounding areas.

Midstream Cost Recovery Charge Related Riders

Rider 6 **Midstream Cost Reconciliation Account** - Applicable to all Customers served by FortisBC Energy, excluding Revelstoke, for the Year ending December 31, 2014.

Rider 8 (Reserved for future use.)

Franchise Fee Charge of 3.09% of the aggregate of the above charges is payable (in addition to the above changes) if the Premises to which Gas is delivered under this Rate Schedule is located within the boundaries of a municipality or First Nations lands (formerly, reserves within the *Indian Act*) to which FortisBC Energy pays Franchise Fees.

Minimum Charge per Month - The minimum charge per Month will be the aggregate of the Basic Charge and the Franchise Fee Charge.

Interim Rate Establishment – Pursuant to the British Columbia Utilities Commission Order No. G-177-11, current delivery rates for FortisBC Energy Inc. all non-bypass customers have been established as interim rates, effective January 1, 2012. Final determination of delivery rates for FortisBC Energy Inc. non-bypass customers will be subject to the Commission's decision on the FortisBC Energy Utilities 2012 and 2013 Revenue Requirements and Natural Gas Rates Application. Any refund or under-collection following the final determination of delivery rates will be addressed by way of a rate rider to refund or collect from customers the variance in interim rates versus permanent delivery rates approved.

Attachment 17.1

Interest rate outlook

%, end of period

	10Q2	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4
Canada											
Overnight	0.50	1.00	1.00	1.00	1.00	1.25	1.75	2.25	2.50	2.75	3.00
Three-month	0.50	0.88	0.97	1.10	1.20	1.70	2.15	2.40	2.65	2.90	3.15
Two-year	1.39	1.40	1.71	1.85	1.75	2.15	2.40	2.80	3.00	3.35	3.75
Five-year	2.32	2.04	2.46	2.65	2.50	3.00	3.30	3.50	3.65	3.85	4.05
10-year	3.08	2.75	3.16	3.25	3.25	3.50	3.80	3.95	4.05	4.15	4.15
30-year	3.65	3.34	3.55	3.80	3.75	4.00	4.30	4.45	4.50	4.50	4.55
United States											
Fed funds	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0 to 0.25	0.50	1.00	1.50
Three-month	0.18	0.16	0.12	0.15	0.20	0.20	0.25	0.35	0.65	1.25	1.70
Two-year	0.61	0.44	0.61	0.70	0.80	0.90	1.10	1.25	1.60	2.00	2.50
Five-year	1.79	1.27	2.01	2.10	2.00	2.30	2.60	2.80	3.05	3.40	3.75
10-year	2.97	2.48	3.30	3.45	3.25	3.65	4.00	4.15	4.25	4.45	4.50
30-year	3.91	3.67	4.34	4.50	4.55	4.60	4.85	4.90	4.95	5.00	5.05
United Kingdom											
Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.75	1.00	1.25	1.50	1.75
Two-year	0.74	0.85	1.09	1.30	1.40	1.50	1.80	2.00	2.20	2.40	2.55
10-year	3.36	3.20	3.40	3.65	3.50	3.70	3.85	4.10	4.10	4.50	4.60
Eurozone											
Minimum bid	1.00	1.00	1.00	1.00	1.25	1.50	1.75	2.00	2.25	2.50	2.75
Two-year	0.59	0.60	0.85	1.75	1.85	2.00	2.25	2.45	2.60	2.70	2.80
10-year	2.55	2.25	2.96	3.30	3.25	3.50	3.60	3.75	3.75	4.00	4.10
Norway											
Sight deposit rate	2.00	2.00	2.00	2.00	2.25	2.50	2.75	3.00	3.25	3.50	3.75
Sweden											
Repo rate	0.25	0.50	1.25	1.50	1.75	2.25	2.50	2.75	3.00	3.25	3.50
Australia											
Cash target rate	4.50	4.50	4.75	4.75	4.75	5.00	5.00	5.25	5.25	5.50	5.50
Two-year	4.44	4.40	5.16	5.00	4.90	5.10	5.20	5.30	5.40	5.50	5.50
10-year	5.10	4.75	5.57	5.55	5.35	5.65	5.75	5.85	5.85	5.95	6.00
New Zealand											
Cash target rate	2.75	3.00	3.00	2.50	2.50	2.50	2.50	2.75	3.25	3.50	3.75
Three-year	4.16	4.20	4.00	3.25	3.40	3.60	3.85	4.10	4.30	4.50	4.60
10-year	5.73	5.20	5.90	5.50	5.20	5.50	5.65	5.75	5.80	6.00	6.10
Yield curve											
Canada	169	135	145	140	150	135	140	115	105	80	40
United States	236	204	269	275	245	275	290	290	265	245	200
United Kingdom	262	235	231	235	210	220	205	210	190	210	205
Eurozone	196	165	211	155	140	150	135	130	115	130	130
Australia	66	35	41	55	45	55	55	55	45	45	50
New Zealand	157	100	190	225	180	190	180	165	150	150	150

* Two-year/10-year spread in basis points **New Zealand's yield curve: 10-year vs. three-year

Source: Reuters, RBC Economics Research

Central bank policy rate

%, end of period

		Current	Last				Current	Last	
United States	Fed funds	0.0-0.25	1.00	Dec. 16, 2008	Eurozone	Min. bid rate	1.25	1.00	April 11, 2011
Canada	Overnight rate	1.00	0.75	Sep. 08, 2010	Australia	Cash rate	4.75	4.50	Nov. 03, 2010
United Kingdom	Repo rate	0.50	1.00	Mar. 5, 2009	New Zealand	Cash rate	2.50	3.00	Mar. 10, 2011

Source: Bloomberg, Reuters, RBC Economics Research

Growth outlook

% change, year-over-year in real GDP

	10Q1	10Q2	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009A	2010A	2011F	2012F
Canada	2.1	3.6	3.8	3.3	2.9	3.1	3.4	3.4	3.3	3.3	2.9	2.7	-2.8	3.2	3.2	3.1
United States	2.4	3.0	3.2	2.8	2.3	2.8	3.2	3.4	3.9	3.8	3.5	3.3	-2.6	2.9	3.0	3.6
United Kingdom	-0.4	1.5	2.5	1.5	1.8	1.0	1.0	2.1	2.3	2.6	2.4	2.4	-4.9	1.3	1.5	2.4
Eurozone	0.8	2.0	2.0	2.0	2.5	1.8	1.8	2.0	1.6	1.7	1.8	1.8	-4.1	1.7	2.0	1.8
Australia	2.2	3.2	2.5	2.7	1.0	1.6	3.9	3.9	5.7	4.2	2.6	2.6	1.4	2.7	2.6	3.8
New Zealand	1.8	1.9	1.5	0.7	-0.1*	0.1	0.9	1.7	2.8	3.5	4.0	4.1	-2.1	1.5	0.7	3.6

* forecast

Inflation outlook

% change, year-over-year

	10Q1	10Q2	10Q3	10Q4	11Q1	11Q2	11Q3	11Q4	12Q1	12Q2	12Q3	12Q4	2009A	2010A	2011F	2012F
Canada	1.6	1.4	1.8	2.3	2.6	3.2	2.7	2.1	1.8	1.9	2.2	2.3	0.3	1.8	2.6	2.1
United States	2.4	1.8	1.2	1.3	2.1	3.3	2.9	2.6	2.0	1.8	1.8	1.7	-0.4	1.6	2.7	1.8
United Kingdom	3.3	3.4	3.1	3.4	4.1	4.5	4.6	4.6	3.1	1.9	1.9	1.9	2.2	3.3	4.5	2.1
Eurozone	1.1	1.6	1.7	2.0	2.5	2.7	2.8	2.7	2.4	2.2	2.2	1.9	0.3	1.6	2.7	2.2
Australia	2.9	3.1	2.8	2.7	3.3	3.6	3.7	4.1	3.4	3.3	3.2	3.1	1.8	2.8	3.7	3.3
New Zealand	2.0	1.7	1.5	4.0	4.5	4.7	4.2	2.1	1.7	1.8	1.7	2.0	2.1	2.3	3.8	1.8

Source: Statistics Canada, Bureau of Labor Statistics, Bank of England, European Central Bank, Reserve Bank of Australia, Reserve Bank of New Zealand, RBC Economics Research

Inflation tracking

Inflation Watch

	Measure	Current period	Month ago	Year ago	Three-month trend	Six-month trend
Canada	Bank of Canada core CPI[1]	Apr.	0.2	1.6	1.7	1.5
United States	Core PCE[2]	Apr.	0.2	1.0	1.7	0.9
United Kingdom	All-items CPI	Apr.	1.0	4.5	6.9	4.8
Eurozone	All-items CPI[3]	Mar.	1.4	2.7	1.8	2.0
Australia	Trimmed mean	Q1	0.9	2.3	N/A	N/A
New Zealand	CPI	Q1	0.8	4.5	N/A	N/A

1 Seasonally adjusted measurement
2 Personal consumption expenditures less food and energy price indices

Source: Statistics Canada, U.S. Bureau of Labor Statistics, Bank of England, European Central Bank, Reserve Bank of Australia, Reserve Bank of New Zealand, RBC Economics Research

RBC Capital Markets

Canada	2011	2012	2013	2014	2015	2016
Overnight Rate	1.75%	3.00%	4.00%	4.25%	4.25%	4.25%
5yr GoC	3.30%	4.05%	4.25%	4.55%	4.75%	4.75%
10yr GoC	3.80%	4.15%	4.75%	5.00%	5.25%	5.25%
30yr GoC	4.30%	4.55%	5.15%	5.40%	5.60%	5.60%

**Forecasts are for the end of each year*

CANADIAN ECONOMIC OUTLOOK

Period-Over-Period Annualized Per Cent Change Unless Otherwise Indicated

	2011				2012				2013				Annual Average				4th Qtr/4th Qtr			
	Q1	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	10	11F	12F	13F	10	11F	12F	13F
Real GDP	3.9	1.3	2.8	2.7	2.6	2.5	2.3	2.2	2.1	2.0	2.0	2.2	3.2	2.8	2.5	2.1	3.3	2.7	2.4	2.1
Consumer Expenditure	0.2	2.5	2.6	2.5	2.4	2.2	2.0	1.7	1.8	2.0	2.1	2.1	3.3	2.3	2.3	1.9	3.2	1.9	2.1	2.0
Durable Goods	-5.6	2.5	2.7	2.5	2.0	1.5	0.8	-0.5	1.0	1.5	1.8	1.9	4.4	1.2	1.8	1.0	2.1	0.5	0.9	1.5
Business Investment	13.5	14.4	8.3	8.0	8.1	8.1	8.3	9.2	8.0	7.4	7.1	6.3	7.3	14.0	8.6	7.9	16.6	11.0	8.4	7.2
Non-Res. Structures	11.8	9.0	8.2	7.9	7.8	7.2	6.7	6.5	5.0	4.8	4.7	4.5	2.8	12.7	7.6	5.5	15.9	9.2	7.0	4.7
Machinery & Equipment	15.4	20.0	8.5	8.1	8.5	9.0	10.0	12.0	11.0	10.0	9.5	8.0	11.8	15.3	9.6	10.4	17.3	12.9	9.9	9.6
Residential Investment	9.4	2.5	-2.0	-4.5	-5.5	-2.0	-0.5	2.1	2.5	2.8	3.0	3.1	10.2	1.3	-2.7	1.9	2.9	1.2	-1.5	2.8
Government Expenditures	5.9	-2.2	-0.6	-0.3	-0.3	-0.3	-0.4	-0.6	-0.2	-0.4	-0.2	-0.2	4.7	0.9	-0.5	-0.3	1.5	-0.3	-0.4	-0.3
Final Domestic Demand	2.3	2.6	2.1	1.9	1.9	2.0	2.0	2.1	2.1	2.1	2.2	2.2	4.5	3.1	2.0	2.1	4.6	2.2	2.0	2.2
Exports	6.4	2.0	6.8	6.4	6.8	6.2	5.9	5.8	5.3	5.0	4.7	4.6	6.4	5.4	6.1	5.3	7.0	5.4	6.2	4.9
Imports	18.7	5.1	3.9	3.9	5.2	5.5	5.0	4.3	4.7	4.6	4.5	4.1	13.1	6.1	4.8	4.6	10.2	5.5	5.0	4.5
Change in Non-Farm Inventories ($2002 Bn)	7.7	5.0	5.3	6.3	7.6	9.2	9.0	8.0	6.5	5.0	3.0	1.8	7.4	6.1	8.5	4.1	--	--	--	--
Final Sales	0.9	1.8	3.2	2.9	2.4	2.1	2.3	2.6	2.4	2.3	2.3	2.4	1.9	2.9	2.5	2.4	3.2	2.2	2.4	2.4
International Current Account Balance ($Bn)	-35.7	-31.8	-23.6	-19.2	2.6	4.5	6.6	8.4	9.6	10.8	11.5	12.7	-50.9	-27.6	5.5	11.1	--	--	--	--
% of GDP	-2.1	-1.8	-1.4	-1.1	0.1	0.2	0.4	0.5	0.5	0.6	0.6	0.7	-3.1	-1.6	0.3	0.6	--	--	--	--
Pre-tax Corp. Profits	22.1	9.2	4.6	3.5	5.0	6.5	7.5	8.0	7.5	7.6	7.7	7.6	21.2	15.4	5.7	7.6	19.1	9.6	6.7	7.6
% of GDP	12.0	12.1	12.1	12.0	12.0	12.1	12.2	12.3	12.4	12.5	12.6	12.7	11.1	12.0	12.2	12.6	--	--	--	--
GDP Deflator (Y/Y)	3.0	4.1	4.4	3.2	2.7	2.0	1.9	2.0	1.9	2.0	2.0	2.0	2.9	3.7	2.2	2.0	2.8	3.2	2.0	2.0
Nominal GDP	8.7	6.2	5.2	4.3	5.0	4.5	4.4	4.1	4.1	4.1	4.0	4.1	6.3	6.6	4.7	4.1	6.2	6.1	4.5	4.1
Labour Force	2.6	1.0	1.5	1.4	1.2	1.0	0.8	0.8	0.8	0.8	0.7	0.7	1.1	1.2	1.1	0.8	0.9	1.6	0.9	0.7
Employment	2.4	2.0	1.2	1.3	1.4	1.3	1.2	1.2	1.1	1.0	1.0	1.0	1.4	1.7	1.3	1.1	1.7	1.7	1.3	1.0
Employment ('000s)	101	85	52	56	61	57	52	53	48	44	44	44	231	283	232	194	279	294	222	181
Unemployment Rate (%)	7.8	7.5	7.6	7.6	7.6	7.5	7.4	7.3	7.2	7.2	7.1	7.1	8.0	7.6	7.4	7.1	--	--	--	--
Personal Disp. Income	3.0	4.2	3.1	3.6	3.8	4.2	4.5	3.9	3.8	3.8	3.8	3.8	4.9	3.7	3.9	3.9	5.6	3.5	4.1	3.8
Pers. Savings Rate (%)	4.2	4.0	3.9	4.0	3.9	3.9	4.1	4.2	4.3	4.3	4.3	4.3	4.8	4.0	4.0	4.3	--	--	--	--
Cons. Price Index (Y/Y)	2.6	3.0	2.8	2.7	2.4	2.2	2.1	2.1	2.1	2.1	2.1	2.0	1.8	2.8	2.2	2.1	2.3	2.7	2.1	2.0
Core CPI (Y/Y)	1.3	1.6	1.8	1.9	2.1	1.9	2.0	2.0	2.2	2.1	2.0	2.0	1.7	1.7	2.0	2.1	1.6	1.9	2.0	2.0
Housing Starts ('000s)	178	176	174	172	170	166	160	160	168	170	172	174	192	175	164	171	--	--	--	--
Productivity: Real GDP / worker (Y/Y)	1.0	1.1	1.3	1.0	0.9	1.4	1.2	1.1	1.1	1.0	1.0	1.0	1.8	1.1	1.2	1.0	1.7	1.0	1.1	1.0

F: Forecast by TD Economics as at June 2011

Source: Statistics Canada, Bank of Canada, Canada Mortgage and Housing Corporation, Haver Analytics

FINANCIAL INDICATOR OUTLOOK *end-of-period level*	Spot Rate	2011				2012				2013			
	14/06/2011	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F	Q1F	Q2F	Q3F	Q4F
CANADIAN FIXED INCOME													
Overnight Target Rate (%)	1.00	1.00	1.00	1.00	1.00	1.50	2.00	2.00	2.00	2.50	3.00	3.00	3.00
3-mth T-Bill Rate (%)	0.98	0.96	1.05	1.10	1.25	1.55	2.05	2.10	2.15	2.55	3.10	3.10	3.10
2-yr Govt. Bond Yield (%)	1.47	1.83	1.45	1.65	2.00	2.30	2.80	2.75	3.10	3.30	3.60	3.60	3.60
5-yr Govt. Bond Yield (%)	2.25	2.77	2.30	2.45	2.70	2.95	3.30	3.40	3.65	4.00	4.20	4.20	4.20
10-yr Govt. Bond Yield (%)	3.00	3.35	3.15	3.30	3.60	3.85	4.10	4.20	4.30	4.40	4.60	4.60	4.60
30-yr Govt. Bond Yield (%)	3.46	3.76	3.50	3.65	3.90	4.10	4.20	4.30	4.35	4.50	4.55	4.55	4.55
10-yr-2-yr Govt. Spread (%)	1.53	1.52	1.70	1.65	1.60	1.55	1.30	1.45	1.20	1.10	1.00	1.00	1.00
GLOBAL CURRENCIES													
USD per CAD	1.02	1.03	1.03	1.01	1.00	1.00	1.02	1.03	1.05	1.05	1.05	1.03	1.03
USD per EUR	1.44	1.42	1.44	1.48	1.45	1.40	1.42	1.45	1.45	1.40	1.40	1.38	1.38
JPY per USD	80.4	83.1	80.0	81.0	85.0	90.0	91.0	92.0	95.0	99.0	99.0	100.0	100.0

F: Forecast by TD Economics as at June 2011
Source: Statistics Canada, Bank of Canada, Bloomberg

ECONOMIC UPDATE

CANADA	11Q1A	11Q2F	11Q3F	11Q4F	12Q1F	12Q2F	12Q3F	2010A	2011F	2012F
Real GDP Growth (AR)	3.9	1.0	2.7	3.3	3.1	2.5	2.1	3.2	2.7	2.6
Real Final Domestic Demand (AR)	2.3	1.9	1.7	2.9	3.4	2.3	2.1	4.5	3.0	2.6
All Items CPI Inflation (Y/Y)	2.6	3.3	2.7	2.4	1.7	1.4	1.8	1.8	2.8	1.7
Core CPI Ex Indirect Taxes (Y/Y)	1.3	1.7	2.1	2.1	2.0	2.1	2.1	1.7	1.8	2.0
Unemployment Rate (%)	7.7	7.5	7.4	7.4	7.6	7.6	7.4	8.0	7.5	7.4

U.S.	11Q1A	11Q2F	11Q3F	11Q4F	12Q1F	12Q2F	12Q3F	2010A	2011F	2012F
Real GDP Growth (AR)	1.9	2.1	3.1	2.1	2.1	2.5	2.7	2.9	2.4	2.4
Real Final Sales (AR)	0.6	2.1	3.6	2.3	2.1	2.5	2.7	1.4	2.6	2.5
All Items CPI Inflation (Y/Y)	2.1	3.5	3.2	3.0	2.3	1.5	2.4	1.6	3.0	2.2
Core CPI Inflation (Y/Y)	1.1	1.4	1.5	1.7	1.8	1.6	1.8	1.0	1.4	1.8
Unemployment Rate (%)	8.9	9.0	9.1	9.2	9.2	9.0	8.8	9.6	9.1	8.9

CANADA

April's GDP is set to be released shortly, but our call for a slow start to the quarter could see Q2 activity come in at 1%, underperforming our prior call of 1.8%. That could take the year's GDP growth down a tick to 2.7%. Activity is set to pick up in the latter half of the year, supported by a re-start to stalled production activity, as well as some relief for consumers as gasoline pump prices decline. A strong employment report for May and an encouraging trend of private-sector hiring had us knock off a tick from our call for the 2011 unemployment rate, now looking to average around 7.5%. As we had long expected, falling gasoline prices should see inflation softening for the rest of the year.

UNITED STATES

Weaker-than-expected consumer numbers have prompted us to further trim estimated Q2 performance. Although our revised estimate for Q2 GDP is just 2.1%, an easing of auto supply constraints and the favourable impact of lower gasoline on consumers should see growth pick up to just over 3% in the third quarter. An increase of 2.4% for the whole of 2012 assumes that the two parties reach agreement to extend tax stimulus for another year, cushioning the blow from fiscal restraint. The high jobless rate and continuing sub-2% core inflation due to appreciable economic slack will keep the Fed on hold through the end of 2012.

Attachment 23.13

Corporate Diversification and the Cost of Capital

by

Rebecca N. Hann[*], Maria Ogneva[**], and Oguzhan Ozbas[***]

September 2009

Abstract

We examine whether organizational form matters for a firm's cost of capital. Contrary to the conventional view, our model shows that coinsurance among a firm's business units can reduce systematic risk through the alleviation of countercyclical deadweight costs. Using measures of implied cost of capital constructed from analyst forecasts, we find that diversified firms have on average a lower cost of capital than stand-alone firms. In addition, diversified firms with less correlated segment cash flows have a lower cost of capital, consistent with a coinsurance effect. Holding the magnitude of cash flows constant, our estimates imply an average value gain of approximately 6% when moving from the highest to the lowest cash flow correlation quintile.

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1. Introduction

The conventional view among practitioners and researchers is that organizational form does not matter for a firm's cost of capital because, while the imperfect correlation of business unit cash flows may help reduce idiosyncratic risk, this should have no effect on systematic risk.[1] In this paper, we present evidence that is contrary to the conventional view. We show that diversified firms have a lower cost of capital than portfolios of comparable stand-alone firms and that the reduction is strongly related to the correlation of business unit cash flows, consistent with a coinsurance effect.

A large body of research inspired by Coase's (1937) fundamental question about the boundaries of the firm points to various costs (Rajan, Servaes, and Zingales (2000), Scharfstein and Stein (2000)) and benefits (Matsusaka and Nanda (2002), Stein (1997)) of integration. In theory, if the cash flows due to integration costs and benefits carry precisely the same systematic risk as the cash flows of the underlying businesses, then the conventional view holds – organizational form will not affect cost of capital. Short of this restrictive condition, however, a diversified firm's cost of capital will differ from that of its business units as stand-alone firms. For instance, if integration benefits (costs) carry less (more) systematic risk, then a diversified firm should have a lower cost of capital.

We argue that organizational form can matter, and in particular, coinsurance among a firm's business units can reduce the firm's cost of capital. The economic intuition underlying our argument is easily illustrated: (i) coinsurance – the imperfect correlation among the cash flows of a diversified firm's business units – reduces default risk (Lewellen (1971)); and (ii) default risk

[1] The conventional view has long been a part of standard finance textbooks such as Brealey, Myers, and Allen or Ross, Westerfield, and Jaffe, and thus may alternatively be referred to as the textbook view. The notion that corporate diversification cannot affect systematic risk is usually covered explicitly in the mergers and acquisitions chapter (e.g., "Systematic variability cannot be eliminated by diversification, so mergers will not eliminate this risk at all," RWJ, p. 823) or implicitly in the capital budgeting chapter (e.g. the stand-alone principle)..

has a systematic component (Elton, Gruber, Agrawal, and Mann (2001), Almeida and Philippon (2007)). Intuitively, if coinsurance enables a diversified firm to avoid systematic financial distress costs that its business units would otherwise incur if they were stand-alone firms, then coinsurance should lead to a reduction in the diversified firm's systematic risk and hence its cost of capital. In this paper, we show in a parsimonious model that the coinsurance idea outlined above is more general and that it extends to an all-equity firm if one replaces costs of financial distress with other kinds of systematic deadweight costs that even an all-equity firm might face. Our main result is that coinsurance and the ability of a diversified firm to avoid deadweight costs by transferring financial resources from cash-rich units to cash-poor units reduce systematic risk when deadweight costs are partly systematic.[2] In addition, we show that the coinsurance effect is stronger when the firm's units have less correlated cash flows.[3]

We examine the connection between organizational form and a firm's cost of capital using a sample of single- and multi-segment firms spanning the period 1988 to 2006. Our cost of capital proxy is the weighted average of cost of equity and cost of debt. We use ex ante measures of expected returns for both components of financing: implied cost of equity constructed from analyst forecasts to proxy for expected equity returns and yields from the Barclays Capital Aggregate Bond Index to proxy for expected debt returns.[4] Thus, our study avoids the many pitfalls of using ex post measures such as stock or bond returns as proxies for expected returns

[2] We assume that it is difficult or costly to write complete state-contingent contracts to transfer resources between cash-rich and cash-poor firms. Without this assumption, corporate diversification would offer no benefit over what investors could achieve through portfolio diversification. We also assume that holding financial slack is costly, as otherwise firms would hold the first-best amount of financial slack to avoid any future deadweight cost.

[3] We consider several extensions, including the possibility of integration costs arising from inefficient transfers and agency problems within diversified firms, and show that under certain conditions the coinsurance effect can be consistent with a diversification discount.

[4] Our empirical proxy for expected debt returns is admittedly a relatively crude proxy, as it is an aggregate measure and hence does not capture any firm-level variation in expected debt returns. However, as Lamont and Polk (2001) point out, debt returns are not readily available for most firms and using a proxy that measures only expected equity returns ignores the importance of debt in a firm's capital structure. To the extent that coinsurance lowers both cost of equity and cost of debt, our empirical proxy would understate the effect of coinsurance on total cost of capital.

(Elton (1999)). We estimate the implied cost of equity based on the approach of Gebhardt, Lee, and Swaminathan (2001), which has been successfully employed in several asset-pricing contexts (Lee, Ng, and Swaminathan (2007), Pastor, Sinha, and Swaminathan (2008)). Our empirical analyses are based on an "excess cost of capital" measure that benchmarks the cost of capital of a diversified firm against that of a comparable portfolio of stand-alone firms.

We find that diversified firms on average have a significantly lower cost of capital compared to portfolios of stand-alone firms, rejecting the conventional view that organizational form does not matter for a firm's cost of capital. To explore whether the difference is due to coinsurance, we consider the correlation of cash flows among a firm's segments as an inverse measure of coinsurance. Consistent with a coinsurance effect, we find a significant and positive association between excess cost of capital and cross-segment cash flow correlations. These findings are robust to using alternative measures of implied cost of equity capital (Claus and Thomas (2001), Easton (2004)) and coinsurance (Duchin (2008)). These findings are also economically significant. Our estimates imply an average cost of capital reduction of approximately 3% and an average value gain of approximately 6% when moving from the highest to the lowest cash flow correlation quintile.[5]

Our estimates of implied cost of equity are subject to potential measurement errors arising from analyst forecast bias.[6] We therefore perform various sensitivity tests to address this issue. First, we control for analyst forecast errors in our main multivariate regression analysis and find similar results. Second, we perform analysis based on Easton and Monahan's (2006)

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[5] It is possible that these estimates represent a lower bound on the effect of coinsurance because our proxies are limited to segment data and do not capture coinsurance among different product lines or geographic areas.

[6] Our analysis is also subject to a potential self-selection bias, an issue that has been addressed extensively in the diversification discount literature (Campa and Kedia (2002), Graham, Lemmon, and Wolf (2002), Villalonga (2004)). However, it is unclear how a strong monotonic relation between our continuous coinsurance measures and excess cost of capital would be driven by a dichotomous selection mechanism that pushes some business units to conglomerate. Nevertheless, we perform a sensitivity test using Heckman's two-stage method to correct for a potential selection bias and we find similar results.

finding that implied cost of equity estimates are generally reliable when analysts' forecast accuracy is high. We partition our sample based on absolute forecast errors and find that our results are strongest in the subsample with the lowest errors, which suggests that our findings are weakened by forecast errors, rather than induced by them. Finally, we use Fama-French factor loadings to estimate cost of equity capital and find remarkably similar results.

We believe our study is the first to establish a link between coinsurance among a firm's business units and the systematic risk of its cash flows, and hence between coinsurance and cost of capital. Following Lewellen (1971), a stream of research studies coinsurance in the context of conglomerate mergers (Higgins and Schall (1975), Scott (1977)) and examines whether such mergers lead to wealth transfers from shareholders to bondholders (Kim and McConnell (1977)), a hypothesis supported by the findings of Mansi and Reeb (2002) based on segment disclosures. More recently, Duchin (2008) studies the relation between coinsurance and firms' cash retention policies. Our paper combines with Duchin's paper to form a nascent literature examining the implications of coinsurance for corporate finance in general.

Our study also complements the literature on corporate diversification and firm value (Lang and Stulz (1994) and Berger and Ofek (1995)) by exploring an important dimension that thus far has received little attention, namely, cost of capital. The discussion in this literature mostly revolves around cash flow differences between conglomerates and stand-alone firms. An exception is Lamont and Polk (2001), who raise the possibility that the discount (or premium) may arise due to differences in expected returns. They find a significant and negative association between excess values and future returns for diversified firms, suggesting that the diversification discount is explained in part by differences in expected returns. While their study introduces the important role of expected returns in understanding the valuation of diversified firms, their main focus is to explain the cross-sectional variation in excess value, and not *how* diversification affects a firm's cost of capital. By exploring whether the cross-sectional variation in cost of capital is due to coinsurance, our work deepens the foundations of this literature.

Our work is also related to Ortiz-Molina and Phillips (2009), who find that firms with more liquid real assets have a lower cost of capital using the implied cost of equity developed by Gebhardt et al. (2001). To the extent their measure of real asset liquidity is inversely related to deadweight costs that firms incur when selling assets, their findings confirm our model assumption that deadweight costs have a systematic component. Benmelech and Bergman's (2009) recent work showing that debt tranches of airlines secured with more redeployable collateral have higher credit ratings and lower credit spreads also supports this notion.

Our evidence also has implications for capital budgeting. In practice, managers tend to ignore the coinsurance benefit of enhanced debt capacity and the resulting tax-related reduction in weighted average cost of capital in their capital budgeting decisions, perhaps because they perceive the tax effect to be small. Our results provide two interesting insights on this issue. First, our model shows that there is a coinsurance effect even in the absence of taxes or debt financing. Second, investors appear to understand the effect of diversification on systematic risk and adjust the discount rate they use in valuing expected future cash flows accordingly. Taken together, our findings suggest that ignoring coinsurance effects and using project-specific discount rates as commonly taught and practiced may yield incorrect (i.e., understated) NPV estimates. In our model, the covariance between a proposed project's cash flows and those of existing projects determines both the expected level and the systematic risk of synergistic coinsurance cash flows. As a result, covariances matter for capital budgeting (Lintner (1965)).[7]

[7] Standard finance textbooks either explicitly cite or implicitly follow Schall (1972) in emphasizing the irrelevancy of covariance and corporate diversification when explaining the *stand-alone principle* and potential synergy

The remainder of the paper is organized as follows. Section 2 develops our model, which shows that corporate diversification can reduce not only idiosyncratic but also systematic risk. Section 3 discusses the valuation approach we use in estimating the implied cost of equity and its empirical implementation, along with the construction of the excess cost of capital and coinsurance measures. Section 4 describes our sample and data. Section 5 presents our empirical results. Section 6 concludes.

2. A Model of Corporate Diversification and the Cost of Capital

As discussed earlier, the conventional view on corporate diversification is that it reduces only *idiosyncratic* risk. In this section, we outline a parsimonious model of corporate diversification to demonstrate *how* integrating business units with imperfectly correlated cash flows under one roof can also lead to a reduction in *systematic* risk and hence the cost of capital.

Our basic model assumes all-equity financing and an efficient internal capital market to illustrate the coinsurance effect. In the Appendix, we relax these assumptions and extend the basic model to incorporate debt financing and the possibility of rent-seeking activities and inefficient transfers in internal capital markets.

2.1. The Two-state Economy and the Relation between Asset Betas and Expected Returns

Before we introduce firms, we first describe the two-state economy in which we study corporate diversification and the effect of coinsurance on cost of capital.

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adjustments in capital budgeting. Schall's analysis rules out by assumption the possibility that synergistic cash flows may be a function of covariance.

Suppose that the economy has two dates, $t \in \{0,1\}$, and is populated with risk-averse investors. At $t = 1$, the economy can be either good (g) or bad (b) with probability p_g and $(1 - p_g)$, respectively. In equilibrium, there exists a strictly positive stochastic discount factor m $(m_g < m_b)$ that prices all assets with cash flow C at $t = 1$ according to the relation

$$V = E[C \cdot m],$$

where E is the expectation operator and V is the value of the asset at $t = 0$. We are interested in the pricing of traded assets with positive cash flow $C \in R^+$.

In the two-state economy described above, the value of asset i at $t = 0$ with cash flow C^i at $t = 1$ is given by

$$V^i = p_g C_g^i m_g + (1 - p_g) C_b^i m_b. \tag{1}$$

Definition 1 *The expected rate of return on asset i, $E[r^i]$, is the discount rate that equates the discounted value of asset i's expected cash flow at $t = 1$ to asset i's value at $t = 0$:*

$$V^i = \frac{E[C^i]}{1 + E[r^i]} \tag{2}$$

Let $\beta^i \equiv (C_g^i / C_b^i - 1)$. Note that β^i is monotone in the conventional measure of systematic risk $-\operatorname{cov}(C^i, m)$ because $m_g < m_b$. This means that we can use β^i as an analytically convenient measure of the systematic risk of asset i's cash flow in deriving comparative statics. The following lemma formalizes this relation.

Lemma 1 *Given any equilibrium summarized by (p_g, m_g, m_b), $E[r^i]$ depends only on β^i and it increases in β^i.*

Proof. Substituting equation (1) into (2),

$$1+E[r^i]=\frac{p_g C_g^i+(1-p_g)C_b^i}{p_g C_g^i m_g+(1-p_g)C_b^i m_b}.$$

Restating $E[r^i]$ in terms of β^i in an equilibrium summarized by (p_g, m_g, m_b),

$$E[r^i]=\frac{p_g\beta^i+1}{p_g\beta^i m_g+(1-p_g)m_b+p_g m_g}-1.$$

Simple algebra shows that

$$\frac{\partial E[r^i]}{\partial\beta^i}=\frac{p_g(1-p_g)(m_b-m_g)}{[p_g\beta^i m_g+(1-p_g)m_b+p_g m_g]^2}.$$

Since the probability-adjusted value of cash flow in the bad state m_b is greater than the probability-adjusted value of cash flow in the good state m_g, $\partial E[r^i]/\partial\beta^i>0$. *Q.E.D.*

2.2. Firm Cash Flows and the Cost of Capital

Having established the relation between betas and equilibrium expected returns, we now turn to firm cash flows and the cost of capital in our model. A maintained assumption in the model is that it is difficult or costly to write complete state-contingent contracts to transfer resources between cash-rich and cash-poor firms. Without this assumption, corporate diversification would offer no cost of capital benefit over what investors can achieve through portfolio diversification. Another maintained assumption in the model is that holding financial slack is costly. Otherwise, firms would hold the first-best amount of financial slack to avoid any future deadweight cost.

One Stand-alone Firm

Suppose that a stand-alone firm is a project that experiences either a high (h) or a low (l) outcome with probability θ and $(1-\theta)$, respectively. The parameter θ depends on the state of the economy. Specifically, the probability of a high outcome is $\theta_g\,(\theta_b)$ when the economy is good (bad).

Investors receive H when the project's outcome is h. When the project's outcome is l, lack of confidence in the firm leads to costly defections by important stakeholders such as suppliers and customers, in which case the firm incurs a deadweight loss L and investors receive 0.[8]

Suppose further that there are sufficiently many firms in the economy that investors can diversify away firm-specific idiosyncratic risk. Thus, investors only care about the *expected* cash flow in each state of the economy. The expected rate of return on a stand-alone firm (S) is determined by $\beta^S \equiv (C_g^S \big/ C_b^S - 1)$, where $C_g^S = \theta_g H$ and $C_b^S = \theta_b H$. A stand-alone firm whose $\theta_g > \theta_b$ carries positive systematic risk, whereas a stand-alone firm whose $\theta_g < \theta_b$ carries negative systematic risk. Accordingly, the former has a higher cost of capital than the latter. Risk-averse investors demand a risk premium for investing in assets that offer more expected cash flow when the economy is good than when the economy is bad.

[8] The assumption that investors receive nothing is without loss of generality. The loss L and the decision of important stakeholders to defect from an *all-equity* firm after observing a low outcome can be given microfoundation with costly external finance. In a multi-period model, the defection decision of suppliers and customers can be driven by concerns about the willingness of the firm to maintain relationship-specific investments (exceeding the firm's riskless debt capacity) if the returns on such investments are greater than the cost of internal finance (in insufficient supply following a low outcome) but lower than the cost of external finance. Another concern of outside parties may be counterparty exposure when entering into long-term contracts. Further, employees may defect if they think waiting to find new employment until other employees are doing the same would be costly. Hence, L represents the present value of both current and future losses.

Combining Two Stand-alone Firms into One Diversified Firm

Suppose that two identical stand-alone firms can be combined under one roof.[9] A benefit of such a corporate structure is that when one of the projects experiences a low outcome, important stakeholders of the project do not defect if the other project has a high outcome because the firm has the ability to transfer financial resources from the high-outcome project to the low-outcome project, or alternatively, the firm can use the high-outcome project as collateral to obtain external financing for the low-outcome project. Hence, while a stand-alone firm incurs some deadweight loss L when the project's outcome is l, a diversified firm with two projects may avoid this loss if the outcome of at least one of the two projects is h.[10] However, if both projects experience a low outcome, then even a diversified firm cannot avoid the deadweight loss.

Enumerating the possible project outcomes (hh, lh, hl, ll) for a diversified firm (D) comprising two stand-alone firms with independent idiosyncratic risks, the cash flows in the good and bad states of the economy are given by

$$
\begin{aligned}
C_g^D &= \theta_g^2(2H) + 2\theta_g(1-\theta_g)(H+L)\left(= 2\theta_g H + 2\theta_g(1-\theta_g)L\right) \\
C_b^D &= \theta_b^2(2H) + 2\theta_b(1-\theta_b)(H+L)\left(= 2\theta_b H + 2\theta_b(1-\theta_b)L\right).
\end{aligned}
$$

Without the terms involving L, the expected cash flow of a diversified firm C_e^D equals twice the expected cash flow of a stand-alone firm, $2C_e^S$, for $e \in \{g, b\}$. That is, without real coinsurance, a diversified firm offers nothing that investors cannot achieve on their own by investing in two stand-alone firms.

[9] For completeness, we note that the integration possibility we consider is small relative to the size of the economy. Hence, we can take the stochastic discount factor *m* as exogenous and study the effect of corporate diversification on cash flows and systematic risk without having to consider the general equilibrium effect on *m*.

[10] Our results hold as long as at least some of the deadweight loss can be avoided. Also, our setup allows for the possibility of contagion ($L < 0$), the opposite of coinsurance ($L > 0$). Indeed, all of our testable implications can be stated in terms of contagion, which our empirical tests reject in favor of coinsurance.

As the next proposition shows, one implication of coinsurance may be to reduce systematic risk in addition to increasing cash flows $(C_g^D > 2C_g^S, C_b^D > 2C_b^S)$.[11]

Proposition 1 *Combining two stand-alone firms with positive systematic and independent idiosyncratic risks reduces systematic risk and cost of capital.*

Proof. Given Lemma 1, it suffices to show that $\beta^S > \beta^D$. Substituting the cash flows above,

$$\beta^S = \frac{\theta_g H}{\theta_b H} - 1$$

$$\beta^D = \frac{2\theta_g H + 2\theta_g(1-\theta_g)L}{\underbrace{2\theta_b H}_{2C_e^S} + \underbrace{2\theta_b(1-\theta_b)L}_{\text{Coinsurance}}} - 1.$$

Finally, since $\theta_g > \theta_b$, $\beta^S > \beta^D$. *Q.E.D.*

An intuitive way to think about Proposition 1 is that a diversified firm offers two sets of cash flows: (i) the cash flow of two stand-alone firms, and (ii) an additional coinsurance cash flow whose beta,

$$\beta^{CI} = C_g^{CI} \big/ C_b^{CI} - 1,$$

is lower than that of stand-alone firms. This is because the relative probability of avoiding deadweight costs is inversely related to the state of the economy (i.e., $(1-\theta_g)$ in the good state and $(1-\theta_b)$ in the bad state). In other words, deadweight costs are partly systematic. Since β^D is a weighted average of β^S and β^{CI}, it follows that β^D must be lower than β^S as long as the probability of coinsurance is not zero.

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[11] Coinsurance effects arise even if we introduce integration costs to make the analysis cash-neutral. We incorporate integration costs in the model in the Appendix.

The intuition above also indicates that the way in which coinsurance reduces systematic risk is not specific to our model. A sufficient (though not necessary) condition for our results to hold in a general *N*-state economy with states indexed by $w \in \{1,..,N\}$ is that for any two states w' and w'' with stochastic discount factor values $m(w') \le m(w'')$, $\theta(w')$ is greater than or equal to $\theta(w'')$, and for at least one pair $m(w') < m(w'')$, $\theta(w')$ is greater than $\theta(w'')$. In other words, our results hold as long as the probability of a high outcome (deadweight loss) increases (decreases) in the state of the economy represented by the value of the stochastic discount factor.

Combining Two Stand-alone Firms with Correlated Idiosyncratic Risks

We now turn to the case of correlated idiosyncratic risks by modeling the structure of the correlation. Let $\rho \in [\underline{\rho},1]$ represent the correlation of idiosyncratic risks in both states of the economy $e \in \{g,b\}$. Then we have:

$$\begin{aligned}
p_{hh,e} &= \theta_e(\theta_e + \rho(1-\theta_e)) \\
p_{lh,e} &= (1-\theta_e)(\theta_e - \rho\theta_e) \qquad (= p_{hl,e}) \\
p_{hl,e} &= \theta_e(1-\theta_e - \rho(1-\theta_e)) \qquad (= p_{lh,e}) \\
p_{ll,e} &= (1-\theta_e)(1-\theta_e + \rho\theta_e).
\end{aligned}$$

These probabilities always add up to 1, and individually always fall between 0 and 1 in the specified region of ρ where

$$\underline{\rho} = \max\left\{-\frac{\theta_g}{1-\theta_g}, -\frac{1-\theta_g}{\theta_g}, -\frac{\theta_b}{1-\theta_b}, -\frac{1-\theta_b}{\theta_b}\right\}.$$

In addition, joint probabilities are consistent with marginal probabilities:

$$\begin{aligned}
\theta_e &= p_{hh,e} + p_{hl,e} = p_{hh,e} + p_{lh,e} \\
1-\theta_e &= p_{lh,e} + p_{ll,e} = p_{hl,e} + p_{ll,e}.
\end{aligned}$$

The case in which ρ equals 0 corresponds to the case of independence in Proposition 1. When ρ equals 1 (perfect correlation),

$$p_{hh,e} = \theta_e,\ p_{lh,e} = p_{hl,e} = 0,\ p_{ll,e} = (1-\theta_e).$$

The case of perfect correlation for a diversified firm represents a doubling of scale without any coinsurance effect.

Proposition 2 *The systematic risk and cost of capital of a diversified firm (combining two stand-alone firms with positive systematic risk) increase in* ρ*, and reach those of a stand-alone firm in the limit when* ρ *equals* 1.

Proof. Given Lemma 1, it suffices to show that $\partial\beta^D / \partial\rho > 0$ and $\beta^D = \beta^S$ when ρ equals 1.

Using the new probability structure,

$$\beta^D = \frac{\theta_g(\theta_g + \rho(1-\theta_g))(2H) + 2\theta_g(1-\theta_g)(1-\rho)(H+L)}{\theta_b(\theta_b + \rho(1-\theta_b))(2H) + 2\theta_b(1-\theta_b)(1-\rho)(H+L)} - 1$$

$$= \frac{2\theta_g H + 2\theta_g(1-\theta_g)(1-\rho)L}{\underbrace{2\theta_b H}_{2C_e^S} + \underbrace{2\theta_b(1-\theta_b)(1-\rho)L}_{\text{Coinsurance}}} - 1.$$

Simple algebra shows that

$$\frac{\partial\beta^D}{\partial\rho} = \frac{4HL\theta_g\theta_b(\theta_g - \theta_b)}{[2\theta_b H + 2\theta_b(1-\theta_b)(1-\rho)L]^2} > 0.$$

Also, when ρ equals 1, coinsurance cash flows drop out of β^D, and β^D equals β^S. *Q.E.D.*

Proposition 2 demonstrates that a diversified firm with a higher level of coinsurance should have a lower cost of capital compared to a portfolio of stand-alone firms. Since β^D is a weighted average of β^S and β^{CI}, and the weight on $\beta^{CI}\left(<\beta^S\right)$ is directly proportional to $(1-\rho)$, β^D is always less than or equal to β^S, increases in ρ, and eventually reaches β^S when

ρ equals 1. Propositions 1 and 2 consider the case of identical stand-alone firms. These results generalize to the case in which stand-alone firms have different positive betas. Given that most businesses have positive betas, the main message of our model covers a wide range of situations.

2.3. Testable Predictions

Our model lends itself to two novel testable predictions about the coinsurance effect of corporate diversification on the total cost of capital.

Prediction 1 A diversified firm, *on average*, has a lower total cost of capital than a portfolio of comparable stand-alone firms.

Prediction 1 follows from Propositions 1 and 2. In our model, a diversified firm is able to avoid deadweight costs that stand-alone firms cannot avoid on their own. The resulting coinsurance cash flows tend to have lower systematic risk than the underlying stand-alone assets, and this in turn reduces the total cost of capital of diversified firms.

Prediction 2 A diversified firm comprised of businesses with less correlated cash flows has a lower total cost of capital.

Prediction 2 follows from Proposition 2, and provides a cross-sectional test. Because the extent of coinsurance is greater for diversified firms comprised of businesses with less correlated cash flows, investors demand less compensation for providing capital to such firms. In the limit where a firm’s different businesses have perfectly correlated cash flows, there are no coinsurance cash flows and therefore no effect on the total cost of capital.

In the empirical work that follows, we test our model’s predictions using not only the correlation of cash flows, but also the correlation of investment opportunities of the segments comprising a diversified firm. The motivation for the latter test is that coinsurance may lower systematic risk through internal capital markets that help firms avoid the deadweight costs of external financing by channeling resources to business units with superior investment opportunities (Matsusaka and Nanda (2002)).

3. Research Design

3.1. Implied Cost of Capital

Prior research in finance has generally used ex post realized returns to proxy for expected returns (e.g., Fama and French (1997), Lamont and Polk (2001)). One shortcoming of this approach is that realized returns are noisy proxies for expected returns due to contamination by information shocks (Elton (1999)). To address this concern, recent literature in accounting and finance has developed an ex ante approach to measuring expected returns by estimating the implied cost of capital (e.g., Claus and Thomas (2001), Gebhardt, Lee, and Swaminathan (2001), Easton (2004), Ohlson and Juettner-Nauroth (2005)). The implied cost of capital is the internal rate of return that equates the current stock price to the present value of all expected future cash flows. The expected future cash flows are usually estimated using analysts' earnings forecasts. In general, these implied cost of capital measures differ in terms of the form of the valuation model and the assumptions regarding terminal value computation.[12]

In our main analysis, we follow the approach of Gebhardt, Lee, and Swaminathan (2001) (hereafter, GLS) in estimating the implied cost of equity. The GLS measure has been successfully employed in several asset-pricing contexts (e.g., Lee, Ng, and Swaminathan (2007), Pastor, Sinha, and Swaminathan (2008)). We also perform sensitivity tests using two alternative

[12] A discussion of the relative advantages of each method is outside the scope of this paper. Prior research evaluates alternative empirical measures of implied cost of equity and reaches different conclusions on their relative merits and demerits (e.g., Guay et al. (2005), Easton and Monahan (2005), Botosan and Plumlee (2005)).

implied cost of equity measures based on Claus and Thomas (2001) and Easton (2004). See Section 5.2.3 for a more detailed discussion.

3.1.1. Valuation Model for Cost of Equity (GLS)

The GLS measure is based on the residual income valuation model, which is derived from the discounted dividend model with an additional assumption of clean-surplus accounting.[13] In the model, the value of the firm at time t is equal to

$$P_t = B_t + \sum_{i=1}^{\infty} \frac{E_t[NI_{t+i} - r_e B_{t+i-1}]}{(1+r_e)^i},$$

where P_t is the market value of equity at time t, B_t is the book value of equity at time t, NI_{t+i} is net income at time $t+i$, and r_e is the implied cost of equity. We assume a flat term structure of interest rates.

GLS further restate the model in terms of ROE, and assume that ROE for each firm reverts to its industry median over a specified horizon. Beyond that horizon, the terminal value is calculated as an infinite annuity of residual ROE,

$$P_t = B_t + \sum_{i=1}^{T} \frac{FROE_{t+i} - r_e}{(1+r_e)^i} B_{t+i-1} + \frac{FROE_{t+T} - r_e}{r_e(1+r_e)^T} B_{t+T-1},$$

where B_{t+i} is book value per share estimated using a clean-surplus assumption ($B_{t+i} = B_{t+i-1} - k{*}FEPS_{t+i} + FEPS_{t+i,}$, where k is the dividend payout ratio and $FEPS_{t+i}$ is the analyst earnings per share forecast for year $t+i$), $FROE_{t+i}$ is future expected return on equity, which is assumed to fade linearly to the industry median from year 3 until year T, and all other variables are as defined previously.

[13] Under the clean-surplus assumption, book value of equity at t+1 is equal to book value of equity at t plus net income earned during t+1 minus net dividends paid during t+1.

3.1.2. Empirical Estimation

Implied Cost of Equity

As in GLS, we assume that the forecast horizon, T, is equal to 12 years. We use median consensus forecasts to proxy for the market's future earnings expectations and require that each observation have non-missing one- and two-year-ahead consensus earnings forecasts ($FEPS_{t+1}$ and $FEPS_{t+2}$) and positive book value of equity. We use three-year-ahead forecasts for future earnings per share, if they are available in I/B/E/S; otherwise, we estimate $FEPS_{t+3}$ by applying the long-term growth rate to $FEPS_{t+2}$. We use stock price per share and forecasts of both EPS and long-term earnings growth from the I/B/E/S summary tape as of the third Thursday in June of each year. Book value of equity and the dividend payout ratio for the latest fiscal year-end prior to each June are obtained from the Compustat annual database.[14] We assume a constant dividend payout ratio throughout the forecast period. For the first three years, expected ROE is estimated as $FROE_{t+i} = FEPS_{t+i} / B_{t+i-1}$. Thereafter, *FROE* is computed by linear interpolation to the industry median *ROE* (where we use Fama and French (1997) industry definitions). The cost of equity is calculated numerically by employing the Newton-Raphson method. We set the initial value of the cost of equity to 9% in the first iteration; the algorithm is considered to converge if the stock price obtained from the implied cost of equity deviates from the actual stock price by no more than $0.005.

Cost of Capital

Our model predicts that coinsurance reduces systematic risk and hence the total cost of capital. Accordingly, our empirical analyses are based on a weighted-average cost of capital (COC) estimate. To compute this estimate, we follow an approach similar to Lamont and Polk

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[14] Book value of equity is Compustat Item #60; the dividend payout ratio is computed as dividends (Compustat Item #21) divided by earnings (Compustat Item #237). If earnings is negative, then the dividend payout ratio is computed as dividends over 6% of total assets (Compustat Item #6).

(2001), who define total cost of capital as the weighted average of a firm's realized equity return and the return on an aggregate bond index. Instead of using realized equity and bond returns, however, we use ex ante measures of the implied cost of equity and bond yields to proxy for expected equity and debt returns, respectively. More specifically, the COC for each firm *i* and year *t* is computed as follows:

$$COC_{i,t} = D_{i,t-1} Y_t^{BC} + (1 - D_{i,t-1})\ COEC_{i,t},$$

where Y_t^{BC} is the aggregate bond yield from the Barclays Capital Aggregate Bond Index (formerly, the Lehman Brothers Aggregate Bond Index), $COEC_{i,t}$ is the implied cost of equity (GLS), and $D_{i,t-1}$ is the firm's book value of debt divided by total value (book value of debt plus market value of common equity).[15]

This cost of capital measure has the limitation that our proxy for the cost of debt does not capture any firm-specific variation in expected debt returns.[16] To the extent that coinsurance reduces the cost of debt (which we show in the Appendix), our results understate the coinsurance effect on cost of capital. Despite this limitation, our measure of total cost of capital is conceptually superior to one that measures only the cost of equity capital, because it takes into consideration the importance of debt in a firm's capital structure.

3.1.3. Excess Cost of Capital

To compare the cost of capital of a diversified firm to the cost of capital that its segments would have if they were stand-alone businesses, we compute excess COC as the natural logarithm of the ratio of the firm's COC to its imputed COC (defined below). An excess COC

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[15] Book value of debt is Compustat Item #9; market value of equity is estimated as fiscal year-end stock price (Compustat #199) times shares outstanding (Compustat Item #25).
[16] Using firm-specific bond yields to proxy for the cost of debt is not without limitation because bond yields reflect both systematic and idiosyncratic risk.

below (above) zero is consistent with diversification reducing (increasing) the firm's cost of capital.

We calculate a firm's *imputed* COC as a value-weighted average of the imputed COC of its segments:

$$iCOC_i = \sum_{k=1}^{n} \frac{iMV_{ik}}{\sum_{k=1}^{n} iMV_{ik}} iCOC_{ik} \, ,$$

where n is the number of the firm's segments, $iCOC_{ik}$ is the imputed COC of segment k, which is equal to the median COC of single-segment firms in the segment's industry, and iMV_{ik} is the imputed market value of segment k, calculated as in Berger and Ofek (1995).

The procedure for estimating segments' imputed market values is described in detail in Berger and Ofek (1995). In short, the estimation consists of: (1) estimating the median ratio of enterprise value to sales for all single-segment firms in the industry to which the segment belongs, and (2) multiplying the segment's sales by the median industry ratio. Industry definitions are based on the narrowest SIC grouping that includes at least five single-segment firms with at least \$20 million in sales and has a non-missing COC estimate.

3.2. Coinsurance Measures: Cross-segment Correlations

Our model calls for a measure of coinsurance among a firm's segments; specifically the correlation among the idiosyncratic part of segments' future free cash flows. A precise measure of coinsurance, however, is difficult to obtain because the distribution of segments' future cash flows is not observable. Moreover, using the distribution of historical segment-level cash flow to estimate coinsurance is problematic because firm composition usually changes over time. Accordingly, we construct empirical proxies of coinsurance using industry-level cash flow series based on single-segment firms. To ensure that estimated correlations are not contaminated with systematic risk, we perform the computation in two stages.

First, for each 2-digit SIC code industry in a given year in our sample, we compute idiosyncratic industry-level cash flows for the prior ten years as residuals from a regression of average industry cash flow on average market-wide cash flow over the same period.[17]

Next, for each year in our sample, we estimate correlations between every industry pair based on the prior ten-year idiosyncratic industry-level cash flows. We then use these estimated correlations to construct our cash flow coinsurance measure. In constructing our investment coinsurance measure, we use capital expenditures but otherwise follow the same procedure.

We compute a sales-weighted correlation measure $\rho_{iy(n)}$ for firm i in year y with n business segments as

$$\sum_{s=1}^{n}\sum_{t=1}^{n}\frac{Sales_{is(j)}}{\sum_{u=1}^{n}Sales_{iu}}\frac{Sales_{it(k)}}{\sum_{u=1}^{n}Sales_{iu}}Corr_{[y-10,y-1]}(j,k),$$

where $Sales_{is(j)}$ is the sales of firm i's business segment s operating in industry j (similarly for business segment t operating in industry k), and $Corr_{[y-10,y-1]}(j,k)$ is the estimated correlation of idiosyncratic industry cash flows or investments between industries j and k over the ten-year period before year y. We obtain similar results using an alternative coinsurance measure, which also includes the standard deviation of industry cash flows and investments (Duchin (2008)).

Note that a single-segment firm's sales-weighted cash flow or investment correlation measure equals one by definition. This is also true for a multi-segment firm whose segments operate in the same industry.

[17] We measure cash flow as operating income before depreciation scaled by total assets.

4. Sample and Data

4.1. Sample Selection

We obtain our sample from the intersection of the Compustat and I/B/E/S databases for the period 1988 to 2006.[18] We construct cost of capital measures by combining firm-level accounting information from the Compustat annual files with analyst forecasts from I/B/E/S. The excess cost of capital measures and the coinsurance measures require availability of segment disclosures from the Compustat segment-level files.

Additionally, we impose the following sample restrictions. First, we follow Berger and Ofek (1995) and require that (1) all firm-years have at least $20 million in sales to avoid distorted valuation multiples; (2) the sum of segment sales be within 1% of the total sales of the firm to ensure the integrity of segment data; (3) all of the firm's segments for a given year have at least five firms in the same 2-digit SIC code industry with non-missing firm value to sales ratios and GLS COC estimates; and (4) all firms with at least one segment in the financial industry (SIC codes between 6000 and 6999) be excluded from the sample. Second, we require the following data to estimate the GLS COC measure: (1) one- and two-year-ahead earnings forecasts; (2) either a three-year-ahead earnings forecast or the long-term growth earnings forecast and a positive two-year-ahead earnings forecast; and (3) positive book value of equity. The full sample with available GLS excess cost of capital estimates consists of 38,369 firm-year observations, of which 26,454 (11,915) observations pertain to single-segment (multi-segment) firms. The sample used in the cross-sectional analyses is further constrained by the availability of control variables. We discuss our control variables in the next subsection.

[18] The start of our sample period in 1988 is determined by our use of cross-segment correlation estimates based on prior ten-year single-segment data, which start in 1978.

4.2. Control Variables for Cross-sectional Analysis

Return Patterns

To ensure that our results on the relation between coinsurance and cost of capital are distinct from the well-documented return patterns (Fama and French (1992) and Jegadeesh and Titman (1993)), we control for size, book-to-market, and momentum as proxied by the log of market capitalization, the book-to-market ratio, and lagged buy-and-hold returns over the past 12 months, respectively. Including a measure of momentum also controls for sluggishness in analyst forecasts. Recent revisions in the stock market's earnings expectations, although immediately reflected in stock prices, may not be incorporated in analyst forecasts on a timely basis, which could induce a negative correlation between past returns and the cost of capital measures. [19]

In addition, we include I/B/E/S's long-term growth forecast to control for LaPorta's (1996) finding that forecasted long-term growth in earnings is negatively associated with returns.

Analyst Forecast Dispersion

Gebhardt et al. (2001) show that the GLS COC measure is positively correlated with dispersion in analysts' forecasts. Accordingly we control for dispersion in analysts' forecasts, as measured by the log of standard deviation of analyst forecasts.

Leverage

We also control for leverage to account for tax-shield benefits of debt in the weighted average cost of capital. In robustness specifications with cost of equity as the dependent variable, we expect a positive relation due to increased financial risk.

[19] It is possible that we are overcontrolling by including size and the book-to-market ratio in our regressions. First, book-to-market may be associated with coinsurance related forward-looking betas in a conditional asset-pricing model (e.g., Petkova and Zhang (2005)). Second, size may serve as an alternative proxy for coinsurance. Larger firms are likely to have a larger number of unrelated projects, which can lead to greater coinsurance.

We summarize the definitions of the control variables below (numbered items refer to the Compustat annual database):

Log(market capitalization)	=	Natural logarithm of fiscal year-end stock price times shares outstanding from Compustat (#199 * #25);
Leverage	=	Book value of long-term debt divided by the sum of the book value of long-term debt and the market value of equity from Compustat (#9 /(#9 + #199 * #25);
Book-to-market	=	Ratio of book value of equity to market value of equity from Compustat (#60/(#199* #25));
Log(forecast dispersion)	=	Natural logarithm of the standard deviation in analysts' one-year-ahead earnings forecasts from I/B/E/S;
Long-term growth forecast	=	Consensus (median) long-term growth forecast from I/B/E/S;
Lagged 12-month return	=	Buy-and-hold return on the firm's stock from the beginning of June (*t*-1) until the end of May (*t*) from CRSP.

The timeline of the variable measurement is depicted in Figure 1. Note that these additional data requirements constrain our sample to 29,153 observations, of which 20,046 (9,107) observations pertain to single-segment (multi-segment) firms. Some of the sensitivity analyses impose further data restrictions on the sample, as discussed in the corresponding sections of the paper.

5. Empirical Results

5.1. Summary Statistics: Excess Cost of Capital

Recall that a diversified firm's excess COC measures the extent to which the firm's cost of capital is higher or lower than the sum of the imputed cost of capital from its segments as stand-alone firms. On average, our model predicts that diversified firms have a lower cost of capital relative to portfolios of comparable stand-alone firms (Prediction 1).

In Table 1, we present summary statistics for multi- and single-segment firms separately. For the multi-segment subsample, both mean and median excess COC are negative and significant (-0.040 and -0.025). For the single-segment subsample, the median excess COC is zero by construction because the imputed COC values are calculated based on industry medians, though the reported figure is different from zero due to additional sample restrictions. The mean excess COC is negative and significant, suggesting that the distribution of excess COC is negatively skewed. The difference in means between the single- and multi-segment subsamples is negative and significant (0.010 at $p<0.01$), suggesting that the cost of capital of diversified firms is on average 1% lower than that of comparable portfolios of stand-alone firms.[20] The modest result is due to the pooling of all multi-segment firms, many of which operate within a single industry and thus enjoy little cross-segment coinsurance as captured by our measure. Indeed, as presented in the next section, we find economically important cross-sectional differences when we sort multi-segment firms based on cash flow and investment correlations.

5.2. Cross-sectional Analysis of Cost of Capital and Coinsurance

5.2.1. Nonparametric Univariate Sorts

In Table 2, we sort our sample of multi-segment firms into quintiles based on the two coinsurance measures and report the average excess COC for each quintile. The results from cash flow and investment correlation sorts are reported in the left and right panels, respectively. We also present results for the single-segment firms. Note that single-segment firms can be

[20] Throughout the paper, we imply logarithmic percentages whenever we discuss percentage differences. For small percentage values, logarithmic percentages and absolute percentages are approximately the same.

viewed as limit observations with respect to the degree of coinsurance – for these firms, cash flow and investment correlations are equal to one by definition.

Because the results are similar, we focus our discussion on the cash flow correlation sort. Consistent with the coinsurance hypothesis, we observe a monotonic increase in excess COC from the highest coinsurance quintile (Q1) to the lowest coinsurance quintile (Q5) (recall that a higher cash flow correlation means lower coinsurance). The mean difference between Q5 and Q1 is a statistically significant 3.2%, i.e., a cost of capital reduction relative to single-segment firms that is 3.2% higher in magnitude for firms in the highest coinsurance quintile (Q1) compared to firms in the lowest coinsurance quintile (Q5). Similarly, the mean difference between the cost of capital of single-segment firms and firms in the highest coinsurance quintile (Q1) is 2.9%, consistent with a significant coinsurance effect. Overall, these nonparametric results support Prediction 2 – diversified firms that consist of businesses with less correlated cash flows have a lower total cost of capital.

5.2.2. Multivariate Analysis

Next, we investigate whether the negative relation between excess COC and coinsurance is robust to controlling for the set of firm characteristics discussed in Section 4.2.

In the first set of regressions, Models 1 and 2, we regress excess COC on cross-segment cash flow and investment correlations, respectively, and control for all variables except for the number of segments and the natural logarithm of market capitalization. We exclude these two measures because they are likely to capture some degree of coinsurance. Larger firms or firms with more segments are more likely to have business units with imperfect cash flow correlations. Therefore, including them in the regressions could overcontrol for the coinsurance effect.

In the second set of regressions, Models 3 and 4, we use the number of segments and the natural logarithm of market capitalization, respectively, as alternative measures of coinsurance. As discussed earlier, both are measures of firm size, and hence they are likely to capture some degree of coinsurance that is not captured by the correlation-based measures.

In the last set of specifications, Models 5 and 6, we include all control variables, *including* the number of segments and the natural logarithm of market capitalization, to disentangle other possible "size effects" from the coinsurance effect that is captured by the cash flow and investment correlation measures. We therefore view this last set of specifications as the most demanding test of our coinsurance hypothesis.

The results from the three sets of regression specifications are presented in Table 3. The robust standard error for each variable (heteroskedasticity consistent and double clustered by firm and year (Petersen (2008)) is reported in brackets below its corresponding coefficient. Because the results across the two correlation measures are qualitatively and statistically similar, we focus our discussion on the cash flow correlation regressions.

Consistent with the results based on univariate sorts in the previous section, the coefficient on the cash flow correlation measure is positive and significant in both Models 1 and 5 (with $p<0.01$). In Models 3 and 4, we find a negative and significant coefficient on the number of segments and the natural logarithm of market capitalization, respectively, at conventional levels. This result suggests that larger firms and firms with more segments, which may have more product lines with coinsurance potential, have a lower cost of capital. As noted earlier, while this result is consistent with the coinsurance hypothesis, it is difficult to attribute the finding solely to the coinsurance effect as size may also proxy for other factors (e.g., information environment) that can affect the cost of capital. We therefore draw inferences primarily from our main regression specifications (i.e., Models 5 and 6).

Overall, our univariate and multivariate test results support Prediction 2: firms with lower cross-segment cash flow correlations have a lower cost of capital, i.e., the coinsurance effect increases as cross-segment cash flow correlation decreases.

5.2.3. Robustness Tests

Excluding Single-segment Firms

Our main regression analysis in the previous subsection includes both single- and multi-segment firms. To investigate the possibility that our results may be spuriously driven by differences between stand-alone and diversified firms, we perform our main analysis using multi-segment firms only. The results, reported in Table 4, are qualitatively and statistically similar to those reported in Models 5 and 6 of Table 3. In particular, the coefficients on cash flow and investment correlations are both positive and significant (at $p<0.01$). These results suggest that our main finding on coinsurance and cost of capital are unlikely driven by differences between single- and multi-segment firms.

Analyst Forecast Errors

A potential limitation of the implied cost of equity measures is the measurement error arising from the bias in analyst forecasts. To address this concern, we perform the following sensitivity tests.

First, we control for one- and two-year-ahead unexpected and expected forecast errors in our main regression models. In particular, we follow Ogneva, Subramanyam, and Raghunandan (2007) and estimate expected forecast errors using the prediction model in Liu and Su (2005).

Our parsimonious version of the model includes the following predictors that proxy for systematic biases in analyst forecasts: (1) past stock returns, (2) recent analyst earnings forecast revisions, and variables related to overreaction to past information, namely, (3) forward earnings-to-price ratios, (4) long-term growth forecasts, and (5) investments in property, plant, and equipment. Estimation of the predicted forecast error is performed separately for one- and two-year-ahead forecast errors. Unexpected forecast errors are computed as the difference between realized errors and their predicted component. Because one- and two-year-ahead expected errors are highly collinear, we use the average expected errors over the two years as the control measure. The results, reported in Panel A of Table 5, continue to show a positive and significant coefficient on the cash flow and investment correlation measures, suggesting that our main findings are unlikely driven by systematic differences in analyst forecast biases between single- and multi-segment firms.

Second, Easton and Monahan (2006) find that the reliability of implied cost of equity estimates increases as analyst forecast accuracy improves. Accordingly, we partition our sample into terciles using absolute forecast errors in one-year-ahead earnings and estimate cost of capital regressions within each sub-sample. The results are reported in Panel B of Table 5. The cost of capital effect is strongest in the subsample with low absolute forecast error. These results suggest that our findings are unlikely driven by measurement errors in the implied cost of equity estimates that are induced by biased forecasts. Rather, our results are weakened by them.

Alternative Measures of Implied Cost of Equity Capital

In our main analysis, we estimate implied cost of equity (COE) using the approach of Gebhardt, Lee, and Swaminathan (2001) and Lee, Ng, and Swaminanthan (2007) – see Section 3.1. In this subsection, we introduce two alternative measures of implied COE.

The first implied COE measure, CT COE, is estimated following the approach of Claus and Thomas (2001) (hereafter, CT). Similar to the GLS COE measure, the CT COE measure is an internal rate of return from the residual income valuation model. The CT model uses five years of earnings forecasts (compared to twelve years in the GLS model) and assumes that the terminal growth in residual income is equal to the expected inflation rate (compared to zero in the GLS model). The CT expression for price per share at time *t* is:

$$P_t = B_t + \sum_{i=1}^{5} \frac{FEPS_{t+i} - r_e B_{t+i-1}}{(1+r_e)^i} + \frac{FEPS_{t+5} - r_e B_{t+4}}{(r_e - g)(1+r_e)^5},$$

where B_{t+i} is the book value per share computed using the clean-surplus assumption, $FEPS_{t+i}$ is the *i*-period-ahead earnings per share forecast,[21] g is the terminal growth rate of residual earnings, which is equal to the expected inflation rate (nominal risk-free rate minus a real risk-free rate of 3%), and r_e is the cost of equity capital. The implied cost of equity is estimated using the iterative procedure described in detail in Section 3.1.2.

The second COE measure, PEG COE, is based on Easton's (2004) specification of the Ohlson and Juettner-Nauroth (2005) abnormal earnings growth model. The model equates the price of one share to the sum of capitalized one-year-ahead EPS and the capitalized abnormal growth in EPS. Easton makes two simplifying assumptions, namely, zero future dividends and zero growth in abnormal earnings changes beyond two years, to arrive at the PEG model:

$$P_t = \frac{FEPS_{t+2} - FEPS_{t+1}}{(r_e)^2},$$

where all variables are as previously defined. From the above model, PEG COE is calculated as a function of the forward earnings-to-price ratio and the expected earnings growth rate:

[21] We use three-, four-, and five-year-ahead forecasts for future earnings per share when available in I/B/E/S. If any of these forecasts is unavailable, we estimate the corresponding value by applying the long-term growth rate to the two-year-ahead forecast.

$$r_e = \sqrt{g * \frac{FEPS_{t+1}}{P_t}}, \text{ where } g = \frac{(FEPS_{t+2} - FEPS_{t+1})}{FEPS_{t+1}}.$$

The PEG COE can be estimated only for firms where two-year-ahead EPS forecasts exceed one-year-ahead EPS forecasts. In addition, the estimation is restricted to firms with forward earnings-to-price ratios greater than 0.5%. We incorporate the predicted earnings long-term growth rate (*ltg*) in the estimation by setting *g* equal to the average of one-year-ahead earnings growth rate and *ltg*. The additional winsorization procedures include restricting *ltg* to be less than 50%, restricting the one-year-ahead growth rate to fall between *ltg* and 1, and restricting PEG COE to be less than 1.

The results of our main analysis using these two alternative measures of cost of equity are reported in Table 6. Consistent with our earlier findings, the coefficients on the cash flow and investment correlation measures are positive and significant. Overall, our main findings are robust to using CT or PEG COE as a proxy for cost of equity capital.

Capital Structure and Cost of Capital

As discussed earlier, because the essence of our model is the reduction in asset beta (systematic risk) that arises from coinsurance, the model's predictions pertain to total cost of capital. As such, we employ an empirical proxy that measures the weighted average of the cost of equity and debt capital. In this subsection, we examine whether our main results are sensitive to the inclusion/exclusion of the variation in capital structure in the cost of capital measure. In particular, we perform the main cross-sectional analysis using an excess cost of equity measure that is constructed similar to excess cost of capital. The results, reported in Table 7, show a positive and significant coefficient on the cash flow and investment correlation measures, suggesting that our main findings are at least partially driven by the cost of equity component. An interesting extension would be to examine whether our results also hold for the cost of debt.[22]

Factor-Model-Based Cost of Equity Estimates

As a further robustness test, we estimate expected returns using the Fama-French three-factor model. To obtain ex-ante estimates of cost of equity at a given point in time, we estimate factor loadings using 24 months of prior excess returns, multiply the estimated factor loadings with corresponding historic risk premiums, and add the yield on the 10-year Treasury note. To deal with low (and sometimes negative) cost of equity estimates, we set cost of equity estimates that are lower than the risk-free rate equal to the risk-free rate.

The results based on Fama-French excess cost of equity are reported in the last two columns of Table 7. The coefficients on the cash flow and investment correlation measures are positive and significant, and remarkably similar to our main findings. The standard errors are higher, reflecting a greater amount of noise in estimating factor loadings.

5.2.4. Economic Significance

To evaluate the economic significance of our findings, we estimate the effect of coinsurance-related reduction in cost of capital on firm value. In a simple Gordon growth model, under a zero dividend growth assumption, a 1% decrease in cost of capital approximately translates into a 1% increase in firm value. However, the relation between cost of capital and

[22] In unreported analyses, we explore the relation between excess debt ratings and cash flow and investment correlations (controlling for the variables used in Kaplan and Urwitz (1979)). The results (untabulated) show a negative and significant association between excess debt ratings and the correlation measures, suggesting that higher cross-segment correlations (i.e., lower coinsurance) are associated with lower debt ratings (i.e., higher default risk). We acknowledge that debt ratings merely proxy for a firm's total default risk (idiosyncratic plus systematic) and we therefore do not draw inferences on coinsurance and the cost of debt from this exercise.

firm value is in general non-linear and depends on other inputs in the valuation formula – expected earnings and earnings growth.

To estimate the effect on firm value, we compare the actual firm values to the as-if firm values calculated using imputed cost of capital (i.e., the cost of capital on a comparable portfolio of single-segment firms). Specifically, we estimate the as-if market value of the firm based on the GLS valuation model (see Section 3.1.1):

$$MV^{iCOC}{}_t = D_{t-1} + \left[B_t + \sum_{i=1}^{T} \frac{FROE_{t+i} - iCOE}{(1+iCOE)^i} B_{t+i-1} + \frac{FROE_{t+T} - iCOE}{iCOE(1+iCOE)^T} B_{t+T-1} \right],$$

where D_{t-1} is the book value of debt for the latest fiscal year, *iCOE* is the imputed cost of equity, and all other variables are as defined in Section 3.1.1. The "excess value" attributable to differences in cost of capital is calculated as the natural logarithm of the ratio of actual firm value (*MV*) to as-if firm value (MV^{iCOC}), where actual value is the sum of the market value of equity at the time of the cost of capital estimation and the book value of debt for the latest fiscal year. This measure of excess value captures the percentage gain or loss in market value resulting from the coinsurance effect on cost of capital.

Using this approach, we find a 5.5% (6%) average gain in total value when moving from the lowest to the highest coinsurance quintile and a 2% (1.8%) average gain in total value when moving from single-segment firms to the highest coinsurance quintile, where the degree of coinsurance is measured using cash flow (investment) correlations. The corresponding median gains in total value are 5.6% (6.2%) and 5.2% (5.1%), respectively. Overall, these results are consistent with the coinsurance effect of diversification having an economically significant effect on firm value.

6. Conclusion

In this paper, we study the connection between organizational form and cost of capital. We show in a model with systematic deadweight costs that combining business units with imperfectly correlated cash flows can lead to a reduction in systematic risk and hence the combined firm's cost of capital. This coinsurance effect is decreasing in the cross-segment correlation of cash flows. Our empirical analysis provides evidence consistent with the model's predictions. In particular, we find that diversified firms have on average a lower cost of capital than portfolios of comparable single-segment firms. We also find a significant and positive association between excess cost of capital and cross-segment cash flow correlations. Holding cash flows constant, these findings imply a 6% value gain when moving from the lowest to the highest cash flow correlation quintile.

The core of our findings represents a major challenge to the conventional view that corporate diversification reduces only idiosyncratic risk. In addition, our evidence suggesting that coinsurance affects firms' cost of capital has novel implications for valuation and capital budgeting as ignoring coinsurance effects may yield incorrect (i.e., understated) firm value and NPV estimates, particularly in the context of diversifying mergers and acquisitions. Moreover, because the effects that we find are economically significant, coinsurance is likely to affect optimal financial policies such as hedging and payout policy. The role of coinsurance in relation to these central corporate finance questions represents an exciting and unexplored avenue for future research.

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Appendix

In this Appendix, we develop three extensions of our basic model by (1) relaxing an assumption that the merged firm operates with an efficient internal capital market that is free of agency problems, (2) showing that the coinsurance effect can also apply to debt financing, (3) allowing deadweight losses to vary with the state of the economy.

A1. Agency Problems and Inefficient Transfers as Costs of Integration

Suppose that diversification brings not only coinsurance benefits, but also integration costs in the form of agency problems and inefficient transfers. Indeed, such costs underlie the main conjecture of previous work showing that diversified firms have lower valuations relative to stand-alone firms (Lang and Stulz (1994), Berger and Ofek (1995)). For instance, the agency costs arising from empire building (Jensen (1986)), entrenched managers (Shleifer and Vishny (1989)), inefficient allocation of resources (Shin and Stulz (1998) and Rajan, Servaes, and Zingales (2000)), and cross-subsidization (Scharfstein and Stein (2000)) can lead to lower cash flows.[23] These costs can be seen as closing our model to prevent the counterfactual prediction that the entire economy should be owned by one big firm to maximize coinsurance benefits.

Recall that in the basic model diversified firms have not only lower cost of capital, but also higher cash flows compared to portfolios of stand-alone firms. Therefore, our model implies that diversified firms have higher valuations, a prediction that is inconsistent with a large body of empirical work showing that diversified firms have lower valuations *on average*. While recent work has challenged the interpretation that diversification leads to lower valuation, the debate is far from settled, and importantly, is not the focus of our paper. Incorporating integration costs into the model allows us to accommodate both valuation possibilities. The extension of the basic model with integration costs is presented below.

Let A_e^D denote the fraction of firm cash flow that is wasted due to rent-seeking activities and inefficient transfers depending on the state of the economy $e \in \{g, b\}$. Then a diversified firm's cash flow net of integration costs is given by

$$C_e^{D/A} = C_e^D(1 - A_e^D) \text{ for } e \in \{g, b\}.$$

[23] Subsequent research questions the view that diversified firms are less productive (Schoar (2002)) or that they allocate resources less efficiently than stand-alone firms (Maksimovic and Phillips (2002)).

Whether integration costs increase or decrease systematic risk depends on the relative magnitudes of A_g^D and A_b^D. If $A_g^D = A_b^D$, then integration costs do not affect systematic risk beyond reducing firm value. If $A_g^D > A_b^D$, say, because bad times discipline managers and survival concerns necessitate efficiency, then integration costs reduce firm beta,

$$\frac{C_g^D\left(1-A_g^D\right)}{C_b^D\left(1-A_b^D\right)}-1<\frac{C_g^D}{C_b^D}-1 \Rightarrow \beta^{D/A}<\beta^D<\beta^S$$

and add to the coinsurance effect. If $A_g^D < A_b^D$, then integration costs work against coinsurance. Beyond a potential level effect (Prediction 1), however, integration costs do not generate a monotonic relation between a firm's cost of capital and the correlation of its segment cash flows (Prediction 2).

A2. Debt Financing

In this subsection, we show that our results extend to debt financing. To see this, suppose that a diversified firm comprises two stand-alone firms, each with a face value of debt $K = H - \Delta$. Further suppose that K is high enough, that is, $0 < \Delta < \left(H-L\right)/2$ so that $\left(H+L\right)/2 < K < H$. Then, depending on the state of the economy $e \in \{g,b\}$, stand-alone bondholders with face value K receive

$$\begin{aligned} B_g^S &= \theta_g\left(H-\Delta\right) \\ B_b^S &= \theta_b\left(H-\Delta\right) \end{aligned},$$

whereas diversified firm bondholders with face value $2K$ receive

$$\begin{aligned} B_g^D &= \theta_g^2(2(H-\Delta))+2\theta_g(1-\theta_g)(H+L) \\ B_b^D &= \theta_b^2(2(H-\Delta))+2\theta_b(1-\theta_b)(H+L). \end{aligned}$$

Using the expected cash flows above to compute bond betas, we have

$$\begin{aligned} \beta_B^S &= \frac{\theta_g\left(H-\Delta\right)}{\theta_b\left(H-\Delta\right)} \\ \beta_B^D &= \frac{2\theta_g(H-\Delta)+2\theta_g(L+\Delta-\theta_g(L+\Delta))}{2\theta_b(H-\Delta)+2\theta_b(L+\Delta-\theta_b(L+\Delta))}. \end{aligned}$$

$$\underbrace{\qquad\qquad}_{2B_e^S}\qquad\underbrace{\qquad\qquad\qquad\qquad}_{\text{Coinsurance}}$$

Similar to the main model, diversified firm bondholders receive two sets of cash flows whose overall beta is less than the beta of cash flows to stand-alone bondholders. As a result, $\beta_B^D < \beta_B^S$, and the cost of debt for a diversified firm comprising two stand-alone firms is lower than the cost of debt for the two stand-alone firms. In our model, diversified firms enjoy coinsurance benefits that reduce their systematic risk, and as this extension shows, these benefits reduce their cost of debt as well.

A3. State-contingent Deadweight Loss

The basic model assumes that L, the deadweight loss suffered by stand-alone firms, does not depend on the state of the economy. If, in contrast, such costs were to depend on the state of the economy $e \in \{g,b\}$, our results would continue to hold as long as the beta of coinsurance cash flows,

$$\beta^{CI} = \frac{\theta_g(1-\theta_g)L_g}{\theta_b(1-\theta_b)L_b} - 1,$$

remains less than β^S.

For instance, if supplier and customer defections are probabilistic and these probabilities are higher during bad times than during good times, then $L_g < L_b$ and state-contingent deadweight losses would strengthen the coinsurance effect. Defection probabilities may indeed be higher during bad times than during good times if suppliers and customers think that the firm is more likely to forgo important relationship-specific investments due to the larger wedge between internal and external finance during bad times.

FIGURE 1
Timeline of Variable Measurement for a Year *t* Observation (Assuming December Fiscal Year-End)

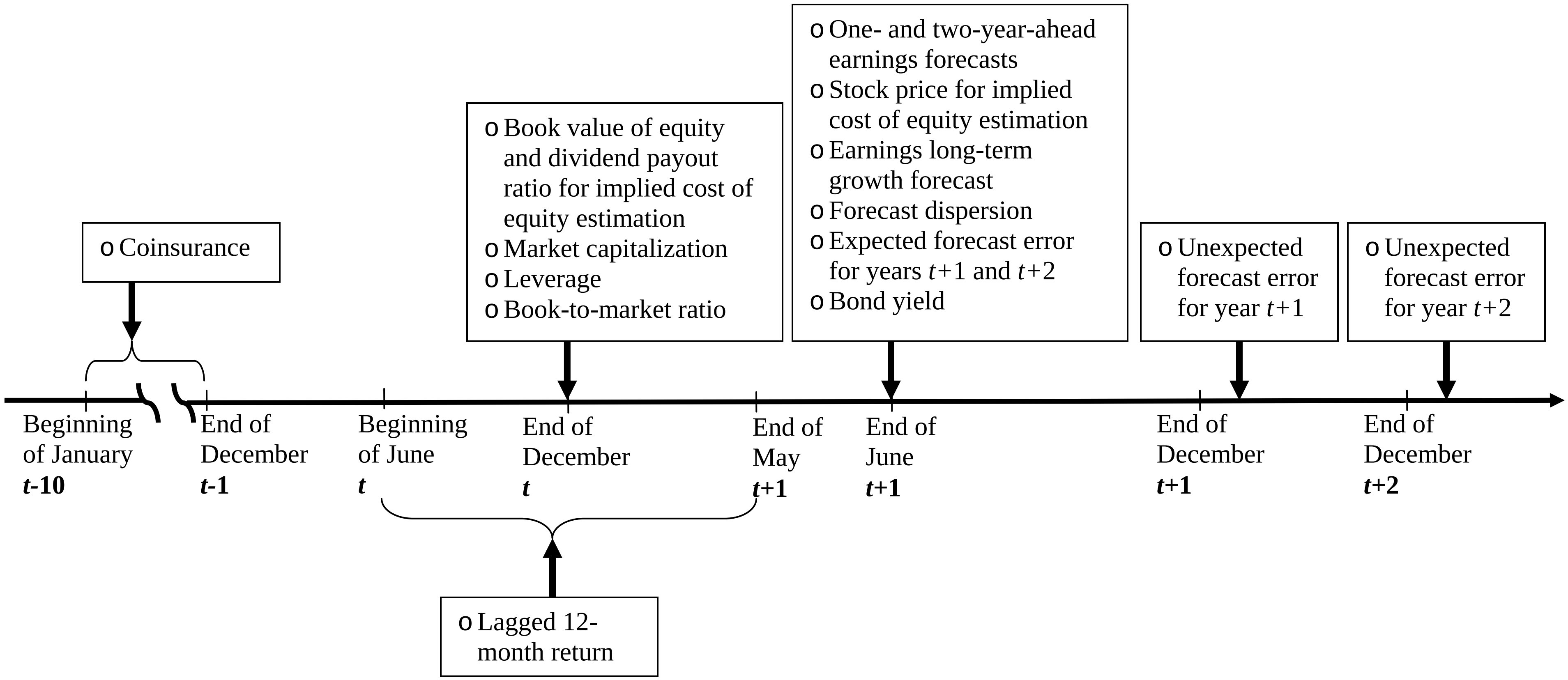

TABLE 1
Summary Statistics: Excess Cost of Capital

This table reports summary statistics for excess cost of capital. The statistics are computed over the period 1988 to 2006 for a sample of single- and multi-segment firms. Excess cost of capital is defined as the natural logarithm of the ratio of a firm's cost of capital to its imputed cost of capital calculated using a portfolio of comparable stand-alone firms. A firm's cost of capital is measured as the weighted average of the implied cost of equity based on the approach of Gebhardt, Lee, and Swaminathan (2001) and the yields from the Barclays Capital Aggregate Bond Index. *** indicates statistical significance at the 1% level.

	Obs.	Mean	Std. Dev.	Lower Quartile	Median	Upper Quartile
Single-Segment (SS)	20,046	-0.030***	0.219	-0.125	-0.001***	0.093
Multi-Segment (MS)	9,107	-0.040***	0.225	-0.150	-0.025***	0.093
MS-SS		-0.010***			-0.024***	

TABLE 2
Univariate Analysis on Excess Cost of Capital and Cross-segment Correlations

This table presents univariate test results on excess cost of capital. The sample period spans from 1988 to 2006. Excess cost of capital is defined in Table 1. Multi-segment firms are sorted into quintiles based on their cash flow and investment correlations. Cash flow and investment correlations for a firm are measured as the portfolio weighted sum of pair-wise segment correlations estimated using historical average industry cash flow and investment based on single-segment firms over a prior ten-year period. *** indicates statistical significance at the 1% level.

	Firms Sorted by							
	Cash-Flow Correlations				Investment Correlations			
	Obs.	Sort Variable	Excess COC		Obs.	Sort Variable	Excess COC	
Multi-Segment Firms								
Q1 (Lowest Correlation)	1,822	0.396	-0.059		1,822	0.372	-0.057	
Q2	1,821	0.710	-0.044		1,821	0.699	-0.044	
Q3	1,822	0.928	-0.038		1,822	0.925	-0.041	
Q4	1,821	0.999	-0.029		1,821	0.999	-0.033	
Q5 (Highest Correlation)	1,821	1.000	-0.028		1,821	1.000	-0.023	
Single-Segment Firms	20,046	1.000	-0.030		20,046	1.000	-0.030	
"Q5" - "Q1"			0.032	***			0.034	***
"Single-Segment" - "Q1"			0.029	***			0.027	***

TABLE 3
Multivariate Regressions of Excess Cost of Capital on Measures of Coinsurance

This table presents regressions of excess cost of capital on measures of coinsurance. The regressions are estimated over the period 1988 to 2006 for a sample of single- and multi-segment firms. Excess cost of capital is defined in Table 1. Cash flow and investment correlations are defined in Table 2. Market capitalization is fiscal year-end stock price (#199) multiplied by shares outstanding (#25). Leverage is long-term debt (#9) divided by the sum of long-term debt and market capitalization. Book-to-market is book value of equity (#60) divided by market capitalization. Forecast dispersion is the standard deviation of analysts' one-year-ahead earnings forecasts from I/B/E/S. Long-term growth forecast is the median long-term growth forecast from I/B/E/S. Lagged 12-month return is buy-and-hold return from beginning of June (*t*-1) to end of May (*t*). Robust standard errors (heteroskedasticity consistent and double clustered by firm and year) are reported in brackets. ***, **, or * indicates that the coefficient estimate is significant at the 1%, 5%, or 10% level (respectively).

	Model 1	Model 2	Model 3	Model 4	Model 5	Model 6
Cash flow correlations	0.057***				0.055***	
	[0.014]				[0.015]	
Investment correlations		0.056***				0.052***
		[0.015]				[0.014]
Number of segments			-0.005*		0.007**	0.007**
			[0.003]		[0.003]	[0.003]
Logarithm of market capitalization				-0.026***	-0.027***	-0.027***
				[0.005]	[0.005]	[0.005]
Leverage	-0.177***	-0.177***	-0.178***	-0.178***	-0.178***	-0.178***
	[0.027]	[0.027]	[0.027]	[0.026]	[0.027]	[0.027]
Book-to-market	0.192***	0.192***	0.192***	0.141***	0.139***	0.139***
	[0.019]	[0.019]	[0.019]	[0.019]	[0.019]	[0.019]
Logarithm of forecast dispersion	0.004	0.004	0.004	0.009***	0.009***	0.009***
	[0.003]	[0.003]	[0.003]	[0.003]	[0.003]	[0.003]
Long-term growth forecast	-0.175*	-0.176*	-0.174*	-0.272***	-0.273***	-0.273***
	[0.105]	[0.104]	[0.102]	[0.103]	[0.100]	[0.099]
Lagged 12-month return	-0.091***	-0.091***	-0.091***	-0.090***	-0.090***	-0.089***
	[0.009]	[0.009]	[0.009]	[0.007]	[0.007]	[0.007]
Constant	-0.092***	-0.091**	-0.031	0.185***	0.130**	0.132**
	[0.035]	[0.036]	[0.026]	[0.058]	[0.057]	[0.060]
Observations	29,153	29,153	29,153	29,153	29,153	29,153
R-squared	0.123	0.123	0.122	0.144	0.145	0.145

TABLE 4

Multivariate Regressions of Excess Cost of Capital on Cross-segment Correlations: Multi-segment Sample

This table presents regressions of excess cost of capital on cross-segment correlations for a subsample of multi-segment firms. The regressions are estimated over the period 1988 to 2006. Excess cost of capital is defined in Table 1. Cash flow and investment correlations are defined in Table 2. The control variables are defined in Table 3. Robust standard errors (heteroskedasticity consistent and double clustered by firm and year) are reported in brackets. ***, **, or * indicates that the coefficient estimate is significant at the 1%, 5%, or 10% level (respectively).

Cash flow correlations	0.043***	
	[0.015]	
Investment correlations		0.041***
		[0.014]
Number of segments	0.012***	0.012***
	[0.003]	[0.003]
Logarithm of market capitalization	-0.028***	-0.028***
	[0.006]	[0.006]
Leverage	-0.234***	-0.234***
	[0.042]	[0.041]
Book-to-market	0.175***	0.175***
	[0.028]	[0.028]
Logarithm of forecast dispersion	0.005	0.005
	[0.004]	[0.004]
Long-term growth forecast	-0.206**	-0.207**
	[0.101]	[0.100]
Lagged 12-month return	-0.081***	-0.081***
	[0.010]	[0.010]
Constant	0.097	0.098
	[0.069]	[0.071]
Observations	9,107	9,107
R-squared	0.134	0.134

TABLE 5

Multivariate Regressions of Excess Cost of Capital on Cross-segment Correlations: Controlling for Analyst Forecast Errors

This table presents regressions of excess cost of capital on cross-segment correlations, controlling for effects of analyst forecast biases. Panel A reports regressions with expected and unexpected forecast errors added as controls. Panel B reports regressions for sub-samples partitioned on the magnitude of absolute forecast error. The regressions are estimated over the period 1988 to 2006 for a sample of single- and multi-segment firms. Excess cost of capital is defined in Table 1. Cash flow and investment correlations are defined in Table 2. The construction of expected and unexpected analyst forecast errors follows Liu and Su (2005) and Ogneva, Subramanyam, and Raghunandan (2007). The rest of the control variables are defined in Table 3. Robust standard errors (heteroskedasticity consistent and double clustered by firm and year) are reported in brackets. ***, **, or * indicates that the coefficient estimate is significant at the 1%, 5%, or 10% level (respectively).

Panel A: Full Sample

Cash flow correlations	0.055***	
	[0.017]	
Investment correlations		0.049***
		[0.015]
Number of segments	0.008*	0.008**
	[0.004]	[0.004]
Logarithm of market capitalization	-0.023***	-0.023***
	[0.005]	[0.005]
Leverage	-0.186***	-0.186***
	[0.031]	[0.031]
Book-to-market	0.149***	0.149***
	[0.019]	[0.019]
Logarithm of forecast dispersion	0.005**	0.005**
	[0.002]	[0.002]
Long-term growth forecast	-0.331***	-0.331***
	[0.104]	[0.104]
Lagged 12-month return	-0.059***	-0.059***
	[0.008]	[0.008]
Unexpected analyst forecast error in year +1	-0.211**	-0.210**
	[0.094]	[0.094]
Unexpected analyst forecast error in year +2	-0.479***	-0.479***
	[0.089]	[0.089]
Average predicted analyst forecast error in years +1 and +2	-1.470***	-1.471***
	[0.267]	[0.267]
Constant	0.084*	0.090*
	[0.047]	[0.051]
Observations	23,270	23,270
R-squared	0.189	0.189

Panel B. Partitions Based on Absolute Forecast Error

	Absolute forecast error					
	Low		Medium		High	
Cash flow correlations	0.065***		0.043**		0.035	
	[0.016]		[0.020]		[0.025]	
Investment correlations		0.057***		0.052***		0.018
		[0.016]		[0.016]		[0.024]
Number of segments	0.007**	0.006**	0.005	0.006*	0.008	0.007
	[0.003]	[0.003]	[0.003]	[0.004]	[0.005]	[0.005]
Logarithm of market capitalization	-0.022***	-0.022***	-0.023***	-0.023***	-0.032***	-0.032***
	[0.005]	[0.005]	[0.005]	[0.005]	[0.006]	[0.006]
Leverage	-0.144***	-0.144***	-0.183***	-0.183***	-0.217***	-0.218***
	[0.034]	[0.034]	[0.035]	[0.034]	[0.024]	[0.024]
Book-to-market	0.199***	0.200***	0.166***	0.166***	0.084***	0.085***
	[0.018]	[0.018]	[0.020]	[0.020]	[0.022]	[0.022]
Logarithm of forecast dispersion	0.006*	0.006*	0.008**	0.008**	0.010**	0.010**
	[0.004]	[0.004]	[0.004]	[0.004]	[0.004]	[0.004]
Long-term growth forecast	-0.176***	-0.176***	-0.294***	-0.296***	-0.377***	-0.376***
	[0.063]	[0.063]	[0.094]	[0.093]	[0.138]	[0.137]
Lagged 12-month return	-0.092***	-0.092***	-0.090***	-0.090***	-0.085***	-0.085***
	[0.009]	[0.009]	[0.006]	[0.006]	[0.008]	[0.008]
Constant	0.022	0.029	0.101*	0.092	0.238***	0.255***
	[0.050]	[0.050]	[0.058]	[0.061]	[0.066]	[0.075]
Observations	9,252	9,252	9,267	9,267	9,261	9,261
R-squared	0.182	0.181	0.173	0.174	0.112	0.112

Does corporate coinsurance enhance shareholder value?

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Does corporate coinsurance enhance shareholder value?

Abstract

This paper tests Leland's (2007) theoretical prediction that depending on specific merger conditions, corporate coinsurance can generate either synergistic gains accruing to both creditors and equityholders or a wealth transfer from stockholders to bondholders. We observe that in merger deals of firms with low cash-flow correlation, synergistic gains enhance shareholder as well as bondholder wealth. The difference in their cash-flow volatilities is positively related to shareholder return around merger announcements and to changes in bond rating of acquiring firms two months after the merger. On the other hand, in mergers of firms with high cash-flow correlation, the result shows a wealth redistribution, where shareholder wealth, and not bondholder wealth, is reduced. Under this condition, the increase in the same cash-flow volatility difference of merging firms negatively affects the combined stockholders' return, but not the bond rating of acquiring firms.

Keywords: M&A, coinsurance, financial synergies, wealth transfer, bondholders, and stockholders

JEL Classification Number: G34, G33

I. Introduction

In his seminal paper, Lewellen (1971) argues that a conglomerate merger between two firms with imperfectly correlated cash flows could reduce the risk of default and hence increase debt capacity. He predicts that such mergers produce a coinsurance effect that benefits shareholders and bondholders. Subsequent studies, however, debate on whether the coinsurance effect could generate a real wealth creation or a mere wealth transfer from stockholders to bondholders. Under varying model conditions, previous studies generate different predictions on the distribution of merger gains between bondholders and stockholders.[1] In a recent article, Leland (2007) contends that all these studies, including Lewellen's, do not explicitly model the optimal capital structure. He presents a simple two-period model in which capital structure is optimized. More importantly, his model explicitly incorporates both the merger benefit from the leverage effect and the merger cost associated with the loss of limited liability protection, and shows the specific conditions under which financial synergies associated with the coinsurance effect can be derived. The purpose of this study is to examine the testable implications of Leland's theoretical model about the sources of merger gains and contrast them with the predictions of Lewellen.

Leland (2007) argues that the coinsurance effect is not always positive, as postulated by Lewellen (1971). The coinsurance effect will be positive if the benefit from the leverage effect outweighs the cost from the loss of limited liability protection, and it will be negative if the reverse occurs. Specifically, Leland's theory posits that mergers of firms produce positive financial synergies if the firms are characterized by low cash-flow correlation, have individually lower cash-flow volatilities than the cash-flow volatility that makes the optimally levered firm value reach the minimum, and have size-weighted volatility difference lower than the minimum of their individual cash flow volatilities. Under these conditions, he predicts that an increase in the size-weighted difference of cash-flow volatilities will enhance the value of the merged firm. Leland's

[1] Higgins (1971), Rubinstein (1973), Higgins and Schall (1975), Galai and Masulis (1976), Kim and McConnell (1977), and Scott (1977) contend that if bankruptcy is costless, the coinsurance effect would benefit bondholders at the expense of shareholders. On the other hand, if bankruptcy is costly, Rubinstein (1973) suggests that corporate coinsurance could benefit both bondholders and stockholders.

theoretical result is the first to explicitly model bankruptcy cost as well as limited liability option and to show that the corporate coinsurance effect may have a positive wealth effect not only on bondholders, but also on shareholders. This result motivates our current study.

We test Leland's (2007) theoretical predictions on a sample of 365 completed mergers between non-financial firms for the period 1981 to 2006. We find evidence that, under the specific circumstances postulated by Leland's theory, corporate coinsurance arising from mergers produces an economically and statistically significant positive wealth effect for stockholders. Results show that mergers of firms with a median size-weighted cash-flow volatility difference of 0.827 could generate a 5.63 percent increase in the combined stockholders' wealth during the three days surrounding merger announcements.[2] This positive impact on the shareholder wealth suggests that when Leland's hypothesized joint conditions are met, the coinsurance effect yields positive synergies and not a simple wealth transfer from bondholders to stockholders.

Consistent with Leland's (2007) other proposition, the results also show that, *ceteris paribus,* the size-weighted volatility difference reduces shareholder value when the cash-flow correlation of two firms prior to the merger is high. When the size-weighted volatility difference increases by one unit, the combined shareholder wealth decreases by 0.38 percent in high cash-flow correlation mergers. This result contradicts Lewellen's (1971) argument that the coinsurance effect always generates a nonnegative financial synergy. The differential results may be due to the fact that Lewellen's model assumes non-negative future cash flows and that it does not consider the loss of limited liability protection when two firms merge.

Further analysis suggests that the coinsurance effect benefits bondholders as well as stockholders. Specifically, an increase in the size-weighted cash-flow volatility difference of the target and acquiring firms is associated with better bond ratings for acquiring firms as long as their

[2] Throughout this study, for convenience, the expression, "size-weighted volatility" refers to "size-weighted cash-flow volatility", unless otherwise stated. We look at the median value (0.827) of the size-weighted volatility difference instead of its mean value (1.871) to examine the synergistic effect. The reason is that our data choose 1.43 as the cash-flow volatility that minimizes the optimally levered firm's value. This requirement confines the maximum value of the size-weighted volatility difference to be below the point at which the effect of size-weighted volatility difference on the wealth effect is positive. The median value of the size-weighted volatility difference is below the bound, whereas its mean value is above the bound.

cash-flow correlation is low. The same increase in the size-weighted volatility difference enhances stockholders' wealth, and more so if all the conditions described earlier are satisfied, one of which is the low cash-flow correlation between merging firms. Interestingly, an increase in the size-weighted volatility difference, in combination with high cash-flow correlation, of firms has no impact on the bondholders' wealth, but has a negative effect on the shareholders' value.

Our study is closely related to Billet, King, and Mauer (2004) and Devos, Kadapakkam, and Krishnamurthy (2009) in that these studies also find that the coinsurance effect can produce financial synergies in mergers. Billet, King, and Mauer examine the wealth change in bondholders and stockholders, and report that the mean value of target's and acquirer's total excess bond and stock returns is 4.43 percent. These authors show that excess stock returns of both targets and acquirers are positively correlated with excess bond returns of targets and acquirers in general. Specifically, the correlation between excess stock returns and excess bond returns of targets with below investment grade is positive and highly significant at 0.28. They argue that there are no wealth transfers, or that the benefits of synergies dominate the existence of wealth transfers.

On the other hand, Devos, Kadapakkam, and Krishnamurthy (2009) employ Value Line forecasts of financial statements to show the existence of financial synergies associated with conglomerate mergers attributable to the positive change in interest tax shields. They further show that, on average, about 1.64% of the total synergy is due to financial synergies and about 8.38% is from operational synergies. In contrast, however, our results suggest that the coinsurance effect could produce synergies only under restrictive conditions, and in high correlation mergers, it does not reduce bondholder wealth while reducing that of shareholders, hence in part supporting the concerns of the wealth transfer from stockholders to bondholders.

The next section reviews the literature on the coinsurance effect and develops tests of Leland (2007). Section III describes the sample and methodology. Section IV documents the impact of coinsurance determinants on the combined wealth of acquiring firms' shareholders and bondholders, and Section V concludes the paper.

II. Literature Review and Tests of Leland's (2007) Hypotheses

A. Literature Review

Lewellen (1971) argues that even if conglomerate mergers lack operational synergy, they could generate financial synergy for stockholders by means of reducing default risk and increasing debt capacity, i.e. the ability to borrow more or at a lower cost when bankruptcy is possible. He conjectures that the increased borrowing capacity of the consolidated firm will help the firm increase its leverage, and consequently its tax-savings from the deduction of interest payment if the cash flows of acquirers and targets are not perfectly correlated. Thus, firm managers who maximize shareholders' wealth would have a financial incentive to engage in conglomerate mergers. This is coined as the "coinsurance effect". According to his model, the coinsurance effect comes from the reduction of cash-flow volatility and the effect becomes larger as the correlation between the merging firms' cash flows decreases, holding other factors constant.

Lewellen's (1971) argument generates active debate on whether the financial benefit from the coinsurance effect is a wealth creation (i.e., a synergistic gain) or a simple wealth redistribution between different stakeholders. Higgins and Schall (1975) show that the gain from a secured debt will be exactly offset by a decrease in the value of equity regardless of whether the bankruptcy is costly or not. Adopting Black and Scholes' (1973) option pricing model, Galai and Masulis (1976) show that with the assumption of costless bankruptcy, the coinsurance effect would lead to an increase in the market value of the merged firm's debt, which will be exactly offset by a decline in the market value of equity. Hence there is no value creation, and the net financial result of non-synergistic mergers would be a wealth transfer from shareholders to bondholders.

In contrast, Rubinstein (1973) suggests that conglomerate mergers could benefit stockholders as well as bondholders when bankruptcy is costly. Furthermore, Stapleton (1982) utilizes a discrete-time bond valuation model of Brennan (1979), and shows that mergers can enhance debt capacity even when cash flows are perfectly correlated.

The empirical tests on the wealth implication of a merger to debtholders provide mixed results. Egger (1983) and Maquieira, Megginson, and Nail (1998) report significantly positive excess returns for acquirer bondholders around the announcement of a merger. Kim and McConnell (1977) and Asquith and Kim (1982) document insignificant excess returns, while Dennis and McConnell (1986) report marginally significant negative excess returns for bondholders of the acquirer. This mixed evidence is attributed to the difficulty in accurately measuring bond returns and to the small sample of firms that issue debt.[3] Recently, Billett, King, and Mauer (2004) find zero or negative bidder bond excess returns, while Penas and Unal (2004) document significantly positive bidder bond returns for their sample of commercial bank mergers.

Early studies of target bond returns, on the other hand, consistently report that excess returns for target bonds are insignificant.[4] More recently, Billett, King, and Mauer (2004) and Penas and Unal (2004) report significantly positive excess returns to target bondholders using recent data on commercial bank mergers and argue that the bond market views bank mergers as default-risk-reducing events.

B. Tests of Leland's hypotheses

Leland (2007) models the benefits and costs of a merger that lacks operational synergy and identifies the source of pure financial synergy. Assuming no information asymmetry, no agency costs, and normally distributed end-of-period cash flows, his model calculates a realistic interest tax shield of debt, with only the interest portion assumed to be tax deductible. Although this assumption causes an endogeneity problem between the value of debt and the fraction of debt service attributed to interest payments, the problem is numerically solved under another assumption that the tax payment of bondholders in bankruptcy follows the interest first rule. Leland argues that when firms issue zero-coupon bonds at time $t = 0$ with principal P due

[3] Betton et al. (2008) show the matrix of price and sample sizes employed across studies.

[4] Refer to Kim and McConnell, Asquith and Kim (1982), Egger (1983), Dennis and McConnell (1986), and Maquieira, Megginson, and Nail (1998)

at time $t = T$, the market value of debt, $D_0(P)$ at $t = 0$ given P depends on the probability distribution of future cash flow X that the firm will earn.

$$D_0(P) = \frac{1}{1+r_T}\left(P\int_{X^d}^{\infty} dF(X) + (1-\alpha)\int_0^{X^d} XdF(X) - \tau\int_{X^Z}^{X^d}(X - X^Z)dF(X)\right),$$

where $X^Z = P - D_0$ is the break-even level of cash flow, which is equivalent to the promised interest payment at time T, and $X^d = P + \frac{\tau}{1-\tau}D_0$ is the default onset level of cash flow. Note that the above is an implicit equation for D_0, because X^Z and X^d also contain D_0. The equity value is represented by the following equation:

$$E_0(P) = \frac{1}{1+r_T}\left(\int_{X^d}^{\infty}(X-P)dF(X) - \tau\int_{X^d}^{\infty}(X - X^Z)dF(X)\right).$$

The value of the optimally levered firm is decomposed into three parts:

$$\begin{aligned} v_o(P) &= D_0(P) + E_0(P) \\ &= V_0 + TS_0(P) - DC_0(P), \end{aligned}$$

where V_0 is the unlevered firm value, $TS_0(P)$ is the present value of tax savings, and DC_0 is the present value of default costs.[5] The financial synergy Δ consists of the benefit from the "leverage effect (LEV)" and the cost due to the "loss of limited liability protection (LL)", i.e. the cost of combining two separate limited liability protections of the merging firms into one limited liability protection of the merged firm.

$$\Delta = LL(\equiv \Delta V_0) + LEV(\equiv \Delta TS - \Delta DC)$$

where $\Delta V_0 = V_{0M} - V_{0A} - V_{0T}$ refers to the change in unlevered firm value, $\Delta TS = TS_{0M} - TS_{0A} - TS_{0T}$ denotes the change in the value of interest tax savings, and $\Delta DC = DC_{0M} - DC_{0A} - DC_{0T}$ represents the change in the value of default costs. The subscripts A, T, and M represent the acquiring, target, and merged firms, respectively.

[5] $V_0(P) = (1-\tau)\frac{1}{1+r_T}\int_0^{\infty} XdF(X) = (1-\tau)H_0$; $TS_0(P) = \tau H_0 - \frac{\tau}{1+r_T}\int_{X^Z}^{\infty}(X - X^Z)dF(X)$; $DC_0(P) = \frac{\alpha}{1+r_T}\int_0^{X^d} XdF(X)$

Scott (1977) notes that one source of value loss in mergers involving all equity firms is the loss of the limited liability protection benefit. In addition, Sarig (1985) notes that the limited liability option provides valuable protection against future negative cash flows to the shareholders, and argues that usage of debt cannot alter the loss incurred. Sarig (1985) points out, the LL effect is always negative.

Intuitively, the limited liability effect ΔV_0 arises because the consolidated firm goes bankrupt less frequently than the unconsolidated firms since the merged firm stays solvent by transferring funds from the solvent subdivisions to the subdivisions that would claim bankruptcy without the merger. This could be a simple wealth transfer from stockholders to noncontractual creditors, such as retired workers still getting health care benefits paid using the cash flows of the solvent subdivisions. Without the consolidation, the firm would have gone bankrupt and the noncontractual creditors would not have been paid or have been paid less.

The leverage effect (LEV) occurs because when a firm borrows more money from creditors, it enjoys larger interest tax shields (ΔTS), but higher debt elevates the default probability (ΔDC) ceteris paribus. Thus, a debt increase without raising the default probability, or a higher debt capacity, would improve a merger's financial synergy.

Leland (2007) argues that the coinsurance effect is not always positive as Lewellen (1971) has suggested. Rather, it depends on whether the leverage effect dominates the loss of limited liability protection. When the sum of two effects is positive, a merger generates financial synergy. Otherwise, divestiture is preferred given no economic benefits. Leland derives specific criteria that determine the sign of the financial synergy and the effect of the coinsurance on total firm value. He argues that the optimally levered firm value, $v(\sigma, \alpha)$, is a U-shaped function. The value of a firm initially decreases as the cash flow volatility and firm risk increase because the benefit of the limited liability is not substantial. As cash-flow volatility increases further, the value of the lost limited liability option decreases and is dominated by the reduced firm risk. Thus, there exists a cash-flow volatility where the value of the optimally levered firm attains its global minimum, $Min[v(\sigma, \alpha)] = v(\sigma_L, \alpha)$, given the bankruptcy cost α.

Henceforth, we use ρ and σ to refer to the cash-flow correlation between acquirer and target firms and cash-flow volatility, respectively, and subscripts a and t to denote the acquirer firm and the target firm. Leland's (2007) propositions that pertain to the effect of coinsurance on value are as follows.

1. *Proposition 4 : A merger of firms with highly different cash flow volatilities will be undesirable when two firms have a high cash-flow correlation.*

   When the cash-flow correlation is high, the expected cash-flow volatility of the consolidated firm will not be significantly different from the cash-flow volatility of acquiring firm. In this case, the benefit from the leverage effect is unlikely to offset the cost of the limited liability effect.

   According to the simulations reported in the Appendix, there is a consistent pattern regardless of marginal tax rate that the increase in volatility difference reduces the change in equity value while it enhances the change in debt value when the change in total firm value is negative. Even though firm value rises in merger deals of high cash flow correlation, the increase in total firm value is achieved at the expense of shareholders. In the simulation, we observe the changes in equity value are mostly negative while the changes in debt value are mostly positive.

2. *Proposition 5 : If (i)$\sigma_a, \sigma_t < \sigma_L$, and (ii)$|\omega_a\sigma_a - \omega_t\sigma_t| < Min[\sigma_a, \sigma_t]$, and ρ is small, a merger of firms with differing volatilities is desirable.*

   When the current cash-flow volatilities of acquiring firms and target firms are so small that they fully benefit from the interest tax shields without facing high probability of bankruptcy, it is not in the best interest of shareholders to attempt to reduce the cash flow volatility of the consolidated firm further because the maximum reduction of cash flow volatility will mostly benefit bondholders while stockholders still incur the loss of limited liability option.

The results of simulations reported in the Appendix show that bondholders mostly benefit from the reduction of cash flow volatility at the expense of shareholders if total firm value increases and cash flow correlation is negative. The increase in volatility difference ameliorates this wealth transfer from shareholders to bondholders when total firm value rises and cash flow correlation is negative. Our simulation results also show it is only in small numbers of synergy sharing deals (less than 1%) that the increase in volatility difference can enhance both debt value and equity value.

C. Test design

To test whether the theories of Lewellen (1971) and Leland (2007) can explain the wealth change of shareholders, we run the following regression using the full sample of mergers:

$$TS = \alpha + \beta_1 \rho + \beta_2 |\omega_a \sigma_a - \omega_t \sigma_t| + \theta \cdot controls + \epsilon$$

where TS denotes the total synergy from a merger, MV is the market capitalization of the firm, $\omega_a = \frac{MV_a}{MV_a + MV_t}$ and $\omega_t = \frac{MV_t}{MV_a + MV_t}$, and *controls* denotes other control variables. Lewellen predicts a significantly negative coefficient of ρ, which would reflect the cash flow stabilizing effect for lower cash flow correlation firms while the effect might be negligible at high cash flow correlations. Leland's theory does not make unconditional predictions about the sign of $|\omega_a \sigma_a - \omega_t \sigma_t|$, as his predictions are based on other accompanying conditions.

Next, we divide the total sample into two subsamples, high ρ subsample and low ρ subsample to test proposition 4 as Leland conditions the prediction about volatility difference and the coinsurance effect on cash flow correlation. Leland (2007) predicts a negative parameter estimate for β_2 for the high cash flow correlation subsample, which would indicate that size weighted volatility difference negatively affects the combined shareholder's wealth if cash flow correlation is high.

Third, we test the proposition 5 of Leland (2007) that the impact of volatility difference on the coinsurance effect is conditional on three joint conditions. We further subdivide the low ρ

subsample into merger deals that meet all three joint conditions and merger deals that do not meet additional two conditions in addition to low cash flow correlation. We then estimate the above regression for the two low ρ subsamples. Leland's (2007) theory predicts a significantly positive coefficient of β_2 that the volatility difference affects the total value change if all three conditions are satisfied.[6]

III. Sample Selection and Methodology

A. Merger Sample

We construct our sample by obtaining data on merger deals by US firms from the Securities Data Company (SDC) Mergers and Acquisition (M&A) Platinum database.[7] We then obtain stock returns, financial and accounting data for acquirers and targets from CRSP and COMPUSTAT databases. We impose the following conditions on all observations:

1. Transactions are merger deals identified by "M" for the deal form and "No" for the tender offer dummy (Betton et al (2008)).[8]

2. The deal is announced between 1978 and 2007 and ultimatelly completed.

3. Returns from CRSP and cash flow from CRSP-COMPUSTAT Merged database are available for both acquirers and targets. This restricts the sample to merger deals between public acquirers and public targets.

4. The market values of merging firms exceeds \$10 million in constant 2001 dollars adjusted for the Consumer Price Index of the Bureau of Labor Statistics.

[6] Refer to the above interpretation of proposition 5.

[7] Betton et al (2008) report that tender offers show different characteristics from mergers. A merger deal is mainly the result of negotiations between the bidder and target management teams. In contrast, a tender offer is an offer made by the bidder management directly to target shareholders to purchase target shares and sometimes carries hostility. The significant difference between mergers and tender offers stems from the choice of payment method. While tender offers prefer cash payment over stock payment, mergers are mainly paid by stock including other contingent claims. With the form of contingent payment, bidder and target shareholders are likely to share the risk that the target and/or bidder shares are overvalued ax ante.

[8] Betton et al (2008) report that mergers compose main proportion of corporate takeovers. The total takeover sample they study is categorized into initial merger bids (28,994), tender offers (4,500), and control-block trades (2,224).

5. To make the measurement of cash flow correlation meaningful, acquirer firms have 5 or more years of cash flow data and target firms have at least 3 years of cash flow data immediately prior to merger announcements. The different requirements to acquirors and targets are adopted to maximize sample size.

6. Merger deals do not involve financial firms.

7. Marginal tax rate is available for both the acquirer and the target.

There are 1149 merger deals that satisfy first four restrictions. In the total sample without firm-year restrictions, the median firm-year observations before mergers are 11 years and 6 years for acquiring firms and acquired firms respectively. Bidders and targets have 6 and 4 firm-year observations at 25 percentile. The 3 years of target cash flow data requirement coincides with 10 percentile firm-year observations for not only bidders but also targets. The firm-year restriction reduces the sample size to 848 merger deals. The non-financial firms and marginal tax rates requirements reduces sample size further. The final sample encompasses 365 mergers during 1981-2006.

B. Event study methodology

We follow the event study approach of Brown and Warner (1985). The market model is utilized to estimate the abnormal return around an announcement date. We estimate the α and β using the daily returns from 300 calendar days to 60 calendar days before the announcement date. We require a minimum of 100 daily return observations during the estimation period.

$$R_{i\tau} = \alpha_i + \beta_i R_{m\tau} + \epsilon_{i\tau},\ \tau = -300, \cdots, -60$$

where $R_{i\tau}$ indicates the return of firm i at the date τ and $R_{m\tau}$ represents the market return which is proxied by a value weighted index return.

We calculate cumulative abnormal returns (CAR) from 1 trading day before to 1 trading day after the announcement date, with benchmark returns calculated using the estimated market-model parameters, $\hat{\alpha}$ and $\hat{\beta}$.

We measure total synergistic gain from a merger deal j using total percentage gain (TPG) of Bradley, Desai, and Kim (1988) based on the notion that the total synergistic gain will be distributed to both acquiring firm and target firm.

$$\Delta\hat{\Pi}_j = [W_{A_j} \cdot C\hat{A}R_{A_j} + W_{T_j} \cdot C\hat{A}R_{T_j}]/[W_{A_j} + W_{T_j}]$$

where $\Delta\hat{\Pi}_j$ is the estimated total synergistic gain from a merger deal j, W_{A_j} is the market value of acquiring firm in deal j as of the end of 15 trading days before the announcement, W_{T_j} is the market value of target firm minus the value of the target shares held by the acquirer in deal j as of the end of 15 trading days ahead of the announcement, and $C\hat{A}R_{A_j}$ and $C\hat{A}R_{T_j}$ is the estimated cumulative abnormal return of the acquirer and the target firm in the deal j, respectively. Market value of bidder and target firms are retrieved from CRSP database on 15 trading days before the merger announcement using number of outstanding stocks and the closing price of each share.

$$w_a = \frac{MV_a}{MV_a + MV_t}, \quad w_t = \frac{MV_t}{MV_a + MV_t}$$

For the purpose of our study, the division of the total synergistic gain between the acquirer and the target is irrelevant.

C. Variable Construction

The main variables that the theories predict are related to financial synergy arising from a merger are cash flow correlation between acquirer and target firms (ρ), acquirer cash flow volatility (σ_a), target cash flow volatility (σ_t), and market value weighted volatility difference ($|w_a\sigma_a - w_t\sigma_t|$).

Cash flow is defined as net income(COMPUSTAT data item 18) plus depreciation(item 14), normalized by the book value of total assets (item 6).[9] Cash flow correlation ρ is the Pearson

[9]Another popular measure for cash flow using item 13 is also tested. However, our measure has much more

correlation coefficient cash flow observations of firm-years common for the acquirer and target firms. We calculate the standard deviation of cash flow using all available cash flow data in the years prior to merger announcement to measure cash flow volatilities, σ_a and σ_t. Consequently, the number of years using to calculate the cash flow volatility for the acquirer may be different from the number of years for the target.

Considering the fact that standard deviation increases mechanically as the number of observations increases, this difference could create larger cash flow volatilities for acquirers, which tend to have more firm-year observations than targets. To address this, we normalize the standard deviation by the square root of the number of firm-years.

$$\sigma_a = \frac{STD(SCF(T_a))}{\sqrt{T_a}}, \quad \sigma_t = \frac{STD(SCF(T_t))}{\sqrt{T_t}}$$

where T_a and T_t denote the number of firm-years used to calculate the standard deviation of scaled cash flows for acquiring and target firms, respectively.

Control variables include such deal characteristics as the proportion of stock payment (PCT_STK item in SDC) and initial attitude of target management toward merger deal(ATTC item in SDC). A merger deal is categorized as hostile if the value of ATTC item is not 'F' or friendly.

Firm characteristic variables include Tobin's Q, relative market value, leverage, and cash. Tobin's Q is measured by the sum of total book value of assets with market value of equity minus total common equity normalized by total book value of assets. Relative market value or RMV is computed as the logarithm of the ratio of the market values of target and bidder 15 trading days prior to the initial announcement. Cash is the ratio of cash and short term investments to book value of total assets, and leverage is the sum of long term debt and short term debt deflated by total assets.

observations than the alternative measure.

IV. Wealth implications of the coinsurance effect

A. For stockholders

In this section, we test whether Lewellen's (1971) prediction that it is cash flow correlation or Leland's (2007) prediction that it is the size-weighted volatility difference that determines the coinsurance effect and consequently determines the change in shareholder's wealth. We assume that total synergy is the sum of financial synergy and operational synergy. Total synergy is calculated as the total percentage gain following Bradley, Desai, and Kim (1988). This total percentage gain is a dependent variable for all regression analyses for stockholders wealth change.

The tests of proposition 5 of Leland (2007) are of particular interest, as they may reveal whether the coinsurance effect is a mere wealth redistribution from firm owners to creditors or it is a wealth creation that benefits stockholders as well as bondholders. If the benefit of positive coinsurance effect solely enhances the wealth of bondholders, then the coefficient of volatility difference should be significantly negative to make the sum of bondholders wealth change and shareholders wealth change zero. If the benefit of positive coinsurance can be shared between bondholders and shareholders, the coefficient of volatility could be zero. If the coinsurance effect can enhance the value of stockholders, the coefficient of volatility difference would be positive. In this case, it is more consistent with the wealth creation argument rather than with wealth redistribution argument.

Panel A of table 1 presents descriptive statistics for the sample. The ρ and $|w_a\sigma_a - w_t\sigma_t|$ are our primary variables of interest. It is noteworthy that $|w_a\sigma_a - w_t\sigma_t|$ is a measure for volatility difference that accommodates the case of different market values and cash flow volatilities of bidders and targets. In addition, $|w_a\sigma_a - w_t\sigma_t|$ provides another special measure. Investors can use the information of previous cash flow correlations between acquirers and targets to estimate the attainable coinsurance effect. Given ρ, σ_a, and σ_t from previous cash flow observations, investors would expect the cash flow volatility of consolidated firm will be

$$\sigma_{consolidated} = \sqrt{w_a^2\sigma_a^2 + 2w_a w_t \rho \sigma_a \sigma_t + w_t^2 \sigma_t^2}$$

if ρ, σ_a, and σ_t will remain the same level after a merger. The market-value weighted difference of cash flow volatilities, $|w_a\sigma_a - w_t\sigma_t|$, coincides with the cash flow volatility of consolidated firms when ρ is -1. In other words, it represents the lowest cash flow volatility among possible set of future cash flow volatilities of the consolidated firm, $[|w_a\sigma_a - w_t\sigma_t|, |w_a\sigma_a + w_t\sigma_t|]$ when it is uncertain which ρ the consolidated firm will have in the future.[10] Assuming the maximum reduction in cash flow volatility, the new volatility would attain $|w_a\sigma_a - w_t\sigma_t|$ given w_a, σ_a, w_t, and σ_t.

The results indicate that the average cash flow volatility of acquiring firms is smaller than that of target firms. The average size of target firms is about 14 % of the size of acquiring firms and the 75 percentile of relative size is below 35%. It appears that large stable bidders merged small unstable targets in the total sample. These patterns accord with the conventional wisdom of the coinsurance effect.[11]

Results in panel B of table 1 indicate that the change in stockholder's wealth is independent of cash flow correlation, acquiring firm's cash flow volatility, acquired firm's cash flow volatility, and size weighted volatility difference, while it is weakly related to the marginal tax rate of the two firms. It is noteworthy that cash flow volatility of acquiring firm and market-value weighted difference of cash flow volatilities exhibit near perfect correlation of 0.941 in the total sample.[12] We can expect this high correlation between $|w_a\sigma_a - w_t\sigma_t|$ and σ_a from the definition of market-value weighted difference of cash flow volatilities and the high relative market capitalization of

[10]Compared with σ_a and σ_t which are calculated with all previous cash flow observations before mergers, ρ are calculated with cash flow observations in common firm-year when both firms have cash flow observations at the same year. These common firm-year observations tend to be smaller than the individual cash flow observations.

[11]Scott (1977) argues that a merger between a large stable firm and a small, profitable, but unstable firm may tend to reduce the present value of future bankruptcy costs and increase value while a merger between a small stable firm and a large volatile one increase the present value of future bankruptcy costs and reduce value.

[12]This high correlation between $|w_a\sigma_a - w_t\sigma_t|$ and σ_a gives rise to the concern about multicollinearity issue. When we investigate the variance inflation factors of model specification with both variables, we observe that the variance inflation factors of $|w_a\sigma_a - w_t\sigma_t|$ and σ_a are so large that we cannot place two variables into a model specification at the same time due to the multicollinearity.

the acquirer. It appears that $|w_a\sigma_a - w_t\sigma_t|$ depends mainly on the acquirer volatility, σ_a.

Table 2 reports the horse-race comparison for the explanatory power of two theoretical coinsurance determinants, ρ of Lewellen (1971) and $|w_a\sigma_a - w_t\sigma_t|$ of Leland (2007). We estimate ordinary least squares (OLS) regressions of total percentage gain to stockholders on several determinants of the coinsurance effect as well as other control variables.[13] Statistical inferences in all regressions are based on heteroscedasticity consistent standard error of White (1980). The results show that either determinant of coinsurance does not unconditionally generate the financial synergistic gains accruing to stockholders in total merger deals. The coefficient of cash flow correlation is positive although it is not significant for all model specifications. The positive coefficients of ρ are inconsistent with the prediction of Lewellen (1971) about a negative relation between the diversification effect and the cash flow correlation. The coefficients for size weighted volatility difference are not significantly different from zero. However, this result was expected in that size weighted volatility difference could play the dual role: the rise in volatility difference is increasing the financial synergy when three joint conditions are met versus decreasing the financial synergy when cash flow correlation is high.

We should set the definition of high ρ merger deals. Our cutoff for high cash flow correlation is 0.2 that is a little bit higher than the median cash flow correlation 0.136 for the whole sample.[14] The cutoff correlation coincides with the cash flow correlation Leland (2007) utilizes for the base case study of firms in Table 3 of the paper.

Table 3 presents the results of the test results of proposition 4 in Leland (2007) for high cash flow correlation and low cash flow correlation mergers. investigate the impact of the correlation and cash flow volatility difference on stockholders wealth. Models (3) and (6) in each set provide

[13]Model (1) through (4) only contain the control variables in Servaes (1991) whereas model (5) through (8) add control variables listed in the section 4 of Moeller, Schlingemann, and Stulz (2005). Especially, cash and leverage are included based on the notion that they are related to financial strength consequently financial synergies.

[14]The natural choice for high ρ should be the median cash flow correlation of whole sample. We observed the same pattern as we report in table 3 when we used the median cash flow correlation. The median cash flow correlation of total sample is somewhat restrictive when we seek the merger deals that satisfy Leland's (2007) joint conditions for positive coinsurance effect. One of joint conditions is low correlation between acquirers cash flows and targets cash flows. We consistently apply the same cutoff for high cash flow correlation to identify merger deals of positive coinsurance effect in the following test.

an additional control for the impact of marginal tax rate of acquirers and targets on stockholders value.

Lewellen's (1971) theory predicts a significantly negative coefficient of ρ. Merger deals of high cash flow correlation encompass the case of very high ρ nearing 1, with very low diversification effect, whereas ρ from -0.999 to 0.2 represents merger deals of low cash flow correlation, with the diversification effect maximized at $\rho = -1$. While the coefficients of ρ for high cash flow correlation subsample have negative coefficient, they all (except one) are statistically insignificant. Furthermore, the coefficients of ρ for low cash flow correlation subsample have the opposite signs to Lewellens prediction. The coefficients are insignificantly different from zero. The negative sign of the coefficients for the low cash flow correlation subsample are consistent with the agency explanation of conglomerate mergers because the agency cost of diversification is most severe at $\rho = -1$ while there is no agency at $\rho = +1$.

We expect that the coefficient of $|w_a\sigma_a - w_t\sigma_t|$ should be significantly negative for the high cash flow correlation mergers from the proposition cited above. The sign and significance of $|w_a\sigma_a - w_t\sigma_t|$ in all models support Leland's proposition 4. The coefficient of $|w_a\sigma_a - w_t\sigma_t|$ is negative and significant at the 0.01 confidence level for all except one that is significant at the 0.05 level. In merger deals with high cash flow correlation, the increase in volatility difference negatively affects the combined shareholder wealth in that the coefficients of $|w_a\sigma_a - w_t\sigma_t|$ are significantly negative across different model specifications. We can observe the significantly negative coefficient -0.136 for volatility difference even with only two explanatory variables, ρ and $|w_a\sigma_a - w_t\sigma_t|$ in model (1). The inclusion of target firm cash flow volatility makes the impact of volatility difference stronger in model(2) while the addition of marginal tax rates does not change the coefficient of volatility difference much in model (3) from model (2). The sign and significance of $|w_a\sigma_a - w_t\sigma_t|$ remain the same as model (1) through (3) even though we add all control variables in model (4) through (6). The significantly negative coefficient implies that the increase in volatility difference negatively affects the combined wealth of shareholders when bidders' cash flow is highly correlated to targets' cash flow. For example, the combined wealth of shareholders enhances 0.25 % less in high correlation mergers when $|w_a\sigma_a - w_t\sigma_t|$ increases by a unit holding other factors constant.

The significantly negative coefficient of acquirer volatility, σ_a in model (4) implies that it's difficult for a firm with high cash flow volatility to achieve the coinsurance effect by means of a merger with a firm it has high cash flow correlation with. If target's cash flow volatility is low, the reduction in combined cash flow volatility would be very small. If target's cash flow volatility is high, the cash flow correlation should be very low to significantly reduce the cash flow volatility of consolidated firm. Another reason is the large value decrease from the loss of the limited liability option. Even if it is possible to reduce cash flow volatility of the consolidated firm when cash flow volatilities of both firms are high and cash flow correlation is low, the loss of the limited liability option is very high because both acquirer and target should have high cash flow volatility that makes the limited liability option more valuable. Thus, firms of high cash flow volatility should restrain themselves from merging other firms to achieve the coinsurance effect.[15]

For the low cash flow correlation subsample, we observe that the coefficient of size-weighted volatility difference is positive and significant, potentially reflecting results consistent with proposition 5 of Leland (2007).

The results of tests of Lelands (2007) proposition 5 are reported in Table 4. The corollary proposes that three joint conditions should be met for a merger to achieve positive coinsurance effect: (1) $|w_a\sigma_a - w_t\sigma_t| < min[\sigma_a, \sigma_t]$, (2) $\sigma_a, \sigma_t < \sigma_L$, and (3) low ρ. The first condition that specifies the possibility of reducing cash flow volatility is easily applied from the measured values of $|w_a\sigma_a - w_t\sigma_t|$, σ_a, and σ_t for each merger deal. This condition imposes the possibility of cash flow volatility reduction in that the minimum cash flow volatility of consolidated firm that could be attained after a merger should be lower than the current volatility of the acquiring firm and target firm. The other two conditions that enhances the odds of reducing the cash flow

[15]Refer to corollary 1 of proposition 5 in Leland (2007). The corollary is rephrased "a firm of high volatility is unlikely to desire a merger with a smaller firm, particularly if that firm has a low volatility."

volatility of the consolidated firm require a decent amount of searching for the joint conditions on σ_L and ρ because σ_L and low ρ is not clearly specified like the first condition. Although the σ_L means the cash flow volatility where optimally levered firm value reaches the minimum in theory, interpretation of σ_L diminishes in empirical study because we include all types of mergers which occur in many different industries. We interpret the second condition in this way that cash flow volatility of acquiring firms and cash flow volatility of target firms should be jointly low. The cutoff criteria for σ_L and ρ are jointly searched to maximize the number of merger deals that satisfy the joint conditions. Too small values for σ_L and ρ significantly reduces sample size while too large values for σ_L and ρ would not satisfy the condition Leland (2007) suggests.

We consistently utilize the cutoff for high cash flow correlation, $\rho = 0.2$ again to determine the merger deals of low cash flow correlation. From the extensive searches, we determine the cutoff of high cash flow volatility, $\sigma_L = 1.43$. To test the validity of three joint conditions, we partition the sample of low cash flow correlation into those that satisfy the joint condition and those that do not. For the former, the market value weighted volatility difference has to be lower than cash flow volatilities of both bidders and targets, both cash flow volatilities are smaller than 1.43, and cash flow correlation is less than 0.2. The number of merger deals that meet the three joint restrictions equals 45, or 12% of total sample of mergers.

Under the second corollary of proposition 5, we expect that the coefficient of $|w_a\sigma_a - w_t\sigma_t|$ should be significantly positive for the subsample of mergers that satisfy the joint condition. The sign and significance of $|w_a\sigma_a - w_t\sigma_t|$ for the mergers that satisfy the joint conditions support Leland's prediction that the increase in volatility difference enhances the stockholders value when three restrictions are met. The coefficient of $|w_a\sigma_a - w_t\sigma_t|$ is 7.350 in model (1) and is significant at 0.05 confidence level. Other model specifications show similar results of positive and statistically significant coefficient of $|w_a\sigma_a - w_t\sigma_t|$. While the increase in volatility difference greatly benefits shareholders when the joint conditions of Leland (20070) is met in this small portion of mergers, it does not affect shareholders value in majority of merger deals. It is noteworthy that the combined value of stockholders increase as volatility difference increases. With median volatility difference 0.827 in total sample, the combined stockholders wealth would increase 5.63 percent during three days around merger announcement if three join restrictions are met. This value change is economically significant.

We also observe exactly same patterns observed in model (1)-(3) at model (4)-(6) that include the impact of marginal tax rate of acquirers and targets on shareholders wealth change except for the larger absolute coefficients for $JCSD \times |w_a\sigma_a - w_t\sigma_t|$ and $JCSD \times \sigma_a$. The coefficients for marginal tax rate of both firms are all positive while all coefficients insignificantly differ from zero. This implies that the financial synergy from the coinsurance effect are mainly derived from volatility difference rather than marginal tax rate.

In merger deals that satisfy three joint conditions and are presented, the increase in volatility difference positively affects the combined shareholder wealth in that the coefficients of $|w_a\sigma_a - w_t\sigma_t|$ are significantly positive across different model specifications. The statistical significance of the coefficient increases when we add more control variables in models (4) through (6). For the subsample of merger deals where cash flow correlation is low but other two conditions of three joint conditions are not fully satisfied, the sign and significance of $|w_a\sigma_a - w_t\sigma_t|$ are similar as those in merger deals that satisfy three joint conditions. However, the coefficient estimates are substantially lower in magnitude for the subsample with the joint conditions not satisfied relative to the subsample where the joint conditions are satisfied. The results reveal that a merger is more value increasing if a bidder has higher cash flow volatility unless it is too high and cash flow correlation is low while a merger is value decreasing if a firm of high cash flow volatility acquires a target firm when cash flow correlation is high.

In sum, we report empirical results consistent with Leland's (2007) predictions on financial gains arising from a merger. A merger could enhance shareholder's value by raising the amount of interest tax shields enough to exceed the costs of elevated default probability and the loss of limited liability option if cash flow volatility of the consolidate firm could be less than the current volatility of the acquiring firm and this reduction of cash flow volatility is highly probable. In this case, acquiring firms have the freedom of target selection to increase volatility difference for maximal coinsurance effect as long as volatility reduction is probable. In contrast, high cash flow correlation makes maximum reduction of cash flow volatility less plausible. It is highly likely that maximal reduction of cash flow volatility cannot be attained in the future when a large unstable firm acquires a small stable firm while the loss of limited liability protection is incurred at the time of merger. This implies that it would be a value-decreasing merger from the perspective of the coinsurance effect that large unstable firms acquire small stable firms to reduce cash flow volatility if their cash flows are highly correlated.

The results hint that the positive coinsurance effect is a synergistic effect in that stockholders can benefit from the coinsurance effect when it is most likely that the coinsurance effect will benefit bondholders. Particulary, the findings in Table 4 shed light to the debate on whether the coinsurance effect could benefit stockholders. Leland (2007) calculates the change in total firm value that is the sum of equity value and debt value after the merger. He only suggests that a merger enhances total firm value when joint conditions are met. The distribution of synergistic gains is not specified. Under the wealth transfer hypothesis, the wealth change in stockholders should be the opposite of the signs predicted for total firm value. However, the significantly positive coefficients for $|w_a\sigma_a - w_t\sigma_t|$ for the low cash flow correlation mergers and the negative coefficients in high cash flow correlation mergers coincides with the change in total firm value. This indicates that synergistic gains from the coinsurance effect seems to be shared between bondholders and stockholders. Next we examine whether volatility difference also benefits bondholders when joint conditions are met.

B. **For bondholders**

We investigate the impact of cash flow volatility difference on the change in bondholders wealth. This analysis is the direct test of whether the coinsurance effect is a wealth transfer or wealth creation. If corporate coinsurance is a just wealth transfer from stockholders to bondholders, the sign of volatility difference should be the opposite of the signs we observed for the effect on the change in stockholders' wealth. If corporate coinsurance is a synergistic gain, the volatility difference is expected to affect the wealth of both stockholders and bondholders similarly.

We use the change in debt ratings around merger announcements as wealth impact on creditors while previous literature on bondholder wealth effects accruing to creditors utilize monthly excess returns of bonds.[16] To motivate our approach, we note that Mansi and Reeb (2002) argue that the average credit rating of both Moody's and S&P most efficiently measures the default risk premium. Second, according to Klock, Mansi, and Maxwell (2005), debt ratings from credit agencies are highly correlated with yield spread. Third, calculating abnormal bondholder returns presents several empirical issues. Specifically, there are variations about the measurement of the wealth implication of mergers to bondholders when a firm issues several types of debt ahead of the merger, as well as the well-known problem of matrix price. Our measure of bondholders wealth change is warranted by the primary role of default costs in Leland's (2007) model and close relation between debt ratings and bondholders wealth.

To calculate the change in debt ratings around the merger announcement, we follow the numerical conversion of bond rate by Klock, Mansi, and Maxwell JFQA (2005). For example, AAA rated bond is converted to 22 while D rated bond is converted to 1. The debt rating change is measured by the difference between the two month average debt rating after the merger and before the merger while the debt rating at merger announcement month is omitted.[17] This measure goes with our natural interpretation of the signs of independent variables in that a positive (negative) change in debt rating is associated with the increase (reduction) in creditors wealth.

Table 7 presents the wealth impact of coinsurance determinants on bondholders of acquiring firms. We cannot calculate the composite wealth change of acquiring firms and acquired firms as we did in stockholders wealth change because we do not have the information of market value

[16]Refer to Warga and Welch (1993), Billet, King, Mauer (2004).

[17]We also used the debt rate change between the debt rate right after merger announcement and the debt rate right before the merger announcement. The results show the same pattern.

of bonds of two firms. Subsequently, we look at the wealth change in bondholders of acquiring firms and acquired firms separately. Similarly to its effect on shareholders, cash flow correlation is not a significant determinant of the wealth change of debtholders of acquiring firms. In contrast, and similarly to the results with the change in shareholder wealth as the dependent variable, it is easily seen that the coefficients for $|w_a\sigma_a - w_t\sigma_t|$ are significantly positive while the coefficient for $high\rho \times |w_a\sigma_a - w_t\sigma_t|$ are significantly negative in table 5. In an unreported table, we examine the wealth change in bondholders of acquired firms. The coefficients of both cash flow correlation and market value weighted volatility difference are insignificant. Thus, the impact of the coinsurance effect is similar between stockholders and bondholders. Interestingly, the relative magnitudes of the coefficients of $|w_a\sigma_a - w_t\sigma_t|$ and $high\rho \times |w_a\sigma_a - w_t\sigma_t|$ differ across different stakeholders: the coefficient of $|w_a\sigma_a - w_t\sigma_t|$ is smaller than the coefficient of $high\rho \times |w_a\sigma_a - w_t\sigma_t|$ for stockholders. However, the coefficient of $|w_a\sigma_a - w_t\sigma_t|$ is larger than the coefficient of $high\rho \times |w_a\sigma_a - w_t\sigma_t|$ for bondholders of acquiring firms.

We investigate the consequence of relative magnitudes of two variables at Table 8. We divide the total sample into two subsamples or merger deals with high cash flow correlation and with low cash flow correlation. The left panel of table 6 shows the regression results for merger deals with high cash flow correlation. In all model specifications, the coefficients of market value weighted volatility difference are not significantly different from zero. It means that volatility difference does not affect the wealth change of bondholders when cash flow correlation is high. The right panel of table 6 presents the regression results for merger deals with low cash flow correlation. In contrast, the coefficients for market value weighted volatility difference are all significantly positive in all model specifications. These results indicate that positive coinsurance effect for bondholders is observed only if cash flow correlation is low. Surprisingly, the coefficients for marginal tax rate are also significantly positive. It implies that the bondholders wealth increases as the marginal tax rate of acquiring firm rises although the tax effect should be prominent in stockholders wealth. In theory, the interest tax shields increase as the marginal tax rate of a firm rises while there is no such benefit to bondhodlers. However, we have not observed any significantly positive impact of high marginal tax rate on stockholders wealth.

In summary, the test result shows that bondholders also benefit from the coinsurance effect. The bondholder gain rises as the size weighted volatility difference increases when cash flow correlation is simply low while stockholders wealth does not increase only if cash flow correlation is low. On top of that, the increase in size weighted volatility difference does not downgrade bond rate while the increase in size weighted volatility difference negatively affect stockholder's wealth when cash flow correlation is high. These results imply that bondholders tend to profit more from the coinsurance effect than stockholders do because the condition of positive coinsurance for stockholders is more restricted than that for bondholders. However, positive coinsurance effect can benefit both stockholders and creditors if the reduction of cash flow volatility is highly likely.

V. Conclusion

Based on the existence of financial synergy that is reported in Devos et al. (2009), we examine the determinants of the coinsurance effect accruing to stockholders and bondholders. While Lewellen (1971) conjectures that this coinsurance effect will increase when the cash-flow correlation of merging firms decreases, Leland (2007) refines the condition of the positive coinsurance effect by including losses of the limited liability option in the model. He predicts that positive coinsurance could be attained when the reduction of cash-flow volatility of a merged firm is possible and most likely. Otherwise, the costs from a merger outweigh its financial gain. In other words, the condition of low cash-flow correlation is not sufficient to generate the coinsurance effect. The same value of minimum cash-flow volatility of the merged firm estimated at the time of the merger, $|w_a\sigma_a - w_t\sigma_t|$, could play a dual role: guaranteeing the coinsurance effect for low correlation mergers versus reducing financial gains for high correlation mergers as $|w_a\sigma_a - w_t\sigma_t|$ increases.

We present evidence that is consistent with Leland's (2007) predictions. In the sample of merger deals with high cash-flow correlation, the market-value weighted-volatility difference between an acquiring firm and an acquired firm negatively affects the shareholders' value. On the contrary, the same volatility difference has a positive impact on the shareholders' value when the cash-flow volatility of a merged firm is less than that of an acquiring firm. However, the cash-flow correlation does not affect the financial synergy. The evidence also suggests that bondholders benefit more from the coinsurance effect than do stockholders. The size-weighted volatility difference negatively affects the combined stockholder's wealth, while not the bond rate of acquiring firms, when their cash-flow correlation is high and there is a change in the debt rate around mergers.

Appendix A: Calibration of the marginal tax rate with Graham's simulated marginal tax rate data

We observe the changes in the present value of debt($\Delta D = D_M - D_1 - D_2$), equity($\Delta E = E_M - E_1 - E_2$), and total firm($\Delta V = V_M - V_1 - V_2$) arising from a merger of two base case firms varying the marginal tax rate to investigate the wealth implication of higher marginal tax rate. This investigation is motivated by our Table 1 that presents that the average marginal tax rate of acquiring firms is about 32% while the average marginal tax rate of target firms is close to 28% on average.

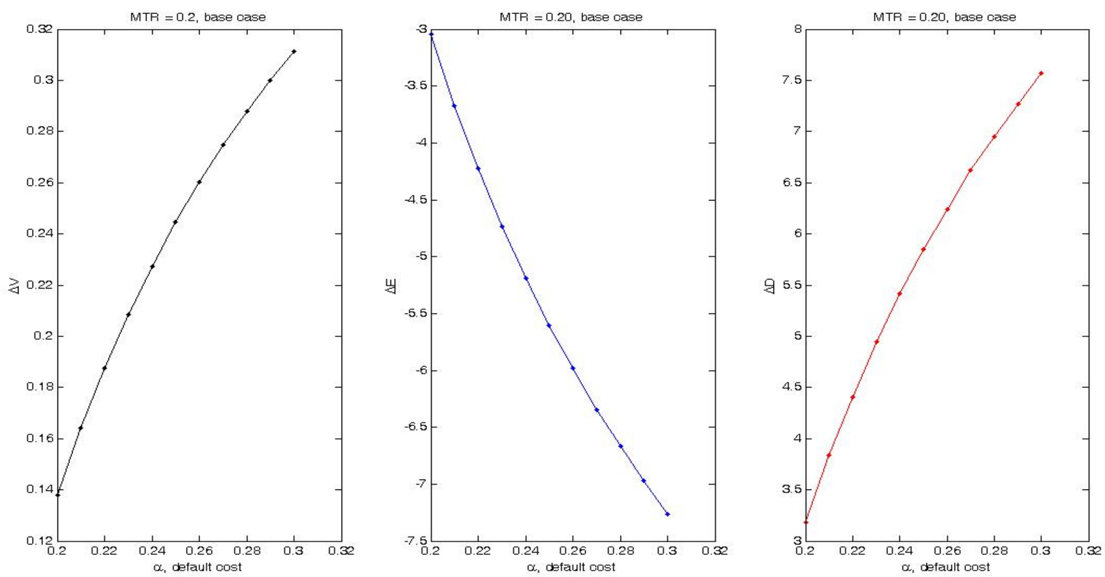

Figure 1: The change in debt, equity, and total firm value when two firms of base case merge and marginal tax rate is 20%

We first look at the base case of Leland's (2007) paper. When two identical firms of the base case merge and marginal tax rate is 20%, the above graph shows that total firm value and debt value enhances by 0.21 and 4.94 respectively while equity value reduces 4.73, which replicates the Leland's Table 3. This is a wealth transfer from shareholders to bondholder in that only bondholders benefit from the merger at the expense of shareholders although total firm value enhances. It is easily seen that this wealth transfer becomes prominent as default cost increases.

The present value of bond monotonically increases with larger default costs. In contrast, the present value of equity continues to fall down as the default cost rises.

Interestingly, the rise of marginal tax rate attenuates the wealth transfer from shareholders to bondholders or even reverses the direction of wealth transfer if default costs are low. Fig 3 shows ΔV, ΔE, and ΔD when marginal tax rate goes up to 30% with the same merger of two base case firms. The changes in equity value are positive whereas the changes in debt value are negative until default cost climbs up to 24% although the changes in total firm value are also negative. The signs of value changes in equity and debt are opposite after default cost is higher than 25%. We observe the same pattern at the value changes due to the merger with higher marginal tax rate as in the graph.

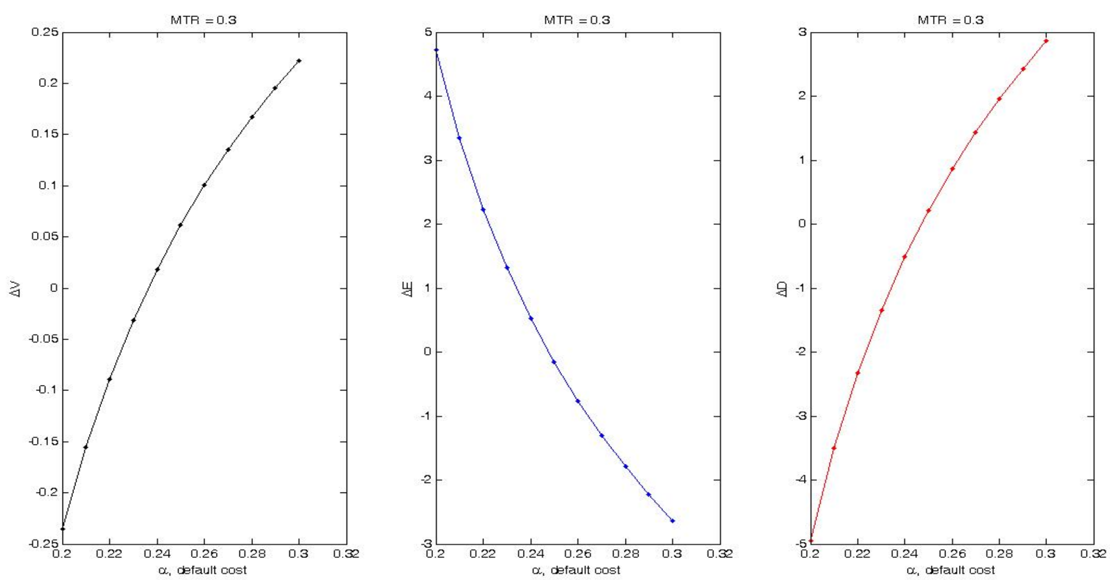

Figure 2: The change in debt, equity, and total firm when two firms of base case merge and marginal tax rate is 30%

We expect that 30% marginal tax rate raise the possibility that both shareholders and bondholders share the synergistic gain compared to 20% marginal tax rate because bondholders can get larger change in debt value while shareholders take smaller change in debt value if cash flow correlation is lower than 0.2.

Appendix B: The impact of volatility difference on sharing the synergistic gains

We run an extensive simulation analysis to investigate the impact of volatility difference on mergers that can benefit shareholders and bondholders. We introduce an asymmetry in firm sizes and cash flow volatilities of acquirers and targets. The size of acquirers spans from 180 to 300 with 40 interval. The target firm size varies between 50 and 95 with the increment of 15. These numbers accord with our empirical observations that first quartile and third quartile of relative market capitalization ($log(\frac{MV_t}{MV_a})$) are about 5% and 35%. The cash flow volatility of acquiring firms ranges from 0.16 to 0.24 with 0.02 increment. The cash flow volatility of target firms extends between 0.2 and 0.32 with 0.04 increment. These numbers reflect the observation that the cash flow volatility of target firms 1.76 times larger than the cash flow volatility of acquiring firms on average. The cash flow correlation covers from -0.5 to 0.7 with 0.1 increase.

We encounter 26 synergy sharing mergers out of total 4160 simulated mergers when the marginal tax rate is set to 30% based on the previous analysis. Both ΔE and ΔD are positive in synergy sharing mergers. When we run the same simulation with 20% marginal tax rate, we cannot find a merger that benefits bondholders as well as shareholders. The following graph shows strongly positive relation between ΔD and $|w_a\sigma_a - w_t\sigma_t|$ and weakly positive relation between ΔE and $|w_a\sigma_a - w_t\sigma_t|$ when financial synergy is shared. The background black dots represent ΔV. When we run OLS regression of ΔE and ΔD on $|w_a\sigma_a - w_t\sigma_t|$, the slope for ΔD is significantly positive while the slope for ΔE is insignificantly positive.

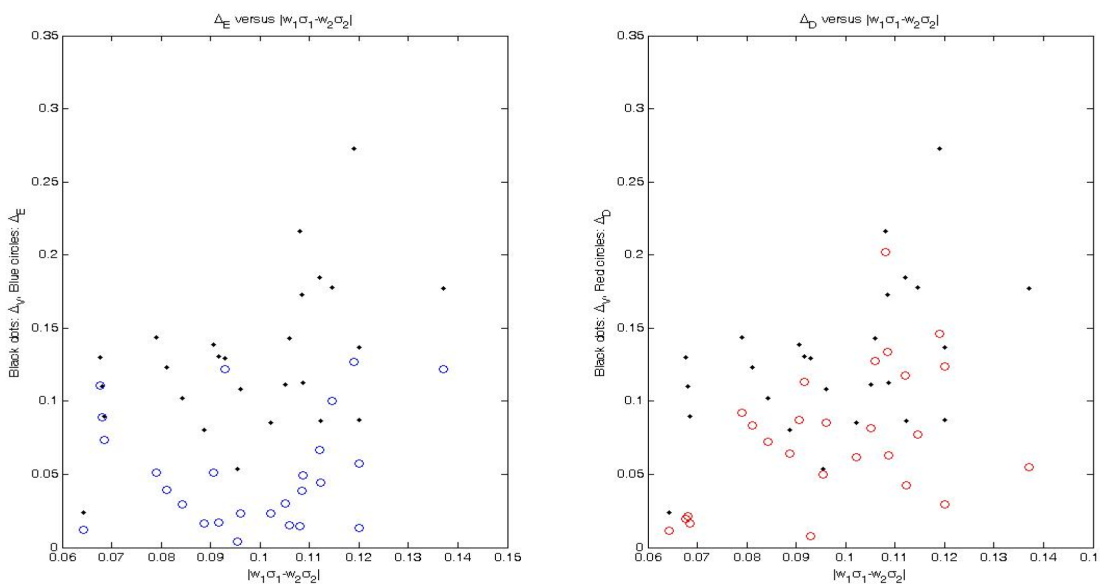

Figure 3: The impact of the increase in volatility difference when a merger enhances the value of bondholders and shareholders

Appendix C: The impact of volatility difference on wealth transfer

When cash flow correlation is high, we have two types of merger deals: total firm value increasing vs decreasing mergers. The increase in volatility difference negatively affect the change in equity value while it positively affect the change in debt value when total firm value declines after the merger. The following graph shows the impact of the increase in volatility difference on the change in equity and bond value respectively when marginal tax rate is 20%. We observe the change in equity value is positive while the change in debt value is negative when cash flow volatility difference is very close to zero. These mergers benefit shareholders at the expense of bondholders, which is exactly opposite of the conventional wealth transfer from shareholders to bondholders.

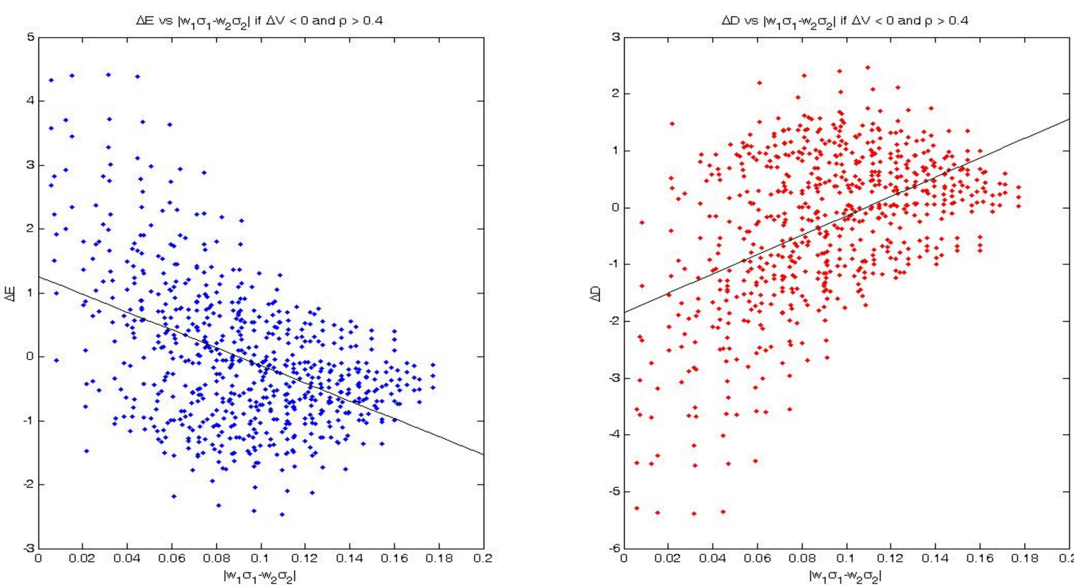

Figure 4: The impact of the increase in volatility difference when a merger reduces the total firm value and cash flow correlation is high

The wealth transfer from bondholders to stockholders becomes more prominent when marginal tax rate is 30%. In this high marginal tax rate, the change in equity value is positive and the change in debt value is negative in most mergers. However, we observe the same negative impact of volatility difference on the change in equity value and positive impact of volatility difference on the change in bond value even though marginal tax rate increases.

The following graph shows the impact of the increase in volatility difference on the change in equity and bond value respectively when marginal tax rate is 20% and total firm value rises after the merger. We observe the opposite impact of volatility difference on the change in equity and debt value as we observed in merger deals where total firm value drops. However, we observe no merger deal enhances stockholder value whereas all merger deals enhance debtholder value after mergers when cash flow correlation is high and total firm value rises. The wealth transfer from stockholders to bondholders is most significant in these mergers.

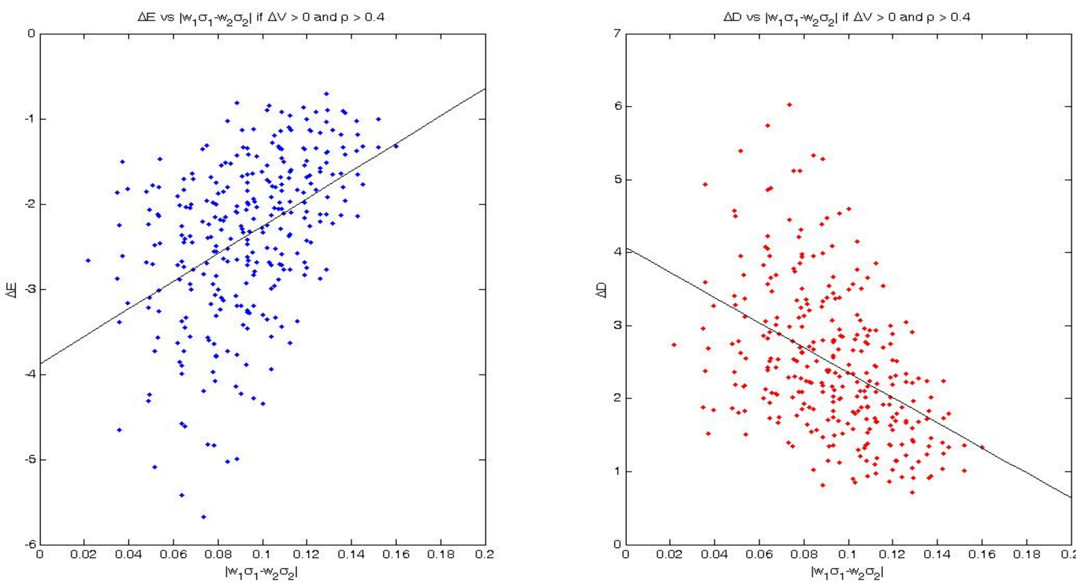

Figure 5: The impact of the increase in volatility difference when a merger enhances the total firm value and cash flow correlation is high

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Table 1
Descriptive Statistics for total sample

This table presents the descriptive statistics of total synergistic gain from a merger deal and its determinants of financial synergy part. The determinants of financial synergy are composed of cash flow correlation(ρ) between acquiring firm and target firm, cash flow volatility of acquiring firm(σ_a), cash flow volatility of target firm(σ_t), sized weighted difference of cash flow volatilities($|w_a\sigma_a - w_t\sigma_t|$) and relative market capitalization($\frac{MV_t}{MV_a}$). The relative market capitalization is measured on 15 trading dates before the announcement date and used to calculate market value weights $w_a = \frac{MV_a}{MV_a+MV_t}$, $w_t = \frac{MV_t}{MV_a+MV_t}$. The total synergistic gain is measured by market value weighted average of cumulative abnormal return of acquirer and target in a merger deal, j. Cumulative abnormal return to bidders and targets are calculated over 3 days (-1,1) period centered on announcement dates.

$$\Delta\hat{\Pi}_j = [w_{a_j} \cdot C\hat{A}R_{A_j} + w_{t_j} \cdot C\hat{A}R_{T_j}]$$

The scaled cash flow correlation is measured by Pearson correlation coefficients for the matching firm-years of common cash flow observations. Cash flow volatilities are measured by standard deviation of scaled cash flow during all previous years before merger announcement which is subsequently normalized by the total number of cash flow observations of each firm.

$$\sigma_a = \frac{STD(CF_{T_a})}{\sqrt{T_a}}, \sigma_t = \frac{STD(CF_{T_t})}{\sqrt{T_t}}$$

MTR_a and MTR_t represent the marginal tax rate of acquiring firm and acquired firm each. The control variables of deal characteristics are the proportion of stock payment and the hostility of the target company's management or board of directors toward the merger deal. The percentage of Stock payment is retrieved from Pct_STK item in SDC. and We utilize ATTC item in SDC to find hostile deals. A merger deal is categorized as hostile if the value of ATTC item is not 'F' or friendly. The control variables of firm characteristics encompass Tobin's Q, leverage, and cash. Tobin's Q is measured by the following relation. $Tobin's\ Q = [item6 + (item25 * item199) - item60]/item6$ Leverage is the sum of long term debt and short term debt deflated by book value of total assets. $Leverage = [item9 + item34]/item6$ Cash is measured by the ratio of cash and short term investments to book value of total assets. $Cash = item1/item6$.

Panel A: Total sample descriptive statistics

Variable	N Obs	Mean	St. Dev	Min	Q1	Median	Q3	Max
$\Delta\hat{\Pi}$	365	-0.383	6.839	-29.869	-3.801	-0.142	3.702	20.883
ρ	365	0.101	0.486	-0.999	-0.201	0.136	0.445	1.000
σ_a	365	2.772	8.959	0.107	0.542	1.281	2.746	161.084
$\|w_a\sigma_a - w_t\sigma_t\|$	365	1.871	5.819	0.013	0.333	0.827	1.721	98.388
σ_t	365	4.880	9.680	0.065	1.034	2.165	4.767	144.216
MTR_a	365	0.315	0.098	0.000	0.338	0.350	0.350	0.460
MTR_t	365	0.278	0.122	0.000	0.204	0.340	0.350	0.460
$\log(\frac{MV_t}{MV_a})$	365	-2.132	1.478	-8.051	-2.996	-1.969	-1.059	3.321
PCT STK	365	83.628	25.699	0.000	70.250	100.000	100.000	100.000
Tobin Q_a	365	2.688	2.673	0.658	1.408	1.923	3.051	37.772
Tobin Q_t	365	2.177	2.047	0.263	1.187	1.538	2.293	20.172
$\mathrm{Leverage}_a$	365	0.228	0.172	0.000	0.085	0.222	0.344	0.876
$\mathrm{Leverage}_a$	365	0.242	0.211	0.000	0.043	0.218	0.378	1.395
Cash_a	365	0.160	0.184	0.000	0.027	0.098	0.219	0.924
Cash_t	365	0.177	0.213	0.000	0.019	0.075	0.295	0.895

Panel B: Total sample correlation analysis								
	$\Delta\hat{\Pi}$	ρ	σ_a	$\lvert w_a\sigma_a - w_t\sigma_t\rvert$	σ_t	MTR_a	MTR_t	$\log(\frac{MV_t}{MV_a})$
$\Delta\hat{\Pi}$		0.074	-0.085	-0.067	0.025	0.106	0.149	-0.079
		(0.16)	(0.11)	(0.20)	(0.63)	(0.04)	(0.00)	(0.13)
ρ			0.038	0.015	-0.047	-0.084	-0.050	0.006
			(0.46)	(0.77)	(0.37)	(0.11)	(0.34)	(0.92)
σ_a				**0.941**	0.309	-0.281	-0.138	0.105
				<.0001	<.0001	<.0001	(0.01)	(0.05)
$\lvert w_a\sigma_a - w_t\sigma_t\rvert$					0.493	-0.306	-0.180	0.066
					<.0001	<.0001	(0.00)	(0.21)
σ_t						-0.295	-0.308	-0.027
						<.0001	<.0001	(0.61)
MTR_a							0.369	-0.192
							<.0001	(0.00)
MTR_t								0.059
								(0.26)

Table 2

The impact of cash flow correlation on the coinsurance effect

In all models, the dependent variable is total percentage gain of a merger deal which is measured by market value weighted average of cumulative abnormal returns of acquirer and target. ρ indicates the cash flow correlation between acquirer and target during common firm-years ahead of merger announcement. σ_a and σ_t respectively symbolize the cash flow volatility of acquirers and targets in past years ahead of merger announcement. w_a is the ratio of market capitalization of acquiring firm to the sum of market capitalization of acquiring firm and acquired firm, $\omega_a = \frac{MV_a}{MV_a+MV_t}$. $|w_a\sigma_a - w_t\sigma_t|$ has two interpretations: it is the market value weighted cash flow volatility difference on the one hand. it is the ex ante minimal cash flow volatility of a consolidated firm with σ_a and σ_t. MTR$_a$ and MTR$_t$ represent the marginal tax rate of acquiring firm and acquired firm each. $log(MV_t/MV_a)$ stands for relative market capitalization of two firms at 15 trading days before merger announcement. The symbols *, **, and *** indicate the statistical significance at 10%, 5%, and 1% levels respectively.

	Model1	Model2	Model3	Model4	Model5	Model6	Model7	Model8	Model9	Model10
ρ	0.928	0.938	1.026	1.059	1.209	0.817	0.823	0.936	0.910	1.069
	(1.25)	(1.27)	(1.39)	(1.42)	(1.63)	(1.13)	(1.14)	(1.30)	(1.22)	(1.46)
$\|w_a\sigma_a - w_t\sigma_t\|$		-0.040		-0.005			-0.020		-0.004	
		(-0.85)		(-0.08)			(-0.35)		(-0.06)	
σ_a			-0.060***		-0.047*			-0.055**		-0.048
			(-2.65)		(-1.79)			(-2.06)		(-1.60)
σ_t			0.065**		0.099***			0.097***		0.113***
			(2.46)		(3.11)			(2.65)		(2.89)
MTR$_a$				2.468	3.402				1.674	2.398
				(0.52)	(0.72)				(0.34)	(0.49)
MTR$_t$				6.182*	7.715**				3.686	5.036
				(1.86)	(2.29)				(1.09)	(1.47)
RMV	-0.522**	-0.508**	-0.449*	-0.522**	-0.446*	-0.493*	-0.489*	-0.417	-0.501*	-0.427
	(-2.21)	(-2.13)	(-1.88)	(-2.10)	(-1.79)	(-1.93)	(-1.90)	(-1.61)	(-1.91)	(-1.61)
PCT STK	-0.010	-0.009	-0.009	-0.010	-0.009	-0.013	-0.013	-0.010	-0.013	-0.011
	(-0.75)	(-0.70)	(-0.67)	(-0.72)	(-0.69)	(-0.93)	(-0.92)	(-0.76)	(-0.93)	(-0.77)
Tobin Q_a	-0.531***	-0.522***	-0.478**	-0.525***	-0.465**	-0.489**	-0.487**	-0.408**	-0.498***	-0.412**
	(-2.95)	(-2.84)	(-2.55)	(-2.92)	(-2.54)	(-2.54)	(-2.51)	(-2.01)	(-2.62)	(-2.09)
Tobin Q_t	-0.251	-0.252	-0.352	-0.178	-0.303	-0.134	-0.137	-0.231	-0.122	-0.224
	(-0.86)	(-0.85)	(-1.15)	(-0.61)	(-1.02)	(-0.45)	(-0.45)	(-0.76)	(-0.40)	(-0.74)
Hostile						2.120	2.099	2.082	2.154	2.149
						(0.71)	(0.70)	(0.70)	(0.69)	(0.68)
Cash$_a$						-2.519	-2.335	-2.766	-1.687	-1.895
						(-0.89)	(-0.82)	(-0.97)	(-0.58)	(-0.65)
Cash$_t$						-4.070*	-4.090*	-5.277**	-3.268	-4.346*
						(-1.76)	(-1.76)	(-2.24)	(-1.35)	(-1.78)
Leverage$_a$						0.795	0.812	0.789	1.156	1.282
						(0.32)	(0.32)	(0.32)	(0.44)	(0.50)
Leverage$_t$						-5.102**	-5.141**	-5.007**	-4.690**	-4.372**
						(-2.59)	(-2.60)	(-2.52)	(-2.39)	(-2.22)
Intercept	1.219	1.246	1.200	-1.483	-2.340	3.297*	3.314*	3.165*	1.279	0.313
	(0.95)	(0.97)	(0.94)	(-0.75)	(-1.19)	(1.85)	(1.86)	(1.77)	(0.50)	(0.12)
N. obs	365	365	365	365	365	365	365	365	365	365
$\bar{R}^2$(%)	7.08	6.94	7.51	7.92	9.26	9.00	8.77	10.06	8.72	10.42

Table 3

The impact of cash flow correlation on the change in stockholders wealth

In all models, the dependent variable is total percentage gain of a merger deal which is measured by market value weighted average of cumulative abnormal returns of acquirer and target. ρ indicates the cash flow correlation between acquirer and target during common firm-years ahead of merger announcement. σ_a and σ_t respectively symbolize the cash flow volatility of acquirers and targets in past years ahead of merger announcement. w_a is the ratio of market capitalization of acquiring firm to the sum of market capitalization of acquiring firm and acquired firm, $\omega_a = \frac{MV_a}{MV_a+MV_t}$. $|w_a\sigma_a - w_t\sigma_t|$ has two interpretations: it is the market value weighted cash flow volatility difference on the one hand. it is the ex ante minimal cash flow volatility of a consolidated firm with σ_a and σ_t. MTR$_a$ and MTR$_t$ represent the marginal tax rate of acquiring firm and acquired firm each. RMV, $log(MV_t/MV_a)$ stands for relative market capitalization of two firms at 15 trading days before merger announcement. **Merger deals of high cash flow correlation have ρ that is greater than 0.2.** The symbols *, **, and *** indicate the statistical significance at 10%, 5%, and 1% levels respectively.

	Merger deals of high cash flow correlation						Merger deals of low cash flow correlation					
	Model1	Model2	Model3	Model4	Model5	Model6	Model1	Model2	Model3	Model4	Model5	Model6
ρ	-2.408	-3.656*	-3.467	-2.166	-3.146	-3.221	1.389	1.299	1.168	0.281	0.280	0.302
	-(1.16)	-(1.66)	-(1.57)	-(0.98)	-(1.42)	-(1.45)	(1.04)	(0.98)	(0.92)	(0.21)	(0.21)	(0.23)
$\|w_a\sigma_a - w_t\sigma_t\|$	-0.136***	-0.267***	-0.268***	-0.085**	-0.256***	-0.249***	0.181**	0.326*	0.553**	0.372***	0.374*	0.515***
	-(3.18)	-(3.77)	-(4.19)	-(2.36)	-(4.05)	-(3.74)	(1.99)	(1.67)	(2.32)	(3.60)	(1.88)	(2.18)
σ_t		0.264	0.346		0.375	0.413		-0.051	-0.038		0.000	0.000
		(2.40)	(3.16)		(3.24)	(3.37)		-(1.04)	-(0.78)		-(0.01)	(0.00)
MTR$_a$			5.230			4.747			10.766			6.547
			(1.03)			(0.89)			(1.29)			(0.79)
MTR$_t$			10.058			8.332			8.533			6.390
			(1.78)			(1.69)			(1.76)			(1.27)
RMV				-0.279	-0.090	-0.034				-0.573	-0.573	-0.602
				-(0.67)	-(0.22)	-(0.08)				-(1.61)	-(1.60)	-(1.62)
PCT STK				-0.019	-0.013	-0.016				-0.002	-0.002	0.000
				-(1.01)	-(0.69)	-(0.84)				-(0.09)	-(0.09)	(0.01)
Hostile				4.881***	4.960***	5.635***				-0.019	-0.018	-0.157
				(2.94)	(3.56)	(2.70)				(0.00)	(0.00)	-(0.03)
Tobin Q$_a$				-0.760***	-0.600***	-0.650***				-0.087	-0.088	-0.072
				-(3.53)	-(2.77)	-(3.16)				-(0.24)	-(0.24)	-(0.22)
Tobin Q$_t$				0.223	-0.100	-0.021				-0.545	-0.545	-0.589*
				(0.65)	-(0.30)	-(0.07)				-(1.47)	-(1.47)	-(1.69)
Cash$_a$				-2.263	-3.396	-2.457				-4.243	-4.244	-2.772
				-(0.43)	-(0.72)	-(0.48)				-(1.19)	-(1.18)	-(0.80)
Cash$_t$				0.064	-2.278	0.073				-5.788**	-5.781*	-4.366
				(0.01)	-(0.58)	(0.02)				-(2.04)	-(1.93)	-(1.42)
Leverage$_a$				-0.211	-0.338	0.469				1.530	1.528	2.415
				-(0.06)	-(0.11)	(0.14)				(0.40)	(0.39)	(0.62)
Leverage$_t$				-2.775	-1.988	-0.786				-6.058*	-6.057*	-5.007
				-(1.15)	-(0.91)	-(0.34)				-(1.82)	-(1.82)	-(1.55)
Intercept	1.863	1.617	-3.150*	5.141**	4.934**	0.332	-0.807	-0.791	-7.179**	1.855	1.856	-3.458
	(1.52)	(1.40)	-(1.68)	(2.30)	(2.20)	(0.11)	-(1.51)	-(1.48)	-(2.40)	(0.62)	(0.62)	-(0.80)
Nobs	159	159	159	159	159	159	206	206	206	206	206	206
$\bar{R}^2$(%)	1.83	5.60	8.66	9.73	16.38	17.81	0.02	-0.14	3.88	9.45	8.99	10.12

Table 4

The impact of positive coinsurance on the change in stockholders wealth

In all models, the dependent variable is total percentage gain of a merger deal which is measured by market value weighted average of cumulative abnormal returns of acquirer and target. ρ indicates the cash flow correlation between acquirer and target during common firm-years ahead of merger announcement. σ_a and σ_t respectively symbolize the cash flow volatility of acquirers and targets in past years ahead of merger announcement. w_a is the ratio of market capitalization of acquiring firm to the sum of market capitalization of acquiring firm and acquired firm. $|w_a\sigma_a - w_t\sigma_t|$ is the market value weighted cash flow volatility difference. MTR$_a$ and MTR$_t$ represent the marginal tax rate of acquiring firm and acquired firm each. RMV, $log(MV_t/MV_a)$ stands for relative market capitalization of two firms at 15 trading days before merger announcement. Left panel includes mergers that satisfy all three constraints, $(i)|w_a\sigma_a - w_t\sigma_t| < Min[\sigma_a, \sigma_t]$, $(ii)\sigma_a, \sigma_t < \sigma_L(= 1.43)$, and $(iii)\rho < 0.2$. Right panel includes mergers of low cash flow correlation that do not meet all other two conditions. The symbols *, **, and *** indicate the statistical significance at 10%, 5%, and 1% levels respectively.

	Mergers that satisfy three conditions						Mergers of low ρ that do not meet all two other conditions					
	Model1	Model2	Model3	Model4	Model5	Model6	Model1	Model2	Model3	Model4	Model5	Model6
ρ	-0.749	-0.701	-0.889	1.577	1.499	1.858	1.655	1.565	1.393	1.209	1.195	1.130
	-(0.38)	-(0.35)	-(0.39)	(0.77)	(0.73)	(0.79)	(1.03)	(0.97)	(0.90)	(0.74)	(0.73)	(0.71)
$\|w_a\sigma_a - w_t\sigma_t\|$	7.350**	6.932*	6.859*	10.002***	9.544***	9.959***	0.226**	0.350*	0.600**	0.408***	0.443**	0.635***
	(2.38)	(1.98)	(2.01)	(3.10)	(2.72)	(2.77)	(2.38)	(1.79)	(2.43)	(3.67)	(2.22)	(2.64)
σ_t		0.983	1.001		1.645	1.773		-0.044	-0.032		-0.013	-0.013
		(0.38)	(0.38)		(0.53)	(0.54)		-(0.91)	-(0.64)		-(0.25)	-(0.23)
MTR$_a$			-9.563			-1.590			13.182			8.508
			-(0.89)			-(0.18)			(1.51)			(1.00)
MTR$_t$			4.477			5.843			9.613*			9.373*
			(0.83)			(0.87)			(1.75)			(1.70)
RMV				1.650**	1.739**	1.744**				-0.939**	-0.951**	-1.018**
				(2.59)	(2.36)	(2.34)				-(2.27)	-(2.30)	-(2.37)
PCT STK				0.025	0.020	0.020				0.004	0.004	0.011
				(1.21)	(0.99)	(0.93)				(0.12)	(0.10)	(0.30)
Hostile				2.015	1.735	1.557				10.811***	10.866***	11.061***
				(0.58)	(0.56)	(0.48)				(6.80)	(6.63)	(6.82)
Tobin Q$_a$				-1.826***	-1.754***	-1.794***				-0.080	-0.092	-0.076
				-(2.49)	-(2.62)	-(2.60)				-(0.20)	-(0.23)	-(0.21)
Tobin Q$_t$				-0.177	-0.197	-0.170				-0.525	-0.520	-0.585
				-(0.31)	-(0.35)	-(0.30)				-(1.31)	-(1.29)	-(1.57)
Cash$_a$				23.082**	22.399**	23.540*				-4.230	-4.266	-2.440
				(2.22)	(2.13)	(1.90)				-(1.12)	-(1.12)	-(0.66)
Cash$_t$				-20.079**	-17.407*	-17.051*				-4.709	-4.507	-2.571
				-(2.13)	-(1.93)	-(1.83)				-(1.58)	-(1.45)	-(0.82)
Leverage$_a$				0.249	0.483	0.793				1.547	1.476	2.787
				(0.04)	(0.07)	(0.11)				(0.36)	(0.34)	(0.67)
Leverage$_t$				-8.049	-8.426	-7.047				-5.204	-5.199	-3.901
				-(1.33)	-(1.42)	-(0.99)				-(1.36)	-(1.36)	-(1.06)
Intercept	-1.746	-2.370	-0.448	6.119	5.317	3.242	-1.147	-1.129	-8.481	0.053	0.070	-7.568
	-(1.56)	-(1.77)	-(0.12)	(1.30)	(1.27)	(0.48)	-(1.64)	-(1.62)	-(2.68)	(0.01)	(0.02)	-(1.48)
Nobs	45	45	45	45	45	45	161	161	161	161	161	161
$\bar{R}^2(\%)$	4.78	2.99	-0.70	21.39	20.49	16.46	0.29	-0.06	4.95	11.75	11.17	13.73

Table 5
The impact of high cash flow correlation on the change in debt rate after mergers

In all models, the dependent variable is the change in acquirer's debt rate during two months after and before mergers that is assessed by Standard and Poors. We follow the numerical conversion of bond rate by Klock, Mansi, and Maxwell JFQA (2005). For example, AAA rate bond is converted to 22 while D rate bond is converted to 1. ρ indicates the cash flow correlation between acquirer and target during common firm-years ahead of merger announcement. σ_a and σ_t respectively symbolize the cash flow volatility of acquirers and targets in past years ahead of merger announcement. w_a is the ratio of market capitalization of acquiring firm to the sum of market capitalization of acquiring firm and acquired firm, $\omega_a = \frac{MV_a}{MV_a+MV_t}$. $|w_a\sigma_a - w_t\sigma_t|$ has two interpretations: it is the market value weighted cash flow volatility difference on the one hand. it is the ex ante minimal cash flow volatility of consolidated firm with σ_a and σ_t. MTR$_a$ and MTR$_t$ represent the marginal tax rate of acquiring firm and acquired firm each. RMV, $log(MV_t/MV_a)$ stands for relative market capitalization of two firms at 15 trading days before merger announcement. **High ρ represents the dummy variable which becomes 1 if ρ is greater than 0.2 and 0 otherwise.** The symbols *, **, and *** indicate the statistical significance at 10%, 5%, and 1% levels respectively.

	Model1	Model2	Model3	Model4	Model5	Model6
ρ	0.076	0.112	0.110	0.085	0.114	0.113
	(1.05)	(1.57)	(1.54)	(0.99)	(1.59)	(1.57)
$\|w_a\sigma_a - w_t\sigma_t\|$		0.134***	0.134***	0.060	0.135***	0.135***
		(2.83)	(2.82)		(2.84)	(2.84)
σ_t			-0.002			-0.002
			(-1.01)			(-1.02)
High $\rho \times \rho$	0.096	0.076	0.075	0.096	0.071	0.070
	(0.72)	(0.58)	(0.57)	(0.75)	(0.53)	(0.52)
High $\rho \times \|w_a\sigma_a - w_t\sigma_t\|$		-0.127***	-0.132***		-0.127***	-0.132***
		(-2.81)	(-2.90)		(-2.85)	(-2.94)
High $\rho \times \sigma_t$			0.007			0.007
			(1.63)			(1.81)
MTR$_a$				0.134	0.123	0.140
				(-0.53)	(0.44)	(0.51)
RMV	-0.002	-0.013**	-0.013**	-0.007	-0.013**	-0.013**
	(-0.57)	(-2.32)	(-2.29)	(-0.57)	(-2.33)	(-2.31)
PCT STK	0.000	-0.001	-0.001	0.000	-0.001	-0.001
	(-0.14)	(-0.75)	(-0.73)	(-0.15)	(-0.73)	(-0.71)
Hostile	-0.051	0.026	0.022	-0.011	0.027	0.023
	(-1.20)	(0.56)	(0.45)	(-1.22)	(0.58)	(0.48)
Tobin Q$_a$	0.008	0.007	0.007	0.009	0.007	0.006
	(0.72)	(0.73)	(0.67)	(0.76)	(0.66)	(0.59)
Cash$_a$	0.068	-0.209	-0.195	-0.246	-0.190	-0.173
	(0.56)	(-1.38)	(-1.27)	(0.28)	(-1.21)	(-1.10)
Leverage$_a$	-0.054	-0.143*	-0.152*	-0.050	-0.127	-0.134
	(-0.66)	(-1.73)	(-1.81)	(-0.77)	(-1.39)	(-1.45)
Intercept	0.072	0.067	0.074	0.016	0.018	0.019
	(0.62)	(0.55)	(0.60)	(0.76)	(0.10)	(0.11)
high ρ	-0.166**	-0.068	-0.081	-0.188**	-0.066	-0.079
	(-2.11)	(-0.80)	(-0.93)	(-2.13)	(-0.76)	(-0.88)
Nobs	190	190	190	190	190	190
$\bar{R}^2$(%)	-2.00	15.23	14.53	-2.49	14.83	14.14

Table 6

The impact of high cash flow correlation on the change in debt rate after mergers

In all models, the dependent variable is the change in acquirer's debt rate during two months after and before mergers that is assessed by Standard and Poors. We follow the numerical conversion of bond rate by Klock, Mansi, and Maxwell JFQA (2005). For example, AAA rate bond is converted to 22 while D rate bond is converted to 1. ρ indicates the cash flow correlation between acquirer and target during common firm-years ahead of merger announcement. σ_a and σ_t respectively symbolize the cash flow volatility of acquirers and targets in past years ahead of merger announcement. w_a is the ratio of market capitalization of acquiring firm to the sum of market capitalization of acquiring firm and acquired firm, $\omega_a = \frac{MV_a}{MV_a+MV_t}$. $|w_a\sigma_a - w_t\sigma_t|$ has two interpretations: it is the market value weighted cash flow volatility difference on the one hand. it is the ex ante minimal cash flow volatility of consolidated firm with σ_a and σ_t. MTR$_a$ and MTR$_t$ represent the marginal tax rate of acquiring firm and acquired firm each. RMV, $log(MV_t/MV_a)$ stands for relative market capitalization of two firms at 15 trading days before merger announcement. **High ρ represents the dummy variable which becomes 1 if ρ is greater than 0.2 and 0 otherwise.** The symbols *, **, and *** indicate the statistical significance at 10%, 5%, and 1% levels respectively.

	Merger deals of high cash flow correlation								Merger deals of low cash flow correlation							
	Model1	Model2	Model3	Model4	Model5	Model6	Model7	Model8	Model1	Model2	Model3	Model4	Model5	Model6	Model7	Model8
ρ	0.167	0.170	0.165	0.169	0.171	0.182	0.168	0.179	0.122	0.137	0.118	0.133	0.113	0.130	0.111	0.128
	(1.49)	(1.50)	(1.46)	(1.48)	(1.51)	(1.58)	(1.48)	(1.55)	(1.71)	(1.90)	(1.67)	(1.86)	(1.55)	(1.77)	(1.53)	(1.75)
$\lvert w_a\sigma_a - w_t\sigma_t\rvert$	0.001	-0.005	-0.003	-0.007	0.009	0.008	0.004	0.004	0.119**	0.133***	0.120**	0.134***	0.136***	0.147***	0.136***	0.147***
	(0.12)	(-0.49)	(-0.43)	(-0.70)	(0.54)	(0.48)	(0.26)	(0.27)	(2.48)	(2.95)	(2.49)	(2.97)	(2.82)	(3.39)	(2.79)	(3.36)
MTR$_a$		-0.349		-0.330		-0.582		-0.557		0.884***		0.875***		0.916**		0.911**
		(-1.00)		(-0.96)		(-1.36)		(-1.33)		(2.74)		(2.73)		(2.60)		(2.58)
σ_t			0.004	0.002			0.005	0.004			-0.003	-0.003			-0.002	-0.002
			(1.08)	(0.92)			(1.40)	(1.26)			(-1.17)	(-1.09)			(-0.98)	(-0.90)
RMV					0.008	0.005	0.010	0.007					-0.014**	-0.015**	-0.014**	-0.015**
					(0.45)	(0.31)	(0.55)	(0.40)					(-2.26)	(-2.58)	(-2.24)	(-2.56)
PCT STK					0.000	0.000	0.000	0.000					-0.001	-0.001	-0.001	-0.001
					(0.10)	(-0.07)	(0.14)	(-0.04)					(-0.74)	(-0.71)	(-0.72)	(-0.70)
Hostile					-0.011	-0.018	-0.021	-0.025					0.056	0.068	0.050	0.063
					(-0.32)	(-0.55)	(-0.58)	(-0.73)					(0.74)	(0.90)	(0.65)	(0.81)
Tobin Q$_a$					0.004	0.005	0.002	0.004					0.008	0.005	0.008	0.005
					(0.31)	(0.42)	(0.17)	(0.31)					(0.43)	(0.28)	(0.44)	(0.28)
Cash$_a$					-0.250	-0.456	-0.271	-0.464					-0.180	-0.105	-0.164	-0.092
					(-0.86)	(-1.46)	(-0.90)	(-1.45)					(-1.01)	(-0.60)	(-0.90)	(-0.50)
Leverage$_a$					-0.171	-0.254	-0.197	-0.270					-0.144	0.016	-0.146	0.013
					(-1.15)	(-1.61)	(-1.28)	(-1.64)					(-1.16)	(0.11)	(-1.16)	(0.09)
Intercept	-0.097	0.018	-0.103	0.008	-0.053	0.181	-0.053	0.172	-0.038	-0.346	-0.029	-0.335	0.116	-0.250	0.118	-0.247
	(-1.46)	(0.14)	(-1.52)	(0.07)	(-0.84)	(1.09)	(-0.82)	(1.05)	(-0.76)	(-2.56)	(-0.55)	(-2.47)	(0.56)	(-1.01)	(0.57)	(-0.98)
Nobs	78	78	78	78	78	78	78	78	112	112	112	112	112	112	112	112
$\bar{R}^2$(%)	1.08	1.34	0.12	0.16	-5.32	-2.85	-5.99	-3.87	19.94	22.18	19.48	21.68	18.24	20.18	17.58	19.49

TABLE 6

Multivariate Regressions of Excess Cost of Capital on Cross-segment Correlations: Alternative Measures of Cost of Capital

This table presents regressions of excess cost of capital on cross-segment correlations using two alternative approaches, CT and PEG, instead of GLS to derive the implied cost of equity. The regressions are estimated over the period 1988 to 2006 for a sample of single- and multi-segment firms. Excess cost of capital is defined in Table 1, and CT and PEG implied cost of equity are computed based on the approach of Claus and Thomas (2001) and Easton (2004), respectively. Cash flow and investment correlations are defined in Table 2. The control variables are defined in Table 3. Robust standard errors (heteroskedasticity consistent and double clustered by firm and year) are reported in brackets. ***, **, or * indicates that the coefficient estimate is significant at the 1%, 5%, or 10% level (respectively).

	CT		PEG	
Cash flow correlations	0.026***		0.051***	
	[0.010]		[0.011]	
Investment correlations		0.029***		0.056***
		[0.009]		[0.012]
Number of segments	0.010***	0.011***	0.002	0.003
	[0.002]	[0.002]	[0.002]	[0.002]
Logarithm of market capitalization	-0.025***	-0.025***	-0.029***	-0.029***
	[0.004]	[0.004]	[0.003]	[0.003]
Leverage	-0.109***	-0.109***	-0.124***	-0.125***
	[0.013]	[0.013]	[0.021]	[0.021]
Book-to-market	-0.083***	-0.083***	0.010	0.009
	[0.010]	[0.010]	[0.006]	[0.006]
Logarithm of forecast dispersion	0.018***	0.018***	0.030***	0.030***
	[0.002]	[0.002]	[0.002]	[0.002]
Long-term growth forecast	0.187***	0.186***	0.517***	0.516***
	[0.041]	[0.041]	[0.046]	[0.046]
Lagged 12-month return	-0.060***	-0.060***	-0.072***	-0.072***
	[0.008]	[0.008]	[0.007]	[0.007]
Constant	0.203***	0.200***	0.153***	0.148***
	[0.033]	[0.036]	[0.035]	[0.037]
Observations	26,280	26,280	27,302	27,302
R-squared	0.194	0.195	0.088	0.088

TABLE 7

Multivariate Regressions of Excess Cost of Equity Capital on Cross-segment Correlations

This table presents regressions of excess cost of equity capital on cross-segment correlations. The regressions are estimated over the period 1988 to 2006 for a sample of single- and multi-segment firms. Excess cost of equity is defined as the natural logarithm of the ratio of a firm's cost of equity to its imputed cost of equity calculated using a portfolio of comparable stand-alone firms. Cash flow and investment correlations are defined in Table 2. Cost of equity is based on the approach of Gebhardt, Lee, and Swaminathan (2001) (GLS) and Fama and French (1997) (FF). The control variables are defined in Table 3. Robust standard errors (heteroskedasticity consistent and double clustered by firm and year) are reported in brackets. ***, **, or * indicates that the coefficient estimate is significant at the 1%, 5%, or 10% level (respectively).

	GLS	GLS	FF	FF
Cash flow correlations	0.084***		0.099**	
	[0.016]		[0.042]	
Investment correlations		0.074***		0.085**
		[0.015]		[0.040]
Number of segments	0.011***	0.010***	0.023***	0.022***
	[0.004]	[0.004]	[0.006]	[0.005]
Logarithm of market capitalization	-0.029***	-0.029***	-0.013**	-0.013**
	[0.006]	[0.006]	[0.006]	[0.006]
Leverage	0.016	0.016	0.237***	0.237***
	[0.023]	[0.023]	[0.042]	[0.042]
Book-to-market	0.193***	0.193***	0.056***	0.056***
	[0.020]	[0.020]	[0.017]	[0.018]
Logarithm of forecast dispersion	0.003	0.002	0.017***	0.017***
	[0.003]	[0.003]	[0.006]	[0.006]
Long-term growth forecast	-0.142	-0.141	0.341***	0.342***
	[0.111]	[0.110]	[0.079]	[0.079]
Lagged 12-month return	-0.097***	-0.097***	0.001	0.001
	[0.007]	[0.007]	[0.039]	[0.039]
Constant	-0.001	0.008	-0.124*	-0.111*
	[0.063]	[0.068]	[0.072]	[0.063]
Observations	29,150	29,150	26,364	26,364
R-squared	0.158	0.158	0.014	0.014

Attachment 31.3.1

FEI Lower Mainland Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]
1	**REVENUES**										
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 871,764**	**$ 542,531**	**$ 150,273**	**$ 433**	**$ 446**	**$ 11,785**	**$ 122,957**	**$ 36,551**	**$ 6,786**
3	Revenue Margin at Proposed 2013 FEI Rates		$ 455,859	$ 279,100	$ 69,225	$ 138	$ 224	$ 11,785	$ 61,981	$ 26,640	$ 6,765
4	Total Cost of Gas [3]		$ 415,905	$ 263,432	$ 81,049	$ 295	$ 222	$ -	$ 60,976	$ 9,911	$ 20
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	line 8 + line 9	**$ 864,391**	**$ 585,544**	**$ 145,824**	**$ 334**	**$ 358**	**$ 728**	**$ 105,505**	**$ 25,346**	**$ 752**
8	Cost of Service Margin		$ 448,486	$ 322,112	$ 64,776	$ 39	$ 136	$ 728	$ 44,528	$ 15,434	$ 732
9	Total Cost of Gas [3]		$ 415,905	$ 263,432	$ 81,049	$ 295	$ 222	$ -	$ 60,976	$ 9,911	$ 20
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / Deficit	line 2 - line 7	**$ 7,373**								
13	% increase to Equal Allocated Cost		-1.6%								
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 864,391**	**$ 538,017**	**$ 149,154**	**$ 431**	**$ 443**	**$ 11,594**	**$ 121,955**	**$ 36,121**	**$ 6,676**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 448,486	$ 274,585	$ 68,105	$ 136	$ 221	$ 11,594	$ 60,979	$ 26,209	$ 6,656
18											
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 864,391**	**$ 538,017**	**$ 149,154**	**$ 431**	**$ 443**	**$ 11,594**	**$ 146,824**	**$ 72,996**	**$ 26,098**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 864,391**	**$ 585,544**	**$ 145,824**	**$ 334**	**$ 358**	**$ 728**	**$ 130,373**	**$ 62,221**	**$ 20,174**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**91.9%**	**102.3%**		**123.5%**		**112.6%**	**117.3%**	
24											

Note:

1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
3. Cost of Gas forecast is based on five-day average forward prices at August 16, 17, 18, 19, and 22, 2011, and the propane gas cost forecast is based on the Mt. Belvieu propane swap prices at August 22, 2011, consistent with the forward pricing utilized in the 2011 Third Quarter Gas Cost reports for the various entities / service areas.

FEI Lower Mainland Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
FUNCTIONALIZATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 152,775	$ 43	$ 2,152	$ -	$ 25,564	$ 3,409	$ 68,227	$ 3,573	$ 49,806
2	BCH Capacity Right	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 38,609	$ -	$ 338	$ -	$ 13,159	$ -	$ 25,111	$ -	$ -
4	Depreciation Expense	$ 99,374	$ 34	$ 1,887	$ -	$ 18,320	$ 4,851	$ 74,281	$ -	$ -
5	Amortization Expense	$ 7,987	$ 2	$ 50	$ -	$ 5,634	$ (1,676)	$ 1,145	$ 2,792	$ 40
6	Other Operating Revenue	$ (37,219)	$ -	$ -	$ -	$ (22,245)	$ (11,346)	$ (1,988)	$ -	$ (1,640)
7	Other Earned Return Provisions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Income Tax	$ 21,825	$ 32	$ 426	$ -	$ 6,905	$ -	$ 14,462	$ -	$ -
9	Earned Return	$ 165,134	$ 239	$ 3,227	$ -	$ 52,247	$ -	$ 109,420	$ -	$ -
10	**Total Cost of Service Margin**	**$ 448,486**	**$ 350**	**$ 8,082**	**$ -**	**$ 99,585**	**$ (4,762)**	**$ 290,659**	**$ 6,365**	**$ 48,206**
11										
12	Cost of Gas - Commodity	$ 302,080	$ 302,080	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 113,825	$ 113,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 864,391**	**$ 416,256**	**$ 8,082**	**$ -**	**$ 99,585**	**$ (4,762)**	**$ 290,659**	**$ 6,365**	**$ 48,206**

FEI Lower Mainland Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 3

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Plant in Service										
2	**Total Gas Plant in Service**		**$ 2,897,581**	**$ 2,029,028**	**$ 426,960**	**$ 160**	**$ 565**	**$ 5,069**	**$ 318,225**	**$ 114,618**	**$ 2,956**
3		Demand	$ 1,521,605	$ 875,096	$ 271,445	$ -	$ 252	$ 4,166	$ 267,812	$ 102,835	$ -
4		Customer	$ 1,371,776	$ 1,151,289	$ 154,653	$ 159	$ 313	$ 903	$ 49,731	$ 11,772	$ 2,956
5		Energy	$ 4,200	$ 2,643	$ 863	$ 0	$ 0	$ -	$ 681	$ 12	$ 0
6	**Total Accumulated Depreciation**		**$ (806,548)**	**$ (561,227)**	**$ (119,025)**	**$ (33)**	**$ (140)**	**$ (1,418)**	**$ (90,873)**	**$ (33,235)**	**$ (597)**
7		Demand	$ (455,863)	$ (262,180)	$ (81,325)	$ -	$ (75)	$ (1,236)	$ (80,237)	$ (30,809)	$ -
8		Customer	$ (350,224)	$ (298,758)	$ (37,605)	$ (33)	$ (65)	$ (182)	$ (10,561)	$ (2,423)	$ (597)
9		Energy	$ (462)	$ (289)	$ (94)	$ (0)	$ (0)	$ -	$ (75)	$ (3)	$ (0)
10	**TOTAL Net Plant**		**$ 2,091,033**	**$ 1,467,801**	**$ 307,936**	**$ 127**	**$ 425**	**$ 3,651**	**$ 227,352**	**$ 81,383**	**$ 2,359**
11		Demand	$ 1,065,742	$ 612,916	$ 190,120	$ -	$ 176	$ 2,930	$ 187,575	$ 72,025	$ -
12		Customer	$ 1,021,553	$ 852,531	$ 117,048	$ 126	$ 249	$ 721	$ 39,170	$ 9,349	$ 2,359
13		Energy	$ 3,738	$ 2,354	$ 768	$ 0	$ 0	$ -	$ 607	$ 8	$ 0
14											
15	Contribution In Aid of Construction										
16	**Total CIAC**		**$ (139,218)**	**$ (102,796)**	**$ (19,185)**	**$ (10)**	**$ (28)**	**$ (208)**	**$ (12,475)**	**$ (4,330)**	**$ (185)**
17		Demand	$ (53,147)	$ (30,562)	$ (9,480)	$ -	$ (9)	$ (151)	$ (9,353)	$ (3,592)	$ -
18		Customer	$ (86,059)	$ (72,227)	$ (9,702)	$ (10)	$ (20)	$ (57)	$ (3,120)	$ (739)	$ (185)
19		Energy	$ (12)	$ (8)	$ (2)	$ (0)	$ (0)	$ -	$ (2)	$ (0)	$ (0)
20	**Total Accumulated Amortization**		**$ 39,559**	**$ 30,078**	**$ 5,236**	**$ 3**	**$ 8**	**$ 52**	**$ 3,086**	**$ 1,037**	**$ 60**
21		Demand	$ 11,814	$ 6,794	$ 2,107	$ -	$ 2	$ 33	$ 2,079	$ 798	$ -
22		Customer	$ 27,738	$ 23,280	$ 3,127	$ 3	$ 6	$ 18	$ 1,006	$ 238	$ 60
23		Energy	$ 7	$ 4	$ 1	$ 0	$ 0	$ -	$ 1	$ 0	$ 0
24	**Total Net Contribution**		**$ (99,659)**	**$ (72,719)**	**$ (13,949)**	**$ (7)**	**$ (20)**	**$ (156)**	**$ (9,389)**	**$ (3,294)**	**$ (126)**
25		Demand	$ (41,333)	$ (23,769)	$ (7,373)	$ -	$ (7)	$ (118)	$ (7,274)	$ (2,793)	$ -
26		Customer	$ (58,321)	$ (48,947)	$ (6,575)	$ (7)	$ (13)	$ (38)	$ (2,114)	$ (500)	$ (126)
27		Energy	$ (5)	$ (3)	$ (1)	$ (0)	$ (0)	$ -	$ (1)	$ (0)	$ (0)
28											
29	Work in Progress, no AFUDC		**$ 12,882**	**$ 8,522**	**$ 2,022**	**$ 1**	**$ 2**	**$ 26**	**$ 1,679**	**$ 621**	**$ 9**
30		Demand	$ 8,653	$ 4,977	$ 1,544	$ -	$ 1	$ 23	$ 1,523	$ 585	$ -
31		Customer	$ 4,210	$ 3,533	$ 475	$ 0	$ 1	$ 3	$ 153	$ 36	$ 9
32		Energy	$ 19	$ 11	$ 4	$ 0	$ 0	$ -	$ 3	$ 0	$ 0
33											
34	Unamortized Deferred Charges										
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 38,467**	**$ 15,605**	**$ 8,614**	**$ 2**	**$ 90**	**$ 156**	**$ 10,206**	**$ 3,854**	**$ (60)**
36		Demand	$ 58,658	$ 33,679	$ 10,447	$ -	$ 93	$ 174	$ 10,307	$ 3,958	$ -
37		Customer	$ (25,850)	$ (21,555)	$ (2,969)	$ (3)	$ (6)	$ (18)	$ (999)	$ (239)	$ (60)
38		Energy	$ 5,660	$ 3,482	$ 1,136	$ 5	$ 3	$ -	$ 898	$ 135	$ 0
39											
40	Cash Working Capital		**$ 5,259**	**$ 3,529**	**$ 881**	**$ 2**	**$ 2**	**$ 6**	**$ 662**	**$ 172**	**$ 5**
41		Demand	$ 1,565	$ 900	$ 279	$ -	$ 0	$ 4	$ 275	$ 106	$ -
42		Customer	$ 1,796	$ 1,461	$ 220	$ 0	$ 1	$ 2	$ 85	$ 21	$ 5
43		Energy	$ 1,899	$ 1,168	$ 381	$ 2	$ 1	$ -	$ 301	$ 45	$ 0
44											
45	Other Working Capital										
46	**Total Other Working Capital**		**$ 72,053**	**$ 40,531**	**$ 13,053**	**$ (1)**	**$ 11**	**$ 213**	**$ 13,172**	**$ 5,088**	**$ (14)**
47		Demand	$ 76,106	$ 43,764	$ 13,575	$ -	$ 13	$ 217	$ 13,394	$ 5,143	$ -
48		Customer	$ (4,047)	$ (3,229)	$ (521)	$ (1)	$ (1)	$ (4)	$ (221)	$ (55)	$ (14)
49		Energy	$ (6)	$ (3)	$ (1)	$ (0)	$ (0)	$ -	$ (1)	$ (0)	$ (0)
50											
51	LILO, Capital Efficiency Mechanism, Others		**$ (851)**	**$ (657)**	**$ (110)**	**$ (0)**	**$ (0)**	**$ (1)**	**$ (61)**	**$ (20)**	**$ (1)**
52		Demand	$ (218)	$ (125)	$ (39)	$ -	$ (0)	$ (1)	$ (38)	$ (15)	$ -
53		Customer	$ (634)	$ (532)	$ (71)	$ (0)	$ (0)	$ (0)	$ (23)	$ (5)	$ (1)
54		Energy	$ -						$ -	$ -	$ -
55											
56	**Total Utility Rate Base**		**$ 2,119,185**	**$ 1,462,613**	**$ 318,447**	**$ 123**	**$ 511**	**$ 3,895**	**$ 243,620**	**$ 87,804**	**$ 2,172**
57		Demand	$ 1,169,173	$ 672,342	$ 208,553	$ -	$ 277	$ 3,231	$ 205,762	$ 79,008	$ -
58		Customer	$ 938,707	$ 783,262	$ 107,606	$ 116	$ 229	$ 664	$ 36,051	$ 8,607	$ 2,172
59		Energy	$ 11,305	$ 7,009	$ 2,287	$ 7	$ 5	$ -	$ 1,807	$ 189	$ 0

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COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 4

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Operating & Maintenance Expense										
2	**Total Operating & Maintenance Expense**		**$ 152,775**	**$ 110,782**	**$ 21,957**	**$ 16**	**$ 40**	**$ 243**	**$ 14,520**	**$ 4,915**	**$ 302**
3		Demand	$ 55,295	$ 31,802	$ 9,865	$ -	$ 9	$ 150	$ 9,733	$ 3,737	$ -
4		Customer	$ 97,437	$ 78,953	$ 12,084	$ 16	$ 31	$ 93	$ 4,781	$ 1,177	$ 302
5		Energy	$ 43	$ 26	$ 9	$ 0	$ 0	$ -	$ 7	$ 1	$ 0
6	BCH Capacity Right		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
7		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 38,609**	**$ 26,657**	**$ 5,799**	**$ 2**	**$ 8**	**$ 72**	**$ 4,428**	**$ 1,601**	**$ 42**
11		Demand	$ 21,267	$ 12,230	$ 3,794	$ -	$ 4	$ 60	$ 3,743	$ 1,437	$ -
12		Customer	$ 17,342	$ 14,427	$ 2,005	$ 2	$ 4	$ 13	$ 685	$ 164	$ 42
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Depreciation Expense		**$ 99,374**	**$ 70,696**	**$ 14,611**	**$ 10**	**$ 26**	**$ 168**	**$ 10,173**	**$ 3,509**	**$ 182**
15		Demand	$ 41,413	$ 23,818	$ 7,388	$ -	$ 7	$ 112	$ 7,289	$ 2,799	$ -
16		Customer	$ 57,927	$ 46,856	$ 7,216	$ 10	$ 19	$ 56	$ 2,879	$ 710	$ 182
17		Energy	$ 34	$ 21	$ 7	$ 0	$ 0	$ -	$ 5	$ 1	$ 0
18	Amortization Expense		**$ 7,987**	**$ 4,697**	**$ 1,390**	**$ 0**	**$ 31**	**$ 21**	**$ 1,336**	**$ 511**	**$ 1**
19		Demand	$ 7,523	$ 4,310	$ 1,337	$ -	$ 30	$ 21	$ 1,319	$ 506	$ -
20		Customer	$ 461	$ 386	$ 52	$ 0	$ 0	$ 0	$ 17	$ 4	$ 1
21		Energy	$ 2	$ 1	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0
22	Other Operating Revenue		**$ (37,219)**	**$ (22,142)**	**$ (6,467)**	**$ (0)**	**$ (7)**	**$ (100)**	**$ (6,152)**	**$ (2,341)**	**$ (9)**
23		Demand	$ (34,099)	$ (19,609)	$ (6,082)	$ -	$ (6)	$ (97)	$ (6,001)	$ (2,304)	$ -
24		Customer	$ (3,120)	$ (2,533)	$ (385)	$ (0)	$ (1)	$ (3)	$ (151)	$ (37)	$ (9)
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Income Tax		**$ 21,825**	**$ 15,342**	**$ 3,209**	**$ 1**	**$ 4**	**$ 38**	**$ 2,361**	**$ 845**	**$ 25**
27		Demand	$ 11,028	$ 6,342	$ 1,967	$ -	$ 2	$ 30	$ 1,941	$ 745	$ -
28		Customer	$ 10,766	$ 8,980	$ 1,235	$ 1	$ 3	$ 8	$ 415	$ 99	$ 25
29		Energy	$ 32	$ 19	$ 6	$ 0	$ 0	$ -	$ 5	$ 1	$ 0
30	Earned Return		**$ 165,134**	**$ 116,081**	**$ 24,278**	**$ 10**	**$ 34**	**$ 286**	**$ 17,861**	**$ 6,394**	**$ 189**
31		Demand	$ 83,440	$ 47,987	$ 14,885	$ -	$ 14	$ 228	$ 14,686	$ 5,639	$ -
32		Customer	$ 81,455	$ 67,946	$ 9,345	$ 10	$ 20	$ 58	$ 3,137	$ 749	$ 189
33		Energy	$ 239	$ 147	$ 48	$ 0	$ 0	$ -	$ 38	$ 6	$ 0
34											
35	**Total Cost of Service Margin**		**$ 448,486**	**$ 322,112**	**$ 64,776**	**$ 39**	**$ 136**	**$ 728**	**$ 44,528**	**$ 15,434**	**$ 732**
36		Demand	$ 185,868	$ 106,881	$ 33,153	$ -	$ 60	$ 504	$ 32,710	$ 12,560	$ -
37		Customer	$ 262,268	$ 215,016	$ 31,552	$ 39	$ 76	$ 224	$ 11,763	$ 2,866	$ 732
38		Energy	$ 350	$ 215	$ 70	$ 0	$ 0	$ -	$ 56	$ 8	$ 0
39	Cost of Gas - Commodity		**$ 302,080**	**$ 189,510**	**$ 57,577**	**$ 295**	**$ 203**	**$ -**	**$ 46,295**	**$ 8,179**	**$ 20**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 302,080	$ 189,510	$ 57,577	$ 295	$ 203	$ -	$ 46,295	$ 8,179	$ 20
43	Cost of Gas - Midstream		**$ 113,825**	**$ 73,922**	**$ 23,472**	**$ -**	**$ 19**	**$ -**	**$ 14,681**	**$ 1,732**	**$ -**
44		Demand	$ 113,825	$ 73,922	$ 23,472	$ -	$ 19	$ -	$ 14,681	$ 1,732	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 864,391**	**$ 585,544**	**$ 145,824**	**$ 334**	**$ 358**	**$ 728**	**$ 105,505**	**$ 25,346**	**$ 752**
48		Demand	$ 299,693	$ 180,803	$ 56,625	$ -	$ 79	$ 504	$ 47,391	$ 14,292	$ -
49		Customer	$ 262,268	$ 215,016	$ 31,552	$ 39	$ 76	$ 224	$ 11,763	$ 2,866	$ 732
50		Energy	$ 302,431	$ 189,726	$ 57,647	$ 295	$ 203	$ -	$ 46,351	$ 8,188	$ 20

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Schedule 5

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 11,305**	**$ 7,009**	**$ 2,287**	**$ 7**	**$ 5**	**$ -**	**$ 1,807**	**$ 189**	**$ 0**
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 11,305	$ 7,009	$ 2,287	$ 7	$ 5	$ -	$ 1,807	$ 189	$ 0
5											
6	LNG Storage Tilbury		**$ 34,143**	**$ 19,690**	**$ 6,108**	**$ -**	**$ 6**	**$ -**	**$ 6,026**	**$ 2,314**	**$ -**
7		Demand	$ 34,143	$ 19,690	$ 6,108	$ -	$ 6	$ -	$ 6,026	$ 2,314	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 773,645**	**$ 444,883**	**$ 137,998**	**$ -**	**$ 128**	**$ 2,207**	**$ 136,151**	**$ 52,278**	**$ -**
17		Demand	$ 773,645	$ 444,883	$ 137,998	$ -	$ 128	$ 2,207	$ 136,151	$ 52,278	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ (1,618)**	**$ (930)**	**$ (289)**	**$ -**	**$ (0)**	**$ (5)**	**$ (285)**	**$ (109)**	**$ -**
22		Demand	$ (1,618)	$ (930)	$ (289)	$ -	$ (0)	$ (5)	$ (285)	$ (109)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 1,283,283**	**$ 982,477**	**$ 168,843**	**$ 117**	**$ 287**	**$ 1,632**	**$ 96,107**	**$ 31,629**	**$ 2,191**
27		Demand	$ 339,568	$ 195,271	$ 60,571	$ -	$ 56	$ 962	$ 59,760	$ 22,948	$ -
28		Customer	$ 943,716	$ 787,206	$ 108,272	$ 117	$ 231	$ 670	$ 36,347	$ 8,681	$ 2,191
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 20,736**	**$ 11,302**	**$ 3,806**	**$ (0.5)**	**$ 87**	**$ 63**	**$ 3,950**	**$ 1,538**	**$ (10)**
32		Demand	$ 23,435	$ 13,428	$ 4,165	$ -	$ 88	$ 67	$ 4,109	$ 1,578	$ -
33		Customer	$ (2,699)	$ (2,126)	$ (359)	$ (0.5)	$ (1)	$ (3)	$ (160)	$ (40)	$ (10)
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ (2,309)**	**$ (1,819)**	**$ (307)**	**$ (0.5)**	**$ (1)**	**$ (3)**	**$ (137)**	**$ (34)**	**$ (9)**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (2,309)	$ (1,819)	$ (307)	$ (0.5)	$ (1)	$ (3)	$ (137)	$ (34)	$ (9)
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Rate Base**		**$ 2,119,185**	**$ 1,462,613**	**$ 318,447**	**$ 123**	**$ 511**	**$ 3,895**	**$ 243,620**	**$ 87,804**	**$ 2,172**
42		Demand	$ 1,169,173	$ 672,342	$ 208,553	$ -	$ 277	$ 3,231	$ 205,762	$ 79,008	$ -
43		Customer	$ 938,707	$ 783,262	$ 107,606	$ 116	$ 229	$ 664	$ 36,051	$ 8,607	$ 2,172
44		Energy	$ 11,305	$ 7,009	$ 2,287	$ 7	$ 5	$ -	$ 1,807	$ 189	$ 0

FEI Lower Mainland Region (Legacy Methodology)
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Rate Design Filing_Common Rates_ 2013 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 6

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 416,256**	**$ 263,647**	**$ 81,119**	**$ 295**	**$ 222**	**$ -**	**$ 61,032**	**$ 9,920**	**$ 20**
2		Demand	$ 113,825	$ 73,922	$ 23,472	$ -	$ 19	$ -	$ 14,681	$ 1,732	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 302,431	$ 189,726	$ 57,647	$ 295	$ 203	$ -	$ 46,351	$ 8,188	$ 20
5											
6	LNG Storage Tilbury		**$ 8,082**	**$ 4,661**	**$ 1,446**	**$ -**	**$ 1**	**$ -**	**$ 1,426**	**$ 548**	**$ -**
7		Demand	$ 8,082	$ 4,661	$ 1,446	$ -	$ 1	$ -	$ 1,426	$ 548	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 99,585**	**$ 57,266**	**$ 17,763**	**$ -**	**$ 16**	**$ 284**	**$ 17,526**	**$ 6,729**	**$ -**
17		Demand	$ 99,585	$ 57,266	$ 17,763	$ -	$ 16	$ 284	$ 17,526	$ 6,729	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ (4,762)**	**$ (2,738)**	**$ (849)**	**$ -**	**$ (1)**	**$ (14)**	**$ (838)**	**$ (322)**	**$ -**
22		Demand	$ (4,762)	$ (2,738)	$ (849)	$ -	$ (1)	$ (14)	$ (838)	$ (322)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 290,659**	**$ 220,344**	**$ 38,972**	**$ 28**	**$ 69**	**$ 388**	**$ 22,809**	**$ 7,516**	**$ 532**
27		Demand	$ 80,171	$ 46,104	$ 14,301	$ -	$ 13	$ 225	$ 14,109	$ 5,418	$ -
28		Customer	$ 210,488	$ 174,240	$ 24,671	$ 28	$ 56	$ 163	$ 8,700	$ 2,098	$ 532
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 6,365**	**$ 4,403**	**$ 968**	**$ 1**	**$ 31**	**$ 12**	**$ 698**	**$ 240**	**$ 14**
32		Demand	$ 2,792	$ 1,589	$ 493	$ -	$ 30	$ 8	$ 486	$ 187	$ -
33		Customer	$ 3,573	$ 2,814	$ 475	$ 1	$ 1	$ 4	$ 211	$ 53	$ 14
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ 48,206**	**$ 37,962**	**$ 6,406**	**$ 10**	**$ 19**	**$ 57**	**$ 2,852**	**$ 715**	**$ 185**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 48,206	$ 37,962	$ 6,406	$ 10	$ 19	$ 57	$ 2,852	$ 715	$ 185
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Cost of Service**		**$ 864,391**	**$ 585,544**	**$ 145,824**	**$ 334**	**$ 358**	**$ 728**	**$ 105,505**	**$ 25,346**	**$ 752**
42		Demand	$ 299,693	$ 180,803	$ 56,625	$ -	$ 79	$ 504	$ 47,391	$ 14,292	$ -
43		Customer	$ 262,268	$ 215,016	$ 31,552	$ 39	$ 76	$ 224	$ 11,763	$ 2,866	$ 732
44		Energy	$ 302,431	$ 189,726	$ 57,647	$ 295	$ 203	$ -	$ 46,351	$ 8,188	$ 20

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Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 7

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Billing Determinants										
1.1	Sales Volume (TJ)			52,547	17,149	74	51	11,504	19,601	11,022	4,733
2	Midstream Sales Volume (TJ)			52,547	17,149	0	51		13,547	2,045	5
3	Commodity Sales Volume (TJ)			47,371	14,392	74	51	11,504	17,626	11,022	4,733
4	Average No. of Customers			540,489	53,217	10	19	21	5,368	677	83
5											
6	**Cost of Service Margin**		**$ 448,486**	**$ 322,112**	**$ 64,776**	**$ 39**	**$ 136**	**$ 728**	**$ 44,528**	**$ 15,434**	**$ 732**
7		Demand	$ 185,868	$ 106,881	$ 33,153	$ -	$ 60	$ 504	$ 32,710	$ 12,560	$ -
8	Unit Demand Charge ($/GJ)			$ 2.26	$ 2.30	$ -	$ 1.18	$ 0.04	$ 1.86	$ 1.14	$ -
9		Customer	$ 262,268	$ 215,016	$ 31,552	$ 39	$ 76	$ 224	$ 11,763	$ 2,866	$ 732
10	Unit Customer Charge ($/GJ)			$ 4.54	$ 2.19	$ 0.52	$ 1.50	$ 0.02	$ 0.67	$ 0.26	$ 0.15
11		Energy	$ 350	$ 215	$ 70	$ 0	$ 0	$ -	$ 56	$ 8	$ 0
12	Unit Energy Charge ($/GJ)			$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ -	$ 0.00	$ 0.00	$ 0.00
13											
14	Unit Cost of Service Margin ($/GJ)			**$ 6.13**	**$ 3.78**	**$ 0.53**	**$ 2.68**	**$ 0.06**	**$ 2.27**	**$ 1.40**	**$ 0.15**
15											
16	**Cost of Gas - Commodity**		**$ 302,080**	**$ 189,510**	**$ 57,577**	**$ 295**	**$ 203**	**$ -**	**$ 46,295**	**$ 8,179**	**$ 20**
17		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ 302,080	$ 189,510	$ 57,577	$ 295	$ 203	$ -	$ 46,295	$ 8,179	$ 20
20	Unit Cost of Gas - Commodity ($/GJ)			**$ 4.001**	**$ 4.001**	**$ 4.001**	**$ 4.001**	**$ -**	**$ 2.63**	**$ 0.74**	**$ 4.00**
21											
22	**Cost of Gas - Midstream**		**$ 113,825**	**$ 73,922**	**$ 23,472**	**$ -**	**$ 19**	**$ -**	**$ 14,681**	**$ 1,732**	**$ -**
23		Demand	$ 113,825	$ 73,922	$ 23,472	$ -	$ 19	$ -	$ 14,681	$ 1,732	$ -
24		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.41**	**$ 1.37**	**$ -**	**$ 0.37**	**$ -**	**$ 0.83**	**$ 0.16**	**$ -**
26											
27	**Total Utility Cost of Service**		**$ 864,391**	**$ 585,544**	**$ 145,824**	**$ 334**	**$ 358**	**$ 728**	**$ 105,505**	**$ 25,346**	**$ 752**
28		Demand	$ 299,693	$ 180,803	$ 56,625	$ -	$ 79	$ 504	$ 47,391	$ 14,292	$ -
29		Customer	$ 262,268	$ 215,016	$ 31,552	$ 39	$ 76	$ 224	$ 11,763	$ 2,866	$ 732
30		Energy	$ 302,431	$ 189,726	$ 57,647	$ 295	$ 203	$ -	$ 46,351	$ 8,188	$ 20
31	Unit Cost of Service ($/GJ)			**$ 12.36**	**$ 10.13**	**$ 4.53**	**$ 7.05**	**$ 0.06**	**$ 5.99**	**$ 2.30**	**$ 0.16**
32											
33	**Total Revenues @ Proposed Rates**		**$ 864,391**	**$ 538,017**	**$ 149,154**	**$ 431**	**$ 443**	**$ 11,594**	**$ 121,955**	**$ 36,121**	**$ 6,676**
34	Unit Rate ($/GJ)			**$ 11.36**	**$ 10.36**	**$ 5.85**	**$ 8.71**	**$ 1.01**	**$ 6.92**	**$ 3.28**	**$ 1.41**
35											
36	**Total Revenue Margin @ Proposed Rates**		**$ 448,486**	**$ 274,585**	**$ 68,105**	**$ 136**	**$ 221**	**$ 11,594**	**$ 60,979**	**$ 26,209**	**$ 6,656**
37	Unit Rate ($/GJ)			**$ 5.80**	**$ 4.73**	**$ 1.85**	**$ 4.34**	**$ 1.01**	**$ 3.46**	**$ 2.38**	**$ 1.41**

FEI Inland Region (Legacy Methodology)
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Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]
1	**REVENUES**										
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 252,454**	**$ 167,477**	**$ 50,073**	**$ 619**	**$ 51**	**$ -**	**$ 23,790**	**$ 8,893**	**$ 1,551**
3	Revenue Margin at Proposed 2013 FEI Rates		$ 136,554	$ 91,382	$ 23,789	$ 173	$ 25	$ -	$ 12,424	$ 7,246	$ 1,515
4	Total Cost of Gas [3]		$ 115,900	$ 76,095	$ 26,284	$ 446	$ 25	$ -	$ 11,366	$ 1,647	$ 36
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	line 8 + line 9	**$ 255,933**	**$ 181,846**	**$ 47,818**	**$ 474**	**$ 43**	**$ -**	**$ 19,936**	**$ 5,617**	**$ 198**
8	Cost of Service Margin		$ 140,033	$ 105,751	$ 21,534	$ 28	$ 18	$ -	$ 8,570	$ 3,970	$ 162
9	Total Cost of Gas [3]		$ 115,900	$ 76,095	$ 26,284	$ 446	$ 25	$ -	$ 11,366	$ 1,647	$ 36
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / Deficit	line 2 - line 7	**$ (3,479)**								
13	% increase to Equal Allocated Cost		2.5%								
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 255,933**	**$ 169,805**	**$ 50,679**	**$ 624**	**$ 51**	**$ -**	**$ 24,107**	**$ 9,078**	**$ 1,589**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 140,033	$ 93,710	$ 24,395	$ 178	$ 26	$ -	$ 12,741	$ 7,431	$ 1,553
18											
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 255,933**	**$ 169,805**	**$ 50,679**	**$ 624**	**$ 51**	**$ -**	**$ 29,443**	**$ 20,917**	**$ 5,862**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 255,933**	**$ 181,846**	**$ 47,818**	**$ 474**	**$ 43**	**$ -**	**$ 25,272**	**$ 17,456**	**$ 4,470**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**93.4%**	**106.0%**		**119.0%**		**116.5%**	**119.8%**	
24											

Note:

1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios. Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
3. Cost of Gas forecast is based on five-day average forward prices at August 16, 17, 18, 19, and 22, 2011, and the propane gas cost forecast is based on the Mt. Belvieu propane swap prices at August 22, 2011, consistent with the forward pricing utilized in the 2011 Third Quarter Gas Cost reports for the various entities / service areas.

FEI Inland Region (Legacy Methodology)
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FUNCTIONALIZATION (000's)

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Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 49,202	$ 16	$ 520	$ -	$ 6,160	$ 838	$ 21,277	$ 1,365	$ 19,026
2	BCH Capacity Right	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 11,060	$ -	$ 82	$ -	$ 3,179	$ -	$ 7,798	$ -	$ -
4	Depreciation Expense	$ 31,444	$ 13	$ 456	$ -	$ 3,858	$ 1,740	$ 25,377	$ -	$ -
5	Amortization Expense	$ 2,015	$ 1	$ 12	$ -	$ 1,361	$ (405)	$ 355	$ 675	$ 15
6	Other Operating Revenue	$ (7,092)	$ -	$ -	$ -	$ (3,107)	$ (2,741)	$ (617)	$ -	$ (627)
7	Other Earned Return Provisions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Income Tax	$ 6,275	$ 12	$ 103	$ -	$ 1,668	$ -	$ 4,491	$ -	$ -
9	Earned Return	$ 47,130	$ 91	$ 774	$ -	$ 12,531	$ -	$ 33,734	$ -	$ -
10	**Total Cost of Service Margin**	**$ 140,033**	**$ 133**	**$ 1,947**	**$ -**	**$ 25,650**	**$ (568)**	**$ 92,416**	**$ 2,040**	**$ 18,415**
11										
12	Cost of Gas - Commodity	$ 84,168	$ 84,168	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 31,732	$ 31,732	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 255,933**	**$ 116,033**	**$ 1,947**	**$ -**	**$ 25,650**	**$ (568)**	**$ 92,416**	**$ 2,040**	**$ 18,415**

FEI Inland Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 3

RATE BASE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Plant in Service										
2	**Total Gas Plant in Service**		**$ 833,043**	**$ 612,661**	**$ 131,666**	**$ 103**	**$ 53**	**$ -**	**$ 58,718**	**$ 29,248**	**$ 594**
3		Demand	$ 402,690	$ 241,949	$ 82,061	$ -	$ 26	$ -	$ 50,833	$ 27,822	$ -
4		Customer	$ 428,746	$ 369,663	$ 49,231	$ 103	$ 27	$ -	$ 7,705	$ 1,424	$ 594
5		Energy	$ 1,607	$ 1,049	$ 374	$ 1	$ 0	$ -	$ 180	$ 3	$ 0
6	**Total Accumulated Depreciation**		**$ (230,647)**	**$ (168,319)**	**$ (36,610)**	**$ (21)**	**$ (13)**	**$ -**	**$ (16,917)**	**$ (8,647)**	**$ (120)**
7		Demand	$ (120,893)	$ (72,636)	$ (24,636)	$ -	$ (8)	$ -	$ (15,261)	$ (8,352)	$ -
8		Customer	$ (109,578)	$ (95,568)	$ (11,933)	$ (21)	$ (6)	$ -	$ (1,636)	$ (293)	$ (120)
9		Energy	$ (177)	$ (115)	$ (41)	$ (0)	$ (0)	$ -	$ (20)	$ (1)	$ (0)
10	**TOTAL Net Plant**		**$ 602,396**	**$ 444,342**	**$ 95,057**	**$ 82**	**$ 40**	**$ -**	**$ 41,801**	**$ 20,602**	**$ 474**
11		Demand	$ 281,797	$ 169,312	$ 57,425	$ -	$ 18	$ -	$ 35,572	$ 19,469	$ -
12		Customer	$ 319,168	$ 274,095	$ 37,298	$ 81	$ 21	$ -	$ 6,068	$ 1,131	$ 474
13		Energy	$ 1,431	$ 934	$ 333	$ 1	$ 0	$ -	$ 161	$ 2	$ 0
14											
15	Contribution In Aid of Construction										
16	**Total CIAC**		**$ (41,608)**	**$ (31,985)**	**$ (6,102)**	**$ (6)**	**$ (3)**	**$ -**	**$ (2,359)**	**$ (1,117)**	**$ (37)**
17		Demand	$ (14,878)	$ (8,939)	$ (3,032)	$ -	$ (1)	$ -	$ (1,878)	$ (1,028)	$ -
18		Customer	$ (26,726)	$ (23,043)	$ (3,069)	$ (6)	$ (2)	$ -	$ (480)	$ (89)	$ (37)
19		Energy	$ (5)	$ (3)	$ (1)	$ (0)	$ (0)	$ -	$ (1)	$ (0)	$ (0)
20	**Total Accumulated Amortization**		**$ 12,128**	**$ 9,538**	**$ 1,705**	**$ 2**	**$ 1**	**$ -**	**$ 598**	**$ 271**	**$ 12**
21		Demand	$ 3,511	$ 2,109	$ 715	$ -	$ 0	$ -	$ 443	$ 243	$ -
22		Customer	$ 8,614	$ 7,427	$ 989	$ 2	$ 1	$ -	$ 155	$ 29	$ 12
23		Energy	$ 3	$ 2	$ 1	$ 0	$ 0	$ -	$ 0	$ 0	$ 0
24	**Total Net Contribution**		**$ (29,481)**	**$ (22,447)**	**$ (4,397)**	**$ (4)**	**$ (2)**	**$ -**	**$ (1,761)**	**$ (846)**	**$ (25)**
25		Demand	$ (11,367)	$ (6,830)	$ (2,316)	$ -	$ (1)	$ -	$ (1,435)	$ (785)	$ -
26		Customer	$ (18,112)	$ (15,616)	$ (2,080)	$ (4)	$ (1)	$ -	$ (325)	$ (60)	$ (25)
27		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
28											
29	Work in Progress, no AFUDC		**$ 3,704**	**$ 2,595**	**$ 629**	**$ 0**	**$ 0**	**$ -**	**$ 314**	**$ 163**	**$ 2**
30		Demand	$ 2,283	$ 1,372	$ 465	$ -	$ 0	$ -	$ 288	$ 158	$ -
31		Customer	$ 1,413	$ 1,218	$ 162	$ 0	$ 0	$ -	$ 25	$ 5	$ 2
32		Energy	$ 7	$ 5	$ 2	$ 0	$ 0	$ -	$ 1	$ 0	$ 0
33											
34	Unamortized Deferred Charges										
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 9,707**	**$ 3,628**	**$ 2,790**	**$ 8**	**$ 33**	**$ -**	**$ 2,132**	**$ 1,129**	**$ (13)**
36		Demand	$ 16,386	$ 9,826	$ 3,333	$ -	$ 33	$ -	$ 2,064	$ 1,130	$ -
37		Customer	$ (8,845)	$ (7,587)	$ (1,039)	$ (2)	$ (1)	$ -	$ (171)	$ (32)	$ (13)
38		Energy	$ 2,166	$ 1,389	$ 496	$ 10	$ 0	$ -	$ 239	$ 31	$ 1
39											
40	Cash Working Capital		**$ 1,947**	**$ 1,386**	**$ 352**	**$ 3**	**$ 0**	**$ -**	**$ 155**	**$ 48**	**$ 2**
41		Demand	$ 513	$ 308	$ 105	$ -	$ 0	$ -	$ 65	$ 35	$ -
42		Customer	$ 787	$ 663	$ 100	$ 0	$ 0	$ -	$ 19	$ 4	$ 2
43		Energy	$ 646	$ 415	$ 148	$ 3	$ 0	$ -	$ 71	$ 9	$ 0
44											
45	Other Working Capital										
46	**Total Other Working Capital**		**$ 16,818**	**$ 9,754**	**$ 3,535**	**$ (1)**	**$ 1**	**$ -**	**$ 2,273**	**$ 1,259**	**$ (3)**
47		Demand	$ 18,340	$ 11,019	$ 3,737	$ -	$ 1	$ -	$ 2,315	$ 1,267	$ -
48		Customer	$ (1,519)	$ (1,264)	$ (202)	$ (1)	$ (0)	$ -	$ (41)	$ (8)	$ (3)
49		Energy	$ (2)	$ (1)	$ (0)	$ (0)	$ (0)	$ -	$ (0)	$ (0)	$ (0)
50											
51	LILO, Capital Efficiency Mechanism, Others		**$ (264)**	**$ (210)**	**$ (36)**	**$ (0)**	**$ (0)**	**$ -**	**$ (12)**	**$ (5)**	**$ (0)**
52		Demand	$ (68)	$ (41)	$ (14)	$ -	$ (0)	$ -	$ (9)	$ (5)	$ -
53		Customer	$ (197)	$ (170)	$ (23)	$ (0)	$ (0)	$ -	$ (4)	$ (1)	$ (0)
54		Energy	$ -						$ -	$ -	$ -
55											
56	**Total Utility Rate Base**		**$ 604,827**	**$ 439,048**	**$ 97,930**	**$ 88**	**$ 72**	**$ -**	**$ 44,904**	**$ 22,349**	**$ 436**
57		Demand	$ 307,885	$ 184,968	$ 62,735	$ -	$ 52	$ -	$ 38,861	$ 21,269	$ -
58		Customer	$ 292,695	$ 251,340	$ 34,217	$ 75	$ 20	$ -	$ 5,571	$ 1,038	$ 435
59		Energy	$ 4,246	$ 2,740	$ 978	$ 13	$ 1	$ -	$ 471	$ 42	$ 1

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COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

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Schedule 4

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Operating & Maintenance Expense										
2	**Total Operating & Maintenance Expense**		**$ 49,202**	**$ 37,797**	**$ 7,424**	**$ 12**	**$ 4**	**$ -**	**$ 2,715**	**$ 1,180**	**$ 70**
3		Demand	$ 14,682	$ 8,821	$ 2,992	$ -	$ 1	$ -	$ 1,853	$ 1,014	$ -
4		Customer	$ 34,504	$ 28,965	$ 4,429	$ 12	$ 3	$ -	$ 860	$ 165	$ 70
5		Energy	$ 16	$ 11	$ 4	$ 0	$ 0	$ -	$ 2	$ 0	$ 0
6	BCH Capacity Right		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
7		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 11,060**	**$ 8,029**	**$ 1,790**	**$ 1**	**$ 1**	**$ -**	**$ 820**	**$ 410**	**$ 8**
11		Demand	$ 5,653	$ 3,396	$ 1,152	$ -	$ 0	$ -	$ 714	$ 391	$ -
12		Customer	$ 5,407	$ 4,633	$ 638	$ 1	$ 0	$ -	$ 106	$ 20	$ 8
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Depreciation Expense		**$ 31,444**	**$ 23,776**	**$ 4,870**	**$ 7**	**$ 3**	**$ -**	**$ 1,894**	**$ 852**	**$ 43**
15		Demand	$ 10,890	$ 6,543	$ 2,219	$ -	$ 1	$ -	$ 1,375	$ 752	$ -
16		Customer	$ 20,540	$ 17,224	$ 2,648	$ 7	$ 2	$ -	$ 517	$ 100	$ 43
17		Energy	$ 13	$ 8	$ 3	$ 0	$ 0	$ -	$ 1	$ 0	$ 0
18	Amortization Expense		**$ 2,015**	**$ 1,248**	**$ 395**	**$ 0**	**$ 7**	**$ -**	**$ 236**	**$ 128**	**$ 0**
19		Demand	$ 1,854	$ 1,110	$ 376	$ -	$ 7	$ -	$ 233	$ 128	$ -
20		Customer	$ 160	$ 137	$ 19	$ 0	$ 0	$ -	$ 3	$ 1	$ 0
21		Energy	$ 1	$ 1	$ 0	$ 0	$ 0	$ -	$ 0	$ 0	$ 0
22	Other Operating Revenue		**$ (7,092)**	**$ (4,522)**	**$ (1,363)**	**$ (0)**	**$ (0)**	**$ -**	**$ (785)**	**$ (420)**	**$ (2)**
23		Demand	$ (6,006)	$ (3,609)	$ (1,224)	$ -	$ (0)	$ -	$ (758)	$ (415)	$ -
24		Customer	$ (1,086)	$ (913)	$ (139)	$ (0)	$ (0)	$ -	$ (27)	$ (5)	$ (2)
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Income Tax		**$ 6,275**	**$ 4,632**	**$ 989**	**$ 1**	**$ 0**	**$ -**	**$ 434**	**$ 214**	**$ 5**
27		Demand	$ 2,919	$ 1,754	$ 595	$ -	$ 0	$ -	$ 369	$ 202	$ -
28		Customer	$ 3,343	$ 2,870	$ 391	$ 1	$ 0	$ -	$ 64	$ 12	$ 5
29		Energy	$ 12	$ 8	$ 3	$ 0	$ 0	$ -	$ 1	$ 0	$ 0
30	Earned Return		**$ 47,130**	**$ 34,791**	**$ 7,428**	**$ 7**	**$ 3**	**$ -**	**$ 3,258**	**$ 1,606**	**$ 37**
31		Demand	$ 21,927	$ 13,174	$ 4,468	$ -	$ 1	$ -	$ 2,768	$ 1,515	$ -
32		Customer	$ 25,112	$ 21,559	$ 2,939	$ 6	$ 2	$ -	$ 480	$ 89	$ 37
33		Energy	$ 91	$ 58	$ 21	$ 0	$ 0	$ -	$ 10	$ 1	$ 0
34											
35	**Total Cost of Service Margin**		**$ 140,033**	**$ 105,751**	**$ 21,534**	**$ 28**	**$ 18**	**$ -**	**$ 8,570**	**$ 3,970**	**$ 162**
36		Demand	$ 51,920	$ 31,191	$ 10,579	$ -	$ 10	$ -	$ 6,553	$ 3,587	$ -
37		Customer	$ 87,980	$ 74,475	$ 10,924	$ 27	$ 7	$ -	$ 2,003	$ 381	$ 162
38		Energy	$ 133	$ 86	$ 31	$ 1	$ 0	$ -	$ 15	$ 2	$ 0
39	Cost of Gas - Commodity		**$ 84,168**	**$ 55,152**	**$ 18,615**	**$ 446**	**$ 22**	**$ -**	**$ 8,515**	**$ 1,381**	**$ 36**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 84,168	$ 55,152	$ 18,615	$ 446	$ 22	$ -	$ 8,515	$ 1,381	$ 36
43	Cost of Gas - Midstream		**$ 31,732**	**$ 20,943**	**$ 7,669**	**$ -**	**$ 3**	**$ -**	**$ 2,851**	**$ 266**	**$ -**
44		Demand	$ 31,732	$ 20,943	$ 7,669	$ -	$ 3	$ -	$ 2,851	$ 266	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 255,933**	**$ 181,846**	**$ 47,818**	**$ 474**	**$ 43**	**$ -**	**$ 19,936**	**$ 5,617**	**$ 198**
48		Demand	$ 83,651	$ 52,134	$ 18,248	$ -	$ 13	$ -	$ 9,404	$ 3,853	$ -
49		Customer	$ 87,980	$ 74,475	$ 10,924	$ 27	$ 7	$ -	$ 2,003	$ 381	$ 162
50		Energy	$ 84,302	$ 55,238	$ 18,646	$ 447	$ 22	$ -	$ 8,530	$ 1,383	$ 36

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Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 5

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		$ 4,246	$ 2,740	$ 978	$ 13	$ 1	$ -	$ 471	$ 42	$ 1
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 4,246	$ 2,740	$ 978	$ 13	$ 1	$ -	$ 471	$ 42	$ 1
5											
6	LNG Storage Tilbury		$ 8,252	$ 4,958	$ 1,682	$ -	$ 1	$ -	$ 1,042	$ 570	$ -
7		Demand	$ 8,252	$ 4,958	$ 1,682	$ -	$ 1	$ -	$ 1,042	$ 570	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		$ 186,954	$ 112,328	$ 38,098	$ -	$ 12	$ -	$ 23,600	$ 12,916	$ -
17		Demand	$ 186,954	$ 112,328	$ 38,098	$ -	$ 12	$ -	$ 23,600	$ 12,916	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		$ (398)	$ (239)	$ (81)	$ -	$ (0)	$ -	$ (50)	$ (27)	$ -
22		Demand	$ (398)	$ (239)	$ (81)	$ -	$ (0)	$ -	$ (50)	$ (27)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		$ 398,657	$ 315,416	$ 55,687	$ 75	$ 27	$ -	$ 18,769	$ 8,243	$ 439
27		Demand	$ 104,123	$ 62,560	$ 21,218	$ -	$ 7	$ -	$ 13,144	$ 7,194	$ -
28		Customer	$ 294,534	$ 252,856	$ 34,469	$ 75	$ 20	$ -	$ 5,626	$ 1,049	$ 439
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		$ 7,928	$ 4,515	$ 1,677	$ (0.4)	$ 32	$ -	$ 1,096	$ 611	$ (3)
32		Demand	$ 8,955	$ 5,361	$ 1,818	$ -	$ 33	$ -	$ 1,126	$ 616	$ -
33		Customer	$ (1,026)	$ (846)	$ (141)	$ (0.4)	$ (0)	$ -	$ (30)	$ (6)	$ (3)
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		$ (812)	$ (670)	$ (112)	$ (0.3)	$ (0)	$ -	$ (24)	$ (5)	$ (2)
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (812)	$ (670)	$ (112)	$ (0.3)	$ (0)	$ -	$ (24)	$ (5)	$ (2)
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Rate Base**		$ 604,827	$ 439,048	$ 97,930	$ 88	$ 72	$ -	$ 44,904	$ 22,349	$ 436
42		Demand	$ 307,885	$ 184,968	$ 62,735	$ -	$ 52	$ -	$ 38,861	$ 21,269	$ -
43		Customer	$ 292,695	$ 251,340	$ 34,217	$ 75	$ 20	$ -	$ 5,571	$ 1,038	$ 435
44		Energy	$ 4,246	$ 2,740	$ 978	$ 13	$ 1	$ -	$ 471	$ 42	$ 1

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Schedule 6

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 116,033**	**$ 76,181**	**$ 26,315**	**$ 447**	**$ 25**	**$ -**	**$ 11,380**	**$ 1,649**	**$ 36**
2		Demand	$ 31,732	$ 20,943	$ 7,669	$ -	$ 3	$ -	$ 2,851	$ 266	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 84,302	$ 55,238	$ 18,646	$ 447	$ 22	$ -	$ 8,530	$ 1,383	$ 36
5											
6	LNG Storage Tilbury		**$ 1,947**	**$ 1,170**	**$ 397**	**$ -**	**$ 0**	**$ -**	**$ 246**	**$ 135**	**$ -**
7		Demand	$ 1,947	$ 1,170	$ 397	$ -	$ 0	$ -	$ 246	$ 135	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 25,650**	**$ 15,412**	**$ 5,227**	**$ -**	**$ 2**	**$ -**	**$ 3,238**	**$ 1,772**	**$ -**
17		Demand	$ 25,650	$ 15,412	$ 5,227	$ -	$ 2	$ -	$ 3,238	$ 1,772	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ (568)**	**$ (341)**	**$ (116)**	**$ -**	**$ (0)**	**$ -**	**$ (72)**	**$ (39)**	**$ -**
22		Demand	$ (568)	$ (341)	$ (116)	$ -	$ (0)	$ -	$ (72)	$ (39)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 92,416**	**$ 72,715**	**$ 13,144**	**$ 19**	**$ 7**	**$ -**	**$ 4,476**	**$ 1,941**	**$ 113**
27		Demand	$ 24,216	$ 14,549	$ 4,935	$ -	$ 2	$ -	$ 3,057	$ 1,673	$ -
28		Customer	$ 68,200	$ 58,166	$ 8,210	$ 19	$ 5	$ -	$ 1,420	$ 268	$ 113
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 2,040**	**$ 1,527**	**$ 323**	**$ 1**	**$ 7**	**$ -**	**$ 124**	**$ 54**	**$ 3**
32		Demand	$ 675	$ 401	$ 136	$ -	$ 7	$ -	$ 84	$ 46	$ -
33		Customer	$ 1,365	$ 1,125	$ 187	$ 1	$ 0	$ -	$ 40	$ 8	$ 3
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ 18,415**	**$ 15,184**	**$ 2,527**	**$ 8**	**$ 2**	**$ -**	**$ 543**	**$ 106**	**$ 46**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 18,415	$ 15,184	$ 2,527	$ 8	$ 2	$ -	$ 543	$ 106	$ 46
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Cost of Service**		**$ 255,933**	**$ 181,846**	**$ 47,818**	**$ 474**	**$ 43**	**$ -**	**$ 19,936**	**$ 5,617**	**$ 198**
42		Demand	$ 83,651	$ 52,134	$ 18,248	$ -	$ 13	$ -	$ 9,404	$ 3,853	$ -
43		Customer	$ 87,980	$ 74,475	$ 10,924	$ 27	$ 7	$ -	$ 2,003	$ 381	$ 162
44		Energy	$ 84,302	$ 55,238	$ 18,646	$ 447	$ 22	$ -	$ 8,530	$ 1,383	$ 36

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Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

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Schedule 7

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Billing Determinants										
2	Sales Volume (TJ)			15,615	5,572	112	6	-	3,983	3,228	1,049
3	Midstream Sales Volume (TJ)			15,552	5,493	112	6		2,610	345	9
4	Commodity Sales Volume (TJ)			13,788	4,654	112	6	-	3,427	3,228	1,049
5	Average No. of Customers			214,680	20,850	8	2	-	1,008	99	20
6											
7	Cost of Service Margin		**$ 140,033**	**$ 105,751**	**$ 21,534**	**$ 28**	**$ 18**	**$ -**	**$ 8,570**	**$ 3,970**	**$ 162**
8		Demand	$ 51,920	$ 31,191	$ 10,579	$ -	$ 10	$ -	$ 6,553	$ 3,587	$ -
9	Unit Demand Charge ($/GJ)			$ 2.26	$ 2.27	$ -	$ 1.85	$ -	$ 1.91	$ 1.11	$ -
10		Customer	$ 87,980	$ 74,475	$ 10,924	$ 27	$ 7	$ -	$ 2,003	$ 381	$ 162
11	Unit Customer Charge ($/GJ)			$ 5.40	$ 2.35	$ 0.25	$ 1.29	$ -	$ 0.58	$ 0.12	$ 0.15
12		Energy	$ 133	$ 86	$ 31	$ 1	$ 0	$ -	$ 15	$ 2	$ 0
13	Unit Energy Charge ($/GJ)			$ 0.01	$ 0.01	$ 0.01	$ 0.01	$ -	$ 0.00	$ 0.00	$ 0.00
14											
15	Unit Cost of Service Margin ($/GJ)			**$ 6.77**	**$ 3.86**	**$ 0.25**	**$ 3.15**	**$ -**	**$ 2.15**	**$ 1.23**	**$ 0.15**
16											
17	Cost of Gas - Commodity		**$ 84,168**	**$ 55,152**	**$ 18,615**	**$ 446**	**$ 22**	**$ -**	**$ 8,515**	**$ 1,381**	**$ 36**
18		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Energy	$ 84,168	$ 55,152	$ 18,615	$ 446	$ 22	$ -	$ 8,515	$ 1,381	$ 36
21	Unit Cost of Gas - Commodity ($/GJ)			**$ 4.000**	**$ 4.000**	**$ 4.000**	**$ 4.000**	**$ -**	**$ 2.48**	**$ 0.43**	**$ 4.00**
22											
23	Cost of Gas - Midstream		**$ 31,732**	**$ 20,943**	**$ 7,669**	**$ -**	**$ 3**	**$ -**	**$ 2,851**	**$ 266**	**$ -**
24		Demand	$ 31,732	$ 20,943	$ 7,669	$ -	$ 3	$ -	$ 2,851	$ 266	$ -
25		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.35**	**$ 1.40**	**$ -**	**$ 0.54**	**$ -**	**$ 0.83**	**$ 0.08**	**$ -**
27											
28	Total Utility Cost of Service		**$ 255,933**	**$ 181,846**	**$ 47,818**	**$ 474**	**$ 43**	**$ -**	**$ 19,936**	**$ 5,617**	**$ 198**
29		Demand	$ 83,651	$ 52,134	$ 18,248	$ -	$ 13	$ -	$ 9,404	$ 3,853	$ -
30		Customer	$ 87,980	$ 74,475	$ 10,924	$ 27	$ 7	$ -	$ 2,003	$ 381	$ 162
31		Energy	$ 84,302	$ 55,238	$ 18,646	$ 447	$ 22	$ -	$ 8,530	$ 1,383	$ 36
32	Unit Cost of Service ($/GJ)			**$ 13.19**	**$ 10.28**	**$ 4.25**	**$ 7.69**	**$ -**	**$ 5.82**	**$ 1.74**	**$ 0.19**
33											
34	Total Revenues @ Proposed Rates		**$ 255,933**	**$ 169,805**	**$ 50,679**	**$ 624**	**$ 51**	**$ -**	**$ 24,107**	**$ 9,078**	**$ 1,589**
35	Unit Rate ($/GJ)			**$ 12.32**	**$ 10.89**	**$ 5.59**	**$ 9.16**	**$ -**	**$ 7.03**	**$ 2.81**	**$ 1.52**
36											
37	Total Revenue Margin @ Proposed Rates		**$ 140,033**	**$ 93,710**	**$ 24,395**	**$ 178**	**$ 26**	**$ -**	**$ 12,741**	**$ 7,431**	**$ 1,553**
38	Unit Rate ($/GJ)			**$ 6.80**	**$ 5.24**	**$ 1.59**	**$ 4.61**	**$ -**	**$ 3.72**	**$ 2.30**	**$ 1.48**

FEI Columbia Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 1

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]
1	**REVENUES**										
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 26,208**	**$ 17,527**	**$ 5,440**	**$ -**	**$ -**	**$ -**	**$ 2,489**	**$ 682**	**$ 69**
3	Revenue Margin at Proposed 2013 FEI Rates		$ 13,895	$ 9,396	$ 2,536	$ -	$ -	$ -	$ 1,296	$ 597	$ 69
4	Total Cost of Gas [3]		$ 12,313	$ 8,131	$ 2,904	$ -	$ -	$ -	$ 1,193	$ 85	$ -
5											
6	**COST OF SERVICE**										
7	Total Utility Cost of Service	line 8 + line 9	**$ 30,930**	**$ 21,886**	**$ 5,918**	**$ -**	**$ -**	**$ -**	**$ 2,443**	**$ 663**	**$ 19**
8	Cost of Service Margin		$ 18,617	$ 13,755	$ 3,014	$ -	$ -	$ -	$ 1,250	$ 578	$ 19
9	Total Cost of Gas [3]		$ 12,313	$ 8,131	$ 2,904	$ -	$ -	$ -	$ 1,193	$ 85	$ -
10											
11	**SURPLUS / DEFICIT**										
12	Total Surplus / Deficit	line 2 - line 7	**$ (4,722)**								
13	% increase to Equal Allocated Cost		34.0%								
14											
15	**REVENUES (adjusted to equal COS)**										
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 30,930**	**$ 20,721**	**$ 6,302**	**$ -**	**$ -**	**$ -**	**$ 2,930**	**$ 885**	**$ 93**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 18,617	$ 12,590	$ 3,398	$ -	$ -	$ -	$ 1,737	$ 799	$ 93
18											
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 30,930**	**$ 20,721**	**$ 6,302**	**$ -**	**$ -**	**$ -**	**$ 3,476**	**$ 2,166**	**$ 245**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 30,930**	**$ 21,886**	**$ 5,918**	**$ -**	**$ -**	**$ -**	**$ 2,989**	**$ 1,945**	**$ 171**
21											
22	**REVENUE TO COST RATIO**										
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**94.7%**	**106.5%**				**116.3%**	**111.4%**	
24											

Note:
1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios.
   Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above as
   these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study.
3. Cost of Gas forecast is based on five-day average forward prices at August 16, 17, 18, 19, and 22, 2011, and the propane gas cost forecast is based on the Mt. Belvieu propane swap prices at August 22, 2011,
   consistent with the forward pricing utilized in the 2011 Third Quarter Gas Cost reports for the various entities / service areas.

FEI Columbia Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
FUNCTIONALIZATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 2

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 6,200	$ 2	$ 89	$ -	$ 1,062	$ 141	$ 2,743	$ 145	$ 2,017
2	BCH Capacity Right	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 1,570	$ -	$ 14	$ -	$ 547	$ -	$ 1,009	$ -	$ -
4	Depreciation Expense	$ 4,039	$ 2	$ 78	$ -	$ 772	$ 190	$ 2,996	$ -	$ -
5	Amortization Expense	$ 330	$ 0	$ 2	$ -	$ 234	$ (70)	$ 46	$ 116	$ 2
6	Other Operating Revenue	$ (1,152)	$ -	$ -	$ -	$ (534)	$ (471)	$ (80)	$ -	$ (66)
7	Other Earned Return Provisions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Income Tax	$ 888	$ 2	$ 18	$ -	$ 287	$ -	$ 581	$ -	$ -
9	Earned Return	$ 6,742	$ 14	$ 135	$ -	$ 2,179	$ -	$ 4,415	$ -	$ -
10	**Total Cost of Service Margin**	**$ 18,618**	**$ 20**	**$ 336**	**$ -**	**$ 4,546**	**$ (209)**	**$ 11,711**	**$ 261**	**$ 1,952**
11										
12	Cost of Gas - Commodity	$ 8,708	$ 8,708	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 3,606	$ 3,606	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 30,931**	**$ 12,334**	**$ 336**	**$ -**	**$ 4,546**	**$ (209)**	**$ 11,711**	**$ 261**	**$ 1,952**

FEI Columbia Region (Legacy Methodology)

Fully Distributed Cost of Service Allocation Study

Rate Design Filing_Common Rates_ 2013 Test Year

RATE BASE SUMMARY - CLASSIFICATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 3

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Plant in Service										
2	**Total Gas Plant in Service**		**$ 117,864**	**$ 84,987**	**$ 19,632**	**$ -**	**$ -**	**$ -**	**$ 8,842**	**$ 4,327**	**$ 77**
3		Demand	$ 62,525	$ 37,474	$ 13,162	$ -	$ -	$ -	$ 7,755	$ 4,133	$ -
4		Customer	$ 55,096	$ 47,355	$ 6,411	$ -	$ -	$ -	$ 1,060	$ 193	$ 77
5		Energy	$ 244	$ 158	$ 58	$ -	$ -	$ -	$ 27	$ 0	$ -
6	**Total Accumulated Depreciation**		**$ (32,818)**	**$ (23,474)**	**$ (5,501)**	**$ -**	**$ -**	**$ -**	**$ (2,550)**	**$ (1,278)**	**$ (15)**
7		Demand	$ (18,727)	$ (11,224)	$ (3,942)	$ -	$ -	$ -	$ (2,323)	$ (1,238)	$ -
8		Customer	$ (14,064)	$ (12,233)	$ (1,552)	$ -	$ -	$ -	$ (224)	$ (40)	$ (15)
9		Energy	$ (27)	$ (17)	$ (6)	$ -	$ -	$ -	$ (3)	$ (0)	$ -
10	**TOTAL Net Plant**		**$ 85,046**	**$ 61,513**	**$ 14,131**	**$ -**	**$ -**	**$ -**	**$ 6,292**	**$ 3,049**	**$ 61**
11		Demand	$ 43,798	$ 26,250	$ 9,220	$ -	$ -	$ -	$ 5,432	$ 2,895	$ -
12		Customer	$ 41,032	$ 35,122	$ 4,859	$ -	$ -	$ -	$ 835	$ 154	$ 61
13		Energy	$ 217	$ 141	$ 52	$ -	$ -	$ -	$ 24	$ 0	$ -
14											
15	Contribution In Aid of Construction										
16	**Total CIAC**		**$ (5,628)**	**$ (4,273)**	**$ (859)**	**$ -**	**$ -**	**$ -**	**$ (336)**	**$ (155)**	**$ (5)**
17		Demand	$ (2,168)	$ (1,300)	$ (456)	$ -	$ -	$ -	$ (269)	$ (143)	$ -
18		Customer	$ (3,460)	$ (2,973)	$ (403)	$ -	$ -	$ -	$ (67)	$ (12)	$ (5)
19		Energy	$ (1)	$ (0)	$ (0)	$ -	$ -	$ -	$ (0)	$ (0)	$ -
20	**Total Accumulated Amortization**		**$ 1,593**	**$ 1,245**	**$ 230**	**$ -**	**$ -**	**$ -**	**$ 81**	**$ 36**	**$ 2**
21		Demand	$ 478	$ 286	$ 101	$ -	$ -	$ -	$ 59	$ 32	$ -
22		Customer	$ 1,115	$ 958	$ 130	$ -	$ -	$ -	$ 21	$ 4	$ 2
23		Energy	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ 0	$ 0	$ -
24	**Total Net Contribution**		**$ (4,035)**	**$ (3,028)**	**$ (629)**	**$ -**	**$ -**	**$ -**	**$ (255)**	**$ (120)**	**$ (3)**
25		Demand	$ (1,690)	$ (1,013)	$ (356)	$ -	$ -	$ -	$ (210)	$ (112)	$ -
26		Customer	$ (2,344)	$ (2,015)	$ (273)	$ -	$ -	$ -	$ (45)	$ (8)	$ (3)
27		Energy	$ (0)	$ (0)	$ (0)	$ -	$ -	$ -	$ (0)	$ (0)	$ -
28											
29	Work in Progress, no AFUDC		**$ 524**	**$ 358**	**$ 95**	**$ -**	**$ -**	**$ -**	**$ 47**	**$ 24**	**$ 0**
30		Demand	$ 356	$ 213	$ 75	$ -	$ -	$ -	$ 44	$ 24	$ -
31		Customer	$ 167	$ 144	$ 19	$ -	$ -	$ -	$ 3	$ 1	$ 0
32		Energy	$ 1	$ 1	$ 0	$ -	$ -	$ -	$ 0	$ 0	$ -
33											
34	Unamortized Deferred Charges										
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 1,731**	**$ 789**	**$ 468**	**$ -**	**$ -**	**$ -**	**$ 317**	**$ 159**	**$ (2)**
36		Demand	$ 2,431	$ 1,457	$ 512	$ -	$ -	$ -	$ 302	$ 161	$ -
37		Customer	$ (1,029)	$ (880)	$ (122)	$ -	$ -	$ -	$ (21)	$ (4)	$ (2)
38		Energy	$ 328	$ 212	$ 78	$ -	$ -	$ -	$ 36	$ 2	$ -
39											
40	Cash Working Capital		**$ 289**	**$ 203**	**$ 55**	**$ -**	**$ -**	**$ -**	**$ 24**	**$ 7**	**$ 0**
41		Demand	$ 94	$ 57	$ 20	$ -	$ -	$ -	$ 12	$ 6	$ -
42		Customer	$ 106	$ 89	$ 14	$ -	$ -	$ -	$ 3	$ 1	$ 0
43		Energy	$ 89	$ 57	$ 21	$ -	$ -	$ -	$ 10	$ 1	$ -
44											
45	Other Working Capital										
46	**Total Other Working Capital**		**$ 2,999**	**$ 1,760**	**$ 644**	**$ -**	**$ -**	**$ -**	**$ 387**	**$ 208**	**$ (0)**
47		Demand	$ 3,163	$ 1,896	$ 666	$ -	$ -	$ -	$ 392	$ 209	$ -
48		Customer	$ (163)	$ (135)	$ (22)	$ -	$ -	$ -	$ (5)	$ (1)	$ (0)
49		Energy	$ (0)	$ (0)	$ (0)	$ -	$ -	$ -	$ (0)	$ (0)	$ -
50											
51	LILO, Capital Efficiency Mechanism, Others		**$ (34)**	**$ (27)**	**$ (5)**	**$ -**	**$ -**	**$ -**	**$ (2)**	**$ (1)**	**$ (0)**
52		Demand	$ (9)	$ (5)	$ (2)	$ -	$ -	$ -	$ (1)	$ (1)	$ -
53		Customer	$ (25)	$ (22)	$ (3)	$ -	$ -	$ -	$ (0)	$ (0)	$ (0)
54		Energy	$ -						$ -	$ -	$ -
55											
56	**Total Utility Rate Base**		**$ 86,520**	**$ 61,567**	**$ 14,758**	**$ -**	**$ -**	**$ -**	**$ 6,811**	**$ 3,327**	**$ 56**
57		Demand	$ 48,142	$ 28,854	$ 10,135	$ -	$ -	$ -	$ 5,971	$ 3,183	$ -
58		Customer	$ 37,743	$ 32,303	$ 4,472	$ -	$ -	$ -	$ 770	$ 142	$ 56
59		Energy	$ 634	$ 410	$ 151	$ -	$ -	$ -	$ 70	$ 3	$ -

FEI Columbia Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 4

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Operating & Maintenance Expense										
2	**Total Operating & Maintenance Expense**		**$ 6,200**	**$ 4,652**	**$ 985**	**$ -**	**$ -**	**$ -**	**$ 385**	**$ 170**	**$ 8**
3		Demand	$ 2,271	$ 1,361	$ 478	$ -	$ -	$ -	$ 282	$ 150	$ -
4		Customer	$ 3,927	$ 3,290	$ 507	$ -	$ -	$ -	$ 103	$ 19	$ 8
5		Energy	$ 2	$ 2	$ 1	$ -	$ -	$ -	$ 0	$ 0	$ -
6	BCH Capacity Right		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
7		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 1,570**	**$ 1,119**	**$ 267**	**$ -**	**$ -**	**$ -**	**$ 123**	**$ 60**	**$ 1**
11		Demand	$ 873	$ 524	$ 184	$ -	$ -	$ -	$ 108	$ 58	$ -
12		Customer	$ 697	$ 595	$ 83	$ -	$ -	$ -	$ 15	$ 3	$ 1
13		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Depreciation Expense		**$ 4,039**	**$ 2,975**	**$ 662**	**$ -**	**$ -**	**$ -**	**$ 273**	**$ 124**	**$ 5**
15		Demand	$ 1,703	$ 1,021	$ 358	$ -	$ -	$ -	$ 211	$ 113	$ -
16		Customer	$ 2,334	$ 1,953	$ 303	$ -	$ -	$ -	$ 62	$ 12	$ 5
17		Energy	$ 2	$ 1	$ 0	$ -	$ -	$ -	$ 0	$ 0	$ -
18	Amortization Expense		**$ 329**	**$ 202**	**$ 68**	**$ -**	**$ -**	**$ -**	**$ 39**	**$ 21**	**$ 0**
19		Demand	$ 311	$ 186	$ 65	$ -	$ -	$ -	$ 39	$ 21	$ -
20		Customer	$ 18	$ 16	$ 2	$ -	$ -	$ -	$ 0	$ 0	$ 0
21		Energy	$ 0	$ 0	$ 0	$ -	$ -	$ -	$ 0	$ 0	$ -
22	Other Operating Revenue		**$ (1,152)**	**$ (721)**	**$ (232)**	**$ -**	**$ -**	**$ -**	**$ (130)**	**$ (68)**	**$ (0)**
23		Demand	$ (1,026)	$ (615)	$ (216)	$ -	$ -	$ -	$ (127)	$ (68)	$ -
24		Customer	$ (126)	$ (106)	$ (16)	$ -	$ -	$ -	$ (3)	$ (1)	$ (0)
25		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Income Tax		**$ 888**	**$ 643**	**$ 147**	**$ -**	**$ -**	**$ -**	**$ 65**	**$ 32**	**$ 1**
27		Demand	$ 453	$ 272	$ 95	$ -	$ -	$ -	$ 56	$ 30	$ -
28		Customer	$ 433	$ 370	$ 51	$ -	$ -	$ -	$ 9	$ 2	$ 1
29		Energy	$ 2	$ 1	$ 0	$ -	$ -	$ -	$ 0	$ 0	$ -
30	Earned Return		**$ 6,742**	**$ 4,884**	**$ 1,118**	**$ -**	**$ -**	**$ -**	**$ 496**	**$ 240**	**$ 5**
31		Demand	$ 3,442	$ 2,063	$ 725	$ -	$ -	$ -	$ 427	$ 228	$ -
32		Customer	$ 3,287	$ 2,812	$ 390	$ -	$ -	$ -	$ 67	$ 12	$ 5
33		Energy	$ 14	$ 9	$ 3	$ -	$ -	$ -	$ 2	$ 0	$ -
34											
35	**Total Cost of Service Margin**		**$ 18,617**	**$ 13,755**	**$ 3,014**	**$ -**	**$ -**	**$ -**	**$ 1,250**	**$ 578**	**$ 19**
36		Demand	$ 8,026	$ 4,811	$ 1,690	$ -	$ -	$ -	$ 996	$ 531	$ -
37		Customer	$ 10,570	$ 8,931	$ 1,320	$ -	$ -	$ -	$ 252	$ 47	$ 19
38		Energy	$ 20	$ 13	$ 5	$ -	$ -	$ -	$ 2	$ 0	$ -
39	Cost of Gas - Commodity		**$ 8,708**	**$ 5,757**	**$ 2,019**	**$ -**	**$ -**	**$ -**	**$ 860**	**$ 71**	**$ -**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 8,708	$ 5,757	$ 2,019	$ -	$ -	$ -	$ 860	$ 71	$ -
43	Cost of Gas - Midstream		**$ 3,606**	**$ 2,374**	**$ 885**	**$ -**	**$ -**	**$ -**	**$ 333**	**$ 15**	**$ -**
44		Demand	$ 3,606	$ 2,374	$ 885	$ -	$ -	$ -	$ 333	$ 15	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 30,930**	**$ 21,886**	**$ 5,918**	**$ -**	**$ -**	**$ -**	**$ 2,443**	**$ 663**	**$ 19**
48		Demand	$ 11,632	$ 7,184	$ 2,575	$ -	$ -	$ -	$ 1,328	$ 545	$ -
49		Customer	$ 10,570	$ 8,931	$ 1,320	$ -	$ -	$ -	$ 252	$ 47	$ 19
50		Energy	$ 8,728	$ 5,771	$ 2,024	$ -	$ -	$ -	$ 863	$ 71	$ -

FEI Columbia Region (Legacy Methodology)
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Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 5

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 634**	**$ 410**	**$ 151**	**$ -**	**$ -**	**$ -**	**$ 70**	**$ 3**	**$ -**
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 634	$ 410	$ 151	$ -	$ -	$ -	$ 70	$ 3	$ -
5											
6	LNG Storage Tilbury		**$ 1,419**	**$ 851**	**$ 299**	**$ -**	**$ -**	**$ -**	**$ 176**	**$ 94**	**$ -**
7		Demand	$ 1,419	$ 851	$ 299	$ -	$ -	$ -	$ 176	$ 94	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 32,154**	**$ 19,271**	**$ 6,769**	**$ -**	**$ -**	**$ -**	**$ 3,988**	**$ 2,126**	**$ -**
17		Demand	$ 32,154	$ 19,271	$ 6,769	$ -	$ -	$ -	$ 3,988	$ 2,126	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ (70)**	**$ (42)**	**$ (15)**	**$ -**	**$ -**	**$ -**	**$ (9)**	**$ (5)**	**$ -**
22		Demand	$ (70)	$ (42)	$ (15)	$ -	$ -	$ -	$ (9)	$ (5)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 51,622**	**$ 40,663**	**$ 7,381**	**$ -**	**$ -**	**$ -**	**$ 2,474**	**$ 1,048**	**$ 57**
27		Demand	$ 13,693	$ 8,207	$ 2,883	$ -	$ -	$ -	$ 1,698	$ 905	$ -
28		Customer	$ 37,929	$ 32,456	$ 4,498	$ -	$ -	$ -	$ 776	$ 143	$ 57
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 837**	**$ 478**	**$ 184**	**$ -**	**$ -**	**$ -**	**$ 114**	**$ 62**	**$ (0)**
32		Demand	$ 946	$ 567	$ 199	$ -	$ -	$ -	$ 117	$ 63	$ -
33		Customer	$ (108)	$ (89)	$ (15)	$ -	$ -	$ -	$ (3)	$ (1)	$ (0)
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ (78)**	**$ (64)**	**$ (11)**	**$ -**	**$ -**	**$ -**	**$ (2)**	**$ (0)**	**$ (0)**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (78)	$ (64)	$ (11)	$ -	$ -	$ -	$ (2)	$ (0)	$ (0)
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Rate Base**		**$ 86,520**	**$ 61,567**	**$ 14,758**	**$ -**	**$ -**	**$ -**	**$ 6,811**	**$ 3,327**	**$ 56**
42		Demand	$ 48,142	$ 28,854	$ 10,135	$ -	$ -	$ -	$ 5,971	$ 3,183	$ -
43		Customer	$ 37,743	$ 32,303	$ 4,472	$ -	$ -	$ -	$ 770	$ 142	$ 56
44		Energy	$ 634	$ 410	$ 151	$ -	$ -	$ -	$ 70	$ 3	$ -

FEI Columbia Region (Legacy Methodology)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Fully Distributed Cost of Service Allocation Study

Schedule 6

Rate Design Filing_Common Rates_ 2013 Test Year

COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Gas Supply Operations		**$ 12,334**	**$ 8,144**	**$ 2,909**	**$ -**	**$ -**	**$ -**	**$ 1,195**	**$ 85**	**$ -**
2		Demand	$ 3,606	$ 2,374	$ 885	$ -	$ -	$ -	$ 333	$ 15	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 8,728	$ 5,771	$ 2,024	$ -	$ -	$ -	$ 863	$ 71	$ -
5											
6	LNG Storage Tilbury		**$ 336**	**$ 202**	**$ 71**	**$ -**	**$ -**	**$ -**	**$ 42**	**$ 22**	**$ -**
7		Demand	$ 336	$ 202	$ 71	$ -	$ -	$ -	$ 42	$ 22	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10											
11	LNG Storage Mt. Hayes		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15											
16	Transmission		**$ 4,546**	**$ 2,725**	**$ 957**	**$ -**	**$ -**	**$ -**	**$ 564**	**$ 301**	**$ -**
17		Demand	$ 4,546	$ 2,725	$ 957	$ -	$ -	$ -	$ 564	$ 301	$ -
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20											
21	Transmission SCP		**$ (209)**	**$ (125)**	**$ (44)**	**$ -**	**$ -**	**$ -**	**$ (26)**	**$ (14)**	**$ -**
22		Demand	$ (209)	$ (125)	$ (44)	$ -	$ -	$ -	$ (26)	$ (14)	$ -
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25											
26	Distribution		**$ 11,711**	**$ 9,151**	**$ 1,710**	**$ -**	**$ -**	**$ -**	**$ 588**	**$ 249**	**$ 14**
27		Demand	$ 3,238	$ 1,941	$ 682	$ -	$ -	$ -	$ 402	$ 214	$ -
28		Customer	$ 8,473	$ 7,210	$ 1,029	$ -	$ -	$ -	$ 186	$ 35	$ 14
29		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30											
31	Marketing		**$ 259**	**$ 188**	**$ 44**	**$ -**	**$ -**	**$ -**	**$ 19**	**$ 8**	**$ 0**
32		Demand	$ 115	$ 69	$ 24	$ -	$ -	$ -	$ 14	$ 8	$ -
33		Customer	$ 145	$ 119	$ 20	$ -	$ -	$ -	$ 5	$ 1	$ 0
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35											
36	Customer Accounting		**$ 1,952**	**$ 1,602**	**$ 271**	**$ -**	**$ -**	**$ -**	**$ 62**	**$ 12**	**$ 5**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 1,952	$ 1,602	$ 271	$ -	$ -	$ -	$ 62	$ 12	$ 5
39		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40											
41	**Total Utility Cost of Service**		**$ 30,930**	**$ 21,886**	**$ 5,918**	**$ -**	**$ -**	**$ -**	**$ 2,443**	**$ 663**	**$ 19**
42		Demand	$ 11,632	$ 7,184	$ 2,575	$ -	$ -	$ -	$ 1,328	$ 545	$ -
43		Customer	$ 10,570	$ 8,931	$ 1,320	$ -	$ -	$ -	$ 252	$ 47	$ 19
44		Energy	$ 8,728	$ 5,771	$ 2,024	$ -	$ -	$ -	$ 863	$ 71	$ -

FEI Columbia Region (Legacy Methodology)
Fully Distributed Cost of Service Allocation Study
Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

Response to BCUC IR2.31.3.1 - COSA Results for FEI by Region

Schedule 7

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27
1	Billing Determinants										
2	Sales Volume (TJ)			1,655	611	-	-	-	416	330	37
3	Midstream Sales Volume (TJ)			1,655	611	0	0				
4	Commodity Sales Volume (TJ)			1,455	510	-	-	-	350	330	37
5	Average No. of Customers			20,940	2,068	-	-	-	106	10	2
6											
7	**Cost of Service Margin**		**$ 18,617**	**$ 13,755**	**$ 3,014**	**$ -**	**$ -**	**$ -**	**$ 1,250**	**$ 578**	**$ 19**
8		Demand	$ 8,026	$ 4,811	$ 1,690	$ -	$ -	$ -	$ 996	$ 531	$ -
9	Unit Demand Charge ($/GJ)			$ 3.31	$ 1.16	$ -	$ -	$ -	$ 0.68	$ 0.36	$ -
10		Customer	$ 10,570	$ 8,931	$ 1,320	$ -	$ -	$ -	$ 252	$ 47	$ 19
11	Unit Customer Charge ($/GJ)			$ 6.14	$ 0.91	$ -	$ -	$ -	$ 0.17	$ 0.03	$ 0.01
12		Energy	$ 20	$ 13	$ 5	$ -	$ -	$ -	$ 2	$ 0	$ -
13	Unit Energy Charge ($/GJ)			$ 0.01	$ 0.00	$ -	$ -	$ -	$ 0.00	$ 0.00	$ -
14											
15	Unit Cost of Service Margin ($/GJ)			**$ 8.31**	**$ 4.93**	**$ -**	**$ -**	**$ -**	**$ 3.00**	**$ 1.75**	**$ 0.51**
16											
17	**Cost of Gas - Commodity**		**$ 8,708**	**$ 5,757**	**$ 2,019**	**$ -**	**$ -**	**$ -**	**$ 860**	**$ 71**	**$ -**
18		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Energy	$ 8,708	$ 5,757	$ 2,019	$ -	$ -	$ -	$ 860	$ 71	$ -
21	Unit Cost of Gas - Commodity ($/GJ)			**$ 3.958**	**$ 3.958**	**$ -**	**$ -**	**$ -**	**$ 2.46**	**$ 0.21**	**$ -**
22											
23	**Cost of Gas - Midstream**		**$ 3,606**	**$ 2,374**	**$ 885**	**$ -**	**$ -**	**$ -**	**$ 333**	**$ 15**	**$ -**
24		Demand	$ 3,606	$ 2,374	$ 885	$ -	$ -	$ -	$ 333	$ 15	$ -
25		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.43**	**$ 1.45**	**$ -**	**$ -**	**$ -**	**$ 0.95**	**$ 0.04**	**$ -**
27											
28	**Total Utility Cost of Service**		**$ 30,930**	**$ 21,886**	**$ 5,918**	**$ -**	**$ -**	**$ -**	**$ 2,443**	**$ 663**	**$ 19**
29		Demand	$ 11,632	$ 7,184	$ 2,575	$ -	$ -	$ -	$ 1,328	$ 545	$ -
30		Customer	$ 10,570	$ 8,931	$ 1,320	$ -	$ -	$ -	$ 252	$ 47	$ 19
31		Energy	$ 8,728	$ 5,771	$ 2,024	$ -	$ -	$ -	$ 863	$ 71	$ -
32	Unit Cost of Service ($/GJ)			**$ 15.05**	**$ 11.60**	**$ -**	**$ -**	**$ -**	**$ 6.97**	**$ 2.01**	**$ 0.51**
33											
34	**Total Revenues @ Proposed Rates**		**$ 30,930**	**$ 20,721**	**$ 6,302**	**$ -**	**$ -**	**$ -**	**$ 2,930**	**$ 885**	**$ 93**
35	Unit Rate ($/GJ)			**$ 14.25**	**$ 12.35**	**$ -**	**$ -**	**$ -**	**$ 8.36**	**$ 2.68**	**$ 2.50**
36											
37	**Total Revenue Margin @ Proposed Rates**		**$ 18,617**	**$ 12,590**	**$ 3,398**	**$ -**	**$ -**	**$ -**	**$ 1,737**	**$ 799**	**$ 93**
38	Unit Rate ($/GJ)			**$ 8.66**	**$ 6.66**	**$ -**	**$ -**	**$ -**	**$ 4.96**	**$ 2.43**	**$ 2.50**

Attachment 71.1

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1 **Schedule 1**
Rate Design Filing_Common Rates_ 2013 Test Year
SUMMARY (000's)

L.No.	Particulars	Reference	Total	RATE 1	RATE 2	RATE 4 [2]	RATE 6	RATE 22 [2] NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27 [2]	Spl Contracts, Bypass, Rate 22A & Rate 22B [5]
1	**REVENUES**											
2	Total Revenues at Proposed 2013 FEI Rates	line 3 + line 4	**$ 1,330,682**	**$ 795,934**	**$ 241,068**	**$ 1,074**	**$ 504**	**$ 11,866**	**$ 187,133**	**$ 46,483**	**$ 8,448**	**$ 38,171**
3	Revenue Margin at Proposed 2013 FEI Rates[4]		$ 707,662	$ 414,446	$ 110,258	$ 314	$ 249	$ 11,866	$ 89,379	$ 34,589	$ 8,390	$ 38,171
4	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58	$ -
5												
6	**COST OF SERVICE**											
7	Total Utility Cost of Service	line 8 + line 9	**$ 1,389,870**	**$ 878,978**	**$ 240,515**	**$ 823**	**$ 471**	**$ 905**	**$ 180,375**	**$ 40,416**	**$ 1,687**	**$ 45,699**
8	Cost of Service Margin		$ 766,849	$ 497,490	$ 109,705	$ 62	$ 216	$ 905	$ 82,621	$ 28,522	$ 1,629	$ 45,699
9	Total Cost of Gas [3]		$ 623,020	$ 381,488	$ 130,810	$ 761	$ 255	$ -	$ 97,754	$ 11,894	$ 58	$ -
10												
11	**SURPLUS / DEFICIT**											
12	Total Surplus / Deficit	line 2 - line 7	**$ (59,187)**									
13	% increase to Equal Allocated Cost		8.4%									
14												
15	**REVENUES (adjusted to equal COS)**											
16	Total Adjusted Revenues at Proposed 2013 FEI Rates	line 17 + line 9	**$ 1,389,870**	**$ 830,598**	**$ 250,290**	**$ 1,101**	**$ 525**	**$ 12,858**	**$ 194,608**	**$ 49,376**	**$ 9,150**	**$ 41,363**
17	Total Adjusted Revenue Margin at Proposed 2013 FEI Rates	line 3 x line 13	$ 766,849	$ 449,110	$ 119,480	$ 340	$ 270	$ 12,858	$ 96,854	$ 37,482	$ 9,092	$ 41,363
18												
19	REVENUES (adjusted for R/C RATIOS) [1]		**$ 1,512,488**	**$ 830,598**	**$ 250,290**	**$ 1,101**	**$ 525**	**$ 12,858**	**$ 233,256**	**$ 109,501**	**$ 32,995**	**$ 41,363**
20	COST OF SERVICE (adjusted for R/C RATIOS) [1]		**$ 1,512,488**	**$ 878,978**	**$ 240,515**	**$ 823**	**$ 471**	**$ 905**	**$ 219,022**	**$ 100,541**	**$ 25,532**	$ 45,699
21												
22	**REVENUE TO COST RATIO**											
23	Revenue to Cost Ratio	line 19 / line 20	**100%**	**94.5%**	**104.1%**		**111.5%**		**106.5%**	**108.9%**		**90.5%**
24												
25	**REVENUE REBALANCING**											
26	Adjustment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Revenues at Proposed Rates [1]	line 28 + line 9	**$ 1,512,488**	**$ 830,598**	**$ 250,290**	**$ 1,101**	**$ 525**	**$ 12,858**	**$ 233,256**	**$ 109,501**	**$ 32,995**	**$ 41,363**
28	Total Revenue Margin at Proposed Rates	ine 17 + line 2	$ 766,849	$ 449,110	$ 119,480	$ 340	$ 270	$ 12,858	$ 96,854	$ 37,482	$ 9,092	$ 41,363
29												
30	**PROPOSED REVENUE TO COST RATIO**											
31	Revenue to Cost Ratio at Proposed Rates	line 27 / line 20	**100.0%**	**94.5%**	**104.1%**		**111.5%**		**106.5%**	**108.9%**		**90.5%**

Note:
1. The revenues (line 27 and line 19) and cost of service (line 20) include the imputed COG number for Rate 23, 25 and 27. This is shown only for the purposes of presenting the Revenue to Cost Ratios
Please note that Rates 23, 25 and 27 do not pay for commodity and midstream charges.
2. Rate 4 is a seasonal service and Rates 22 and Rate7/27 are interruptible customer classes. The revenue to cost ratio for Rate 4, Rate 22 and Rate 7/27 are not shown in the schedule above a
these rate classes do not drive system capacity additions and therefore, no demand-related costs are allocated to these customer classes in the COSA Study
3. Cost of Gas forecast is based on five-day average of the November 1, 2, 3, 4, and 7, 2011 forward prices, and which reflect the forward prices utilized in the various FEU 2011 Fourth Quarter Gas Cost report
4. Revenue Margin includes UAF allocation to rate classes.
5. The revenue to cost ratio for special contracts, bypass and closed industrilas Rate 22A and Rate 22B (line 31) has no commodity and midstream gas costs and revenues.

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1 **Schedule 2**
Rate Design Filing_Common Rates_ 2013 Test Year
FUNCTIONALIZATION (000's)

L.No.	Particulars	Total	Gas Supply Operations	LNG Storage Tilbury	LNG Storage Mt. Hayes	Transmission	Transmission SCP	Distribution	Marketing	Customer Accounting
1	Total Operating & Maintenance Expense	$ 243,770	$ -	$ 2,609	$ 4,236	$ 41,385	$ 7,537	$ 100,365	$ 5,371	$ 82,267
2	BCH Capacity Right	$ 244	$ -	$ -	$ -	$ 244	$ -	$ -	$ -	$ -
3	Property & Sundry Taxes	$ 61,924	$ -	$ 377	$ 1,076	$ 16,378	$ 5,621	$ 38,472	$ -	$ -
4	Depreciation Expense	$ 171,007	$ -	$ 2,349	$ 7,050	$ 34,157	$ 9,766	$ 117,684	$ -	$ -
5	Amortization Expense	$ 12,458	$ (2)	$ 49	$ 158	$ 8,245	$ (1,888)	$ 1,359	$ 4,474	$ 63
6	Other Operating Revenue	$ (40,019)	$ -	$ -	$ (18,039)	$ (181)	$ (14,827)	$ (4,412)	$ -	$ (2,560)
7	Other Earned Return Provisions	$ (97)	$ -	$ (1)	$ (4)	$ (24)	$ (8)	$ (59)	$ -	$ -
8	Income Tax	$ 36,742	$ -	$ 502	$ 1,581	$ 9,276	$ 2,907	$ 22,477	$ -	$ -
9	Earned Return	$ 280,821	$ -	$ 3,841	$ 12,081	$ 70,893	$ 22,215	$ 171,791	$ -	$ -
10	**Total Cost of Service Margin**	**$ 766,849**	**$ (2)**	**$ 9,726**	**$ 8,139**	**$ 180,373**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**
11										
12	Cost of Gas - Commodity	$ 459,919	$ 459,919	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Cost of Gas - Midstream	$ 163,102	$ 163,102	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Utility Cost of Service**	**$ 1,389,870**	**$ 623,018**	**$ 9,726**	**$ 8,139**	**$ 180,373**	**$ 31,322**	**$ 447,676**	**$ 9,845**	**$ 79,770**

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1 **Schedule 3**
Rate Design Filing_Common Rates_ 2013 Test Year
RATE BASE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27	Spl Contracts, Bypass, Rate 22A & Rate 22B
1	Gas Plant in Service											
2	**Total Gas Plant in Service**		**$ 5,204,738**	**$ 3,238,630**	**$ 792,275**	**$ 523**	**$ 771**	**$ 5,328**	**$ 584,882**	**$ 201,946**	**$ 11,141**	**$ 369,243**
3		Demand	$ 2,873,646	$ 1,374,796	$ 518,044	$ 14	$ 349	$ 4,395	$ 482,553	$ 170,815	$ 454	$ 322,226
4		Customer	$ 2,107,177	$ 1,776,132	$ 242,603	$ 291	$ 355	$ 933	$ 68,941	$ 14,052	$ 3,869	$ -
5		Energy	$ 223,914	$ 87,703	$ 31,628	$ 217	$ 66	$ -	$ 33,387	$ 17,080	$ 6,817	$ 47,017
6	**Total Accumulated Depreciation**		**$ (1,422,596)**	**$ (879,752)**	**$ (217,436)**	**$ (84)**	**$ (187)**	**$ (1,507)**	**$ (162,592)**	**$ (55,586)**	**$ (1,485)**	**$ (103,965)**
7		Demand	$ (865,054)	$ (411,788)	$ (155,332)	$ (4)	$ (105)	$ (1,307)	$ (144,740)	$ (51,238)	$ (139)	$ (100,401)
8		Customer	$ (540,569)	$ (461,316)	$ (59,707)	$ (64)	$ (77)	$ (200)	$ (15,321)	$ (3,053)	$ (830)	$ -
9		Energy	$ (16,973)	$ (6,648)	$ (2,397)	$ (16)	$ (5)	$ -	$ (2,531)	$ (1,295)	$ (517)	$ (3,564)
10	**TOTAL Net Plant**		**$ 3,782,142**	**$ 2,358,878**	**$ 574,838**	**$ 438**	**$ 584**	**$ 3,821**	**$ 422,289**	**$ 146,360**	**$ 9,655**	**$ 265,278**
11		Demand	$ 2,008,592	$ 963,008	$ 362,712	$ 10	$ 245	$ 3,088	$ 337,813	$ 119,576	$ 315	$ 221,825
12		Customer	$ 1,566,609	$ 1,314,815	$ 182,896	$ 228	$ 278	$ 733	$ 53,620	$ 10,999	$ 3,040	$ -
13		Energy	$ 206,941	$ 81,055	$ 29,230	$ 201	$ 61	$ -	$ 30,857	$ 15,785	$ 6,300	$ 43,453
14												
15	Contribution In Aid of Construction											
16	**Total CIAC**		**$ (425,839)**	**$ (261,364)**	**$ (63,105)**	**$ (25)**	**$ (58)**	**$ (453)**	**$ (45,745)**	**$ (15,317)**	**$ (335)**	**$ (39,437)**
17		Demand	$ (250,673)	$ (113,935)	$ (42,925)	$ -	$ (29)	$ (376)	$ (39,958)	$ (14,115)	$ -	$ (39,335)
18		Customer	$ (174,683)	$ (147,240)	$ (20,112)	$ (24)	$ (29)	$ (77)	$ (5,715)	$ (1,165)	$ (321)	$ -
19		Energy	$ (483)	$ (189)	$ (68)	$ (0)	$ (0)	$ -	$ (72)	$ (37)	$ (15)	$ (101)
20	**Total Accumulated Amortization**		**$ 118,407**	**$ 75,008**	**$ 17,542**	**$ 8**	**$ 17**	**$ 123**	**$ 12,379**	**$ 4,117**	**$ 107**	**$ 9,104**
21		Demand	$ 64,243	$ 29,479	$ 11,299	$ -	$ 8	$ 99	$ 10,575	$ 3,737	$ -	$ 9,046
22		Customer	$ 53,885	$ 45,420	$ 6,204	$ 7	$ 9	$ 24	$ 1,763	$ 359	$ 99	$ -
23		Energy	$ 278	$ 109	$ 39	$ 0	$ 0	$ -	$ 41	$ 21	$ 8	$ 58
24	**Total Net Contribution**		**$ (307,433)**	**$ (186,356)**	**$ (45,563)**	**$ (17)**	**$ (42)**	**$ (330)**	**$ (33,366)**	**$ (11,199)**	**$ (228)**	**$ (30,332)**
25		Demand	$ (186,430)	$ (84,456)	$ (31,626)	$ -	$ (21)	$ (276)	$ (29,383)	$ (10,378)	$ -	$ (30,289)
26		Customer	$ (120,798)	$ (101,820)	$ (13,908)	$ (17)	$ (20)	$ (53)	$ (3,952)	$ (806)	$ (222)	$ -
27		Energy	$ (205)	$ (80)	$ (29)	$ (0)	$ (0)	$ -	$ (31)	$ (16)	$ (6)	$ (43)
28												
29	Work in Progress, no AFUDC		**$ 19,418**	**$ 11,450**	**$ 3,121**	**$ 2**	**$ 3**	**$ 22**	**$ 2,502**	**$ 889**	**$ 52**	**$ 1,378**
30		Demand	$ 13,221	$ 6,603	$ 2,386	$ 1	$ 2	$ 19	$ 2,202	$ 790	$ 17	$ 1,202
31		Customer	$ 5,362	$ 4,519	$ 617	$ 1	$ 1	$ 2	$ 175	$ 36	$ 10	$ -
32		Energy	$ 835	$ 327	$ 118	$ 1	$ 0	$ -	$ 125	$ 64	$ 25	$ 175
33												
34	Unamortized Deferred Charges											
35	**Total Unamortized Deferred Charges - Rate Base**		**$ 68,411**	**$ 15,207**	**$ 8,993**	**$ 2**	**$ 152**	**$ 92**	**$ 9,806**	**$ 3,125**	**$ (281)**	**$ 31,315**
36		Demand	$ 91,293	$ 34,524	$ 11,142	$ (3)	$ 151	$ 100	$ 9,756	$ 3,354	$ (101)	$ 32,368
37		Customer	$ (26,240)	$ (22,413)	$ (3,178)	$ (4)	$ (2)	$ (8)	$ (580)	$ (27)	$ (29)	$ -
38		Energy	$ 3,358	$ 3,096	$ 1,028	$ 9	$ 3	$ -	$ 630	$ (203)	$ (152)	$ (1,053)
39												
40	Cash Working Capital		**$ 10,310**	**$ 6,489**	**$ 1,650**	**$ 6**	**$ 4**	**$ 8**	**$ 1,388**	**$ 379**	**$ 25**	**$ 360**
41		Demand	$ 3,385	$ 1,672	$ 608	$ 0	$ 0	$ 5	$ 563	$ 202	$ 5	$ 329
42		Customer	$ 3,369	$ 2,699	$ 314	$ 0	$ 2	$ 3	$ 242	$ 93	$ 15	$ 0
43		Energy	$ 3,556	$ 2,118	$ 728	$ 6	$ 2	$ -	$ 583	$ 85	$ 5	$ 31
44												
45	Other Working Capital											
46	**Total Other Working Capital**		**$ 101,420**	**$ 41,555**	**$ 15,508**	**$ (1)**	**$ 6**	**$ 128**	**$ 13,830**	**$ 4,824**	**$ (53)**	**$ 25,624**
47		Demand	$ 108,626	$ 47,078	$ 16,110	$ (0)	$ 10	$ 137	$ 14,512	$ 5,110	$ (5)	$ 25,673
48		Customer	$ (6,971)	$ (5,431)	$ (569)	$ (0)	$ (5)	$ (9)	$ (647)	$ (269)	$ (41)	$ (0)
49		Energy	$ (235)	$ (92)	$ (33)	$ (0)	$ (0)	$ -	$ (35)	$ (18)	$ (7)	$ (49)
50												
51	LILO, Capital Efficiency Mechanism, Others		**$ (1,150)**	**$ (843)**	**$ (169)**	**$ (0)**	**$ (0)**	**$ (1)**	**$ (102)**	**$ (32)**	**$ (1)**	**$ -**
52		Demand	$ (362)	$ (179)	$ (79)	$ -	$ (0)	$ (1)	$ (77)	$ (27)	$ -	$ -
53		Customer	$ (788)	$ (664)	$ (91)	$ (0)	$ (0)	$ (0)	$ (26)	$ (5)	$ (1)	$ -
54		Energy	$ -						$ -	$ -	$ -	$ -
55												
56	**Total Utility Rate Base**		**$ 3,673,117**	**$ 2,246,380**	**$ 558,379**	**$ 431**	**$ 706**	**$ 3,741**	**$ 416,347**	**$ 144,345**	**$ 9,168**	**$ 293,622**
57		Demand	$ 2,038,325	$ 968,250	$ 361,254	$ 7	$ 387	$ 3,072	$ 335,386	$ 118,628	$ 232	$ 251,108
58		Customer	$ 1,420,542	$ 1,191,706	$ 166,082	$ 208	$ 253	$ 669	$ 48,833	$ 10,020	$ 2,771	$ (0)
59		Energy	$ 214,251	$ 86,423	$ 31,042	$ 216	$ 66	$ -	$ 32,128	$ 15,697	$ 6,166	$ 42,513

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1 **Schedule 4**
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - CLASSIFICATION (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27	Spl Contracts, Bypass, Rate 22A & Rate 22B
1	Operating & Maintenance Expense											
2	**Total Operating & Maintenance Expense**		**$ 243,770**	**$ 163,762**	**$ 30,602**	**$ 17**	**$ 92**	**$ 363**	**$ 27,144**	**$ 10,146**	**$ 931**	**$ 10,712**
3		Demand	$ 91,560	$ 44,161	$ 16,455	$ 3	$ 12	$ 215	$ 15,319	$ 5,476	$ 96	$ 9,823
4		Customer	$ 147,973	$ 117,942	$ 13,548	$ 10	$ 80	$ 148	$ 11,193	$ 4,347	$ 706	$ -
5		Energy	$ 4,236	$ 1,659	$ 598	$ 4	$ 1	$ -	$ 632	$ 323	$ 129	$ 890
6	BCH Capacity Right		**$ 244**	**$ 106**	**$ 36**	**$ -**	**$ 0**	**$ 0**	**$ 33**	**$ 12**	**$ -**	**$ 57**
7		Demand	$ 244	$ 106	$ 36	$ -	$ 0	$ 0	$ 33	$ 12	$ -	$ 57
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Property & Sundry Taxes		**$ 61,924**	**$ 38,198**	**$ 9,645**	**$ 5**	**$ 9**	**$ 69**	**$ 7,204**	**$ 2,446**	**$ 85**	**$ 4,263**
11		Demand	$ 36,499	$ 17,414	$ 6,618	$ 0	$ 4	$ 57	$ 6,179	$ 2,186	$ 3	$ 4,037
12		Customer	$ 24,349	$ 20,362	$ 2,875	$ 4	$ 4	$ 12	$ 864	$ 178	$ 49	$ -
13		Energy	$ 1,076	$ 421	$ 152	$ 1	$ 0	$ -	$ 160	$ 82	$ 33	$ 226
14	Depreciation Expense		**$ 171,007**	**$ 111,633**	**$ 25,693**	**$ 25**	**$ 32**	**$ 167**	**$ 17,382**	**$ 5,781**	**$ 477**	**$ 9,817**
15		Demand	$ 75,085	$ 36,271	$ 13,436	$ 1	$ 9	$ 111	$ 12,461	$ 4,426	$ 33	$ 8,337
16		Customer	$ 88,871	$ 72,601	$ 11,261	$ 17	$ 21	$ 55	$ 3,870	$ 817	$ 229	$ -
17		Energy	$ 7,050	$ 2,761	$ 996	$ 7	$ 2	$ -	$ 1,051	$ 538	$ 215	$ 1,480
18	Amortization Expense		**$ 12,458**	**$ 5,655**	**$ 1,777**	**$ 0**	**$ 44**	**$ 15**	**$ 1,597**	**$ 570**	**$ 11**	**$ 2,790**
19		Demand	$ 11,355	$ 4,834	$ 1,667	$ 0	$ 43	$ 14	$ 1,507	$ 532	$ 2	$ 2,756
20		Customer	$ 947	$ 760	$ 88	$ 0	$ 0	$ 1	$ 67	$ 25	$ 4	$ -
21		Energy	$ 156	$ 61	$ 22	$ 0	$ 0	$ -	$ 23	$ 12	$ 5	$ 33
22	Other Operating Revenue		**$ (40,019)**	**$ (20,388)**	**$ (6,175)**	**$ (18)**	**$ (10)**	**$ (31)**	**$ (5,862)**	**$ (2,500)**	**$ (572)**	**$ (4,462)**
23		Demand	$ (16,396)	$ (8,811)	$ (3,087)	$ -	$ (2)	$ (26)	$ (2,805)	$ (989)	$ -	$ (675)
24		Customer	$ (5,584)	$ (4,511)	$ (540)	$ (0)	$ (3)	$ (5)	$ (367)	$ (135)	$ (23)	$ -
25		Energy	$ (18,039)	$ (7,066)	$ (2,548)	$ (17)	$ (5)	$ -	$ (2,690)	$ (1,376)	$ (549)	$ (3,788)
26	Income Tax		**$ 36,742**	**$ 22,976**	**$ 5,570**	**$ 4**	**$ 6**	**$ 37**	**$ 4,065**	**$ 1,397**	**$ 81**	**$ 2,607**
27		Demand	$ 19,754	$ 9,432	$ 3,545	$ 0	$ 2	$ 30	$ 3,300	$ 1,167	$ 2	$ 2,275
28		Customer	$ 15,408	$ 12,925	$ 1,801	$ 2	$ 3	$ 7	$ 530	$ 109	$ 30	$ -
29		Energy	$ 1,581	$ 619	$ 223	$ 2	$ 0	$ -	$ 236	$ 121	$ 48	$ 332
30	Earned Return		**$ 280,821**	**$ 175,608**	**$ 42,572**	**$ 30**	**$ 43**	**$ 285**	**$ 31,069**	**$ 10,675**	**$ 616**	**$ 19,922**
31		Demand	$ 150,979	$ 72,086	$ 27,098	$ 1	$ 18	$ 230	$ 25,219	$ 8,923	$ 19	$ 17,386
32		Customer	$ 117,761	$ 98,790	$ 13,768	$ 17	$ 21	$ 55	$ 4,049	$ 831	$ 230	$ -
33		Energy	$ 12,081	$ 4,732	$ 1,706	$ 12	$ 4	$ -	$ 1,801	$ 922	$ 368	$ 2,537
34												
35	**Total Cost of Service Margin**		**$ 766,849**	**$ 497,490**	**$ 109,705**	**$ 62**	**$ 216**	**$ 905**	**$ 82,621**	**$ 28,522**	**$ 1,629**	**$ 45,699**
36		Demand	$ 369,029	$ 175,468	$ 65,759	$ 5	$ 87	$ 631	$ 61,204	$ 21,730	$ 155	$ 43,990
37		Customer	$ 389,684	$ 318,836	$ 42,797	$ 49	$ 126	$ 274	$ 20,204	$ 6,172	$ 1,226	$ -
38		Energy	$ 8,137	$ 3,187	$ 1,149	$ 8	$ 2	$ -	$ 1,213	$ 621	$ 248	$ 1,709
39	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**	**$ -**
40		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58	$ -
43	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**	**$ -**
44		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -	$ -
45		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	**Total Utility Cost of Service**		**$ 1,389,870**	**$ 878,978**	**$ 240,515**	**$ 823**	**$ 471**	**$ 905**	**$ 180,375**	**$ 40,416**	**$ 1,687**	**$ 45,699**
48		Demand	$ 532,131	$ 279,023	$ 101,180	$ 5	$ 111	$ 631	$ 83,302	$ 23,733	$ 155	$ 43,990
49		Customer	$ 389,684	$ 318,836	$ 42,797	$ 49	$ 126	$ 274	$ 20,204	$ 6,172	$ 1,226	$ -
50		Energy	$ 468,056	$ 281,120	$ 96,538	$ 769	$ 234	$ -	$ 76,869	$ 10,511	$ 306	$ 1,709

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1
Rate Design Filing_Common Rates_ 2013 Test Year

Schedule 5

RATE BASE SUMMARY - FUNCTIONALIZATION (000's)

L.No.	Particulars		Total	Total Distribution	Total T-Service	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27	Spl Contracts, Bypass, Rate 22A & Rate 22B
1	**Gas Supply Operations**		**$ 58,800**	**$ 11,784**	**$ -**	**$ 7,121**	**$ 2,444**	**$ 19**	**$ 6**	**$ -**	**$ 1,938**	**$ 253**	**$ 1**	**$ -**
2		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 58,800	$ 11,784	$ -	$ 7,121	$ 2,444	$ 19	$ 6	$ -	$ 1,938	$ 253	$ 1	$ 47,017
5														
6	**LNG Storage Tilbury**		**$ 41,717**	**$ 37,343**	**$ 4,374**	**$ 23,690**	**$ 8,120**	**$ -**	**$ 5**	**$ -**	**$ 7,321**	**$ 2,580**	**$ -**	**$ -**
7		Demand	$ 41,717	$ 37,343	$ 4,374	$ 23,690	$ 8,120	$ -	$ 5	$ -	$ 7,321	$ 2,580	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10														
11	**LNG Storage Mt. Hayes**		**$ 202,467**	**$ 132,982**	**$ 69,485**	**$ 79,302**	**$ 28,598**	**$ 196**	**$ 60**	**$ -**	**$ 30,189**	**$ 15,444**	**$ 6,164**	**$ 42,513**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ 202,467	$ 132,982	$ 69,485	$ 79,302	$ 28,598	$ 196	$ 60	$ -	$ 30,189	$ 15,444	$ 6,164	$ 42,513
15														
16	**Transmission**		**$ 989,048**	**$ 678,953**	**$ 310,094**	**$ 430,726**	**$ 147,639**	**$ -**	**$ 97**	**$ 1,250**	**$ 133,103**	**$ 46,908**	**$ -**	**$ 229,325**
17		Demand	$ 989,048	$ 678,953	$ 310,094	$ 430,726	$ 147,639	$ -	$ 97	$ 1,250	$ 133,103	$ 46,908	$ -	$ 229,325
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20														
21	**Transmission SCP**		**$ 305,472**	**$ 261,345**	**$ 44,127**	**$ 165,796**	**$ 56,830**	**$ -**	**$ 37**	**$ 481**	**$ 51,235**	**$ 18,057**	**$ -**	**$ 13,036**
22		Demand	$ 305,472	$ 261,345	$ 44,127	$ 165,796	$ 56,830	$ -	$ 37	$ 481	$ 51,235	$ 18,057	$ -	$ 13,036
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25														
26	**Distribution**		**$ 2,084,865**	**$ 1,976,130**	**$ 108,738**	**$ 1,523,395**	**$ 309,123**	**$ 215**	**$ 353**	**$ 1,962**	**$ 187,494**	**$ 59,319**	**$ 3,003**	**$ -**
27		Demand	$ 664,216	$ 579,429	$ 84,787	$ 331,607	$ 143,033	$ 7	$ 100	$ 1,294	$ 138,650	$ 49,294	$ 232	$ -
28		Customer	$ 1,420,649	$ 1,396,700	$ 23,948	$ 1,191,788	$ 166,090	$ 208	$ 253	$ 669	$ 48,844	$ 10,025	$ 2,771	$ -
29		Energy	$ -	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30														
31	**Marketing**		**$ 41,727**	**$ 3,305**	**$ 550**	**$ 19,384**	**$ 5,920**	**$ 0.1**	**$ 151**	**$ 53**	**$ 5,481**	**$ 1,962**	**$ 26**	**$ 8,748**
32		Demand	$ 37,872	$ 3,305	$ 550	$ 16,430	$ 5,632	$ -	$ 148	$ 48	$ 5,077	$ 1,789	$ -	$ 8,748
33		Customer	$ 3,855	$ -	$ -	$ 2,954	$ 289	$ 0.1	$ 3	$ 5	$ 404	$ 173	$ 26	$ -
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35														
36	**Customer Accounting**		**$ (3,962)**	**$ (3,395)**	**$ (563)**	**$ (3,036)**	**$ (297)**	**$ (0.1)**	**$ (3)**	**$ (5)**	**$ (415)**	**$ (178)**	**$ (27)**	**$ -**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ (3,962)	$ (3,396)	$ (565)	$ (3,036)	$ (297)	$ (0.1)	$ (3)	$ (5)	$ (415)	$ (178)	$ (27)	$ (0)
39		Energy	$ -	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40														
41	**Total Utility Rate Base**		**$ 3,720,134**	**$ 3,098,447**	**$ 536,804**	**$ 2,246,380**	**$ 558,379**	**$ 431**	**$ 706**	**$ 3,741**	**$ 416,347**	**$ 144,345**	**$ 9,168**	**$ 293,622**
42		Demand	$ 2,038,325	$ 1,560,375	$ 443,933	$ 968,250	$ 361,254	$ 7	$ 387	$ 3,072	$ 335,386	$ 118,628	$ 232	$ 251,108
43		Customer	$ 1,420,542	$ 1,393,304	$ 23,383	$ 1,191,706	$ 166,082	$ 208	$ 253	$ 669	$ 48,833	$ 10,020	$ 2,771	$ (0)
44		Energy	$ 261,267	$ 144,768	$ 69,489	$ 86,423	$ 31,042	$ 216	$ 66	$ -	$ 32,128	$ 15,697	$ 6,166	$ 89,530

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1
Rate Design Filing_Common Rates_ 2013 Test Year
COST OF SERVICE SUMMARY - FUNCTIONALIZATION (000's)

Schedule 6

L.No.	Particulars		Total	Total Distribution	Total T-Service	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27	Spl Contracts, Bypass, Rate 22A & Rate 22B
1	Gas Supply Operations		**$ 623,018**	**$ 459,916**	**$ -**	**$ 381,487**	**$ 130,810**	**$ 761**	**$ 255**	**$ -**	**$ 97,754**	**$ 11,894**	**$ 58**	**$ -**
2		Demand	$ 163,102	$ -	$ -	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -	$ -
3		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4		Energy	$ 459,916	$ 459,916	$ -	$ 277,931	$ 95,388	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58	$ -
5														
6	LNG Storage Tilbury		**$ 9,726**	**$ 8,706**	**$ 1,020**	**$ 5,523**	**$ 1,893**	**$ -**	**$ 1**	**$ -**	**$ 1,707**	**$ 602**	**$ -**	**$ -**
7		Demand	$ 9,726	$ 8,706	$ 1,020	$ 5,523	$ 1,893	$ -	$ 1	$ -	$ 1,707	$ 602	$ -	$ -
8		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10														
11	LNG Storage Mt. Hayes		**$ 8,139**	**$ 5,346**	**$ 2,793**	**$ 3,188**	**$ 1,150**	**$ 8**	**$ 2**	**$ -**	**$ 1,214**	**$ 621**	**$ 248**	**$ 1,709**
12		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14		Energy	$ 8,139	$ 5,346	$ 2,793	$ 3,188	$ 1,150	$ 8	$ 2	$ -	$ 1,214	$ 621	$ 248	$ 1,709
15														
16	Transmission		**$ 180,373**	**$ 123,788**	**$ 56,585**	**$ 78,490**	**$ 26,915**	**$ 2**	**$ 18**	**$ 307**	**$ 24,289**	**$ 8,584**	**$ 41**	**$ 41,727**
17		Demand	$ 180,373	$ 123,788	$ 56,585	$ 78,490	$ 26,915	$ 2	$ 18	$ 307	$ 24,289	$ 8,584	$ 41	$ 41,727
18		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20														
21	Transmission SCP		**$ 31,322**	**$ 26,797**	**$ 4,525**	**$ 17,000**	**$ 5,827**	**$ -**	**$ 4**	**$ 49**	**$ 5,253**	**$ 1,852**	**$ -**	**$ 1,337**
22		Demand	$ 31,322	$ 26,797	$ 4,525	$ 17,000	$ 5,827	$ -	$ 4	$ 49	$ 5,253	$ 1,852	$ -	$ 1,337
23		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25														
26	Distribution		**$ 447,676**	**$ 424,054**	**$ 23,625**	**$ 325,960**	**$ 66,914**	**$ 52**	**$ 80**	**$ 426**	**$ 40,651**	**$ 12,831**	**$ 761**	**$ -**
27		Demand	$ 143,575	$ 125,503	$ 18,072	$ 72,717	$ 30,528	$ 4	$ 22	$ 270	$ 29,417	$ 10,504	$ 114	$ -
28		Customer	$ 304,102	$ 298,550	$ 5,551	$ 253,244	$ 36,386	$ 48	$ 59	$ 156	$ 11,234	$ 2,328	$ 647	$ -
29		Energy	$ -	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30														
31	Marketing		**$ 9,845**	**$ 4,982**	**$ 829**	**$ 6,192**	**$ 1,031**	**$ 0**	**$ 47**	**$ 13**	**$ 1,146**	**$ 450**	**$ 39**	**$ 925**
32		Demand	$ 4,033	$ 4,982	$ 829	$ 1,738	$ 596	$ -	$ 43	$ 5	$ 537	$ 189	$ -	$ 925
33		Customer	$ 5,812	$ -	$ -	$ 4,454	$ 435	$ 0	$ 5	$ 8	$ 609	$ 261	$ 39	$ -
34		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35														
36	Customer Accounting		**$ 79,770**	**$ 68,389**	**$ 11,384**	**$ 61,138**	**$ 5,975**	**$ 1**	**$ 63**	**$ 110**	**$ 8,360**	**$ 3,583**	**$ 540**	**$ -**
37		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Customer	$ 79,770	$ 68,388	$ 11,382	$ 61,138	$ 5,975	$ 1	$ 63	$ 110	$ 8,360	$ 3,583	$ 540	$ -
39		Energy	$ -	$ 1	$ 2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40														
41	**Total Utility Cost of Service**		**$ 1,389,870**	**$ 1,121,980**	**$ 100,761**	**$ 878,978**	**$ 240,515**	**$ 823**	**$ 471**	**$ 905**	**$ 180,375**	**$ 40,416**	**$ 1,687**	**$ 45,699**
42		Demand	$ 532,131	$ 289,777	$ 81,030	$ 279,023	$ 101,180	$ 5	$ 111	$ 631	$ 83,302	$ 23,733	$ 155	$ 43,990
43		Customer	$ 389,684	$ 366,939	$ 16,933	$ 318,836	$ 42,797	$ 49	$ 126	$ 274	$ 20,204	$ 6,172	$ 1,226	$ -
44		Energy	$ 468,056	$ 465,264	$ 2,797	$ 281,120	$ 96,538	$ 769	$ 234	$ -	$ 76,869	$ 10,511	$ 306	$ 1,709

FORTISBC ENERGY INC. (AMALGAMATED)
Fully Distributed Cost of Service Allocation Study_BCUC IR 2.71.1 **Schedule 7**
Rate Design Filing_Common Rates_ 2013 Test Year
ALLOCATORS SUMMARY (000's)

L.No.	Particulars		Total	RATE 1	RATE 2	RATE 4	RATE 6	RATE 22 NON BYPASS	RATE 3/23	RATE 5/25	RATE 7/27	Spl Contracts, Bypass, Rate 22A & Rate 22B
1	Billing Determinants											
2												
3	Sales Volume (TJ)		162,502	74,862	26,997	185	56	11,504	28,499	14,579	5,819	40,133
4	Midstream Sales Volume (TJ)		125,322	74,800	26,918	185	56	-	20,940	2,408	14	-
5	Commodity Sales Volume (TJ)		111,962	67,660	23,221	185	56	-	18,417	2,408	14	-
6	Average No. of Customers		971,089	877,036	85,717	18	21	21	7,384	786	105	32
7												
8	Cost of Service Margin		**$ 766,849**	**$ 497,490**	**$ 109,705**	**$ 62**	**$ 216**	**$ 905**	**$ 82,621**	**$ 28,522**	**$ 1,629**	**$ 45,699**
9		Demand	$ 369,029	$ 175,468	$ 65,759	$ 5	$ 87	$ 631	$ 61,204	$ 21,730	$ 155	$ 43,990
10	Unit Demand Charge ($/GJ)			$ 2.34	$ 0.88	$ 0.00	$ 0.00	$ 0.01	$ 0.82	$ 0.29	$ 0.00	$ 0.59
11		Customer	$ 389,684	$ 318,836	$ 42,797	$ 49	$ 126	$ 274	$ 20,204	$ 6,172	$ 1,226	$ -
12	Unit Customer Charge ($/GJ)			$ 4.26	$ 0.57	$ 0.00	$ 0.00	$ 0.00	$ 0.27	$ 0.08	$ 0.02	$ -
13		Energy	$ 8,137	$ 3,187	$ 1,149	$ 8	$ 2	$ -	$ 1,213	$ 621	$ 248	$ 1,709
14	Unit Energy Charge ($/GJ)			$ 0.04	$ 0.02	$ 0.00	$ 0.00	$ -	$ 0.02	$ 0.01	$ 0.00	$ 0.02
15												
16	Unit Cost of Service Margin ($/GJ)			**$ 6.65**	**$ 4.06**	**$ 0.34**	**$ 3.83**	**$ 0.08**	**$ 2.90**	**$ 1.96**	**$ 0.28**	**$ 1.14**
17												
18	Cost of Gas - Commodity		**$ 459,919**	**$ 277,933**	**$ 95,389**	**$ 761**	**$ 232**	**$ -**	**$ 75,655**	**$ 9,890**	**$ 58**	**$ -**
19		Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21		Energy	$ 459,919	$ 277,933	$ 95,389	$ 761	$ 232	$ -	$ 75,655	$ 9,890	$ 58	$ -
22	Unit Cost of Gas - Commodity ($/GJ)			**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ -**	**$ 4.11**	**$ 4.11**	**$ 4.11**	**$ -**
23												
24	Cost of Gas - Midstream		**$ 163,102**	**$ 103,555**	**$ 35,421**	**$ -**	**$ 23**	**$ -**	**$ 22,098**	**$ 2,004**	**$ -**	**$ -**
25		Demand	$ 163,102	$ 103,555	$ 35,421	$ -	$ 23	$ -	$ 22,098	$ 2,004	$ -	$ -
26		Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27		Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Unit Cost of Gas - Midstream ($/GJ)			**$ 1.38**	**$ 1.32**	**$ -**	**$ 0.41**	**$ -**	**$ 1.06**	**$ 0.83**	**$ -**	**$ -**
28												
29	Total Utility Cost of Service		**$ 1,389,870**	**$ 878,978**	**$ 240,515**	**$ 823**	**$ 471**	**$ 905**	**$ 180,375**	**$ 40,416**	**$ 1,687**	**$ 45,699**
30		Demand	$ 532,131	$ 279,023	$ 101,180	$ 5	$ 111	$ 631	$ 83,302	$ 23,733	$ 155	$ 43,990
31		Customer	$ 389,684	$ 318,836	$ 42,797	$ 49	$ 126	$ 274	$ 20,204	$ 6,172	$ 1,226	$ -
32		Energy	$ 468,056	$ 281,120	$ 96,538	$ 769	$ 234	$ -	$ 76,869	$ 10,511	$ 306	$ 1,709
33	Unit Cost of Service ($/GJ)			**$ 11.74**	**$ 8.91**	**$ 4.45**	**$ 8.35**	**$ 0.08**	**$ 6.33**	**$ 2.77**	**$ 0.29**	**$ 1.14**
34												
35	Total Revenues @ Proposed Rates		**$ 1,389,870**	**$ 830,598**	**$ 250,290**	**$ 1,101**	**$ 525**	**$ 12,858**	**$ 194,608**	**$ 49,376**	**$ 9,150**	**$ 41,363**
36	Unit Rate ($/GJ)			**$ 11.10**	**$ 9.27**	**$ 5.94**	**$ 9.31**	**$ 1.12**	**$ 6.83**	**$ 3.39**	**$ 1.57**	**$ 1.03**
37												
38	Total Revenue Margin @ Proposed Rates		**$ 766,849**	**$ 449,110**	**$ 119,480**	**$ 340**	**$ 270**	**$ 12,858**	**$ 96,854**	**$ 37,482**	**$ 9,092**	**$ 41,363**
39	Unit Rate ($/GJ)			**$ 6.00**	**$ 4.43**	**$ 1.83**	**$ 4.79**	**$ 1.12**	**$ 3.40**	**$ 2.57**	**$ 1.56**	**$ 1.03**

Attachment 73.1

(Provided in electronic format only due to
document size and in order to conserve paper)

FORTISBC ENERGY INC.

GENERAL TERMS AND CONDITIONS

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BILLING

DISCONTINUANCE OF SERVICE AND REFUSAL OF SERVICE

LIABILITY AND INDEMNITY PROVISIONS

MISCELLANEOUS PROVISIONS

DIRECT PURCHASE AGREEMENTS

COMMODITY UNBUNDLING

BIOMETHANE RATE OFFERING

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Definitions

Unless the context indicates otherwise, in the General Terms and Conditions of FortisBC Energy and in the rate schedules of FortisBC Energy the following words have the following meanings:

Basic Charge	Means a fixed charge required to be paid by a Customer for Service as specified in the applicable Rate Schedule, or the prorated daily equivalent charge – calculated on the basis of a 365.25-day year (to incorporate the leap year), and rounded down to four decimal places.
Biogas	Means raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen.
Biomethane	Means Biogas purified or upgraded to pipeline quality gas.
Biomethane Service	Means the Service provided to Customers under Rate Schedules 1B for Residential Biomethane Service, 2B for Small Commercial Biomethane Service, 3B for Large Commercial Biomethane Service, 11B for Large Volume Interruptible Biomethane Service, and 30 for Off-System Interruptible Biomethane Sales
British Columbia Utilities Commission	Means the British Columbia Utilities Commission constituted under the *Utilities Commission Act* of British Columbia and includes and is also a reference to (i) any commission that is a successor to such commission, and (ii) any commission that is constituted pursuant to any statute that may be passed which supplements or supersedes the *Utilities Commission Act* of British Columbia
Carbon Offsets	Means what FortisBC Energy will 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. One Carbon Offset represents the reduction of one metric ton of carbon dioxide or its equivalent in other greenhouse gases.
Commercial Service	Means the provision of firm Gas supplied to one Delivery Point and through one Meter Set for use in approved appliances in commercial, institutional or small industrial operations.
Commodity Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

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Commodity Unbundling Service Means the service provided to Customers under Rate Schedule 1U for Residential Unbundling Service, Rate Schedule 2U for Small Commercial Commodity Unbundling Service and Rate Schedule 3U for Large Commercial Commodity Unbundling Service.

Conversion Factor Means a factor, or combination of factors, which converts gas meter data to Gigajoules or cubic metres for billing purposes.

Customer Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.

Day Means any period of 24 consecutive Hours beginning and ending at 7:00 a.m. Pacific Standard Time or as otherwise specified in the Service Agreement.

Delivery Point Means the outlet of the Meter Set unless otherwise specified in the Service Agreement.

Delivery Pressure Means the pressure of the Gas at the Delivery Point.

First Nations Means those First Nations that have attained legally recognized self-government status pursuant to self-government agreements entered into with the Federal Government and validly enacted self-government legislation in Canada.

Franchise Fees Means the aggregate of all monies payable by FortisBC Energy to a municipality or First Nations

(i) for the use of the streets and other property to construct and operate the utility business of FortisBC Energy within a municipality or First Nations lands (formerly, reserves within the *Indian Act*),

(ii) relating to the revenues received by FortisBC Energy for Gas consumed within the municipality or First Nations lands (formerly, reserves within the *Indian Act*), or

(iii) relating, if applicable, to the value of Gas transported by FortisBC Energy through the municipality or First Nations lands (formerly, reserves within the *Indian Act*).

FortisBC Energy Means FortisBC Energy Inc., a body corporate incorporated pursuant to the laws of the Province of British Columbia under number xxxxxxx.

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FortisBC Energy System	Means the Gas transmission and distribution system owned and operated by FortisBC Energy, as such system is expanded, reduced or modified from time to time for distribution services.
Gas	Means natural gas (including odorant added by FortisBC Energy) and propane and Biomethane.
Gas Service	Means the delivery of Gas through a Meter Set.
General Terms & Conditions of **FortisBC Energy**	Means these general terms and conditions of FortisBC Energy from time to time approved by the British Columbia Utilities Commission.
Gigajoule	Means a measure of energy equal to one billion joules used for billing purposes.
Heat Content	Means the quantity of energy per unit volume of Gas measured under standardized conditions and expressed in megajoules per cubic metre (MJ/m^3).
Hour	Means any consecutive 60 minute period.
Hydronic Heating System	A heating / cooling system where water is heated or cooled and distributes hot water through pipes to radiators or to another style of water-to-air heat exchanger.
Landlord	A Person who, being the owner of a property, has leased or rented it to another person, called the Tenant, and includes the agent of that owner.
Main	Means pipes used to carry Gas for general or collective use for the purposes of distribution.
Main Extension	Means an extension of one of FortisBC Energy's mains with low, distribution, intermediate or transmission pressures, and includes tapping of transmission pipelines, the installation of any required pressure regulating facilities and upgrading of existing Mains, or pressure regulating facilities on private property.
Marketer	Means a Person who has entered into an agreement to supply a Customer under Commodity Unbundling Service.
Meter Set	Means an assembly of FortisBC Energy owned metering and ancillary equipment and piping.
Midstream Cost Recovery Charge	Is as defined in the Table of Charges of the various FortisBC Energy Rate Schedules.

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Month	Means a period of time, for billing purposes, of 27 to 34 consecutive Days.
Municipal Operating Fees	Has the same meaning as Franchise Fees.
Other Service	Means the provision of Service other than Gas Service including, but not limited to, rental of equipment, natural gas vehicle fuel compression, alterations and repairs, merchandise purchases, and financing.
Other Service Charges	Means charges for rental, natural gas vehicle fuel compression service, damages, alterations and repairs, financing, insurance and merchandise purchases, and late payment charges, Franchise Fees, Social Service Tax, Goods and Services Tax or other taxes related to these charges.
Person	Means a natural person, partnership, corporation, society, unincorporated entity or body politic.
Premises	Means a building, a separate unit of a building, or machinery together with the surrounding land.
Profitability Index	The revenue to cost ratio comparing the revenues expected from a Main Extension project to the expected costs over a set period of time.
Rate Schedule	Means a schedule attached to and forming part of this Tariff, which sets out the charges for Service and certain other related terms and conditions for a class of Service.
Residential Premises	Means the Premises of a single Customer, whether single family dwelling, separately metered single-family townhouse, rowhouse, condominium, duplex or apartment, or single-metered apartment blocks with four or less apartments.
Residential Service	Means firm Gas Service provided to a Residential Premises.
Rider	Means an additional charge or credit attached to a rate.
Seasonal Service	Means firm Gas Service provided to a Customer during the period commencing April 1st and ending November 1st.
Service	Means the provision of Gas Service or other service by FortisBC Energy.
Service Agreement	Means an agreement between FortisBC Energy and a Customer for the provision of Service.

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Service Header	Means a Gas distribution pipeline located on private property connecting three or more Service Lines or Meter Sets to a Main.
Service Line	Means that portion of FortisBC Energy's gas distribution system extending from a Main or a Service Header to the inlet of the Meter Set. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.
Service Related Charges	Include, but are not limited to, application fees, Franchise Fees, and late payment charges, plus Social Services Tax, Goods and Service Tax, or other taxes related to these charges.
Standard Fees & Charges Schedule	Means the schedule attached to and forming part of the General Terms and Conditions which lists the various fees and charges relating to Service provided by FortisBC Energy as approved from time to time by the British Columbia Utilities Commission.
Temporary Service	Means the provision of Service for what FortisBC Energy determines will be a limited period of time.
Tenant	A Person who has the temporary use and occupation of real property owned by another Person.
Thermal Energy	Means thermal energy supplied by a Gas fired hydronic heating system (where hydronic heating is the primary heating source), and measured by a thermal meter, to premises of a Vertical Subdivision where the thermal meter is used to apportion the gigajoules of Gas consumed by the Gas fired hydronic heating system among the premises in the Vertical Subdivision.
Thermal Metering	Thermal / heat meters measure the energy which, in a heat-exchange circuit, is absorbed or given up by the heat conveying liquid. The thermal / heat meter indicates the quantity of heat in legal units.
Vertical Subdivision	Means a multi-storey building that has individually metered units and a common Service Header connecting banks of meters, typically located on each floor.
Year	Means a period of 12 consecutive Months.
10^3m^3	Means 1,000 cubic metres.

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Areas Served by FortisBC Energy

These General Terms and Conditions of FortisBC Energy refer to the following areas served by FortisBC Energy: Mainland, Fort Nelson, Vancouver Island and Whistler.

Mainland Area	Means the areas including, but not limited to, the following locations and surrounding areas of	
	Abbotsford Anmore Belcarra Burnaby Chilliwack	New Westminster North Vancouver City North Vancouver Dist. Pitt Meadows Port Coquitlam
	Coquitlam Delta Harrison Hot Springs Hope Kent	Port Moody Richmond Squamish Surrey Vancouver
	Langley City Langley District Maple Ridge Matsqui Mission	West Vancouver White Rock
	Armstrong Ashcroft Bear Lake Cache Creek Castlegar	Nelson Okanagan Falls Oliver 100 Mile House 108 Mile House
	Chase Chetwynd Christina Lake Clinton Coldstream	150 Mile House Osoyoos Oyama Peachland Penticton

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Mainland Area (continued)	Collettville Craigmont Falkland Ferguson Lake Fruitvale Gibralter Mines Grand Forks Greenlake Greenwood Hedley Hixon Honeymoon Creek Hudson's Hope Kamloops Kelowna Keremeos Lac La Hache Lakeview Heights Logan Lake Lumby MacKenzie Merritt Midway Montrose Naramata	Prince George Princeton Quesnel Revelstoke Robson Rossland Salmo Salmon Arm Savona Shelley Sorrento Spallumcheen Summerland Trail Vernon Warfield Westbank Westwold Williams Lake Winfield Woodsdale
	Cranbrook Creston Elkford Fernie Galloway	Jaffray Kimberley Sparwood Yahk

Fort Nelson Area Means the areas including, but not limited to, the following locations and surrounding areas of

Fort Nelson
Prophet River

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Vancouver Island and Whistler Areas — Means the areas including, but not limited to, the following locations and surrounding areas of

Campbell River
Central Saanich
Colwood
Comox
Courtenay

Cumberland
Duncan
Esquimalt
Gibsons
Highlands

Ladysmith
Langford
Lantzville
Metchosin
Nanaimo

North Cowichan
North Saanich
Oak Bay
Parksville
Pemberton

Port Alberni
Powell River
Qualicum Beach
Saanich
Sechelt

Sechelt Indian Band
Sidney
Sooke
Squamish
Sunshine Coast

Victoria
View Royal
Whistler

PART A

DISTRIBUTION SALES

and

SERVICE

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1. Application Requirements

1.1 **Requesting Services** - A Person requesting FortisBC Energy

(a) to provide Gas Service,

(b) to provide a new Service Line,

(c) to re-activate an existing Service Line,

(d) to transfer an existing account,

(e) to change the type of Service provided, or

(f) to make alterations to an existing Service Line or Meter Set

must apply to FortisBC Energy at any of its office locations in person, by mail, by telephone, by facsimile or by other electronic means.

1.2 **Required Documents** - An applicant for

(a) Residential Service may be required to sign an application and a Service Agreement provided by FortisBC Energy,

(b) Commercial Service may be required to sign an application and a Service Agreement provided by FortisBC Energy, and

(c) Service on other Rate Schedules must sign the applicable Service Agreement provided by FortisBC Energy.

1.3 **Separate Premises / Businesses** - If an applicant is requesting Service from FortisBC Energy at more than one Premises, or for more than one separately operated business, the applicant will be considered a separate Customer for each of the Premises and businesses. For the purposes of this provision, FortisBC Energy will determine whether or not any building contains one or more Premises or any business is separately operated.

1.4 **Required References** - FortisBC Energy may require an applicant for Service to provide reference information and identification acceptable to FortisBC Energy.

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1.5 **Rental Premises** - In the case of rental Premises, FortisBC Energy may

(a) require an owner of rental Premises or its agent who wishes FortisBC Energy to contract directly with a Tenant to enter into an agreement with FortisBC Energy defining the responsibilities of the owner or agent for payment for Service to the Premises,

(b) contract directly with the owner or agent of the rental Premises as a Customer of FortisBC Energy with respect to any or all Services to the Premises, or

(c) contract directly with each Tenant as a Customer of FortisBC Energy.

1.6 **Refusal of Application** - FortisBC Energy may refuse to accept an application for Service for any of the reasons listed in Section 23 (Discontinuance of Service and Refusal of Service).

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2. Agreement to Provide Service

2.1 **Service Agreement** - The agreement for Service between a Customer and FortisBC Energy will be

(a) the oral or written application of the Customer which has been approved by FortisBC Energy and which is deemed to include the General Terms and Conditions, or

(b) a Service Agreement signed by the Customer.

2.2 **Customer Status** - A Person becomes a Customer of FortisBC Energy when FortisBC Energy

(a) approves the Person's application for Service, or

(b) provides Service to the Person.

A Person who is being provided Service by FortisBC Energy but who has not applied for Service shall be served in accordance with these General Terms and Conditions.

2.3 **No Assignment / Transfer** - A Customer may not transfer or assign an agreement for Service without the written consent of FortisBC Energy.

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3. Conditions on Use of Service

3.1 **Authorized Consumption** - A Customer must not increase the maximum rate of consumption of Gas delivered to it by FortisBC Energy from that which may be consumed by the Customer under the applicable Rate Schedule nor significantly change its connected load without the written approval of FortisBC Energy, which approval will not be unreasonably withheld.

3.2 **Unauthorized Sale / Supply / Use** - Unless authorized in writing by FortisBC Energy, a Customer must not sell or supply Gas supplied to it by FortisBC Energy to other Persons or use Gas supplied to it by FortisBC Energy for any purpose other than as specified in the Service Agreement.

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4. Rate Classification

4.1 **Rate Classification** - Subject to Section 4.2 (a) (Special Contracts and Tariff Supplements), Customers may be served under any Rate Schedule for which they meet the applicability criteria as set out in the appropriate Rate Schedule.

4.2 **Special Contracts and Tariff Supplements** - In exceptional circumstances, special contracts and tariff supplements may be negotiated between FortisBC Energy and the Customer and submitted for British Columbia Utilities Commission approval where

(a) a minimum rate or revenue stream is required by FortisBC Energy to ensure that service to the Customer is economic; or

(b) factors such as system by-pass opportunities exist or alternative fuel costs are such that a reduced rate is justified to keep the Customer on-system.

4.3 **Periodic Review** - FortisBC Energy may

(a) conduct periodic reviews of the quantity of Gas delivered and the rate of delivery of Gas to a Customer to determine which Rate Schedule applies to the Customer, and

(b) change the Customer's charge to the appropriate charge, or

(c) change the Customer to the appropriate Rate Schedule.

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5. Application Fee and Charges

5.1 **Application Fee** - An applicant for Service must pay the applicable application fee set out in the Standard Fees and Charges Schedule.

5.2 **Application Fee for Manifold Meters and Vertical Subdivisions** - Where a new Service Line is required to serve more than one Customer at a Premises and the Service is provided with Gas meters connected to a meter manifold, the application fee for manifold meters set out in the Standard Fees and Charges Schedule will apply. Where a new Service Header is required to serve a Vertical Subdivision, the application fee set out in the Standard Fees and Charges Schedule will apply.

5.3 **Waiver of Application Fee** - The application fee

(a) will be waived by FortisBC Energy if Service to a Customer is reactivated after it was discontinued for any of the reasons described in Section 13.2 (Right to Restrict), and

(b) may be waived by FortisBC Energy if a Landlord requires Gas Service for a short period between the time a previous Tenant moves out and a new Tenant moves in.

5.4 **Reactivation Charges** - If

(a) Service is terminated

(i) at the request of a Customer, or

(ii) for any of the reasons described in Section 23 (Discontinuance of Service and Refusal of Service), or

(iii) to permit Customers to make alterations to their Premises, and

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(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year, the applicant for reactivation must pay the greater of

(i) the costs FortisBC Energy incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service.

5.5 **Identifying Load or Premises Served by Meter Sets** - If a Customer requests FortisBC Energy to identify the Meter Set that serves the Premises and/or load after the Meter Set was installed, the Customer will pay the cost FortisBC Energy incurs in re-identifying the Meter Set where

(a) the Meter Set is found to be properly identified, or

(b) the Meter Set is found to be improperly identified as a result of Customer activity, including

(i) a change in the legal civic address of the Premises,

(ii) renovating or partitioning the Premises, or

(iii) rerouting Gas lines after the Delivery Point.

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6. Security for Payment of Bills

6.1 **Security for Payment of Bills** - If a Customer or applicant cannot establish or maintain credit to the satisfaction of FortisBC Energy, the Customer or applicant may be required to make a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy. As security for payment of bills, all Customers who have not established or maintained credit to the satisfaction of FortisBC Energy, may be required to provide a security deposit or equivalent form of security, the amount of which may not

(a) be less than $50, and

(b) exceed an amount equal to the estimate of the total bill for the two highest consecutive Months consumption of Gas by the Customer or applicant.

6.2 **Interest** - FortisBC Energy will pay interest to a Customer on a security deposit at the rate and at the times specified in the Standard Fees and Charges Schedule. Subject to Section 6.5, if a security deposit in whole or in part is returned to the Customer for any reason, FortisBC Energy will credit any accrued interest to the Customer's account at that time.

No interest is payable

(a) on any unclaimed deposit left with FortisBC Energy after the account for which it is security is closed, and

(b) on a deposit held by FortisBC Energy in a form other than cash.

6.3 **Refund of Deposit** - When the Customer pays the final bill, FortisBC Energy will refund any remaining security deposit plus any accrued interest or cancel the equivalent form of security.

6.4 **Unclaimed Refund** - If FortisBC Energy is unable to locate the Customer to whom a security deposit is payable, FortisBC Energy will take reasonable steps to trace the Customer; but if the security deposit remains unclaimed 10 Years after the date on which it first became refundable, the deposit, together with any interest accrued thereon, becomes the absolute property of FortisBC Energy.

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6.5 **Application of Deposit** - If a Customer's bill is not paid when due, FortisBC Energy may apply all or any part of the Customer's security deposit or equivalent form of security and any accrued interest toward payment of the bill. Even if FortisBC Energy applies the security deposit or calls on the equivalent form of security, FortisBC Energy may, under Section 23 (Discontinuance of Service and Refusal of Service), discontinue Service to the Customer for failure to pay for Service on time.

6.6 **Replenish Security Deposit** - If a Customer's security deposit or equivalent form of security is called upon by FortisBC Energy towards paying an unpaid bill, the Customer must re-establish the security deposit or equivalent form of security before FortisBC Energy will reconnect or continue Service to the Customer.

6.7 **Failure to Pay** - Failure to pay a security deposit or to provide an equivalent form of security acceptable to FortisBC Energy may, in FortisBC Energy's discretion, result in discontinuance or refusal of Service as set out in Section 23 (Discontinuance of Service and Refusal of Service).

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7. Term of Service Agreement

7.1 **Initial Term for Residential and Commercial Service** - If a Customer is being provided Residential or Commercial Service, the initial term of the Service Agreement

(a) when a new Service Line is required will be one Year, or

(b) when a Main Extension is required will be for a period of time fixed by FortisBC Energy not exceeding the number of Years used to calculate the revenue in the Main Extension economic test used in Section 12 (Main Extensions).

7.2 **Initial Term for Gas Service other than Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service, the initial term of the Service Agreement will be as specified in the Service Agreement or as specified in the appropriate Rate Schedule.

7.3 **Transfer to Residential or Commercial Service** - If a Customer is being provided Gas Service other than Residential or Commercial Service and transfers to Residential or Commercial Service, the initial term of the Service Agreement will be determined by the criteria set out in Section 7.1 (Initial Term for Residential and Commercial Service). A Customer may only transfer Service from one Rate Schedule to another Rate Schedule once a Year.

7.4 **Renewal of Agreement** - Unless

(a) the Service Agreement or the applicable Rate Schedule specifies otherwise,

(b) the Service Agreement is terminated under Section 8 (Termination of Service Agreement),

(c) a refund has been made under Section 9.2 (Refund of Charges), or

(d) the Service Agreement is for Seasonal Service,

the Service Agreement will be automatically renewed at the end of its initial term from Month to Month for Residential or Commercial Service, and from Year to Year for all other types of Gas Service.

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8. Termination of Service Agreement

8.1 **Termination by Customer** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, the Customer may terminate the Service Agreement after the end of the initial term by giving FortisBC Energy at least 48 Hours notice.

8.2 **Continuing Obligation** - The Customer is responsible for, and must pay for, all Gas delivered to the Premises and is responsible for all damages to and loss of Meter Sets or other FortisBC Energy property on the Premises until the Service Agreement is terminated.

8.3 **Effect of Termination** - The Customer is not released from any previously existing obligations to FortisBC Energy under the Service Agreement by terminating the agreement.

8.4 **Sealing Service Line** - After receiving a termination notice for a Premises and after a reasonable period of time during which a new Customer has not applied for Gas Service at the Premises, FortisBC Energy may seal off the Service Line to the Premises.

8.5 **Termination by FortisBC Energy** - Unless the Service Agreement or applicable Rate Schedule specifies otherwise, FortisBC Energy may terminate the Service Agreement for any reason by giving the Customer at least 48 Hours written notice.

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9. Delayed Consumption

9.1 **Additional Charges** - If a Customer has not consumed Gas

(a) within 2 Months after the installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the minimum charge for each billing period after that, and

(b) within one Year after installation of the Service Line to the Customer's Premises, FortisBC Energy may charge the Customer the full cost of construction and installation of the Service Line and Meter Set less the total of the minimum charges billed to the Customer to that date.

9.2 **Refund of Charges** - If a Customer who has paid the charges for a Service Line under Section 9.1(b) (Additional Charges) consumes Gas in the second Year after installation of the Service Line, FortisBC Energy will refund to the Customer the payments made under Section 9.1(b) (Additional Charges). If a refund is made under Section 9.2 (Refund of Charges), the term of the Service Agreement will be one Year from the time the Customer begins consuming Gas.

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10. Service Lines

10.1 **Provided Installation** - If FortisBC Energy's Main is adjacent to the Customer's Premises, FortisBC Energy

(a) will designate the location of the Service Lines on the Customer's Premises and determine the amount of space that must be left unobstructed around them,

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(b) will install for Rate 1 and 2 Customers the Service Line from the Main to the Meter Set on the Customer's Premises at no additional cost to the Customer provided

(i) the Service Line follows the route which is the most suitable to FortisBC Energy,

(ii) the estimated direct cost of the Service Line does not exceed the Service Line Cost Allowance set out in the Standard Fees and Charges Schedule, and

(iii) the distance from the front of the Customer's building or machinery to the meter does not exceed 1.5 metres;

(c) will charge Rate 1 and 2 Customers for the estimated direct construction costs in excess of the Service Line Cost Allowance set out in the Standard Fees and Charges Schedule, and

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(d) will perform an economic test for Rate 3 and larger Customers and for any Customers connecting to a Service Header including Vertical Subdivisions, and, when the Profitability Index of the test is less than 0.8, will charge the Customer a contribution sufficient to achieve a minimum Profitability Index of 0.8. The economic test will be discounted cash flow test, similar to the economic test for Main Extensions set out in Section 12.

10.2 **Extended Installation** - The Customer may make application to FortisBC Energy to extend the Service Line beyond that described in Section 10.1 (Provided Installation) part (b) (iii). Upon approval by FortisBC Energy and agreement for payment by the Customer of the additional costs, FortisBC Energy will extend the Service Line only if it is on the route approved by FortisBC Energy.

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10.3 **Customer Requested Routing** - If

(a) FortisBC Energy's Main is adjacent to the Customer's Premises, and

(b) the Customer requests that its piping or Service Line enter its Premises at a different point of entry or follow a different route from the point or route designated by FortisBC Energy,

FortisBC Energy may charge the Customer for all additional costs as determined by FortisBC Energy to install the Service Line in accordance with the Customer's request.

10.4 **Temporary Service** - A Customer applying for Temporary Service must pay FortisBC Energy in advance for the costs which FortisBC Energy estimates it will incur in the installation and subsequent removal of the facilities necessary to supply Gas to the Customer.

10.5 **Winter Construction** - If an applicant or Customer applies for Service which requires construction when, in FortisBC Energy's opinion, frost conditions may exist, FortisBC Energy may postpone the required construction until the frost conditions no longer exist.

If FortisBC Energy carries out the construction, the applicant or Customer may be required to pay all costs in excess of the Service Line Cost Allowance which are incurred due to the frost conditions.

10.6 **Additional Connections** - If a Customer requests more than one Service Line to the Premises, on the same Rate Schedule, FortisBC Energy may install the additional Service Line and may charge the Customer the Application Fee set out in the Standard Fees and Charges Schedule, as well as the full cost (including overheads) for the Service Line installation. FortisBC Energy will bill the additional Service Line from a separate meter and account. If the additional Service Line is requested by a spouse, contractor, employee, agent or partner of the existing Customer, the same charges will apply.

10.7 **Easement Required** - If an intervening property is located between the Customer's Premises and FortisBC Energy's Main, the Customer is responsible for the costs of obtaining an easement in favour of FortisBC Energy and in a form specified by FortisBC Energy, for the installation, operation and maintenance on the intervening property of all necessary facilities for supplying Gas to the Customer.

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10.8 **Ownership** - FortisBC Energy owns the entire Service Line from the Main up to and including the Meter Set, whether it is located inside or outside the Customer's Premises. In case of a Vertical Subdivision, or multi-family housing complex, the Service Line may include the piping from the outlet of the Meter Set to the Customer's individual Premises, but not within the Customer's individual Premises.

10.9 **Maintenance** - FortisBC Energy will maintain the Service Line, subject to section 24.2 (Responsibility Before Delivery Point)..

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10.10 **Supply Cut Off** - If the supply of Gas to a Customer's Premises is cut off for any reason, FortisBC Energy is not required to remove the Service Line from the Customer's property or Premises

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10.11 **Damage Notice** - The Customer must advise FortisBC Energy immediately of any damage occurring to the Service Line.

10.12 **Prohibition** - A Customer must not construct any permanent structure over a Service Line or install any air intake openings or sources of ignition which contravene government regulations, codes or FortisBC Energy policies.

10.13 **No Unauthorized Changes** - No changes, extensions, connections to or replacement of, or disconnection from FortisBC Energy's Mains or Service Lines, shall be made except by FortisBC Energy's authorized employees, contractors or agents or by other Persons authorized in writing by FortisBC Energy. Any change in the location of an existing Service Line

(a) must be approved in writing by FortisBC Energy, and

(b) will be made at the expense of the Customer if the change is requested by the Customer or necessitated by the actions of the Customer.

10.14 **Site Preparation** - The Customer will be responsible for all necessary site preparation including but not limited to clearing building materials, construction waste, equipment, soil and gravel piles over the proposed service line route to the standards established by FortisBC Energy. FortisBC Energy may recover any additional costs associated with delays or site visits necessitated by inadequate or substandard site preparation by the Customer.

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11. Meter Sets & Metering

11.1 **Installation** - In order to bill the Customer for Gas delivered, FortisBC Energy will install one or more Meter Sets on the Customer's Premises. Unless approved by FortisBC Energy, all Meter Sets will be located outside the Customer's Premises at locations designated by FortisBC Energy.

11.2 **Measurement** - The quantity of Gas delivered to the Premises will be metered using apparatus approved by Consumer and Corporate Affairs Canada. The amount of Gas registered by the Meter Set during each billing period will be converted to Gigajoules in accordance with the *Electricity and Gas Inspection Act* and rounded to the nearest one-tenth of a Gigajoule.

11.3 **Testing Meters** - If a Customer applies for the testing of a Meter Set and

(a) the Meter Set is found to be recording incorrectly, the cost of removing, replacing and testing the meter will be borne by FortisBC Energy subject to Section 24.4 (Responsibility for Meter Set), and

(b) if the testing indicates that the Meter Set is recording correctly, as defined by the *Electricity and Gas Inspection Act*, the Customer must pay FortisBC Energy for the cost of removing, replacing and testing the Meter Set as set out in the Standard Fees and Charges Schedule.

11.4 **Defective Meter Set** - If a Meter Set ceases to register, FortisBC Energy will estimate the volume of Gas delivered to the Customer according to the procedures set out in Section 16.6 (Incorrect Register).

11.5 **Protection of Equipment** - The Customer must take reasonable care of and protect all Meter Sets and related equipment on the Customer's Premises. The Customer's responsibility for expense, risk and liability with respect to all Meter Sets and related equipment is set out in Section 24.4 (Responsibility for Meter Set).

11.6 **No Unauthorized Changes** - No Meter Sets or related equipment will be installed, connected, moved or disconnected except by FortisBC Energy's authorized employees, contractors or agents or by other Persons with FortisBC Energy's written permission.

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11.7 **Removal of Meter Set** - At the termination of a Service Agreement, FortisBC Energy may disconnect or remove a Meter Set from the Premises if a new Customer is not expected to apply for Service for the Premises within a reasonable time.

11.8 **Customer Requested Meter Relocation or Modifications** - Any change in the location of a Meter Set or related equipment, or any modifications to the Meter Set, including automatic and/or remote meter reading

(a) must be approved by FortisBC Energy in writing, and

(b) will be made at the expense of the Customer if the change or modification is requested by the Customer or necessitated by the actions of the Customer. If any of the changes to the Meter Set or related equipment require FortisBC Energy to incur ongoing incremental operating and maintenance costs, FortisBC Energy may recover these costs from the Customer through a Monthly charge.

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11.9 **Meter Set Consolidations** - A Customer who has more than one Meter Set at the same Premises or adjacent Premises may apply to FortisBC Energy to consolidate its Meter Sets. If FortisBC Energy approves the Customer's application, the Customer will be charged the value for all plant abandoned except for Meter Sets that are removed to facilitate Meter Set consolidations. In addition, the Customer will be charged FortisBC Energy's full costs, including overheads, for any abandonment, Meter Set removal and alteration downstream of the new Meter Set. If a new Service Line is required, FortisBC Energy will charge the Customer the Application Fee. In addition, the Customer will be required to sign a release waiving FortisBC Energy's liability for any damages should the Customer decide to re-use the abandoned plant downstream of the new Meter Set.

11.10 **Delivery Pressure** - The normal Delivery Pressure is 1.75 kPa. FortisBC Energy may charge Customers who require Delivery Pressure at other than the normal Delivery Pressure the additional costs associated with providing other than the normal Delivery Pressure.

11.11 **Customer Requested Mobile Service** - The Customer will be charged the cost of providing temporary mobile Gas Service if the request for such service is made by or brought on by the actions of the Customer.

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12. Main Extensions

12.1 **System Expansion** - FortisBC Energy will make extensions of its Gas distribution system in accordance with system development requirements.

12.2 **Ownership** - All extensions of the Gas distribution system will remain the property of FortisBC Energy.

12.3 **Economic Test** - All applications to extend the Gas distribution system to one or more new Customers will be subject to an economic test approved by the British Columbia Utilities Commission. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Main Extension. The Main Extension will be deemed to be economic and will be constructed if the results of the economic test indicate a Profitability Index of 0.8 or greater for an individual main extension.

12.4 **Revenue** - The projected revenue to be used in the economic test will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the Main Extension;

(b) establishing consumption estimates for each Customer;

(c) projecting when the Customer will be connected to the Main Extension; and

(d) applying the appropriate revenue margins for each Customer's consumption.

The revenue projection will take into consideration the estimated number and type of Gas appliances used and the effect variations in weather conditions throughout the applicable areas served by FortisBC Energy have on consumption. Customers who intend to install both high efficiency gas fired space (namely an Energy Star rated furnace or boiler) and water heating appliances (tankless water heaters, or water heaters with efficiency rating of 78 percent or greater), will receive a credit of 10 percent of the volume otherwise used for both appliances. Customers who intend to install both high efficiency gas fired space and water heating appliances and attain a minimum of LEED™ (Leadership in Energy and Environmental Design) General Certification will receive a credit of 15 percent of the volume otherwise used for both. In addition, the projected revenue from Application Fees will be included. Only those Customers expected to connect to the Main Extension within 5 Years of its completion will be considered.

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12.5 **Costs** - The total costs to be used in the economic test include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers including Mains, Service Lines, Meter Sets and any related facilities such as pressure reducing stations and pipelines;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the Main Extension;

(c) the incremental operating and maintenance expenses necessary to serve the Customers; and

(d) an allocation of system improvement costs.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

In cases where a larger Gas distribution Main is installed to satisfy future requirements, the difference in cost between the larger Main and the smaller Main necessary to serve the Customers supporting the application may be eliminated from the economic test.

12.6 **Contributions in Aid of Construction** - If the economic test results indicate a Profitability Index of less than 0.8, the Main Extension may proceed provided that the shortfall in revenue is eliminated by contributions in aid of construction by the Customers to be served by the Main Extension, their agents or other parties, or if there are non-financial factors offsetting the revenue shortfall that are deemed to be acceptable by the British Columbia Utilities Commission.

FortisBC Energy may finance the contributions in aid of construction for Customers. Contributions of less than $100 per Customer may be waived by FortisBC Energy.

12.7 **Contributions Paid by Connecting Customers** - The total required contribution will be paid by the Customers connecting at the time the Main Extension is built. FortisBC Energy will collect contributions from all Customers connecting during the first five Years after the Main Extension is built. As additional contributions are received from Customers connecting to the main extension, partial refunds will be made to those Customers who had previously made contributions. At the end of the fifth Year, all Customers will have paid an equal contribution, after reconciliation and refunds.

For larger Main Extension projects, FortisBC Energy may use the Main Extension Contribution Agreement for initial contributions. Customers will be billed the contribution amount after the Main Extension is built.

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12.8 **Refund of Contributions** - A review will be performed annually, or more often at FortisBC Energy's discretion, to determine if a refund is payable to all Customers who have contributed to the extension.

If the review of contributions indicates that refunds are due,

(a) individual refunds greater than $100 will be paid at the time of the review;

(b) individual refunds less than $100 will be held until a subsequent review increases the refund payable over $100, or until the end of the five-Year contributory period;

(c) no interest will be paid on contributions that are subsequently refunded;

(d) the total amount of refunds issued will not be greater than the original amount of the contribution; and

(e) if, after making all reasonable efforts, FortisBC Energy is unable to locate a Customer who is eligible for a refund, the Customer will be deemed to have forfeited the contribution refund and the refund will be credited to the other Customers who contributed towards the Main Extension.

12.9 **Extensions to Contributory Extensions** - When a Main Extension is attached to an existing contributory Main Extension within the five-Year contributory period for the existing extension, the new extension will be evaluated using the Main Extension Test to determine whether a contribution is required. A prorated portion of the total contribution for the existing contributory extension will be assigned to the new extension on the basis of expected use, point of connection, and other factors. Any contributions toward the cost of the existing extension from Customers on the new extension will be used to provide partial refunds to the contributing Customers on the existing extension. The total refunds issued will not exceed the total amount of contributions paid by Customers on the existing extension.

12.10 **Security** - In those situations where the financial viability of a Main Extension is uncertain, FortisBC Energy may require a security deposit in the form of cash or an equivalent form of security acceptable to FortisBC Energy.

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12A. Alternative Energy Extensions

12A.1 **System Expansion** - FortisBC Energy will make extensions to the FortisBC Energy System using technology that produces alternative energy, in accordance with the provisions of this section. The alternative energy extensions include geo-exchange, solar-thermal and district energy systems which are described below:

Geo-exchange systems, also referred to as geo-thermal systems, earth exchange systems or ground and water source heat pumps, utilize the latent heat energy contained in near surface layers of the earth, ground water and surface water. A subsurface piping system contains a liquid that absorbs heat from the surrounding material and delivers it to a central heat exchanger. High efficiency heat pumps convert this latent energy into hot water or steam contained in a separate piping system that can then deliver the heat energy to where it is required for space heating and hot water uses. Centralized equipment is usually contained within specifically designed mechanical room that serves the entire development. The heat exchanger is reversed to provide space cooling, removing heat from the building(s) and returning it to the subsurface substrate.

Solar-thermal water heating systems, also called solar hybrid water heating systems, are a system of solar collection tubes and piping capture heat energy from the sun's rays and deliver it to a central heat exchanger, where it is converted to domestic hot water and distributed in a manner similar to that described above for geo-exchange systems. The solar collection tubes are located outside the building or buildings, typically on the roof, while centralized equipment is again housed in a specifically designed mechanical room.

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District energy systems employ a range of energy technologies and sources to deliver piped heating (steam or hot water) and/or cooling (cool water) to multiple buildings and customers within a neighbourhood from a central plant location or locations.

12A.2 **Ownership** - All alternative energy extensions will remain the property of FortisBC Energy.

12A.3 **Cost of Service Model** - All applications by Customers for service using an alternative energy extension will be subject to review using a cost of service model. The cost of service model will determine the rate that a customer will pay for the service associated with the alternative energy extension. Service will be provided under the terms and conditions of the Service Agreement between FortisBC Energy and the Customer.

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12A.4 **Projected Energy Consumption/Number of Customers** - The projected energy consumption and number of customers to be used in the cost of service model will be determined by FortisBC Energy by

(a) estimating the number of Customers to be served by the alternative energy extension;

(b) if applicable, establishing consumption estimates for each Customer; and

(c) projecting when the Customer will be connected to the alternative energy extension.

If applicable, the projection will take into consideration the estimated number and type of thermal appliances used and the effect variations in weather conditions throughout all areas served by FortisBC Energy have on consumption. All Customers expected to connect to the alternative energy extension will be considered in the cost of service model.

12A.5 **Costs** - The total costs to be used in the cost of service model include, without limitation

(a) the full labour, material, and other costs necessary to serve the new Customers less any contributions in aid of construction by the Customers or third parties, grants, tax credits, or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) the appropriate allocation of FortisBC Energy's overheads associated with the construction of the alternative energy extension;

(c) depreciation expense related to the capital equipment associated with the alternative energy extension; and

(d) the incremental operating and maintenance expenses necessary to serve the Customers.

In addition to the costs identified, the cost of service model will include applicable taxes and the appropriate return on investment as approved by the British Columbia Utilities Commission.

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12B. Vehicle Fuelling Stations

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12B.1 **Compression and Dispensing Service for Compressed Natural Gas (CNG) Fueling and Fuel Storage and Dispensing Service for Liquefied Natural Gas (LNG) Fueling** – FortisBC Energy will provide CNG and LNG Services to vehicles in accordance with the provisions of this section.

CNG or LNG Service will be provided under the terms and conditions of a Service Agreement between FortisBC Energy and the Customer. The Service Agreement must comply with the provisions of this Section of the General Terms and Conditions.

The CNG and LNG Services are described below:

CNG Service will typically consist of:

(a) installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer /dehydrator, high pressure storage, dispensing equipment; and

(b) dispensing of compressed natural gas.

LNG Service will typically consist of:

(a) transport and delivery of the LNG from FortisBC Energy's LNG facilities to the Customer premises by LNG tankers, the service charge for which will be determined pursuant to Rate Schedule 16;

(b) installing and maintaining an LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and

(c) dispensing of liquefied natural gas.

12B.2 **Ownership** - All CNG and LNG fueling stations, temporary or permanent, will remain the property of FortisBC Energy, regardless of whether they are located on the customer's property. The ownership includes all components of the fueling station(s).

12B.3 **Cost of Service Recovery** - Customers will be charged a "take-or-pay" rate (i.e. minimum contract demand) under the Service Agreement that recovers the present value of the cost of service associated with provision of CNG or LNG Service over the term of the Service Agreement, as calculated pursuant to section 12B.4, where the minimum contract demand stipulated in the Service Agreement is the forecast consumption based on the forecast number of vehicles served by the vehicle fueling station.

12B.4 **Calculation of Cost of Service** – The total costs to be used in determining the cost of service to be recovered from the Customer under the Service Agreement include, without limitation

(a) the actual capital investment in the fueling station including any associated labour, material, and other costs necessary to serve the Customer, less any contributions in aid of construction by the Customer or third parties, grants, tax credits or non-financial factors offsetting the full costs that are deemed to be acceptable by the British Columbia Utilities Commission;

(b) depreciation and net negative salvage rates and expense related to the capital assets associated with the vehicle fueling station;

(c) all operating and maintenance expenses, with no adjustment for capitalized overhead, necessary to serve the Customer , escalated annually by British Columbia CPI inflation rates as published by BC Stats monthly; and

(d) an allowance for overhead and marketing costs relating to developing NGV Fueling Station Agreements to be recovered from the Customer.

In addition to the costs identified, the cost of service recovery will include applicable property and incomes taxes and the appropriate return on rate base as approved by the British Columbia Utilities Commission for FortisBC Energy.

12B.5 **Customer's Obligation at the Expiration of Initial Term of the Service Agreement** - If, at the expiry of the initial term of an executed Service Agreement, the Customer does not wish to renew the Service Agreement, the Customer can terminate the Service Agreement provided the Customer agrees to pay any unrecovered capital costs (including the positive or negative salvage value) associated with the fueling stations, or agrees to similar provisions that permit recovery from the Customer of the remaining un-depreciated capital costs of the fueling station. Examples of such provisions include, but are not limited to, adjusting the contract rate or adjusting the contract term.

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13. Interruption of Service

13.1 **Regular Supply** - FortisBC Energy will use its best efforts to provide the constant delivery of Gas and the maintenance of unvaried pressures.

13.2 **Right to Restrict** - FortisBC Energy may require any of its Customers, at all times or between specified Hours, to discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons:

(a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy,

(b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems,

(c) in order to comply with any legal requirements,

(d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems,

(e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage.

13.3 **Notice** - FortisBC Energy will, to the extent practicable, give notice of its requirements and removal of its requirements under Section 13.2 (Right to Restrict) to its Customers by

(a) newspaper, radio or television announcement, or

(b) notice in writing that is

(i) sent through the mail to the Customer's billing address,

(ii) left at the Premises where Gas is delivered,

(iii) served personally on a Customer, or

(iv) sent by facsimile or other electronic means to the Customer, or

(c) oral communication.

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13.4 **Failure to Comply** - If, in the opinion of FortisBC Energy, a Customer has failed to comply with any requirement under Section 13.2 (Right to Restrict), FortisBC Energy may, after providing notice to the Customer in the manner specified in Section 13.3 (Notice), discontinue Service to the Customer.

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14. Access to Premises and Equipment

14.1 **Access to Premises** - FortisBC Energy must have a right of entry to the Customer's Premises. The Customer must provide free access to its Premises at all reasonable times to FortisBC Energy's authorized employees, contractors and agents for the purpose of reading, testing, repairing or removing meters and ancillary equipment, turning Gas on or off, completing system leakage surveys, stopping leaks, examining pipes, connections, fittings and appliances and reviewing the use made of Gas delivered to the Customer, or for any other related purpose which FortisBC Energy requires.

14.2 **Access to Equipment** - The Customer must provide clear access to FortisBC Energy's equipment. The equipment installed by FortisBC Energy on the Customer's Premises will remain the property of FortisBC Energy and may be removed by FortisBC Energy upon termination of Service.

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15. Promotions and Incentives

15.1 **Promotion of Gas Appliances** - FortisBC Energy may promote, sell, rent, lease, or finance natural Gas vehicle equipment, Gas appliances and related accessories and services on a cash or finance plan basis and make reasonable charges for these Services.

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16. Billing

16.1 **Basis for Billing** - FortisBC Energy will bill the Customer in accordance with the Customer's Service Agreement, the Rate Schedule under which the Customer is provided Service, and the fees and charges contained in the General Terms and Conditions.

16.2 **Meter Measurement** - FortisBC Energy will measure the quantity of Gas delivered to a Customer using a Meter Set and the starting point for measuring delivered quantities during each billing period will be the finishing point of the preceding billing period.

16.3 **Multiple Meters** - Gas Service to each Meter Set will be billed separately for Customers who have more than one Meter Set on their Premises.

16.4 **Estimates** - For billing purposes, FortisBC Energy may estimate the Customer's meter readings if, for any reason, FortisBC Energy does not obtain a meter reading.

16.5 **Estimated Final Reading** - If a Service Agreement is terminated under Section 8.1 (Termination by Customer), FortisBC Energy may estimate the final meter reading for final billing.

16.6 **Incorrect Register** - If any Meter Set has failed to measure the delivered quantity of Gas correctly, FortisBC Energy may estimate the meter reading for billing purposes, subject to Section 19 (Back-Billing).

16.7 **Bills Issued** - FortisBC Energy may bill a Customer as often as FortisBC Energy considers necessary but generally will bill on a Monthly basis.

16.8 **Bill Due Dates** - The Customer must pay FortisBC Energy's bill for Service on or before the due date shown on the bill which will be

(a) the first business Day after the twenty-first calendar Day following the billing date, or

(b) such other period as may be agreed upon by the Customer and FortisBC Energy.

16.9 **Historical Billing Information** - Customers who request historical billing information may be charged the cost of processing and providing the information.

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17. Thermal Energy

17.1 All references to Gas shall be deemed to include a reference to Thermal Energy. For example, Gas Service shall be deemed to include the delivery of Thermal Energy through a Meter Set. Notwithstanding the foregoing, the meaning of Gas Distribution System shall be deemed not to include a hydronic heating system that delivers energy to Residential Customers but shall include the meters that measure the amount of energy by Residential Customers in a Vertical Subdivision.

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18. Section Reserved for Future Use

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19. Back-Billing

19.1 **When Required** - FortisBC Energy may, in the circumstances specified herein, charge, demand, collect or receive from its Customers in respect of a regulated Service rendered hereunder a greater or lesser compensation than that specified in the subsisting schedules applicable to that Service.

In the case of a minor adjustment to a Customer's bill, such as an estimated bill or an equal payment plan billing, such adjustments do not require back-billing treatment to be applied.

19.2 **Definition** - Back-billing means the rebilling by FortisBC Energy for Services rendered to a Customer because the original billings are discovered to be either too high (over-billed) or too low (under-billed). The discovery may be made by either the Customer or FortisBC Energy, and may result from the conduct of an inspection under provisions of the federal statute, the *Electricity and Gas Inspection Act* ("*EGI Act*"). The cause of the billing error may include any of the following non-exhaustive reasons or combination thereof:

(a) stopped meter

(b) metering equipment failure

(c) missing meter now found

(d) switched meters

(e) double metering

(f) incorrect meter connections

(g) incorrect use of any prescribed apparatus respecting the registration of a meter

(h) incorrect meter multiplier

(i) the application of an incorrect rate

(j) incorrect reading of meters or data processing

(k) tampering, fraud, theft or any other criminal act.

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19.3 **Application of Act** - Whenever the dispute procedure of the *EGI Act* is invoked, the provisions of that Act apply, except those which purport to determine the nature and extent of legal liability flowing from metering or billing errors.

19.4 **Billing Basis** - Where metering or billing errors occur and the dispute procedure under the *EGI Act* is not invoked, the consumption and demand will be based upon the records of FortisBC Energy for the Customer, or the Customer's own records to the extent they are available and accurate, or if not available, reasonable and fair estimates may be made by FortisBC Energy. Such estimates will be on a consistent basis within each Customer class or according to a contract with the Customer, if applicable.

19.5 **Tampering / Fraud** - If there are reasonable grounds to believe that the Customer has tampered with or otherwise used FortisBC Energy's Service in an unauthorized way, or there is evidence of fraud, theft or other criminal acts, or if a reasonable Customer should have known of the under-billing and failed to promptly bring it to the attention of FortisBC Energy, then the extent of back-billing will be for the duration of the unauthorized use, subject to the applicable limitation period provided by law, and the provisions of Sections 19.8 (Under-Billing) to 19.11 (Changes in Occupancy), below, do not apply.

In addition, the Customer is liable for the direct (unburdened) administrative costs incurred by FortisBC Energy in the investigation of any incident of tampering, including the direct costs of repair, or replacement of equipment.

Under-billing resulting from circumstances described above will bear interest at the rate normally charged by FortisBC Energy on unpaid accounts from the date of the original under-billed invoice until the amount under-billed is paid in full.

19.6 **Remedying Problem** - In every case of under-billing or over-billing, the cause of the error will be remedied without delay, and the Customer will be promptly notified of the error and of the effect upon the Customer's ongoing bill.

19.7 **Over-billing** - In every case of over-billing, FortisBC Energy will refund to the Customer all money incorrectly collected for the duration of the error, subject to the applicable limitation period provided by law. Simple interest, computed at the short-term bank loan rate applicable to FortisBC Energy on a Monthly basis, will be paid to the Customer.

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19.8 **Under-billing** - Subject to Section 19.5 (Tampering / Fraud), above, in every case of under-billing, FortisBC Energy will back-bill the Customer for the shorter of

(a) the duration of the error; or

(b) six Months for Residential or Commercial Service; and

(c) one Year for all other Customers or as set out in a special or individually negotiated contract with FortisBC Energy.

19.9 **Terms of Repayment** - Subject to Section 19.5 (Tampering / Fraud), above, in all cases of under-billing, FortisBC Energy will offer the Customer reasonable terms of repayment. If requested by the Customer, the repayment term will be equivalent in length to the back-billing period. The repayment will be interest free and in equal instalments corresponding to the normal billing cycle. However, delinquency in payment of such instalments will be subject to the usual late payment charges.

19.10 **Disputed Back-bills** - Subject to Section 19.5 (Tampering / Fraud), above, if a Customer disputes a portion of a back-billing due to under-billing based upon either consumption, demand or duration of the error, FortisBC Energy will not threaten or cause the discontinuance of Service for the Customer's failure to pay that portion of the back-billing, unless there are no reasonable grounds for the Customer to dispute that portion of the back-billing. The undisputed portion of the bill shall be paid by the Customer and FortisBC Energy may threaten or cause the discontinuance of Service if such undisputed portion of the bill is not paid.

19.11 **Changes in Occupancy** - Subject to Section 19.5 (Tampering / Fraud), above, back-billing in all instances where changes of occupancy have occurred, FortisBC Energy will make a reasonable attempt to locate the former Customer. If, after a period of one Year, such Customer cannot be located, the applicable over or under billing will be cancelled.

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20. Equal Payment Plan

20.1 **Definitions** - In this Section, "equal payment plan period" means a period of twelve consecutive Months commencing with a normal meter reading date at the Customer's Premises.

20.2 **Application for Plan** - A Customer may apply to FortisBC Energy by mail, by telephone, by facsimile or by other electronic means to pay fixed Monthly instalments for Gas delivered to the Customer during the equal payment plan period. Acceptance of the application will be subject to FortisBC Energy finding the Customer's credit to be satisfactory.

20.3 **Monthly Instalments** - FortisBC Energy will fix Monthly instalments for a Customer so that the total sum of all the instalments to be paid during the equal payment plan period will equal the total amount payable for the Gas which FortisBC Energy estimates the Customer will consume during the equal payment plan period.

20.4 **Changes in Instalments** - FortisBC Energy may, at any time, increase or decrease the amount of Monthly instalments payable by a Customer in light of new consumption information or changes to the Rate Schedules or the General Terms and Conditions.

20.5 **End of Plan** - Participation in the equal payment plan may be ended at any time

(a) by the Customer giving 5 Days' notice to FortisBC Energy, or

(b) by FortisBC Energy, without notice, if the Customer has not paid the Monthly instalments as required.

20.6 **Payment Adjustment** - At the earlier of the end of the equal payment plan period for a Customer or the end of the Customer's participation in the plan under Section 20.5 (End of Plan), FortisBC Energy will

(a) compare the amount which is payable by the Customer to FortisBC Energy for Gas actually consumed on the Customer's Premises from the beginning of the equal payment plan period to the sum of the Monthly instalments billed to the Customer from the beginning of the equal payment plan period, and

(b) pay to the Customer or credit to the Customer's account any excess amount or bill the Customer for any deficit amount payable.

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21. Late Payment Charge

21.1 **Late Payment Charge** - If the amount due for Service or Service Related Charges on any bill has not been received in full by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, and the unpaid balance is $15 or more, FortisBC Energy may include in the next bill to the Customer the late payment charge specified in the Standard Fees and Charges Schedule.

21.2 **Equal Payment Plan** - If the Monthly instalment, Service Related Charges and payment adjustment as defined under Section 20.6 (Payment Adjustments) due from a Customer billed under the equal payment plan set out in Section 20 (Equal Payment Plan) have not been received by FortisBC Energy or by an agent acting on behalf of FortisBC Energy on or before the due date specified on the bill, FortisBC Energy may include in the next bill to the Customer the late payment charge in accordance with Section 21.1 (Late Payment Charge) on the amount due.

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22. Returned Cheque Charge

22.1 **Dishonoured Cheque Charge** - If a cheque received by FortisBC Energy from a Customer in payment of a bill is not honoured by the Customer's financial institution for any reason other than clerical error, FortisBC Energy may include a charge specified in the Standard Fees and Charges Schedule in the next bill to the Customer for processing the returned cheque whether or not the Service has been disconnected.

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23. Discontinuance of Service and Refusal of Service

23.1 **Discontinuance With Notice and Refusal Without Notice** - FortisBC Energy may discontinue Service to a Customer with at least 48 Hours written notice to the Customer or Customer's Premises, or may refuse Service for any of the following reasons:

(a) the Customer has not fully paid FortisBC Energy's bill with respect to Services on or before the due date,

(b) the Customer or applicant has failed to pay any required security deposit, equivalent form of security, or post a guarantee or required increase in it by the specified date,

(c) the Customer or applicant has failed to pay FortisBC Energy's bill in respect of another Premises on or before the due date,

(d) the Customer or applicant occupies the Premises with another occupant who has failed to pay FortisBC Energy's bill, security deposit, or required increase in the security deposit in respect of another Premises which was occupied by that occupant and the Customer at the same time,

(e) the Customer or applicant is in receivership or bankruptcy, or operating under the protection of any insolvency legislation and has failed to pay any outstanding bills to FortisBC Energy,

(f) the Customer has failed to apply for Service, or

(g) the land or portion thereof on which FortisBC Energy's facilities are, or are proposed to be, located contains contamination which FortisBC Energy, acting reasonably, determines has adversely affected or has the potential to adversely affect FortisBC Energy's facilities, or the health or safety of its workers or which may cause FortisBC Energy to assume liability for clean up and other costs associated with the contamination. If FortisBC Energy, acting reasonably, determines that contamination is present it is the obligation of the occupant of the land to satisfy FortisBC Energy that the contamination does not have the potential to adversely affect FortisBC Energy or its workers. For the purposes of this Section, "contamination" means the presence in the soil, sediment or groundwater of special waste or another substance in quantities or concentrations exceeding criteria, standards or conditions established by the British Columbia Ministry of Environment, Lands and Parks or as prescribed by present and future laws, rules, regulations and orders of any other legislative body, governmental agency or duly constituted authority now or hereafter having jurisdiction over the environment.

23.2 **Discontinuance or Refusal Without Notice** - FortisBC Energy may discontinue without notice or refuse the supply of Gas or Service to a Customer for any of the following reasons:

(a) the Customer or applicant has failed to provide reference information and identification acceptable to FortisBC Energy, when applying for Service or at any subsequent time on request by FortisBC Energy,

(b) the Customer has defective pipe, appliances, or Gas fittings in the Premises,

(c) the Customer uses Gas in such a manner as in FortisBC Energy's opinion

(i) may lead to a dangerous situation, or

(ii) may cause undue or abnormal fluctuations in the Gas pressure in FortisBC Energy's Gas transmission or distribution system,

(d) the Customer fails to make modifications or additions to the Customer's equipment which have been required by FortisBC Energy in order to prevent the danger or to control the undue or abnormal fluctuations described under paragraph (c),

(e) the Customer breaches any of the terms and conditions upon which Service is provided to the Customer by FortisBC Energy,

(f) the Customer fraudulently misrepresents to FortisBC Energy its use of Gas or the volume delivered,

(g) the Customer vacates the Premises,

(h) the Customer's Service Agreement is terminated for any reason, or

(i) the Customer stops consuming Gas on the Premises.

23.3 **Application to Former Tariffs** - Section 23.1 (Discontinuance With Notice and Refusal Without Notice), parts (c), (d) and (e), apply to bills rendered under these General Terms and Conditions and under the following former tariffs:

Lower Mainland - Gas Tariff,

Inland - Gas Tariff B.C.E.C. No. 2,

Columbia - Gas Tariff B.C.U.C. No.1.

BC Gas Tariff

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Terasen Gas Inc. Tariff

FortisBC Energy Inc. Gas Tariff

FortisBC Energy Inc. Fort Nelson Service Area Gas Tariff

FortisBC Energy (Vancouver Island) Inc. Gas Tariff

FortisBC Energy (Whistler) Inc. Gas Tariff

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24. Limitations on Liability

24.1 **Responsibility for Delivery of Gas** - FortisBC Energy, its employees, contractors or agents are not responsible or liable for any loss, damage, costs or injury (including death) incurred by any Customer or any Person claiming by or through the Customer caused by or resulting from, directly or indirectly, any discontinuance, suspension or interruption of, or failure or defect in the supply or delivery or transportation of, or refusal to supply, deliver or transport Gas, or provide Service, unless the loss, damage, costs or injury (including death) is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents provided, however that FortisBC Energy, its employees, contractors and agents are not responsible or liable for any loss of profit, loss of revenues, or other economic loss even if the loss is directly attributable to the gross negligence or wilful misconduct of FortisBC Energy, its employees, contractors or agents.

24.2 **Responsibility Before Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to

(a) the use or presence of Gas before it passes the Delivery Point in the Customer's Premises, and

(b) FortisBC Energy-owned facilities serving the Customer's Premises

if any loss or damage caused by or resulting from failure to meet that responsibility is caused, or contributed to, by the act or omission of the Customer or a Person for whom the Customer is responsible.

24.3 **Responsibility After Delivery Point** - The Customer is responsible for all expense, risk and liability with respect to the use or presence of Gas after it passes the Delivery Point.

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24.4 **Responsibility for Meter Set** - The Customer is responsible for all expense, risk and liability with respect to all Meter Sets or related equipment at the Customer's Premises unless any loss or damage is

(a) directly attributable to the negligence of FortisBC Energy, its employees, contractors or agents, or

(b) caused by or resulting from a defect in the equipment. The Customer must prove that negligence or defect.

For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by FortisBC Energy in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service Line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such Service Line(s).

24.5 **Customer Indemnification** - The Customer will indemnify and hold harmless FortisBC Energy, its employees, contractors and agents from all claims, loss, damage, costs or injury (including death) suffered by the Customer or any Person claiming by or through the Customer or any third party caused by or resulting from the use of Gas by the Customer or the presence of Gas in the Customer's Premises, or from the Customer or Customer's employees, contractors or agents damaging FortisBC Energy's facilities.

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25. Miscellaneous Provisions

25.1 **Taxes** - The rates and charges specified in the applicable Rate Schedules do not include any local, provincial or federal taxes, assessments or levies imposed by any competent taxing authorities which FortisBC Energy may be lawfully authorized or required to add to its normal rates and charges or to collect from or charge to the Customer.

25.2 **Conflicting Terms and Conditions** - Where anything in these General Terms and Conditions conflicts with special terms or conditions specified under an applicable Rate Schedule or Service Agreement, then the terms or conditions specified under the Rate Schedule or Service Agreement govern.

25.3 **Authority of Agents of FortisBC Energy** - No employee, contractor or agent of FortisBC Energy has authority to make any promise, agreement or representation not incorporated in these General Terms and Conditions or in a Service Agreement, and any such unauthorized promise, agreement or representation is not binding on FortisBC Energy.

25.4 **Additions, Alterations and Amendments** - The General Terms and Conditions, fees and charges, and Rate Schedules may, with the approval of the British Columbia Utilities Commission, be added to, cancelled, altered or amended by FortisBC Energy from time to time.

25.5 **Headings** - The headings of the Sections set forth in the General Terms and Conditions are for convenience of reference only and will not be considered in any interpretation of the General Terms and Conditions.

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26. Direct Purchase Agreements

26.1 **Collection of Incremental Direct Purchase Costs** - Where FortisBC Energy incurs any costs relating to implementing, providing or facilitating the direct purchase arrangements of a Customer, agent, broker or marketer, FortisBC Energy may, subject to BCUC approval, collect those costs from the Customer, agent, broker or marketer. Such costs may include the costs of arranging, acquiring or transporting substitute Gas supplies as well as any other costs or obligations relating to the direct purchase arrangement that are incurred by FortisBC Energy. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

26.2 **Direct Purchase Customers Returning to FortisBC Energy System Supply** - Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy,

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply,

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer, and

(c) FortisBC Energy may, subject to BCUC approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy can bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

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27. Commodity Unbundling Service

27.1 In the event a Customer enters into a Gas supply contract with a Marketer for Commodity Unbundling Service under Rate Schedule 1U, 2U or 3U, the following terms and conditions will apply:

(a) The Customer must sign a Notice of Appointment of Marketer as notification to FortisBC Energy that the Marketer has the authority to do what is required with respect to the Customer's enrolment in Commodity Unbundling Service, including entering into the necessary Commodity Unbundling Service agreements and related Rate Schedules. Such Notice of Appointment of Marketer shall also authorize FortisBC Energy to share with the Marketer certain historical and ongoing consumption information and to verify the Commodity Cost Recovery Charge used to bill the Customer as directed by the Marketer.

(b) FortisBC Energy shall be entitled to rely solely on communications from the Marketer with respect to the enrolment of the Customer in Commodity Unbundling Service and with respect to the termination or expiry of any contract between the Customer and Marketer.

(c) FortisBC Energy will bill the Customer a Commodity Cost Recovery Charge according to the price indicated by the Marketer. Such price must be expressed as a single fixed price per Gigajoule in Canadian dollars. Such price shall not include amounts payable by the Customer to the Marketer for services other than the Gas commodity cost. The price may only be changed by Marketer no more than once per year on the anniversary of the Customers' enrolment in Commodity Unbundling Service with such Marketer. FortisBC Energy shall have no obligation to verify that the price communicated by the Marketer is the price agreed to between the Customer and the Marketer.

(d) FortisBC Energy will continue to bill the Customer as per the billing, payment, credit and collections policies set out in these General Terms and Conditions.

(e) The Customer shall make payment to FortisBC Energy based on the total charges on the bill and under no circumstances will payments be prorated between the various charges on the bill. Payments made by Customers to FortisBC Energy pursuant to the bills rendered by FortisBC Energy shall be made without any right of deduction or set-off and regardless of any rights or claims the Customers may have against the Marketer.

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(f) Non-payment of any amounts designated as Commodity Cost Recovery Charge charged on the bill shall entitle FortisBC Energy to the same recourse as non-payment of any other FortisBC Energy service charges and may result in termination of service by FortisBC Energy in accordance with these General Terms and Conditions and any applicable Rate Schedules. In the event FortisBC Energy terminates the Customer's service, the subject Customer will be removed from the Commodity Unbundling Service. Should the Customer wish to re-enrol in Commodity Unbundling Service, the Customer will be required to re-apply for service with FortisBC Energy as per the then existing General Terms and Conditions and then be required to enrol as a new participant in order to be eligible for Commodity Unbundling Service.

(g) FortisBC Energy is not responsible for the terms of any of the Customer's contract(s) with the Marketer. Provision of Commodity Unbundling Service in no way makes FortisBC Energy liable for any obligation incurred by a Marketer vis-à-vis the Customer or third parties.

(h) In the event the British Columbia Utilities Commission issues an order to FortisBC Energy to return Customers to FortisBC Energy as supplier of last resort, the Customer will be returned with no notice to the FortisBC Energy standard system supply rate with no interruption of service upon the then applicable terms and conditions of FortisBC Energy system supply service. In the event there are incremental costs associated with returning the Customer to the standard system supply rate, these costs may be recovered by FortisBC Energy directly from the Customer.

(i) The Customer's enrolment in Commodity Unbundling Service shall be on a Premises specific basis.

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28. Biomethane Service

28.1 **Notional Gas** - Customers agree and recognize that the location of generation facilities will determine where Biomethane will physically be introduced to the FortisBC Energy System and that Customers receiving Biomethane Service may not receive actual Biomethane at their Premises, but instead be contributing to the cost for FortisBC Energy to deliver an amount of Biomethane proportionate to the Customer's Gas usage into the FortisBC Energy System.

28.2 **Biomethane Physical Delivery** - Customers located in the vicinity of Biomethane generation facilities may receive Biomethane as a component of Gas in such proportion as FortisBC Energy determines in its sole discretion.

28.3 **Reduced Supply** - Customers agree and recognize that the production of Biomethane is subject to biological processes and production levels may fluctuate. Customers registered for Biomethane Service for applicable Rate Schedules 1B, 2B and 3B, agree that in the event that Biomethane production does not provide sufficient gas supply, FortisBC Energy may purchase Carbon Offsets in an amount equivalent to the greenhouse gas reduction that would have been achieved through Biomethane supply, and at a price not to exceed the funding received from Customers registered for Biomethane Service.

28.4 **Price Determination** - Customers registered for Biomethane Service will be billed for Gas pursuant to their applicable Rate Schedule. The cost of Biomethane will be based on the cost of acquiring Biomethane, including, but not limited to commodity, production, infrastructure, equipment and operating costs required to deliver pipeline quality Gas.

28.5 **Biomethane Customers** - Customers registered for Biomethane Service will be charged a Biomethane Energy Recovery Charge based on a calculation that will deem the Customer's Gas usage to be a pre-determined percentage of Biomethane and pre-determined percentage of conventionally sourced Gas. Applicable Rate Schedules will be reviewed and updated quarterly with regard to the price of conventionally sourced Gas and annually with regard to the price of Biomethane with rate changes subject to BCUC approval.

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28.6 **Enrolment** - In the event a Customer enters into a Service Agreement with FortisBC Energy for Biomethane Service under Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B, the following terms and conditions will apply:

(a) **Notice** - the Customer will provide notification to FortisBC Energy that he or she wishes to receive Biomethane Service, and FortisBC Energy will provide confirmation to the Customer once the Customer is registered for Biomethane Service.

(b) **Eligibility** - the number of Customers eligible to receive Biomethane Service will be limited and the determination of eligibility will be made by FortisBC Energy in its discretion, acting reasonably.

(c) **Change in Rate** - Customers registered for Biomethane Service will be charged for Gas at the rates set out in Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B. FortisBC Energy will use reasonable efforts to switch Customers to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B in a timely manner. However, Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B rates will only be commenced on the first day of a Month, therefore, Customers registered for Biomethane Service within one (1) week on the last day of a Month may not be switched to Rate Schedule 1B, Rate Schedule 2B or Rate Schedule 3B until five (5) weeks after their registration date.

(d) **Biomethane Offering** - Biomethane Service is available in all areas served by FortisBC Energy except Revelstoke

(e) **Moving** - If a Customer registered for Biomethane Service moves to a new Premises within the areas served by FortisBC Energy described above, that Customer may remain registered for Biomethane Service at the new Premises.

(f) **Switching Back to FortisBC Energy Standard Rate Schedule** - Customers may at any time request to terminate Biomethane Service and be returned to a FortisBC Energy conventional Gas Rate Schedule. On receiving notice that a Customer wishes to return to conventional Gas Service, FortisBC Energy will return that Customer to the applicable FortisBC Energy conventional Gas Rate Schedule in accordance with the FortisBC Energy General Terms and Conditions.

(g) **Switching to a Gas Marketer Contract** - Customers may at any time request to terminate Biomethane Service and receive their commodity from a Gas Marketer. On receiving notice that a Customer has entered into an agreement with a Gas Marketer, FortisBC Energy will process this request in accordance with Section 27.

(h) **Program Termination** - FortisBC Energy reserves the right to remove and/or terminate Customers from Biomethane Service at any time.

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Standard Fees and Charges Schedule

Application Fee	
Existing Installation	$25.00
New Installation	$25.00
New Installation - Manifold Meters	$25.00 per meter
New Installation - Vertical Subdivision	$25.00 per meter
Service Line Cost Allowance	
Other than a duplex	$1,535.00
Duplex	$3,070.00

Administrative Charges

Late Payment Charge	1.5% per month (19.56% per annum) on outstanding balance
Dishonoured Cheque Charge	$20.00

Interest on Cash Security Deposits

FortisBC Energy will pay interest on cash security deposits at FortisBC Energy's prime interest rate minus 2%. FortisBC Energy prime interest rate is defined as the floating annual rate of interest which is equal to the rate of interest declared from time to time by FortisBC Energy's lead bank as its "prime rate" for loans in Canadian dollars.

Payment of interest will be credited to the Customer's account in January of each Year.

Metering Related Charges

Disputed Meter Testing Fees

Meters rated at less than or equal to 14.2 m^3/Hour	$60.00
Meters rated greater than 14.2 m^3/Hour	Actual Costs of Removal and Replacement

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Attachment 78.1

TARIFF SUPPLEMENT NO. 4

STORAGE AND DELIVERY AGREEMENT and

AMENDING AGREEMENT

BETWEEN

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)

AND

FORTISBC ENERGY INC.
(formerly Terasen Gas Inc.)

Effective April 1, 2011

C

STORAGE AND DELIVERY AGREEMENT

This STORAGE AND DELIVERY AGREEMENT made as of this 10th day of January, 2008.

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC. a company incorporated under the laws of British Columbia having an office at 16075 Fraser Highway, Surrey, British Columbia ("TGVI")

AND:

TERASEN GAS INC. a company incorporated under the laws of British Columbia having an office at 16075 Fraser Highway, Surrey, British Columbia ("TGI")

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

WHEREAS

A. TGVI intends to construct a Liquefied Natural Gas ("LNG") Storage Facility on Vancouver Island at Mount Hayes near Ladysmith that is scheduled to be available for usage on the Commencement Date.

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

C. TGI is interested in contracting with TGVI for LNG storage and delivery services for the benefit of TGI's core market customers.

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

1. DEFINITIONS

In this Agreement:

"**Agreement**" means this Storage and Delivery Agreement;

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

"**Capacity Demand Charge**" is the demand rate for providing Storage Capacity expressed in dollars per GJ;

"**Coloured Gas Tax Commodity Charge**" has the meaning set out in section 14.1 a);

"**Commencement Date**" has the meaning set out in section 2.1;

"**Day**" means the twenty-four hour period beginning 7:00 a.m. Pacific Clock Time;

"**Delivery Service**" has the meaning set out in section 3.2;

"**Firm Liquefaction Rate**" has the meaning set out in section 3.1 a);

"**Firm Liquefaction Service**" has the meaning set out in section 3.1 a);

"**Firm Redelivery Service**" has the meaning set out in section 3.2 b);

"**Firm Storage Capacity**" means the maximum quantity of gas that TGI has the right to store at the LNG Facility pursuant to section 4.1;

"**Firm Storage Service**" has the meaning set out in section 3.1 b);

"**Firm Vaporization Rate**" means that maximum level of Firm Vaporization Service per Day as contracted for by TGI, and that TGVI is obliged to provide pursuant to section 4.1;

"**Firm Vaporization Service**" has the meaning set out in section 3.1 c);

"**Force Majeure**" means a condition, cause or event that is beyond the reasonable control of a Party and not caused in whole or in part by its default, and includes acts of war, revolution, riot, sabotage, vandalism, earthquakes, storms, lightning, weather conditions and other acts of God, local or national emergencies, strikes, lockouts, work slowdowns and other labour disputes, acts and orders of government or regulatory authorities, provided "Force Majeure" will not include an act of negligence or intentional wrongdoing of the Party or any lack of money or credit by the Party and will not include: (a) loss by either Party of markets (unless it is a result of an act of Force Majeure); or (b) inability economically to use or sell gas; or (c) either Party's loss of gas supply (unless it is a result of an act of Force Majeure); or (d) an ability to sell gas to a market at a more advantageous price; or (e) depletion of either Party's LNG in the LNG Facility. "Force Majeure" will include a curtailment or interruption on WEI Transmission South ("T-South") resulting in a reduction in the supply of TGVI's firm supply or a declaration of Force Majeure by any transmission pipeline other than WEI that transports gas on a firm basis on TGVI's behalf;

"**Initial Term**" has the meaning set out in section 2.2;

"**Interruptible Delivery Service**" has the meaning set out in section 3.2 a);

"**Interruptible Liquefaction Service**" has the meaning set out in section 6.2;

"**Lapsed Pro-rata**" means that the maximum rate for the remainder of a Day will be the firm rate times the number of hours remaining in the Day after a nomination becomes effective divided by twenty four;

"**Liquefaction Commodity Charge**" has the meaning set out in section 14.1 b);

"LNG Facility" is the LNG Storage facility at Mount Hayes near Ladysmith on Vancouver Island that is scheduled to be available for usage on the Commencement Date;

"**LNG Service**" has the meaning set out in section 3.1;

"**LNG Service Gas**" means the quantity of gas used during liquefaction, storage and vaporization of gas at the LNG Facility;

"**Primary LNG Service**" has the meaning set out in section 4.2;

"**Secondary Term**" has the meaning set out in section 2.2(b);

"**Storage Inventory**" is that volume of gas that TGVI records as being as being stored in the LNG Facility for TGI;

"Storage Year" means a twelve month period, beginning on any April 1, which falls within the term of the Agreement except in the first year when "Storage Year" is the period from the Commencement Date to the next March 31;

"**Summer Period**" means the period from April 16 to October 14;

"**Supplementary LNG Service**" has the meaning set out in section 4.1;

"**Supplementary Service Notice**" has the meaning set out in section 4.4; C

"**TGVI System**" means the TGVI transmission system;

"**Transportation Fuel Gas**" means the quantity of fuel gas used on the TGVI System to deliver gas to the LNG Facility.

"**V1**" means the TGVI Eagle Mountain Compressor Station;

"**Vaporization Commodity Charge**" has the meaning set out in section 14.1 c);

"**Vaporization Demand Charge**" is the demand rate for providing vaporization service expressed in dollars per GJ per Day;

"**WEI**" means Westcoast Energy Inc.; and

"**Winter Period**" means the period from October 15 to April 15.

2. TERM

2.1 The commencement date ("Commencement Date") for the provision of LNG Service under this Agreement is the later of April 1, 2011 or such date notified by TGVI to TGI pursuant to section 2.3.

2.2 The term of this Agreement is for a period of 35 Storage Years and consists of two periods as follows:

a) the Initial Term is the period of 20 Storage Years beginning on the Commencement Date; and

b) the Secondary Term is the period of 15 Storage Years following the Initial Term.

2.3 The term will automatically extend for consecutive one year periods until such time either Party provides the other Party with at least two years' written notice of termination. Upon the provision of such notice this Agreement will terminate on the March 31 which is at least two years after the date on which the written notice is provided.

2.4 TGVI will provide 60 days written prior notice to TGI of the Commencement Date. TGVI will notify TGI in writing no later than November 1, 2008 of any expected change in the Commencement Date due to delay in commencement of construction of the LNG Facility. TGVI will also use reasonable efforts to notify TGI of any expected changes in the Commencement Date during the construction of the LNG Facility.

3. STORAGE AND DELIVERY SERVICE

3.1 During the term of this Agreement, TGVI will provide to TGI the following services (collectively the "LNG Service") at the LNG Facility:

a) Firm Storage Service for the storage of gas in a liquid state at the LNG Facility based on the Firm Storage Capacity in each Storage Year pursuant to sections 4.2 and 4.4;

b) Firm Liquefaction Service for the conversion of gas from a gaseous state to a liquid at a Firm Liquefaction Rate equal to 0.5% of the Firm Storage Capacity; and

c) Firm Vaporization Service for the conversion of gas from a liquid state to a gaseous state at the Firm Vaporization Rate in each Storage Year pursuant to sections 4.2 and 4.4.

3.2 During the term of this Agreement, TGVI will provide to TGI the following services (collectively the "Delivery Service"):

a) Interruptible Delivery Service from V1 to the LNG Facility; and

b) Firm Redelivery Service, with the place of redelivery being, as TGVI so elects from time to time, at either V1 or at the interconnection between the systems of TGI and WEI at Huntingdon.

3.3 TGVI may elect to provide Delivery Service either through either or a combination of displacement or physical transportation of gas to meet TGI's nominations.

4. CONTRACT LEVELS

4.1 In each Storage Year TGVI will provide LNG Service to TGI based on the

a) Primary LNG Service levels pursuant to sections 4.2 and 4.3; and

b) Supplemental LNG Service levels pursuant to section 4.4.

4.2 During the Initial Term, TGVI will make available to TGI the following minimum level of LNG Service ("Primary LNG Service)" at the LNG Facility:

a) Firm Storage Capacity of 1.0 Bcf; and

b) Firm Vaporization Rate of 100 MMcfd.

4.3 TGVI may make a one time reduction to the Primary LNG Service levels it makes available to TGI during the Secondary Term by providing written notice to TGI at least two years prior the expiry of the Initial Term. The Primary LNG Service level in the Secondary Term may be decreased only to the degree TGVI reasonably forecasts it will require the capacity to serve customers connected on TGVI's transmission and distribution.

4.4 In each Storage Year, TGVI may provide TGI with Supplemental LNG Service in addition to the Primary LNG Service by providing written notice to TGI at least two years before the commencement of a Storage Year, ("Supplementary Service Notice") specifying:

a) the Storage Year to which the Supplementary Service Notice relates;

b) the supplemental Firm Storage Capacity in the LNG Facility that will be available to TGI for that Storage Year; and

c) the supplemental Firm Vaporization Rate of the Firm Vaporization Service that will be available to TGVI for that Storage Year.

4.5 The storage capacity and vaporization at the LNG Facility that TGVI makes available to TGI pursuant to each Supplementary Service Notice will be the storage capacity and vaporization, subject to section 4.4, that TGVI reasonably forecasts will be surplus to the requirements of the customers on TGVI's natural gas transmission and distribution system.

4.6 Unless otherwise agreed by the Parties, the Firm Storage Capacity specified in a Supplementary Service Notice may not be less than the quantity of gas that can be vaporized in six Days nor greater than the quantity of gas that can be vaporized in twenty Days, at the Firm Vaporization Rate specified in the same Supplementary Service Notice.

5. LNG SERVICE - Capacity

5.1 During each Storage Year TGVI will provide TGI with the Firm Storage Capacity for which TGI has contracted pursuant to section 4.1.

6. LNG SERVICE - Liquefaction

6.1 Subject to sections 11.1 b) and 11.5, on each Day TGVI will provide TGI with Firm Liquefaction Service at the lesser of:

(i) the Firm Liquefaction Rate, or

(ii) the volume of gas that TGI delivers to TGVI, net of Transportation Fuel Gas and LNG Service Gas, on that Day.

6.2 If TGVI has available liquefaction capacity that is not being utilized on a Day, then TGI may increase the liquefaction rate for its gas on that Day above the Firm Liquefaction Rate at no incremental cost. This additional liquefaction capacity will be made available as Interruptible Liquefaction Service.

6.3 In the event that more than one party contracting for LNG Service from TGVI wishes to increase their liquefaction rate above their firm rate and this results in a service constraint, the excess liquefaction capacity will be allocated pro-rata amongst such parties based on each party's respective Firm Liquefaction Rate.

7. LNG SERVICE - Vaporization

7.1 Subject to section 11.1 d) and section 11.5, on each Day upon TGI nominating to TGVI, TGVI will provide TGI with Firm Vaporization Service up to the Firm Vaporization Rate in effect for the applicable Storage Year.

7.2 If TGVI has available vaporization capacity that is not being utilized on a Day then, TGI may increase the vaporization rate for its gas on that Day above the Firm Vaporization Rate, provided TGVI is able to redeliver the gas to TGI. If later during that Day TGVI requires this service for its own requirements then the vaporization rate for TGI may be reduced to no less than the Firm Vaporization Rate for the remainder of the Day as provided in section 10.5.

7.3 In the event that more than one party contracting for LNG Service from TGVI wishes to increase their vaporization rate above their firm rate and this results in a service constraint, the excess vaporization capacity will be allocated pro-rata amongst such parties based on each party's respective LNG firm vaporisation rate.

7.4 TGVI is not be obligated to vaporize for TGI any amount of LNG greater than the amount of LNG TGI has in storage at the LNG Facility at that point in time.

8. DELIVERY SERVICE - Interruptible Delivery Service

8.1 Each Day TGI will deliver to TGVI at the inlet of V1 the quantity of gas that TGI specifies for delivery to, and liquefaction at, the LNG Facility on that Day plus the applicable LNG Service Gas and Transportation Fuel Gas.

8.2 Each Day TGVI will, subject to capacity constraints on the TGVI System, deliver to the LNG Facility the gas delivered to it by TGI on that Day, less the applicable allowance for Transportation Fuel Gas.

8.3 TGVI will make available to TGI sufficient Interruptible Delivery Service during the period from April 1 to October 31 of a Storage Year to deliver to the LNG Facility the quantity of gas that will fill, based on gas being liquefied at the Firm Liquefaction Rate for that Storage Year, the Storage Capacity that TGI has contracted for that Storage Year, and the applicable LNG Service Gas.

8.4 The priority for the delivery of TGI gas to the LNG Facility will be the same as the priority of shippers using interruptible transportation on the TGVI System.

8.5 This Agreement does not oblige TGVI to provide to Interruptible Delivery Service to the LNG Facility during the Winter Period.

8.6 TGVI will deduct the LNG Service Gas from the quantity of gas delivered to the LNG Facility to determine the quantity of gas that is liquefied and stored on behalf of TGI at the LNG Facility.

9. DELIVERY SERVICE - Firm Redelivery Service

9.1 Each Day TGVI will provide TGI with Firm Redelivery Service for the TGI gas vaporized at the LNG Facility on that Day pursuant to Article 7.

9.2 Firm redeliveries will be on a Lapsed Pro-rata basis.

10. NOMINATIONS

10.1 TGI will nominate for delivery to the LNG Facility at least one and one half (1 1/2) hours before TGVI must make its nominations on the WEI system nomination cycles and TGVI will notify TGI at least one hour before the time that TGVI must make its nominations of the authorized quantity of gas that TGVI will deliver to the LNG Facility for TGI.

10.2 TGVI will notify TGI at least one hour before the WEI evening or intra-day one ("ID-1") nomination cycle if TGI's previously authorized nomination for delivery to the LNG Facility has been modified. TGI's previously authorized nomination will not be modified by TGVI, without TGI's approval, after the ID-1 cycle.

10.3 TGI will nominate to TGVI the quantity of gas TGI requires to be vaporized and redelivered at least two hours prior to the time when TGI requires the gas during the Winter Period, and at least twelve hours prior during the Summer Period.

10.4 To the extent, pursuant to section 7.2, that TGVI wishes to reduce within a Day the quantity of gas authorized to be vaporized and redelivered to the Firm Vaporization Rate, TGVI will provide TGI with at least one hour's notice of any such reduction.

10.5 To the extent that TGI wishes to increase or decrease within a Day the quantity of gas that is authorized to be vaporized and redelivered, TGI will provide at least one hour's notice to TGVI prior to the change in the vaporization rate. To the extent that TGI wishes to increase the rate of vaporization above the Firm Vaporization Rate, such an increase must be authorized by TGVI before becoming effective.

10.6 Changes in the Firm Liquefaction and Interruptible Delivery Service, Firm Vaporization Rate and Firm Redelivery Service during a Day are subject to Lapsed Pro-rata.

10.7 Nominations by and confirmations between TGI and TGVI will be sent to the attention of:

a) Nominations from TGI to TGVI to Operations Manager; and

b) Confirmation from TGVI to TGI to Manager, Midstream.

Either Party may change the contact specified above by giving the other Party notice of such change.

10.8 Nominations and confirmations will be in electronic form as established from time to time by TGVI.

10.9 If the WEI nomination cycles, or their names, change, the Parties will amend this Agreement to accord with the revised nomination cycles.

11. PERFORMANCE OBLIGATIONS

11.1 Subject to section 11.2, TGVI has the following obligations to TGI during the term of this Agreement:

a) To make sufficient available Interruptible Delivery Service to the LNG Facility for the Summer Period of a Storage Year to meet the obligation as set out in section 8.3;

b) To provide Firm Liquefaction Service at the Firm Liquefaction Rate each Day of the Storage Year, except on the Days when planned maintenance is being performed by TGVI for the liquefaction component of the LNG Facility;

c) To provide during each Storage Year the capacity in the LNG Facility to store up to the Firm Storage Capacity contracted by TGI for that Storage Year; and

d) To provide during each Storage Year Firm Vaporization Service at the Firm Vaporization Rate contracted by TGI for that Storage Year and to provide Firm Redelivery Service for the TGI gas vaporized from the LNG Facility to TGI, except on the Days when planned maintenance is being performed by TGVI on the vaporization component of the LNG Facility.

11.2 In each Storage Year, TGVI will use reasonable commercial efforts to schedule planned maintenance such that planned maintenance in any Storage Year does not exceed a cumulative period of 60 Days for each of the vaporization and liquefaction components of the LNG Facility and shall only occur during:

a) May 1 to September 30 with respect to the vaporization component; and

b) December 1 to February 28 with respect to the liquefaction component.

Prior to April 1 of each Storage Year, TGVI will provide TGI with a forecast schedule of planned maintenance to take place over the next 12 months.

11.3 In each Storage Year, if TGVI is unable to meet its obligations to TGI as set out in section 11.1, TGVI will provide TGI with a demand charge credit as set out below:

a) to the extent that TGVI has not provided sufficient Interruptible Delivery Service and Firm Liquefaction Service, or otherwise credited TGI's Storage Inventory, such that TGI's Storage Inventory on 1 November is equal to lower of the Firm Storage Capacity or the total volume nominated by TGI, the demand charge credit will be equal to the amount obtained by multiplying the demand charges otherwise payable in that Storage Year pursuant to sections 13.1 and 13.3 by the quantity that remains unfilled; and

b) to the extent that TGVI is not required to provide a demand charge credit pursuant to section 11.3(a) and TGVI is unable to provide Firm Redelivery Service to match TGI's nominations, up to the Firm Vaporization Rate, the demand charge credit will be equal to the amount obtained by multiplying the annual Vaporization Demand Charge provided in Schedule A by the quantity of gas not redelivered.

TGI's sole remedy, and TGVI's sole obligation, for the failure of TGVI to perform its obligations under this Agreement are the provision of demand charge credits as set out above.

11.4 If there is a shortfall in vaporization or liquefaction capability at the LNG Facility on any Day the shortfall will be allocated between TGI, other parties contracting for service at the LNG Facility, and TGVI, on a pro rata basis.

11.5 In any Storage Year, TGVI's obligations are limited to crediting TGI's Storage Inventory account up to the Firm Storage Capacity for which TGI has contracted the case of nominations for liquefaction, and redelivering gas to TGI in the case of nominations for vaporization. Nothing in this Agreement will require TGVI to operate its transmission facilities or require service from the LNG Facility to match the nominations from TGI on the Day.

12. FORCE MAJEURE

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

13. DEMAND CHARGES

13.1 Each month, TGI will pay to TGVI the sum of the following amounts:

a) In respect of the Primary LNG Service, a monthly demand charge as approved and amended from time to time by the BCUC, and as set out from time to time in Schedule A; and

b) In respect of the Supplemental LNG Service, an amount equal to one twelfth of the sum of:

i) the amount obtained by multiplying the supplemental Storage Capacity contracted by TGI for that Storage Year pursuant to section 4.4 by the Capacity Demand Charge, as approved and amended from time to time by the BCUC, expressed in dollars per GJ of Storage Capacity, and as set out from time to time in Schedule A; and

ii) the amount obtained by multiplying the supplemental Firm Vaporization Rate contracted by TGI in that Storage Year pursuant to section 4.4 by the Vaporization Demand Charge as approved and amended from time to time by the BCUC, expressed in dollars per GJ per Day, as set out from time to time in Schedule A..

13.2 If the Storage Year in the initial year of the term of this Agreement is less than 12 months such that TGI is unable to fill its Firm Storage Capacity before November 1 of that year, then a reduction in the monthly demand charge for the Primary LNG Service for the initial year will be determined based on the volume that TGI was unable to fill.

14. COMMODITY CHARGES

14.1 In each month, TGI will pay to TGVI the following commodity charges:

a) an amount equal to the Coloured Gas Tax Commodity charge taxes payable by TGVI in respect of TGI gas delivered to the LNG Facility under the *Motor Fuel Tax Act* (British Columbia); and any excise or other taxes payable by TGVI in respect of TGI gas delivered to the LNG Facility in that month ("Coloured Gas Tax Commodity Charge");

b) an amount obtained by multiplying the Liquefaction Commodity Charge, as set out in Schedule A, by the amount of TGI gas liquefied at the LNG Facility in that month. The Liquefaction Commodity Charge will be adjusted from period to period to reflect changes in the applicable BC Hydro rate per kWh; and

c) an amount obtained by multiplying the Vaporization Commodity Charge, as set out in Schedule A, by the amount of TGI gas vaporized at the LNG Facility in that month. The Vaporization Commodity Charge will be adjusted from period to period to reflect changes in the applicable BC Hydro rate per kWh.

15. FUEL GAS

15.1 TGVI will on a daily basis provide TGI with an estimate of Transportation Fuel Gas and LNG Service Gas.

15.2 TGVI on a monthly basis will reconcile the estimated Transportation Fuel Gas with the actual usage and provide TGI with a summary. TGI and TGVI will cooperate to ensure that any imbalances are kept as close to zero as possible.

15.3 TGVI on an annual basis will reconcile the estimated LNG Service Gas with actual usage and provide TGI with a summary. TGI and TGVI will cooperate to ensure that any imbalances are kept as close to zero as possible

16. BILLING

16.1 TGVI will provide TGI by the 15th of each month beginning in the month following the commencement of the term of this Agreement with an invoice relating to the preceding month for:

a) the monthly demand charge for the Primary LNG Service contracted by TGI;

b) the demand charge for the month for Supplementary LNG Service contracted for by TGI, setting out the Capacity Demand Charge and the Vaporization Demand Charge for the month at rates set out in Schedule A;

c) the Coloured Gas Tax Commodity Charge for the month setting out the rate for the commodity charge for the month and the quantity of TGI gas delivered to the LNG Facility in the month;

d) the Liquefaction Commodity Charge for the month setting out the rate per GJ as set out in Schedule A and the quantity of TGI gas liquefied;

e) the Vaporization Commodity Charge for the month setting out the rate per GJ per Day as set out in Schedule A and the quantity of TGI gas vaporized; and

f) any demand charge credits pursuant to section 11.4.

16.2 In addition to the invoice, TGVI will provide TGI with a summary for the preceding month setting out:

a) TGI's Storage Inventory at the beginning and end of the month;

b) the quantity of gas delivered to the LNG Facility in the month,

c) the amount of gas liquefied and the amount of gas vaporized by Day for TGI,

d) the amount of gas redelivered to TGI by TGVI by Day and delivery point; and

e) the quantity of Transportation Fuel Gas and LNG Services Gas.

16.3 TGI will pay TGVI the amount associated with the invoice on the 25th of the month the invoice is received or ten days after the receipt of the invoice, whichever is later.

16.4 In the event that TGI is late in paying the invoice then TGVI will assess TGI and TGI will pay to TGVI a late payment fee equal to the current prime interest rate charged by the Main Branch of the Toronto-Dominion Bank in Vancouver, British Columbia, to its most creditworthy commercial customers, plus 4%, per annum calculated on a daily basis.

17. NOTICES

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

a) If to TGI: Terasen Gas Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Attention: Vice President, Gas Supply and Transmission
Facsimile: 604-592-7420

b) If to TGVI: Terasen Gas (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Attention: Vice President, Regulatory Affairs & CFO
Facsimile: 604-576-7074

Either Party may change its address specified above by giving the other Party notice of such change in accordance with this section 17.1

18. REGULATORY AUTHORITY

18.1 This Agreement is subject to all rules, regulations, orders and other requirements of each governmental and regulatory authority having jurisdiction over this Agreement, the Parties or either of them, including without limitation, the BCUC.

18.2 This Agreement is subject to the approval of the BCUC.

19. GOVERNING LAW

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

20. EFFECT OF WAIVER OR CONSENT

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

21. HEADINGS

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

22. SEVERABILITY

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

23. ASSIGNMENT

23.1 Subject to the provisions of this section 23.1, this Agreement will enure to and be binding upon the respective successors and permitted assigns of the Parties. Neither Party may assign this Agreement without the prior written consent of the other Party, which consent will not be unreasonably withheld, provided, that either Party may assign its interest under this Agreement (a) to any entity that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with such Party, (b) to any entity into which it consolidates or merges or (c) as security to the holder of any indebtedness, present or future, of such Party, without the prior written approval of the other Party, but no such assignment will operate to relieve the assigning Party of any of its obligations under this Agreement. Any Party's transfer or assignment in violation of this section 23.1 will be void.

24. RESPONSIBILITY FOR DAMAGE

24.1 As between the Parties, TGI will be deemed to be in exclusive control and possession of gas which is the subject of this Agreement and will be responsible for any damage or injury caused thereby prior to the point at which TGVI receives gas pursuant to this Agreement and after the point TGVI redelivers gas pursuant to this Agreement. As between the Parties, TGVI will be deemed to be responsible for any damage or injury or damage caused thereby after the point at which TGVI receives gas pursuant to this Agreement and prior to the point at which TGVI redelivers gas pursuant to this Agreement.

25. WARRANTY

25.1 TGI warrants that (i) it has good title to all gas to be received to be received by TGVI under this Agreement, (ii) it has the right to deliver such gas, and (iii) that such gas is free from all liens and adverse claims, and agrees, if notified by TGVI, to indemnify TGVI from and against all suits, actions, debts, accounts, damages, costs, losses, and expenses (including reasonable lawyers' fees) arising from or out of any adverse legal claims of any and all persons and entities regarding title to such gas. TGI agrees to pay, or cause to be paid or delivered in kind to the parties entitled thereto, all royalties, overriding royalties or like charges against such gas or the value thereof.

26. TERMINATION

26.1 If either Party is at any time in material breach of or default under this Agreement (the "Defaulting Party"), the other Party (the "terminating Party") will have the right to terminate this Agreement by giving the Defaulting Party written notice of such termination. Such termination will be effective upon the Defaulting Party's receipt of such notice of termination pursuant to this section 26.1. For the purposes of this section 26.1, a Party will be deemed to be in material breach if or default under this Agreement if such Party:

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

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

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

In no event will either Party incur any liability (whether for lost revenues or lost profits or otherwise) as a result of any termination of this Agreement pursuant to this section 26.

26.2 Either Party shall have the right to terminate this Agreement should the LNG Facility not proceed to construction by giving written notice of termination to the other Party not later than November 1, 2008.

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

27. WAIVER OF CERTAIN DAMAGES

27.1 In no other event will either Party be liable to the other Party for consequential, incidental, punitive, special, exemplary or indirect damages, in tort, strict liability, warranty, contract, equity or otherwise.

28. DISPUTE RESOLUTION

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

29. ENTIRE AGREEMENT

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

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

TERASEN GAS (VANCOUVER ISLAND) INC.	TERASEN GAS INC.
BY: (Signature)	BY: (Signature)
DOUGLAS STOUT (Name – Please Print)	JAN MARSTON (Name – Please Print)
VICE PRESIDENT, MARKETING & BUSINESS DEVELOPMENT (Title)	VICE PRESIDENT, GAS SUPPLY & TRANSMISSION (Title)

SCHEDULE A

SCHEDULE OF DEMAND RATES AND COMMODITY CHARGES

DEMAND CHARGES FOR PRIMARY LNG SERVICE

Monthly Demand Charge	$1,002,600.00 (Note 1)	C

ANNUAL DEMAND CHARGES FOR SUPPLEMENTARY LNG SERVICE

Capacity Demand Charge	$ 2.80 per GJ of Storage Capacity (Note 1)	C
Vaporization Demand Charge	$ 83.87 per GJ per Day (Note 1)	C

COMMODITY CHARGES FOR PRIMARY AND SUPPLEMENTARY LNG SERVICE

Vaporization Commodity Charge	$ 0.06/GJ	R/C
Liquefaction Commodity Charge	$ 0.46/GJ	A/C

Note 1 – The rates will be as approved and amended from time to time by the BCUC. C

***Electrical Commodity Charge is based on BC Hydro's Transmission Service Stepped Rate Schedule 1823, at the current and/or interim rate per kWh. Future charges will be adjusted to reflect changes and/or final BCUC approval of BC Hydro's rate.* C

AMENDING AGREEMENT TO STORAGE AND DELIVERY AGREEMENT

Between

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

and

FORTISBC ENERGY INC.

AMENDING AGREEMENT TO

STORAGE AND DELIVERY AGREEMENT

This AMENDING AGREEMENT made as of September 21, 2011.

BETWEEN:

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

(hereinafter called "FEVI")

AND:

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

(hereinafter called "FEI")

WITNESSES THAT WHEREAS:

A. FEVI (formerly Terasen Gas (Vancouver Island Inc.) and FEI (formerly Terasen Gas Inc.) entered into a Storage and Delivery Agreement (the "Agreement") dated as of January 10, 2008, for LNG storage and delivery services at LNG Storage Facility on Vancouver Island at Mount Hayes;

B. FEVI and FEI are now desirous of amending the Agreement.

NOW THEREFORE in consideration of the mutual agreements herein contained and other good and valuable consideration, the parties hereto covenant and agree as follows:

1. Unless otherwise defined herein, capitalized terms used herein have the meanings ascribed in the Agreement.

2. All references to "Terasen Gas (Vancouver Island) Inc." or "TGVI" shall be deleted and replaced with "FortisBC Energy (Vancouver Island) Inc." or "FEVI" respectively.

3. All references to "Terasen Gas Inc." or "TGI" shall be deleted and replaced with "FortisBC Energy Inc." or "FEI" respectively.

4. Clause 4.4 shall be deleted in its entirety and replaced with the following:

   "4.4 In each Storage Year, FEVI may provide FEI with supplemental LNG Service in addition to the Primary LNG Service by providing written notice to FEI at least one year before the commencement of a Storage year, ("Supplementary Service Notice") specifying:

   (a) the Storage Year to which the Supplementary Service Notice relates;

(b) the supplemental Firm Storage Capacity in the LNG Facility that will be available to FEI for that Storage Year; and

(c) the supplemental Firm Vaporization Rate of the Firm Vaporization Service that will be available to FEVI for that Storage Year."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be effective immediately.

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

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

____
Signature

Scott Thomson – Executive Vice President, Finance, Regulatory & Energy Supply

FORTISBC ENERGY INC.

____
Signature

Cynthia Des Brisay –Vice President, Energy Supply & Resource Development

AMENDING AGREEMENT No. 2 TO STORAGE AND DELIVERY AGREEMENT

Between

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

and

FORTISBC ENERGY INC.

AMENDING AGREEMENT No. 2 TO

STORAGE AND DELIVERY AGREEMENT

This AMENDING AGREEMENT made as of January 23, 2012.

BETWEEN:

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

(hereinafter called "FEVI")

AND:

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

(hereinafter called "FEI")

WITNESSES THAT WHEREAS:

A. FEVI (formerly Terasen Gas (Vancouver Island Inc.) and FEI (formerly Terasen Gas Inc.) entered into a Storage and Delivery Agreement dated as of January 10, 2008, for LNG storage and delivery services at LNG Storage Facility on Vancouver Island at Mount Hayes which was subsequently modified by way of amending agreement dated as of September 21, 2011 (collectively the "Agreement");

B. The parties wish to rectify a clerical error in the Definitions section of the Agreement.

C. Accordingly, FEVI and FEI are now desirous of amending the Agreement.

NOW THEREFORE in consideration of the mutual agreements herein contained and other good and valuable consideration, the parties hereto covenant and agree as follows:

1. Unless otherwise defined herein, capitalized terms used herein have the meanings ascribed in the Agreement.

2. Clause 1, Definitions shall be amended by deleting the definition of "Supplementary Service Notice" and replacing it with the following:

   ""**Supplementary Service Notice**" has the meaning set out in Section 4.4;"

3. This Amending Agreement shall be read together with the Agreement as modified.

1. This Amending Agreement shall be effective immediately.

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

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

Signature

Roger Dall'Antonia –Vice President, Strategic Planning, Corporate Development & Regulatory Affairs

FORTISBC ENERGY INC.

Signature

Cynthia Des Brisay –Vice President, Energy Supply & Resource Development

Attachment 78.3

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1510 , *Approved and Ordered* DEC. 13.1995

I hereby certify that the following is a true copy of a Minute of the Honourable the Executive Council of the Province of British Columbia approved by His Honour the Lieutenant-Governor.

Order-inCouncil Custodian

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Vancouver Island Natural Gas Pipeline Special Direction is issued to the British Columbia Utilities Commission.

Anne Edwards
Minister of Energy, Mines and Petroleum Resources

M Harcourt
Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section:- Vancouver Island Natural Gas Pipeline Act, s. 7 (4)

Other (specify):-

December 8, 1995

1970/95/11/aaa

SPECIAL DIRECTION
TO THE
BRITISH COLUMBIA UTILITIES COMMISSION

PART 1
PRELIMINARY & GENERAL MATTERS

1.1 Definitions

"Annual CPI" means the percentage increase in the CPI over the most recent twelve month period for which information is available at any particular time when New Customer rates are approved pursuant to Section 2.7;

"Annual Revenue Deficiency" and "Revenue Deficiency Deferral Account" shall have the meanings given to these terms in Section 2.10;

"BCUC" means the British Columbia Utilities Commission;

"Canada Repayable Contribution" and "British Columbia Repayable Contribution" shall each have the meanings given to these terms in an agreement entered into among Her Majesty the Queen in Right of Canada, the Province, and PCEC substantially in the form of the Pacific Coast Energy Pipeline Agreement attached as Schedule 3 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order.

"CPI" means the monthly consumer price index for Victoria, British Columbia for all items, as published by Statistics Canada;

"Centra" means, at the effective date of this Special Direction, collectively, Centra Gas British Columbia Inc., Centra Gas Vancouver Island Inc. and Centra Gas Victoria Inc., and thereafter means such other company or companies that may from time to time own and operate all or any part of the Centra Distribution System;

"Centra Distribution System" means the gas distribution systems of Centra that were connected to the Pipeline as of the effective date of this Special Direction, together with any extensions thereof;

"Class "A" Instruments" means cumulative redeemable preferred shares issued by Centra, having attached the right to receive dividends at an annual rate determined by Centra, based on the issue price of such shares, not exceeding 58% of the Current 5 Year Canada Rate at the date of iseuance, plus 275 basis points and having such other terms (including provision for a dividend reset date) as are set out in the form of Class "A" Instrument attached as Schedule "A" to this Special Direction, or as may be otherwise determined by Centra and approved by the BCUC;

"Class "B" Instruments" means promissory notes or other debt instruments issued by Centra bearing interest at an annual rate determined by Centra, not exceeding the Current 5 Year Canada Rate at the date of issuance, plus 275 basis points and having such other terms (including provision for an interest reset date) as are set out in the form of Class "B" Instrument attached as Schedule "B" to this Special Direction, or as may be otherwise determined by Centra and approved by the BCUC;

"Current 5 Year Canada Rate" means, on any particular date, the most recent monthly rate published by the Bank of Canada as the benchmark yield on 5 year Government of Canada Bonds, as set out in column B14069 of the most recent release of the Bank of Canada Review;

"Interruptible Incentive Payments" means those payments to be made by the Province to PCEC in accordance with Sections 2.06, 2.07, and 2.08 of the Vancouver Island Natural Gas Pipeline Agreement;

"Joint Venture" means those corporations or other entities which, from time to time, own and operate the seven pulp mills that were being served by the Pipeline at the effective date of this Special Direction (the "**Mills**"), and which are operating as a joint venture for the purpose of obtaining gas transportation service from PCEC for the Mills;

"**Long Canada Rate**" means for any particular year, the Government of Canada long term bond reference rate used by the BCUC to determine return on equity for public utilities for that year and, in the event that such a reference rate does not exist for any particular year, then Long Canada Rate shall mean the rate implied by an independent consensus forecast of Government of Canada long term bond yields for that year that is approved by the BCUC;

"**PCEC**" means Pacific Coast Energy Corporation, or such other company that may from time to time own and operate the Pipeline;

"**Pipeline**" means the Vancouver Island natural gas pipeline, as described in the Energy Project Certificate issued to PCEC;

"**Province**" means Her Majesty the Queen in Right of the Province of British Columbia;

"**Rate Stabilization Facility**" means the financial facility continued in respect of Squamish Gas under the Rate Stabilization Facility Continuation Agreement;

"**Rate Stabilization Facility Continuation Agreement**" means an agreement between the Province and PCEC substantially in the form of the agreement attached as Schedule 2 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order;

"**Royalty Revenue Payments**" means those payments to be made by the Province to Centra in accordance with Sections 2.03 and 2.04 of the Vancouver Island Natural Gas Pipeline Agreement and, in the event that the Pipeline and the Centra Distribution System are owned and operated by a single legal entity, "Royalty Revenue Payments" shall also include the Interruptible Incentive Payments;

"**Single Entity**" means a single legal entity which owns and operates both the Centra Distribution System and the Pipeline;

"**Squamish Gas**" means, at the effective date of this Special Direction, Squamish Gas Co. Ltd., and thereafter means such other company or companies that may, from time to time, own and operate the Squamish Gas Distribution System;

"**Squamish Gas Distribution System**" means the gas distribution system of Squamish Gas that was in existence as of the effective date of this Special Direction, together with any extensions thereof;

"**Squamish Gas Transportation Service Agreement**" means that Agreement between PCEC and Squamish Gas dated April 1, 1990;

"**Squamish Rate Stabilization Agreement**" means that Agreement between the Province and Squamish Gas dated July 9, 1992;

"**Utilities**" means, collectively, PCEC, Centra, and Squamish Gas, and "**Utility**" means any one of them;

"**Vancouver Island Natural Gas Pipeline Agreement**" means an agreement among the Province, Westcoast Energy Inc., PCEC and Centra substantially in the form of the agreement attached as Schedule 1 to the Vancouver Island Natural Gas Pipeline Agreement Approval Order.

1.2 Schedules

The following Schedules are a part of this Special Direction:

Schedule "A" - FORM OF CLASS "A" INSTRUMENT

Schedule "B" - FORM OF CLASS "B" INSTRUMENT

Schedule "C" - INITIAL NEW CUSTOMER RATE SCHEDULE

Schedule "D" - DESIGNATED ROYALTY ADJUSTED COST OF GAS

Schedule "E" - EXAMPLES OF CALCULATION OF REVENUE DEFICIENCY DEFERRAL ACCOUNT BALANCE

Schedule "F" - JOINT VENTURE TRANSPORTATION SERVICE AGREEMENT

Schedule "G" - CENTRA TRANSPORTATION SERVICE AGREEMENT

Schedule "H" - PACIFIC COAST ENERGY CORPORATION GENERAL TERMS AND CONDITIONS

1.3 Effective Date, Special Direction No. 5 and Duration

This Special Direction shall become effective and supersede and replace Special Direction No. 5 (established pursuant to Order in Council No. 990, July 11, 1991) when the Secretary of the BCUC receives a written notice from each of the parties to the Vancouver Island Natural Gas Pipeline Agreement confirming that such Agreement has been executed and delivered. This Special Direction shall cease to have any application after the latest of:

(a) the time when the balance of the Revenue Deficiency Deferral Account has been reduced to zero; and

(b) the date of the expiration or earlier termination of the Joint Venture Transportation Service Agreement appended as Schedule "F", which date shall in no event be later than January 1, 2011; and

(c) the date of the termination of the Squamish Gas Transportation Service Agreement.

1.4 General

The BCUC shall regulate the Utilities and fix the rates charged by the Utilities in accordance with the requirements of this Special Direction , and in accordance with the requirements of the Utilities Commission Act and such regulatory principles that are otherwise applicable to the Utilities from time to time that are not inconsistent with this Special Direction. In the event of any inconsistency between this Special Direction and any requirement of the Utilities Commission Act or any regulatory principles that would otherwise be applicable to the Utilities, the BCUC shall follow the provisions of this Special Direction. For greater certainty, the BCUC shall not apply any provisions of the Utilities Commission Act (including, without limitation, Sections 64, 65, 66, and 67) in any manner which has the effect, directly or indirectly, of eliminating or varying any rates that have been specified in, or determined in accordance with, this Special Direction, or eliminating or varying any other determination or matter provided for herein.

PART 2
DIRECTION RESPECTING CENTRA

2.1 General Direction With Respect to Rates

Rates, changes in rates, changes in customer classifications or other rate design matters, shall be filed with and approved by the BCUC on an annual basis or such other periodic basis as the BCUC may determine.

2.2 Pioneer and New Customers

All customers of Centra (other than customers who have entered into long term commercial gas supply contracts that have been individually approved by the BCUC) shall be categorized as either a "**Pioneer Customer**" or a "**New Customer**" based upon the criteria set out below. Such categories shall be for the purpose of fixing rates for the period from the effective date of this Special Direction to December 31, 2003, in the case of Pioneer Customers within the ACR-2 customer rate class, and for the period from the effective date of this Special Direction to December 31, 2002, in the case of all other Pioneer and New Customers.

(a) Pioneer Customer

Any customer of Centra:

(i) who applies for service as a Pioneer Customer prior to February 13, 1996, and whose application is accepted by Centra; and

(ii) to whom gas has been delivered within 60 days after a service line has been provided to that customer by Centra,

shall be a Pioneer Customer for the purpose of service to that customer at the location applied for. A customer shall cease to be classified as a Pioneer Customer:

(iii) if the customer enters into an agreement with Centra, releasing its entitlement to be classified as a Pioneer Customer; or,

(iv) if the customer enters in a gas supply contract with a party other than Centra, the other party provides gas for the customer, and Centra is subsequently required to provide the customer's gas supply.

(b) <u>New Customer</u>

Any customer of Centra who does not satisfy the requirements for classification as a Pioneer Customer, or any customer who has released its entitlement to be classified as a Pioneer Customer, shall be classified as a New Customer. The BCUC may require Centra to develop policies for approval by the BCUC for the purpose of determining whether there has been a change that would result in any particular customer not being entitled to service as a Pioneer Customer.

2.3 Closing of Pioneer Customer Rate Classes

The customer rate classes for Pioneer Customers shall be the SGS-1, SGS-2, ACR-1, ACR-2, LGS-1, LGS-2, and LGS-3 customer rate classes as defined in the rate schedule filed by Centra with the BCUC and in effect as of January 1, 1995. Entry into the Pioneer

Customer rate classes shall be closed in accordance with the definitions in paragraph 2.2, however, a customer within a particular Pioneer Customer rate class may move from one Pioneer Customer rate class to another, in accordance with the applicable terms and conditions of service, so long as the customer is continuing to receive service at the same location.

2.4 Rates for Pioneer Customers Within the ACR-2 Customer Rate Class 1995 - 2003

The BCUC shall fix the rates charged by Centra to Pioneer Customers within the ACR-2 rate class for the period from the effective date of this Special Direction to December 31, 2003, independently from Centra's cost of service and in accordance with the applicable provisions of the rate schedule filed by Centra with the BCUC and in effect as of January 1, 1995. In order to apply such provisions, the BCUC shall require Centra to determine the Vancouver rack price for No. 2 fuel oil for such period, and employing such methods, as may be approved by the BCUC from time to time.

2.5 Other Pioneer Customer Rates 1995 - 2001

The BCUC shall fix the rates charged by Centra to Pioneer Customers (other than those within the ACR-2 customer rate class) for the period from the effective date of this Special Direction to December 31, 2001, in accordance with the following directions.

(a) Market Monitoring and Determination of Competitive Energy Prices

The BCUC shall require Centra to monitor the competitive fuel oil markets within its service area for such period, and employing such methods, as may be approved by the BCUC from time to time, and Centra shall be required to provide the results of its market monitoring to the BCUC and, based thereon, the BCUC shall determine the market price at which fuel oil would be available to a Pioneer Customer within each applicable rate class and the price or prices so determined shall be the "Competitive Fuel Price" for the applicable period and customer class. The BCUC shall also determine the price equal to 67% of the B.C. Hydro Trailing Block Rate for residential service available to Pioneer Customers and the price or prices so determined (expressed in dollars per gigajoule equivalent) shall be the "Discounted Electricity Price" for the applicable period.

(b) SGS-1, SGS-2, ACR-1, LGS-1, LGS-2 and LGS-3 Rates

Rates for Pioneer Customers within the SGS-1, SGS-2, ACR-1, LGS-1, LGS-2 and LGS-3 rate classes shall be determined independently from Centra's cost of service and shall be equal to the lesser of:

(i) the applicable Competitive Fuel Price, less the applicable Fuel Oil Discount as set out in Table 1 below; or

(ii) the applicable Discounted Electricity Price.

Table 1

FUEL OIL DISCOUNT

Year	Discount
1995	13%
1996	12%
1997	11%
1998 - 2001	10%

2.6 Other Pioneer Customer Rates 2002

The BCUC shall fix the rates charged by Centra to Pioneer Customers (other than those within the ACR-2 customer rate class) during 2002 independently from Centra's cost of service at the lesser of the rate that would be determined under Section 2.5(b)(i) (given a Fuel

Oil Discount of zero) and the rate for New Customers set in accordance with Section 2.7.

2.7 New Customer Rates 1995 - 2002

The BCUC shall fix the rates charged by Centra to New Customers for the period from the effective date of this Special Direction to December 31, 2002, in accordance with the following directions.

(a) General Principles

Rates should, to the greatest extent reasonably possible, be consistent with the goals of simplicity, equity between the various New Customer rate classes and the optimization of revenue to Centra. Centra is to be allowed flexibility in structuring its rates and, where it is determined by the BCUC to be appropriate, rates may be structured to include demand charges and commodity charges. The foregoing general principles shall be subject to the more specific directions set out below.

(b) Initial New Customer Rate Schedule

Rates charged to New Customers for the period from the effective date of this Special Direction to December 31, 1996, shall be those rates set out in the Initial New Customer Rate Schedule that is attached as Schedule "C" to this Special Direction.

(c) Rate Ceilings

Subject only to paragraph (d) below, the rates that are approved for each year from January 1, 1997, to December 31, 2002, shall be subject to rate ceilings determined in accordance with the following directions:

(i) A rate shall not be approved if it would result in an average customer (as described by reference to volume in Table 2 below) in any particular customer rate class being charged an effective unit price that would be greater than the effective unit price (determined as set out in subparagraph (iii) below) charged to that average customer in the immediately preceding year, increased by the allowable percentage increase set out in Table 3 below.

Table 2

AVERAGE ANNUAL CUSTOMER CONSUMPTION

SGS 11	70 GJ
SGS 12	270 GJ
LGS 11	945 GJ
LGS 12	2844 GJ
LGS 13	18793 GJ

Table 3

ANNUAL ALLOWABLE PERCENTAGE POINT INCREASE

1997	8%	2000	Annual CPI + 1%
1998	6%	2001	Annual CPI + 1%
1999	Annual CPI + 1%	2002	Annual CPI + 1%

(ii) If the increase in the effective unit price for an average customer in any particular customer rate class in any particular year described above is less than the allowable increase, then the difference may be carried forward to the next year so that the allowable percentage point increase for that customer rate class in the next year is increased accordingly. To the extent that the increased allowable percentage point increase is not utilized it may be carried forward in a similar fashion to subsequent years.

(iii) For the purpose of determining the rate ceilings, effective unit prices shall be calculated by taking into account all relevant demand and commodity charges, but shall not include any increase or decrease in charges which resulted from Passthrough Costs in accordance with paragraph (d) below and shall not include the charge described in Rider A as set out in Schedule "C" or any special service rates in the nature of those approved by the BCUC as of the effective date of this Special Direction. For greater certainty, it is intended that the rate ceilings be calculated so that any decrease or increase in Centra rates resulting from a Passthrough Cost in any particular year does not increase or decrease the rate ceiling applicable to a subsequent year.

(iv) Because the limitations on rate increases are governed by the effective unit price payable by average customers for each of the various customer rate classes, the effective unit prices actually payable by some New Customers may be subject to greater increases than described in this paragraph (c).

(v) If the BCUC approves a change to Centra's customer rate classes, then any resulting changed or additional customer rate class shall be subject to the limitations on rate increases described in this paragraph (c). The BCUC shall make any determination of average customer volumes, or any other matter that is necessary in order to calculate the effective unit price for an average customer of any changed or additional customer rate class.

(d) <u>Passthrough Costs and the New Customer Rate Balancing Account</u>

If, in any particular year, "Passthrough Costs" (meaning only those costs described below) have either increased or decreased, then notwithstanding the limitation on rate increases set out in paragraph (c) the rates charged by Centra to New Customers may be varied in accordance with Section 67(4) of the <u>Utilities Commission Act</u> and the following directions.

(i) Passthrough Costs for any particular year shall be determined by the BCUC as the aggregate of the following amounts:

(A) the change in the cost of service to New Customers in a particular year as a result of a change in Federal, Provincial, or Municipal tax rates;

(B) a change in the cost of service to New Customers as a result of a material and uncontrollable change in costs associated with a program established by any governmental or regulatory authority;

(C) the change in the cost of service to New Customers as a result of a difference between the "Actual Royalty Adjusted Cost of Gas" for a particular year, and the Designated Royalty Adjusted Cost of Gas for that year as set out in Schedule "D". The "Actual Royalty Adjusted Cost of Gas" for a particular year shall be determined as follows. Firstly, the BCUC shall determine Centra's cost of gas for the year being all of the costs incurred by Centra, and approved by the BCUC, to obtain gas for customer use and system use (including line losses, unaccounted for gas, and fuel requirements), including, without limitation:

(1) the purchase price of gas;

(2) gathering, processing, transportation, and storage costs; and

(3) costs of any arbitration relating to Centra's gas supply arrangements;

but excluding:

(4) commissions and gas management fees paid in connection with the purchase of gas;

(5) any toll paid by Centra to PCEC or any other cost associated with the transportation of gas through the Pipeline; and

(6) any cost associated with the transportation of gas from the point of interconnection of the pipeline systems of Westcoast Energy Inc. and BC Gas Utility Ltd. near Huntingdon (the "**Huntingdon Point of Interconnection**"), to the point of interconnection of the pipeline systems of BC Gas Utility Ltd. and PCEC in Coquitlam.

Secondly, the cost of gas for the year shall be reduced by the total of all

Royalty Revenue Payments for that year. Thirdly, the resulting number shall be divided by the total volume of gas delivered to Centra at the Huntingdon Point of Interconnection. For greater certainty, a change to the cost of service to New Customers as a result of a variation in the cost of gas as described herein may be either a negative or a positive amount.

(ii) Passthrough Costs shall include only that portion of increased costs that can be reasonably allocated to New Customers. Any portion of an increased cost that is allocated to the cost of service to other customers of Centra, together with other costs that would be allowed by the BCUC under Section 67(4) of the Utilities Commission Act, but which do not otherwise satisfy the definition of Passthrough Costs, shall be taken into account in determining whether Centra has incurred an Annual Revenue Deficiency, but shall not affect the rate ceilings applicable to Centra's New Customers.

(iii) Passthrough Costs for a particular year shall be recorded in a "New Customer Rate Balancing Account", which is a notional account for the purpose of determining adjustments to New Customer rates. The BCUC shall determine the manner in which positive or negative balances affect rates by taking into account the following objectives. Firstly, the impact of the variable nature of gas costs on New Customer rates should be minimized. Secondly, Centra, to the extent possible, should be able to increase its rates to New Customers by such amounts as are commensurate with any positive balance within the New Customer Rate Balancing Account that may exist from time to time.

(iv) The BCUC may require Centra to reduce the rates charged to New Customers in the event that the BCUC determines that there is a significant negative balance accumulating within the New Customer Rate Balancing Account that is not likely to be offset within a reasonable period of time.

2.8 Customer Rates 2003 and After

The BCUC shall fix the rates charged by Centra to its customers for the period beginning January 1, 2003, in the case of all customers other than those within the ACR-2 customer rate class, and January 1, 2004, in the case of customers formerly within the ACR-2 customer rate class, so that Centra is able to recover its cost of service in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

2.9 Gas Supply Hedging Arrangements and Transportation and Sales Service

Centra may use gas supply hedging arrangements, the terms and conditions of which have been approved by the BCUC, in order to manage the risk associated with the Revenue Deficiency Deferral Account. Centra shall file with the BCUC, in accordance with the requirements specified by the BCUC from time to time, transportation rates that shall be generally available for Centra's large commercial customers. Such rates shall be available in accordance with such terms and conditions as are from time to time determined by Centra and approved by the BCUC. If requested by Centra, such terms and conditions shall include a requirement that any customer who is purchasing gas from Centra at the time the terms and conditions are approved or who thereafter enters into a gas purchase agreement with Centra, shall not be permitted to switch to transportation service prior to December 31, 2002.

2.10 Cost of Service and Revenue Deficiencies

Subject to Part 4 of this Special Direction, the BCUC shall determine Centra's cost of service and shall make the various associated determinations, all as described in, and in accordance with, the following directions.

(a) General Principles

For each year in the period beginning January 1, 1996, Centra shall be regulated on a forecast test year basis and shall be required to apply to the BCUC for approval of its:

(i) cost of service for each year and in conjunction therewith the BCUC shall determine the allowable capital additions to be made during such year and such other matters as the BCUC may deem appropriate for the determination of Centra's cost of service; and

(ii) projected revenue for such year inclusive of all Royalty Revenue Payments payable by the Province in respect of that year.

(b) Rate Base, Revenue Deficiency Deferral Account Balance and Cost of Service 1991 - 1995

The following amounts shall be determined in accordance with the Vancouver Island Natural Gas Pipeline Agreement and shall be set forth in notices delivered by the Province to the BCUC pursuant to Article 9 thereof:

(i) net plant in service as of December 31, 1995, determined as the aggregate of:

(A) net plant in service as of December 31, 1994, of $211,474,000, less $90,000,000; and

(B) additions to net plant in service during 1995 which shall be determined by taking gross additions made during 1995 and adjusting for disposals and depreciation in 1995;

(ii) the Annual Revenue Deficiency for 1995;

(iii) the balance of the Revenue Deficiency Deferral Account as of December 31, 1995;

(iv) Centra's cost of service for the period October 1, 1991, to December 31, 1991 and each year from January 1, 1992 to December 31, 1995; and

(v) work in progress as of December 31, 1995.

Centra's rate base as of December 31, 1995, or any time thereafter, shall be:

(vi) the amount specified in paragraph (i) above; plus

(vii) an allowance for working capital as determined and approved by the BCUC from time to time; plus

(viii) the capital cost of any additions to Centra's Distribution System made after December 31, 1995 as determined and approved by the BCUC from time to time; plus

(ix) deferred charges and other miscellaneous rate base items (which shall in no event include any amount of the Revenue Deficiency Deferral Account or any amount that would change the amount for the net plant in service as of December 31, 1995) as determined and approved by the BCUC from time to time; less

(x) accumulated depreciation and disposals for the period after December 31, 1995, as determined and approved by the BCUC from time to time.

(c) <u>Deemed Equity</u>

Subject to paragraph (e), the equity component of Centra's rate base:

(i) shall be deemed to be 35% for each year from January 1, 1996, to December 31, 2002, and for greater certainty the balance of Centra's rate base shall be deemed to be financed by debt; and

(ii) for the period after December 31, 2002, shall be such percentage of Centra's rate base that is determined to be appropriate in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

(d) <u>Return on Equity</u>

The return on the equity component of Centra's rate base shall be the Long Canada Rate plus 375 basis points for each year from January 1, 1996, to December 31, 2002, and thereafter shall be such return that is determined to be appropriate in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia.

(e) <u>Debt Financing of Rate Base</u>

The level of deemed equity and the return allowed thereon that are stipulated in paragraphs (c) and (d) may be varied by the BCUC for any year from January 1, 1996, to December 31, 2002, if:

(i) the actual level of debt financing of Centra (excluding Class "B" Instruments that are actually issued to finance all or any portion of the Revenue Deficiency Deferral Account balance) exceeds 65% of the rate base that the BCUC has determined for Centra; and

(ii) the BCUC determines that this level of debt financing is adversely affecting the cost of debt for the purpose of determining cost of service.

(f) Determination of Revenue Deficiency Deferral Account Balance

The BCUC shall determine the amount recorded in Centra's Revenue Deficiency Deferral Account, which amount shall equal, at any particular time:

(i) the total of all Annual Revenue Deficiencies incurred on or before that time; plus

(ii) the total amount of Class "A" Instruments and Class "B" Instruments that are deemed to have been issued pursuant to paragraph 2.10(h)(v)B(2) on or before that time; less

(iii) the total amount of Class "A" Instruments and Class "B" Instruments that are deemed to have been redeemed or repaid pursuant to paragraph 2.10(i) on or before that time.

"**Annual Revenue Deficiency**" for the 1995 year is the amount described in paragraph 2.10(b)(ii) and for any particular year after December 31, 1995 is the amount, if any, by which Centra's "Adjusted Cost of Service" exceeds Centra's actual revenues relating to the Centra Distribution System (including Royalty Revenue Payments) for that year.

"**Adjusted Cost of Service**" means Centra's cost of service as approved by the BCUC on a forecast test year basis, excluding any amount for the amortization of Class "A" Instruments or Class "B" Instruments pursuant to paragraph 2.10(j) and subject to adjustments for variations as described below. BCUC approved variations (which may be either an increase or a decrease) between actual and forecast costs shall be taken into account in the determination of Adjusted Cost of Service, however, the BCUC shall not:

(iv) approve a variation between Centra's actual and forecast operating and maintenance expenses unless the variation was caused by a factor over which Centra had no effective control; and

(v) make any adjustment after the end of a particular year to the Long Canada Rate used to determine return on equity for that year.

For the purpose of illustration only, examples of the determination of Annual Revenue Deficiency and Adjusted Cost of Service for the purpose of determining the balance of the Revenue Deficiency Deferral Account are attached as Schedule "E" to this Special Direction.

(g) <u>Effect of Annual Revenue Deficiencies on Rate Base and Cost of Service</u>

The balance of the Revenue Deficiency Deferral Account, or any amount relating to the Annual Revenue Deficiency for any particular year, shall not at any time be included within Centra's rate base. Except as specifically allowed by paragraphs 2.10(h) and 2.10(j), Centra's cost of service for the purpose of determining the rates to be charged to Centra's customers shall not include any cost of financing the Revenue Deficiency Deferral Account balance, and shall not include any amount for the amortization, reduction, or recovery of the Revenue Deficiency Deferral Account balance.

(h) <u>Deemed Financing Costs That Are To Be Included Within the Cost of Service</u>

The amount recorded in the Revenue Deficiency Deferral Account shall be deemed to be financed by Class "A" Instruments, or, in the circumstances provided below, by Class "B" Instruments. Centra's cost of service for any particular year shall include the interest and dividends, as the case may be, that are payable in respect of that year on the Class "A" Instruments and the Class "B" Instruments that are deemed to be outstanding during that year. The amount of such interest and dividends shall be determined in accordance with the following directions.

(i) Unless a determination is made under paragraph (ii), the amount recorded in the Revenue Deficiency Deferral Account shall be deemed to be financed by Class "A" Instruments.

(ii) When the BCUC approves Centra's forecast cost of service the BCUC shall determine whether it would be appropriate to deem the amount recorded in the Revenue Deficiency Deferral Account, or any particular portion thereof, to be financed by Class "B" Instruments.

(iii) A determination under paragraph (ii) may only be made if the BCUC determines that the financing by Class "B" Instruments will not have an impact on Centra's cost of service for the forecast test year and subsequent years that would, on a cumulative basis, result in an adverse impact on the Revenue Deficiency Deferral Account that would have to be recovered through rates charged to customers.

(iv) To the extent that the BCUC deems any portion of the balance of the Revenue Deficiency Deferral Account to be financed by Class "B" Instruments which has previously been deemed to be financed by Class "A" Instruments, the Class "B" Instruments shall be deemed to have been converted from Class "A" Instruments in accordance with the terms and conditions contained in the form of Class "A" Instrument attached as Schedule "A". To the extent that the BCUC deems any portion of the balance of the Revenue Deficiency Deferral Account to be financed by Class "A" Instruments which has previously been deemed to be financed by Class "B" Instruments, the Class "A" Instruments shall be deemed to have been converted from Class "B" Instruments in accordance with the terms and conditions contained in the form of Class "B" Instrument attached as Schedule "B".

(v) The instruments that are deemed to be issued to finance any particular year's Annual Revenue Deficiency shall be deemed:

(A) to be issued on June 30th of the year following the year in which the Annual Revenue Deficiency was incurred for the purpose of determining the dividend or interest rate payable pursuant to such instruments;

(B) to be issued in an aggregate amount equal to the sum of:

(1) the Annual Revenue Deficiency for the year; and

(2) an additional amount to take into account Centra's cost of financing the Annual Revenue Deficiency during the year in which it arose. This additional amount shall equal the

interest or dividends, as the case may be, payable for a 6 month period, under the instruments deemed to be issued in respect of the amount in subparagraph (1) above; and

(C) to be issued on January 1 of the year following the year in which the Annual Revenue Deficiency was incurred, for the purpose of determining when interest or dividends begin to accrue and become payable pursuant to such instruments.

(i) <u>Deemed Redemption or Repayment of Instruments for the Determination of the Balance of the Revenue Deficiency Deferral Account</u>

If Centra's actual revenues relating to the Centra Distribution System for any particular year would exceed what would otherwise be Centra's Adjusted Cost of Service for that year, the BCUC shall deem Centra to redeem Class "A" Instruments or repay Class "B" Instruments at the midpoint of that year to the extent necessary to cause Centra's Adjusted Cost of Service to equal such revenues. The instruments that are deemed to be redeemed or repaid shall be those instruments which have a dividend or interest reset date, as defined in the terms and conditions applicable to the instrument, which is closest to the date of deemed redemption or repayment.

(j) <u>Deemed Redemption or Repayment of Instruments for the Determination of Cost of Service and Setting of Rates</u>

For each year beginning January 1, 2003, the cost of service of Centra that is approved by the BCUC for the purpose of determining the rates to be charged to Centra's customers shall include an amount for the deemed redemption of Class "A" Instruments or repayment of Class "B" Instruments that the BCUC determines to be appropriate in order to amortize the balance of the Revenue Deficiency Deferral Account over the shortest period reasonably possible, having regard for Centra's competitive position relative to alternative energy sources and the desirability of reasonable rates.

2.11 Assistance for Financing Requirements

The BCUC shall not apply Paragraph 3 of BCUC Order G-16-90 (the "Order") in any way that would require Centra to obtain assistance in regard to its debt/equity financing requirements from Westcoast Energy Inc., or from any corporation that is a parent, grandparent or successor, as these terms are used in Paragraph 3 of the Order, other than what is provided for in the Vancouver Island Natural Gas Pipeline Agreement.

PART 3
DIRECTION RESPECTING PCEC

3.1 Cost of Service

Subject to Part 4 of this Special Direction, the BCUC shall determine PCEC's cost of service in accordance with the following directions:

(a) Rate Base and Cost of Service 1991 - 1995

The following amounts shall be determined in accordance with the Vancouver Island Natural Gas Pipeline Agreement and shall be set forth in notices delivered by the Province to the BCUC pursuant to Article 9 thereof:

(i) PCEC's net plant in service as of December 31, 1995, determined as the aggregate of:

(A) PCEC's net plant in service as of December 31, 1994, of $192,120,673, less $30,000,000; and

(B) PCEC's additions to net plant in service during 1995 which shall be determined by taking gross additions made during 1995 and adjusting for disposals and depreciation in 1995;

(ii) PCEC's cost of service for each year from 1991 to December 31, 1995; and

(iii) work in progress as of December 31, 1995.

PCEC's rate base as of December 31, 1995, or any time thereafter, shall be:

(iv) the amount set out in paragraph (i); plus

(v) an allowance for working capital as determined and approved by the BCUC from time to time; plus

(vi) the capital cost of any additions to the Pipeline made after December 31, 1995 as determined and approved by the BCUC from time to time; plus

(vii) any amounts of the Canada Repayable Contribution or the British Columbia Repayable Contribution which have been repaid by PCEC; plus

(viii) deferred charges and other miscellaneous rate base items (which shall in no event include any amount that would change the amount for the net plant in service as of December 31, 1995) as determined and approved by the BCUC from time to time; less

(ix) accumulated depreciation and disposals for the period after December 31, 1995, as determined and approved by the BCUC from time to time.

(b) Adjustment to Cost of Service

For each year from January 1, 1996, to December 31, 2011, the return on the equity component of PCEC's rate base that would have been otherwise approved by the BCUC shall be reduced by the amount of $1,867,000. Such reduction shall not be recovered in whole or in part, directly or indirectly, through rates or tolls in any manner whatsoever.

(c) Effect of Interruptible Incentive Payments

Interruptible Incentive Payments that are payable to PCEC in respect of any particular year shall be taken into account as revenues received by PCEC in partial recovery of its cost of service for that year.

(d) Effect of Monthly Toll Revenue - Squamish Gas

During the term of the Rate Stabilization Facility Continuation Agreement, the Monthly Toll Revenues determined pursuant to that agreement shall be taken into account as the only revenues received by PCEC in recovery of its cost of service with respect to the transportation and delivery of gas pursuant to the Squamish Gas Transportation Service Agreement.

3.2 Joint Venture Transportation Service Agreement

The BCUC shall approve the transportation service agreement between PCEC and the Joint Venture, including the transportation tolls provided for therein, that is attached as Schedule "F" to this Special Direction.

3.3 Squamish Gas Transportation Service Agreement

In regulating the transportation tolls charged by PCEC to Squamish Gas for service provided pursuant to the Squamish Gas Transportation Service Agreement, the BCUC shall apply the service rate provisions of that agreement for the period contemplated by the Squamish Rate Stabilization Agreement.

3.4 Centra Transportation Service Agreement

The BCUC shall approve the transportation service agreement between PCEC and Centra, including the transportation tolls provided for therein, that is attached as Schedule "G" to this Special Direction.

3.5 General Terms and Conditions

The "General Terms and Conditions" attached as Schedule "H" to this Special Direction shall be approved by the BCUC as the general contractual terms and conditions applicable to the transportation service agreements referred to in Sections 3.2 and 3.4 and to the other transportation service agreements that PCEC may enter into from time to time after the effective date of this Special Direction.

3.6 Variations of General Terms and Conditions and Joint Venture Transportation Service Agreement

The BCUC shall not amend, change, alter, or vary the transportation service agreement referred to in Section 3.2 or the General Terms and Conditions referred to in Section 3.5, if such amendment, change, alteration, or variation would have the effect of either:

(a) varying the transportation tolls or other amounts payable to PCEC for the services provided to the Joint Venture pursuant to that transportation service agreement; or

Premier Harcourt

(b) increasing or decreasing the Contract Demand for Firm Transportation Service determined in accordance with that transportation service agreement, or the quantities of Interruptible Offset Gas which the Joint Venture is entitled to receive pursuant to that transportation service agreement.

3.7 Rates and Transportation Tolls Otherwise Applicable to the Joint Venture, Squamish Gas, and Centra

For the purpose of fixing transportation tolls to be charged by PCEC other than as directed in Sections 3.2, 3.3 and 3.4, the BCUC shall, subject to the exception set out below, apply such regulatory principles that are generally applied by the BCUC from time to time to gas utilities operating within British Columbia. In no event whatsoever shall the rates or transportation tolls that are approved for the Joint Venture or Squamish Gas pursuant to this Section 3.7 include any amount for the recovery in whole or in part, directly or indirectly, of dividends or interest as described in paragraph 2.10(h), or for the amortization, reduction, or recovery of the Revenue Deficiency Deferral Account balance.

3.8 Allocation of PCEC's Cost of Service to Service Squamish Gas

The BCUC shall, upon receipt of a written request from the Province, determine that portion of PCEC's annual cost of service for any particular year that relates to providing transportation service to Squamish Gas during that year.

PART 4
DETERMINATION OF ANNUAL REVENUE DEFICIENCY, RATE BASE, CAPITAL STRUCTURE AND RETURN ON EQUITY WHERE THE PIPELINE AND THE CENTRA DISTRIBUTION SYSTEM ARE OWNED BY A SINGLE ENTITY

4.1 Annual Revenue Deficiencies

The BCUC shall determine Annual Revenue Deficiencies and the balance of the Revenue Deficiency Deferral Account for a Single

Entity in the manner set out in Section 2.10 based upon the actual revenue and the cost of service associated with both the Centra Distribution System and the Pipeline but without taking into account any revenue or costs that relate to any other business conducted, or assets owned, by the Single Entity.

4.2 Rate Base, Capital Structure and Return on Equity

A single rate base shall be determined for the Single Entity in accordance with the directions in paragraphs 2.10(b) and 3.1(a). Subject to Sections 4.3 and 4.4, for any particular year from January 1, 1996, to December 31, 2002:

(a) the equity component of the Single Entity's rate base shall be deemed to be 35% and, for greater certainty, the balance of the Single Entity's rate base shall be deemed to be financed by debt; and

(b) the return on the equity component of the Single Entity's rate base shall be the Long Canada Rate plus 362.5 basis points.

Subject to Section 4.3, after December 31, 2002, the capital structure and return on equity for the Single Entity shall be determined in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas transportation and distribution utilities operating within British Columbia.

4.3 Adjustment to Return on Equity

The reduction to the return on the equity component of PCEC's rate base that is described in paragraph 3.1(b) shall continue to be made to the return on the equity component of the rate base of the Single Entity.

4.4 Debt Financing of Rate Base

The level of deemed equity and the return allowed thereon that are stipulated in Section 4.2 may be varied by the BCUC for any year from January 1, 1996, to December 31, 2002, if:

(a) the actual level of debt financing of the Single Entity (excluding Class "B" Instruments that are actually issued to finance all or any portion of the Revenue Deficiency Deferral Account balance) exceeds 65% of the rate base that the BCUC has determined for the Single Entity; and

(b) the BCUC determines that this level of debt financing is adversely affecting the cost of debt for the purpose of determining cost of service.

4.5 Separate Records

The BCUC shall require that the Single Entity keep separate records relating to the Pipeline and the Centra Distribution System sufficient at all times to differentiate, where appropriate, between all activities related to the construction and operation of the Pipeline and the Centra Distribution System.

PART 5
DIRECTION RESPECTING SQUAMISH GAS

5.1 Customer Rates

The BCUC shall fix the rates charged by Squamish Gas to its customers in accordance with the Squamish Rate Stabilization Agreement during the period for which that agreement remains in effect and, thereafter, in accordance with the regulatory principles that are generally applied by the BCUC from time to time to gas distribution utilities operating within British Columbia. In this regard, the BCUC shall have regard, during the period when the Squamish Rate Stabilization Agreement remains in effect, to the provisions in the "Binding Agreement", as that term is defined in the Squamish Rate Stabilization Agreement, notwithstanding any amendment or termination of the Binding Agreement subsequent to July 9, 1992.

5.2 Regulation and Other Determinations Pursuant to the Squamish Rate Stabilization Agreement

The BCUC shall regulate Squamish Gas, determine the cost of service of Squamish Gas, and make the various determinations required in order to implement the Squamish Rate Stabilization Agreement, all in accordance with the Squamish Rate Stabilization Agreement during the period for which that agreement is in effect.

SCHEDULE F
TO
SPECIAL DIRECTION
TO THE BRITISH COLUMBIA UTILITIES COMMISSION

See attached JOINT VENTURE TRANSPORTATION SERVICE AGREEMENT

TRANSPORTATION SERVICE AGREEMENT

THIS AGREEMENT dated as of the 14th day of December, 1995

BETWEEN:

PACIFIC COAST ENERGY CORPORATION, a company incorporated under the laws of British Columbia and having offices in Vancouver, British Columbia

("Pacific Coast")

OF THE FIRST PART

AND

MACMILLAN BLOEDEL LIMITED, HOWE SOUND PULP AND PAPER LIMITED, FLETCHER CHALLENGE CANADA LIMITED, WESTERN PULP LIMITED PARTNERSHIP and **HARMAC PACIFIC INC.**, each of which is a corporation or limited partnership having offices in Vancouver, British Columbia, operating for the purposes of this Agreement as a joint venture called the "Vancouver Island Gas Joint Venture"

("Shipper")

OF THE SECOND PART

WHEREAS Shipper has requested Pacific Coast to provide it with the Firm Transportation Service and the Interruptible Transportation Service described in this Agreement and Pacific Coast has agreed to provide Shipper with such services in accordance with and subject to the terms and conditions hereinafter set forth;

NOW THEREFORE, in consideration of the mutual agreements hereinafter contained, the parties hereto agree as follows:

ARTICLE 1.

GENERAL TERMS AND CONDITIONS

1.01 Incorporation. The provisions of Pacific Coast's General Terms and Conditions for Gas Transportation Service, other than Section 17.02 thereof, as accepted for filing by the BCUC and in effect from time to time, are incorporated herein by reference and constitute part of this Agreement. Unless otherwise defined herein, the terms and expressions used in this Agreement have the same meaning as the corresponding terms and expressions used in Pacific Coast's General Terms and Conditions for Gas Transportation Service. If there is any conflict or inconsistency between the provisions of this Agreement and the provisions of the General Terms and Conditions for Gas Transportation Service, the provisions of this Agreement shall prevail.

Accepted for filing: DEC - 8 1995
Effective: DEC 30 1995
Order No: G-105-95/G-108-95 & G-4-96
JAN 25 199

ARTICLE 2.

DEFINITIONS

2.01 Definitions. In and for the purposes of this Agreement:

(a) "Centra Distribution System" means the property and assets used by Centra Gas British Columbia Inc. and its subsidiaries in the gas distribution business carried on in the areas served by the Pacific Coast System, both as of the date of this Agreement and following the transfer of such property and assets to Pacific Coast whether by conveyance, assignment, merger, amalgamation or otherwise;

(b) "Commodity Toll" means in respect of each Month in the term of this Agreement, including the Renewal Period, that toll, expressed in dollars per gigajoule, fixed by the BCUC in respect of:

(i) Motor Fuel Tax and other taxes payable by Pacific Coast in respect of System Gas;

any excise or other taxes payable by Pacific Coast in respect of gas transported and delivered through the Pacific Coast System; and

odorant costs payable by Pacific Coast to BC Gas in accordance with the Wheeling Agreement;

(c) "Contract Demand Reduction" means in respect of each Month in the term of this Agreement, including the Renewal Period, that quantity of gas, in gigajoules per Day, equal to the quantity by which:

(i) the aggregate of the reductions in the Contract Demand effected by Shipper in accordance with Sections 3.04 and 3.05 hereof as of the first day of the Month exceeds

the aggregate of the reinstatements of the Contract Demand effected in accordance with Section 3.10 hereof as of the first day of the Month,

subject to reduction for any part of that quantity of gas in respect of which a Third Party Shipper is paying tolls to Pacific Coast pursuant to a Service Agreement entered into by that other shipper with Pacific Coast.

(d) "Demand Toll" means, in respect of each Month in the term of this Agreement including the Renewal Period, that toll, expressed in dollars per gigajoule of Contract Demand per Day, determined in accordance with Schedule A;

(e) "Expansion Project" means any project for the construction, installation or modification of facilities on the Pacific Coast System, which increases the capacity of the Pacific Coast System to transport and deliver additional gas under a Service Agreement providing for Firm Transportation Service;

(f) "Fibre Supply Shortage" means those circumstances where, for any reason, one or more of Owners' Mills is unable to obtain sufficient fibre supply to operate at capacity and, as a direct result, the production level at any such mill is curtailed;

"Initial Term" means the period commencing at the Transition Time and ending at 0800 PST on January 1, 2006;

(h) "Interruptible Offset Account" means the account in respect of Interruptible Offset Gas maintained in accordance with Article 4;

(i) "Interruptible Offset Gas" means the quantities of gas recorded in the Interruptible Offset Account in accordance with Article 4;

(j) "Interruptible Toll" means, in respect of each Month in the term of this Agreement including the Renewal Period, that toll, expressed in dollars per gigajoule, determined in accordance with Schedule B;

"Labour Disturbance" means a strike, lockout or other labour disruption affecting one or more of Owners' Mills;

(l) "Market Out" means those circumstances where one or more of Owners' Mills is shut down or production curtailed by reason of lack of demand for the products produced at the mill and, as a direct result, the production level at such mill is curtailed;

"Owners" means, collectively, the corporations and partnerships specified in the first column in Section 9.01, and such other corporations or partnerships as may become parties to this Agreement in addition to or in substitution for the corporations and partnerships specified in Section 9.01 pursuant to an amendment made in accordance with Section 9.03;

(n) "Owners' Mills" means the seven pulp and paper mills and related facilities located on the sites owned by one or more of the Owners at Woodfibre, Port Mellon, Powell River, Elk Falls, Port Alberni, Harmac and Crofton, British Columbia, which mills are connected to the Pacific Coast System at the Delivery Points;

"Participating Interest" means in respect of each of the Owners, that share of the total liability of Shipper under this Agreement allocated to each such Owner from time to time in accordance with Article 9;

(p) "Renewal Period" means the five year period commencing at 0800 PST on January 1, 2006 and ending at 0800 PST on January 1, 2011;

"Revenue Deficiency" means for any period the amount by which the cost of service incurred in that period exceeds the actual revenues received for that period, whether recorded or not in a revenue deficiency or deferral account;

(r) "Schedule A" means the schedule entitled "Demand Tolls, Firm Transportation Service" attached to this Agreement;

(s) "Schedule B" means the schedule entitled "Interruptible Tolls, Interruptible Transportation Service" attached to this Agreement;

(t) "Schedule C" means the schedule entitled "Delivery Points" attached to this Agreement;

"Third Party Shipper" means any party other than Shipper, Pacific Coast, Centra Gas British Columbia Inc., or their respective successors;

"this Agreement" means this agreement and includes Pacific Coast's General Terms and Conditions for Gas Transportation Service, Schedule A, Schedule B and Schedule C; and

"Transition Time" means the Transition Time as defined in the Transition and Release Agreement dated as of December 14, 1995 among Pacific Coast, Shipper and Her Majesty the Queen in Right of British Columbia as represented by the Minister of Energy, Mines and Petroleum Resources.

ARTICLE 3.

FIRM TRANSPORTATION SERVICE

3.01 Firm Service. Subject to the provisions of this Agreement, Pacific Coast shall, on each Day in the term of this Agreement, provide Shipper with Firm Transportation Service to the Delivery Points in respect of that quantity of gas requested and supplied by Shipper at the Receipt Point not exceeding the Contract Demand.

3.02 Contract Demand - Initial Term. The Contract Demand for the Initial Term shall be 40,000 gigajoules of gas per Day,

(a) less any reduction in the Contract Demand effected in accordance with Sections 3.04, 3.07, 3.08 and 10.01; and

JAN 25 1996

Accepted for filing: DEC - 8 1995
Effective: DEC 30 1995
Order No.: G-105-95/G-108-95
G-4-96 stale/5%

(b) plus any reinstatement of the Contract Demand effected in accordance with Section 3.10.

Contract Demand - Renewal Period. The Contract Demand for the Renewal Period shall be the Contract Demand in effect on the last Day of the Initial Term, less any reduction in the Contract Demand effected in accordance with Sections 3.05, 3.07, 3.08 and 10.01 during the Renewal Period.

Contract Demand Reduction by Notice - Initial Term. If there is a reduction, other than a temporary reduction, in:

(a) the energy requirements of Owners' Mills; or

(b) the gas requirement of Owners' Mills as a result of increased or more efficient usage of wood waste as a form of energy for any of Owners' Mills,

Shipper may, subject to Sections 3.09 and 10.01 and subject to giving notice to Pacific Coast in accordance with Section 3.06, reduce the Contract Demand in effect in accordance with this Agreement by a quantity of gas not exceeding 10,000 gigajoules per Day in aggregate, as follows:

(c) 5,000 gigajoules per Day, by giving notice to Pacific Coast in accordance with this Section to be effective at any time during that part of the Initial Term ending on December 31, 2000; and

(d) 5,000 gigajoules per Day, by giving notice to Pacific Coast in accordance with this Section to be effective at any time during the last five years in the Initial Term.

Contract Demand Reduction by Notice - Renewal Period. If in the Renewal Period there is a reduction, other than a temporary reduction, in:

(a) the energy requirements of Owners' Mills; or

(b) the gas requirements of Owners' Mills as a result of increased or more efficient usage of wood waste as a form of energy for any of Owners' Mills,

Shipper may, subject to giving notice to Pacific Coast in accordance with Section 3.06, reduce the Contract Demand in effect in accordance with this Agreement by a quantity of gas equal to:

(c) that portion of the 10,000 gigajoules per Day available to reduce the Contract Demand under Section 3.04 which was not utilized during the Initial Terms to a maximum of 5,000 gigajoules per Day in aggregate; or if the Contract Demand is reduced in accordance with Subsection 10.01(e), that portion of the 10,000 gigajoules per Day available to reduce the Contract Demand under Section 3.04 which was not utilized during the Initial Term, less the sum of:

(i) any reduction in the Contract Demand effected in accordance with this Section prior to any reduction being made to the Contract Demand pursuant to Subsection 10.01(e); and

(ii) the reduction in the Contract Demand effected in accordance with Subsection 10.01(e).

No reduction in the Contract Demand shall be made in accordance with this Section if or to the extent that such reduction would reduce the Contract Demand to a quantity of less than 30,000 gigajoules per Day.

3.06 Notice and Effective Time. To effect a reduction in the Contract Demand pursuant to Sections 3.04 or 3.05, Shipper shall give Pacific Coast at least six months notice of any Contract Demand reduction not exceeding 3,000 gigajoules per Day, and at least 12 months notice of any Contract Demand reduction in excess of 3,000 gigajoules per Day, provided that Shipper shall not, during any period of 12 consecutive months, give two or more notices of Contract Demand reductions not exceeding 3,000 gigajoules per Day if the aggregate of those reductions would exceed 3,000 gigajoules per Day. Any notice given by Shipper pursuant to this Section shall set out sufficient information to permit Pacific Coast to determine the circumstances giving rise to the reduction in energy requirements and to assess the quantity of that reduction. A Contract Demand reduction effected by notice in accordance with Sections 3.04 and 3.05 shall come into effect at 0800 PST on the first Day of the Month immediately following:

(a) the expiration of the six month notice period, in the case of a reduction not exceeding 3,000 gigajoules per Day; and

the expiration of the 12 month notice period, in the case of a reduction exceeding 3,000 gigajoules per Day.

3.07 Contract Demand Reduction - Cogeneration Plant. If a cogeneration plant, which utilizes gas transported through the Pacific Coast System, is brought into operation and if the operation of that cogeneration plant results in a reduction, other than a temporary reduction, in the gas requirements of one or more of Owners' Mills, Shipper may, by giving at least six months notice to Pacific Coast, reduce the Contract Demand then in effect by a quantity of gas, in gigajoules per Day, not exceeding the reduction in the gas requirements of Owners' Mills resulting from the operation of the cogeneration plant. Any notice given by Shipper pursuant to this section shall set out sufficient information to permit Pacific Coast to assess the quantity of the reduction in the gas requirements of Owners' Mills resulting from the operation of the cogeneration plant. Any reduction in the Contract Demand effected by notice in accordance with this Section shall come into effect at 0800 PST on the later of:

the first Day of the Month immediately following the expiration of the notice period; or

the Day on which that cogeneration plant has been commissioned and commences regular operation.

3.08 Contract Demand Reduction - Expansion Projects. If Pacific Coast proposes to proceed with an Expansion Project, Pacific Coast shall give notice to Shipper no more than 24 months prior to the planned in-service date for the Expansion Project, which notice shall set out the planned in-service date and the increase in the firm capacity of the Pacific Coast System, in gigajoules per Day, which would result from the Expansion Project. If Pacific Coast gives Shipper notice of an Expansion Project, Shipper shall have the right to reduce the Contract Demand in effect in accordance with this Agreement by a quantity of gas, in gigajoules per Day, not exceeding the capacity increase specified in the notice given by Pacific Coast, provided that notice of Shipper's election to so reduce the Contract Demand is given to Pacific Coast within 90 days of the receipt by Shipper of the notice given by Pacific Coast pursuant to this Section. Any Contract Demand reduction effected by Shipper in accordance with this Section shall be effective at 0800 PST on the earlier of the in-service date specified in the notice given by Pacific Coast or on the actual in-service date for the Expansion Project.

3.09 Limitation on Contract Demand Reductions. If Shipper reduces the Contract Demand by a notice given pursuant to Section 3.08 which becomes effective during either of the periods specified in Subsections 3.04(c) and (d), then Shipper's right to reduce the Contract Demand in either such period pursuant to Section 3.04 shall be reduced, effective the Day Shipper gives a notice pursuant to Section 3.08, by a quantity of gas, in gigajoules per Day, equal to the lesser of:

(a) 25 percent of the reduction in the Contract Demand effected by Shipper in accordance with Section 3.08; and

(b) that part of the 5,000 gigajoules of gas per Day for either such period in respect of which Shipper has not exercised its reduction rights under Section 3.04 as of the Day notice is given by Shipper pursuant to Section 3.08.

3.10 Reinstatement of Contract Demand. If Shipper has reduced the Contract Demand pursuant to any of Sections 3.04, 3.05, 3.07, 3.08 or 10.01, Shipper may, by giving notice to Pacific Coast, request the reinstatement of the Contract Demand to a quantity not exceeding 40,000 gigajoules per Day. Pacific Coast shall, following the receipt of a notice given by Shipper, reinstate the Contract Demand up to that quantity requested by Shipper, subject to firm capacity being or becoming available on the Pacific Coast System for the remainder of the term of this Agreement, including the Renewal Period, or, if such capacity is not so available, for such shorter period as may be specified by Pacific Coast. Such reinstatement of the Contract Demand shall become effective at 0800 PST on the first Day of the Month following the time at which such firm capacity becomes available, or at such earlier time as may be agreed upon by Shipper and Pacific Coast. Nothing in this Section shall be construed to require Pacific Coast to undertake or proceed with an Expansion Project.

Assignment of Contract Demand. Shipper shall have the right to assign all or part of the Contract Demand in effect under this Agreement to a Third Party Shipper provided Shipper has obtained the prior written approval of Pacific Coast for such assignment, such approval not to be unreasonably withheld or delayed. Shipper shall be relieved, for the period of the assignment, from its obligations under this Agreement in respect of the Contract Demand or part thereof so assigned with the approval of Pacific Coast.

Contract Demand Reductions. For greater certainty, nothing in this Agreement shall operate to limit the quantity of a reduction in the Contract Demand that may be effected by Shipper pursuant to and in accordance with Sections 3.07, 3.08, 3.11 and 10.01, except as provided in those Sections.

ARTICLE 4.

UNUTILIZED CONTRACT DEMAND AND INTERRUPTIBLE OFFSET GAS

4.01 Interruptible Offset Gas. Shipper shall be entitled during any year in the term of this Agreement, including the Renewal Period, to offset unutilized Firm Transportation Service with deliveries of gas under Interruptible Transportation Service in the manner and to the extent provided in this Article, if:

(a) the operations of one or more of Owners' Mills are interrupted or curtailed by reason of a Market Out, a Fibre Supply Shortage or a Labour Disturbance;

(b) as a result of such interruption or curtailment, the total quantity of gas delivered to Shipper on any Day pursuant to this Agreement is less than the Contract Demand in effect on such Day; and

(c) Shipper has first given notice to Pacific Coast in accordance with Section 4.02.

4.02 Notice by Shipper. If Shipper anticipates that the operations of one or more of Owners' Mills is or will be interrupted or curtailed by reason of a Market Out, a Fibre Supply Shortage or a Labour Disturbance, Shipper shall give as much notice to Pacific Coast as is practicable specifying its intention to offset unutilized Firm Transportation Service in accordance with this Article, which notice shall:

(a) state which of Owners' Mills is or will be affected by an interruption or curtailment of operations;

(b) state the date on which such interruption or curtailment of operations commenced or is to commence and its anticipated duration; and

(c) describe the circumstances constituting the Market Out, Fibre Supply Shortage or Labour Disturbance giving rise to such interruption or curtailment of operations.

4.03 Quantity. Subject to the limitations set out in Section 4.04, the quantity of gas which may be added to the Interruptible Offset Account in respect of any Day from and including the Day specified in the notice given pursuant to Section 4.02 as being the Day upon which an interruption or curtailment in the operation of Owners' Mills is to commence, shall be that quantity of gas, in gigajoules, equal to the difference obtained by subtracting the actual quantity of gas delivered to Shipper on any such Day from the lesser of:

(a) the Contract Demand in effect on that Day; and

(b) the quantity of gas which would have been delivered to Shipper on that Day if such interruption or curtailment in the operations of Owners' Mills had not occurred,

provided that the difference shall not be less than zero. For the purposes of Subsection 4.03(b), the arithmetic average of the daily quantities of gas delivered by Pacific Coast to Shipper during the Month in which such Day occurred in each of the two immediately preceding years shall, subject to adjustment for Labour Disturbances and permanent changes in the production levels of Owners' Mills, be deemed to be the quantity of gas which would have been delivered to Shipper on any such Day.

4.04 Limitations. The quantity of gas in gigajoules which may be added to the Interruptible Offset Account in any year in the term of this Agreement, including the Renewal Period, shall not exceed:

(a) 40 percent of the then current Contract Demand on up to 28 Days in any year; and

(b) 20 percent of the then current Contract Demand on any other Day in the year,

provided that the total quantity of gas added to the Interruptible Offset Account in any year shall not under any circumstances exceed one million gigajoules.

Monthly Statements. Pacific Coast shall include in the statement delivered to Shipper for each Month in accordance with Section 8.01 of the General Terms and Conditions, for Gas Transportation Service the following information respecting the Interruptible Offset Account:

(a) the opening balance in the account at the beginning of the Month;

(b) the quantities of gas added to, and delivered from, the account during the Month; and

(c) the closing balance in the account at the end of the Month.

ARTICLE 5.

INTERRUPTIBLE TRANSPORTATION SERVICE

Interruptible Service. Subject to the provisions of this Agreement and to the availability of capacity on the Pacific Coast System, Pacific Coast shall, on each Day in the term of this Agreement including the Renewal Period, provide Shipper with Interruptible Transportation Service to the Delivery Points in respect of that quantity of gas in excess of the Contract Demand requested and supplied by Shipper at the Receipt Point.

ARTICLE 6.

TOLLS

Monthly Tolls - Firm Transportation Service. Shipper shall pay to Pacific Coast in respect of the Firm Transportation Service provided to Shipper in each Month in the term of this Agreement, including the Renewal Period, an amount equal to the sum of:

(a) the product obtained by multiplying the Demand Toll by the product obtained by multiplying the Contract Demand in effect in each such Month by the number of Days in the Month; and

(b) the product obtained by multiplying the Commodity Toll for each such Month by the total quantity of gas delivered to Shipper under such service at the Delivery Points in each such Month.

JAN 25 1996

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Additional Monthly Demand Toll Amount. If Shipper reduces its Contract Demand in accordance with Section 3.04 or Section 3.05, Shipper shall, in addition to the Demand Tolls payable in accordance with Section 6.01, pay to Pacific Coast an additional Demand Toll amount determined for each Month in the term of this Agreement, including the Renewal Period, in accordance with the following formula:

$$ADT = 35/100 \times DT \times CDR \times DM$$

Where:

"ADT" is the additional Demand Toll amount payable for the Month;

"DT" is the Demand Toll in effect for the Month;

"CDR" is the Contract Demand Reduction for the Month; and

"DM" is the number of days in the Month.

Monthly Tolls - Interruptible Transportation Service. Shipper shall pay to Pacific Coast in respect of the Interruptible Transportation Service provided to Shipper in each Month in the term of this Agreement, including the Renewal Period, an amount equal to the sum of:

(a) the product obtained by multiplying the Interruptible Toll by the quantity of gas, other than Interruptible Offset Gas, delivered to Shipper under such service in each such Month; and

(b) the product obtained by multiplying the Commodity Toll by the total quantity of gas delivered to Shipper under such service in each such Month.

ARTICLE 7.

DELIVERY POINTS, TEMPERATURE AND PRESSURE

Delivery Points. The Delivery Points shall be at those points where the Pacific Coast System connects with the facilities of Shipper, as described in Schedule C.

Delivery Temperature and Pressure. Gas delivered by Pacific Coast to Shipper at the Delivery Points shall be at a pressure not exceeding 225 psig, and at a temperature of not less than 40 degrees Fahrenheit.

ARTICLE 8.

SHIPPER'S GAS SUPPLY MANAGER

Appointment and Functions. Shipper has appointed Inland Pacific Energy Services Ltd. ("Inland") as Shipper's gas supply manager, and Inland will on behalf of Shipper:

(a) arrange for Shipper's gas supply;

(b) make nominations and administer curtailments for and on behalf of Shipper;

(c) receive statements delivered by Pacific Coast for transportation services; and

(d) arrange payments to Pacific Coast for and on behalf of Shipper.

Shipper acknowledges that Pacific Coast shall be entitled to deal with, and Shipper shall deal with, Inland as Shipper's gas supply manager on its behalf until notice of the revocation of Inland's appointment has been given by Shipper to Pacific Coast. Shipper may thereafter appoint another person as Shipper's gas supply manager, and shall give notice of such appointment to Pacific Coast.

ARTICLE 9.

LIABILITY

Several Liability. The parties hereto agree that each reference to Shipper in this Agreement shall include each of the Owners severally only, and that all covenants, agreements, representations, and warranties of Shipper contained in, and liabilities and obligations of Shipper under, this Agreement shall be deemed to be several covenants, agreements, representations, warranties, liabilities and obligations of each of the Owners, allocated as follows:

Owner	Share of Total Liability
Fletcher Challenge Canada Limited	36.72%
Howe Sound Pulp and Paper Limited	14.92%
MacMillan Bloedel Limited	27.23%
Western Pulp Limited Partnership	10.37%
Harmac Pacific Inc.	10.76%

as such allocation may be modified from time to time in accordance with Section 9.03

Participating Interests. Shipper represents and warrants to Pacific Coast that, as of December 14, 1995, the respective Participating Interests (as defined in the joint venture agreement among the parties comprised in Shipper) in the Vancouver Island Gas Joint Venture are the same as the allocation of liability set forth in the second column in Section 9.01.

Change in Participating Interests. Shipper shall give notice to Pacific Coast each time there is any change in the corporations and partnerships having Participating Interests in the Vancouver Island Gas Joint Venture from those specified in the first column in Section 9.01, or in the respective Participating Interests of the Owners in the Vancouver Island Gas Joint Venture from those specified in the second column in Section 9.01. At the request of Shipper from time to time and with the consent of Pacific Coast, each such consent not to be unreasonably withheld or delayed, Pacific Coast and Shipper shall execute and deliver an amendment to this Agreement amending the list of Owners set forth in Section 9.01, or allocation of liability set forth in Section 9.01 to conform with the Participating Interests then existing in the Vancouver Island Gas Joint Venture.

ARTICLE 10.

DEFAULT BY OWNER

10.01 Default by Owner. If Shipper fails to pay the entire amount due in respect of any Month in the term of this Agreement within the time and in the manner provided in Section 8.02 of the General Terms and Conditions for Gas Transportation Service by reason of the failure of an Owner (the "Defaulting Owner") to perform its obligations under this Agreement, Shipper shall forthwith give notice to Pacific Coast identifying the Defaulting Owner. In addition to any other rights and remedies which Pacific Coast may have arising out of such failure by the Defaulting Owner, the following provisions shall apply:

(a) Pacific Coast shall give notice of the default in payment to Shipper. If Shipper has not, within two business days of the day upon which such notice is received from Pacific Coast, remedied the default in payment in accordance with Section 8.02 of the General Terms and Conditions for Gas Transportation Service, the provisions of Subsections 10.01(b) to (h), inclusive, shall apply.

(b) Pacific Coast may immediately suspend all further deliveries of gas to the Defaulting Owner.

(c) Shipper may, with the consent of Pacific Coast, such consent not to be unreasonably withheld or delayed, reallocate to one or more of the other Owners all or part of the Contract Demand, allocated in accordance with the Participating Interests specified in Section 9.01, to the Defaulting Owner (the "Defaulting Owner's Contract Demand"), provided that Shipper gives notice to Pacific Coast within five business days of the receipt of the notice given by Pacific Coast pursuant to Subsection 10.01(a), of such reallocation to the other Owners and of the change in the Participating Interests of the Owners (other than the Defaulting Owner) resulting from such reallocation.

(d) The reallocation of the Contract Demand effected by Shipper in accordance with Subsection 10.01(c) shall take effect on the Day next following the day on which Shipper receives a notice from Pacific Coast consenting to:

(i) the reallocation of all or part of the Defaulting Owner's Contract Demand made by Shipper in accordance with Subsection 10.01(c); and

the change in the Participating Interests of the other Owners in accordance with Section 9.03.

(e) If the default in payment occurs during the Initial Term or the Renewal Period, that part of the Defaulting Owner's Contract Demand which has not been reallocated to the other Owners in accordance with Subsections 10.01(c) and (d), shall be applied:

(i) as a reduction of the Contract Demand in effect pursuant to Article 3 as at the time of the default in payment by the Defaulting Owner;

(ii) as a reduction of Shipper's right to reduce the Contract Demand in accordance with Section 3.04 in the manner provided in Subsection 10.01(f), if the default in payment occurs during the Initial Term; and

as a reduction of Shipper's right to reduce the Contract Demand in accordance with Section 3.05 in the manner provided in Section 3.05, if the default in payment occurs during the Renewal Period,

such reductions to be effective:

in the case where part of the Defaulting Owner's Contract Demand is reallocated to one or more of the other Owners in accordance with Subsections 10.01(c) and (d), on the Day upon which such reallocation becomes effective in accordance with Subsection 10.01(d); and

(v) in any other case, at 0800 PST on the seventh business day following the day on which notice is given by Pacific Coast to Shipper in accordance with Subsection 10.01(a).

(f) If the Contract Demand is reduced during the Initial Term in accordance with Subsection 10.01(e), then, notwithstanding Subsections 3.04(c) and (d), Shipper may, at any time during the remainder of the Initial Term, reduce the Contract Demand in accordance with Section 3.04 by a quantity equal to 10,000 gigajoules per Day less the sum of:

(i) any reductions in the Contract Demand effected by Shipper pursuant to Section 3.04 prior to the default in payment by the Defaulting Owner; and

(ii) the reduction in the Contract Demand effected in accordance with Subsection 10.01(e)

provided that the quantity shall not be less than zero.

(g) The Owners other than the Defaulting Owner, as Shipper, shall pay to Pacific Coast the additional Demand Toll amount, determined in accordance with Section 6.02, in respect of any reduction of the Contract Demand effected in accordance with Subsection 10.01(e) during the Initial Term or the Renewal Period to the extent those reductions reduce the Contract Demand to a quantity of not less than 30,000 gigajoules per Day, subject to reduction for any amounts recovered by Pacific Coast from the Defaulting Owner as a result of the failure of payment by the Defaulting Owner.

ARTICLE 11.

COVENANTS OF PACIFIC COAST

11.01 Covenants. Pacific Coast covenants with and in favour of Shipper that Pacific Coast:

(a) shall not at any time seek to recover from Shipper, directly or indirectly, whether in tolls or otherwise, any Revenue Deficiency incurred prior to or during the term of this Agreement, including the Renewal Period, in the operations of the Pacific Coast System or in the operations of any gas distribution utility connected to the Pacific Coast System, and that Pacific Coast shall oppose any application or other proposal made by any party to seek any such recovery from Shipper;

(b) shall, in respect of the tolls to be charged to any new Third Party Shipper of gas through the Pacific Coast System, apply to the BCUC for approval of tolls which are determined in accordance with the full fixed-variable cost of service methodology and which, in the case of the mainline sections of the Pacific Coast System, are determined on a rolled-in basis as opposed to an incremental basis; and

(c) Pacific Coast will operate the Pacific Coast System so as to provide Firm Transportation Service and Interruptible Transportation Service under the General Terms and Conditions for Gas Transportation Service on a non-discriminatory basis in respect of gas to be transported and delivered to Shipper, Third Party Shippers and to the Centra Distribution System.

11.02 Survival. Notwithstanding Section 14.01, the provisions of Subsection 11.01(a) shall survive the termination or expiration of this Agreement.

ARTICLE 12.

APPLICATION OF GENERAL TERMS AND CONDITIONS FOR GAS TRANSPORTATION SERVICE

12.01 Application of General Terms and Conditions. Pacific Coast agrees that, if the Centra Distribution System is transferred to Pacific Coast, then, following such transfer and for all purposes of this Agreement, the provisions of the General Terms and Conditions for Gas Transportation Service, other than Sections 5.03(b), 5.05, 5.06, 6.01 and 6.02, Article 7, Article 8, Article 9, Section 12.04, Article 13, Article 14, Article 16 and Article 17, shall apply to the transportation of gas through the Pacific Coast System to the Centra Distribution System as if the Centra Distribution System was a Third Party Shipper which had entered into a Service Agreement with Pacific Coast and, for that purpose, Pacific Coast shall be deemed to be entitled to Firm Transportation Service through the Pacific Coast System in respect of a Contract Demand equal to the total firm capacity of the Pacific Coast System, in gigajoules per Day, less the aggregate of the Contract Demands in effect from time to time under this Agreement and any Service Agreements with Third Party Shippers.

ARTICLE 13.

GENERAL

13.01 Address for Notices. The address of each of the parties hereto for the purpose of giving any notice in accordance with this Agreement is as follows:

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B.C. UTILITIES COMMISSION

Pacific Coast:

Pacific Coast Energy Corporation
Suite 1700
1188 West Georgia Street
Vancouver, British Columbia
V6E 4A2

Telecopier: (604) 691-5136

Notices to Pacific Coast respecting statements and payments shall be sent to the attention of the Comptroller and all other notices shall be sent to the attention of the President.

Shipper:

Vancouver Island Gas Joint Venture
c/o Inland Pacific Energy Services Ltd.
Suite 1600
1095 West Pender Street
Vancouver, British Columbia
V6E 2M6

Attention: Gas Manager
Telecopier: (604) 895-3524

with a copy to each of:

MacMillan Bloedel Limited
22nd Floor
925 West Georgia Street
Vancouver, British Columbia
V6C 3L2

Attention: General Counsel
Telecopier: (604) 687-2314

Howe Sound Pulp and Paper Limited
30th Floor
Four Bentall Centre
1055 Dunsmuir Street
Vancouver, British Columbia
V7X 1B5

Attention: Vice President, Environment and Energy
Telecopier: (604) 661-5464

Fletcher Challenge Canada Limited
9th Floor
Toronto Dominion Bank Tower
700 West Georgia Street
Vancouver, British Columbia
V7H 1J7

Attention: General Counsel
Telecopier: (604) 654-4132

Western Pulp Limited Partnership
c/o Western Pulp Inc., General Partner
Suite 2300
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M3

Attention: Secretary - Treasurer
Telecopier: (604) 665-8806

Harmac Pacific Inc.
980 MacMillan Road
P.O. Box 1800
Vancouver, British Columbia
V9R 5M5

Attention: Vice-President, Manufacturing
Telecopier: (604) 722-4310

or at such other address as any party may from time to time designate by notice in writing to the others.

13.02 Counterpart Execution. This Agreement may be executed in any number of counterparts, and all of those counterparts shall, for all purposes, constitute one agreement binding on the parties notwithstanding that all parties are not signatory to the same counterpart.

13.03 Performance in Good Faith. In making any determinations or deciding whether to grant any consent or approval under and in accordance with this Agreement, and in performing their covenants and obligations under this Agreement, the parties shall act in good faith.

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B.C. UTILITIES COMMISSION

ARTICLE 14.

TERM

14.01 Term. The term of this Agreement shall be the Initial Term and, if Shipper exercises the option conferred by Section 14.02, the term shall be extended for the Renewal Period.

14.02 Renewal Option. Shipper shall have the option, exercisable in its exclusive discretion, to extend the term of this Agreement for the Renewal Period, provided such option is exercised by Shipper by giving notice to so extend the term of this Agreement at least 12 months prior to the expiration of the Initial Term.

ARTICLE 15.

SECURITY

15.01 Modification of General Terms and Conditions. Pacific Coast and Shipper agree that the provisions of Sections 9.01 and 9.02 of the General Terms and Conditions for Gas Transportation Service shall not apply to any of the Owners, and that, as between Pacific Coast and each of the Owners, the provisions of Sections 15.02, 15.03, 15.04 and 15.05 hereof shall apply.

15.02 Requirement for Security. In order to secure the prompt and orderly payment of the amounts to be paid by an Owner for service under this Agreement, if Pacific Coast determines, acting reasonably, that a change in the financial condition of an Owner has resulted in there being a serious risk that that Owner will not be able to make payments for service to be provided by Pacific Coast pursuant to this Agreement, Pacific Coast shall give notice to that Owner requiring that Owner to provide security for payment in accordance with this Section. Within four business days of the receipt of such notice from Pacific Coast that Owner shall either:

(a) provide, and at all times maintain, an irrevocable letter of credit in favour of Pacific Coast issued by a financial institution acceptable to Pacific Coast in an amount not to exceed the maximum amount payable by that Owner, in accordance with its Participating Interest, for 90 days of service; or

(b) pay to Pacific Coast a prepayment for service in an amount not to exceed the maximum amount payable by that Owner in accordance with its Participating Interest, for 60 days of service.

If Pacific Coast requires an Owner to provide a letter of credit or prepayment and the Owner is able to provide alternative security, Pacific Coast shall not unreasonably withhold or delay acceptance of the alternative security.

15.03 Rescission of Requirement for Security. If Pacific Coast has required an Owner to provide security for payment in accordance with Section 15.02 and if Pacific Coast, acting reasonably, subsequently determines that the financial condition of the Owner has improved such that there is no longer a serious risk that the Owner will not be able to make payments as they become due in accordance with this Agreement, Pacific Coast will rescind the requirement that the Owner provide security in accordance with Section 15.02, without prejudice to Pacific Coast's right to require security at a subsequent time in accordance with Section 15.02.

15.04 Review by the BCUC. If an Owner has provided security for payment to Pacific Coast in accordance with Section 15.02, but disputes the determination by Pacific Coast to require that security be provided in accordance with Section 15.02 or a determination that the requirement for security not be rescinded in accordance with Section 15.03, that Owner may apply to the BCUC to review the determination made by Pacific Coast to require security. Pacific Coast and the Owner shall be bound by the determination made by the BCUC. If the BCUC determines on its review that Pacific Coast ought not to have required security from the Owner in accordance with Section 15.02 or ought to have rescinded the requirement in accordance with Section 15.03, Pacific Coast shall reimburse the Owner for all costs and expenses incurred in providing and cancelling such security, including, without limitation, all reasonable costs and expenses related to the proceedings before the BCUC. If the BCUC upholds Pacific Coast's requirement for such security or its decision not to rescind that requirement, the Owner shall reimburse Pacific Coast for all reasonable costs and expenses related to the proceedings before the BCUC.

15.05 Default in Payment. If Shipper defaults in the payment of the full amount due and owing for service in any Month and Pacific Coast has given notice to Shipper of that default in accordance with Section 10.01, and if the default is not remedied within two business days of the giving of such notice by Pacific Coast, Pacific Coast may then draw upon the letter of credit, prepayment or alternative security provided by the defaulting Owner in accordance with Section 15.02, in an amount necessary to satisfy the amount due and payable by such defaulting Owner for such Month.

15.06 General Terms and Conditions for Gas Transportation Service. For the purposes of Sections 9.03 and 9.04 of the General Terms and Conditions for Gas Transportation Service, each of the Owners shall be deemed to be a Shipper and each Owner shall comply with the requirements of those Sections in the same manner and to the same extent as if each Owner has entered into a separate Service Agreement with Pacific Coast.

JAN 25 1996
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SECRETARY
UTILITIES COMMISSION

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

PACIFIC COAST ENERGY CORPORATION

MACMILLAN BLOEDEL LIMITED

HOWE SOUND PULP AND PAPER LIMITED

FLETCHER CHALLENGE CANADA LIMITED

WESTERN PULP INC. as General Partner of WESTERN PULP LIMITED PARTNERSHIP

J. Waldie Manion.

VICE PRESIDENT

HARMAC PACIFIC INC.

JAN 25 1996

Accepted for filing: DEC - 8 1995

Effective: DEC 30 1995

Order No.: G-105-95/G-108-95 &

OIC 1510
9-4-96

SECRETARY

B.C. UTILITIES COMMISSION

Schedule A

TO THE
TRANSPORTATION SERVICE AGREEMENT
DATED AS OF December 14th, 1995
BETWEEN
PACIFIC COAST ENERGY CORPORATION
AND
THE VANCOUVER ISLAND GAS JOINT VENTURE

DEMAND TOLLS,
FIRM TRANSPORTATION SERVICE

01 Demand Tolls - Initial Term. Subject to adjustment in accordance with Section 1.02 of this Schedule, the Demand Toll, in dollars per gigajoule of Contract Demand per Day, for each year in the Initial Term shall be:

YEAR	DEMAND TOLL ($/GJ/Day)
1995	0.863
1996	0.863
1997	0.844
1998	0.845
1999	0.828
2000	0.843
2001	0.890
2002	0.890
2003	0.890
2004	0.910
2005	0.916

JAN 25 1996
Accepted for filing: DEC - 8 1995
Effective: DEC 3 0 1995
Order No.: G-105-95/G-108-95 & OIC 1510 G-4-96
SECRETARY
B.C. UTILITIES COMMISSION

Cumulative Inflation Adjustment. The Demand Toll specified in Section 1.01 of this Schedule for 1997 and each subsequent year in the Initial Term shall be adjusted, effective January 1 of each such year, to reflect the difference, whether positive or negative, between an assumed annual inflation rate of 2 percent and the actual inflation rate, on a cumulative basis, in accordance with the method shown for the adjustment of the Demand Toll in the sample calculation set out on page 2 of this Schedule.

Demand Tolls - Renewal Period. The Demand Toll, in dollars per gigajoule of Contract Demand per Day, for 2006 and each subsequent year in the Renewal Period shall be equal to the Demand Toll in effect during 2005 in accordance with Sections 1.01 and 1.02 of this Schedule, escalated annually, effective January 1, 2006 and of each year thereafter, by a percentage amount equal to one-half the percentage increase in the CPI over the 12 month period ending on the September 30 immediately preceding each such year in the Renewal Period.

1.04 Interpretation. In this Schedule, "CPI" means the All-Items Consumer Price Index for Vancouver, British Columbia (time base 1986 = 100) as published by Statistics Canada in Consumer Price Index (catalogue no. 62-001).

SAMPLE CALCULATION OF CUMULATIVE INFLATION ADJUSTMENT

1 YEAR COMMENCING JANUARY 1	2 ANNUAL INFLATION RATE (%)[1]	3 ANNUAL INFLATION ADJUSTMENT (%)[2]	4 CUMULATIVE INFLATION ADJUSTMENT (%)[3]	5 CUMULATIVE INFLATION ADJUSTMENT FACTOR	6 DEMAND TOLL ($/GJ/DAY)	7 ADJUSTED DEMAND TOLL ($/GJ/DAY)[4]
1997	4.000	1.000	1.000	1.01000	0.844	0.852
1998	3.500	0.750	1.758	1.01758	0.845	0.860
1999	2.000	0.000	1.758	1.01758	0.828	0.843
2000	1.000	-0.500	1.249	1.01249	0.843	0.854
2001	2.500	0.250	1.502	1.01502	0.890	0.903

Notes:

1. *Annual Inflation Rate is the actual percentage change in the CPI for the 12 month period ending on the September 30 immediately preceding the year specified in column 1;*

2. *Annual Inflation Adjustment ("AIA") is one-half the difference between the Annual Inflation Rate, specified in column 2, and 2.0%, where:*

   Annual Inflation Rate = 2.0%, AIA is nil
   Annual Inflation Rate > 2.0%, AIA is a positive difference
   Annual Inflation Rate < 2.0%, AIA is a negative difference

3. *Cumulative Inflation Adjustment in column 4 is the compounded Annual Inflation Adjustments from column 3; and*

4. *Adjusted Demand Toll in column 7 is the Demand Toll specified in column 6, multiplied by the Cumulative Inflation Adjustment Factor in column 5.*

JAN 25 1996
Accepted for filing: DEC - 8 1995
Effective: DEC 30 1995
Order No.: G-105-95/G-108-95 & OIC 1510
G-4-96

SECRETARY
B.C. UTILITIES COMMISSION

Schedule B

TO THE
TRANSPORTATION SERVICE AGREEMENT
DATED AS OF December 14th, 1995
BETWEEN
PACIFIC COAST ENERGY CORPORATION
AND
THE VANCOUVER ISLAND GAS JOINT VENTURE

INTERRUPTIBLE TOLLS, <u>INTERRUPTIBLE TRANSPORTATION SERVICE</u>

1.01 <u>Interruptible Tolls - Initial Term</u>. Subject to adjustment in accordance with Section 1.02 of this Schedule, the Interruptible Toll, in dollars per gigajoule, for each year in the Initial Term shall be the applicable toll specified in Column 1, provided that, if Shipper takes delivery of a total quantity of gas in excess of 15.8 petajoules in any year after 1995, the Interruptible Toll, in dollars per gigajoule, for any gas taken in excess of that quantity in any such year shall be the applicable Incentive Toll specified in Column 2.

YEAR	COLUMN 1 INTERRUPTIBLE TOLL ($/GJ)	COLUMN 2 INCENTIVE TOLL ($/GJ)
1995	0.686	
1996	0.686	0.500
1997	0.669	0.488
1998	0.669	0.488
1999	0.655	0.477
2000	0.665	0.485
2001	0.701	0.511
2002	0.701	0.511
2003	0.701	0.511
2004	0.716	0.522
2005	0.721	0.525

1.02 <u>Cumulative Inflation Adjustment</u>. The Interruptible Tolls specified in Section 1.01 of this Schedule for 1997 and each subsequent year in the Initial Term shall be adjusted, effective January 1 of each such year, to reflect the difference, whether positive or negative, between an assumed annual inflation rate of 2 percent and the actual inflation rate, on a cumulative basis, in accordance with the method shown for the adjustment of the Demand Toll in the sample calculation set out on page 2 of Schedule A to this Agreement.

<u>Interruptible Toll - Renewal Period</u>. The Interruptible Tolls, in dollars per gigajoule, for 2006 and each subsequent year in the Renewal Period shall be equal to the Interruptible Tolls in effect during 2005 in accordance with Sections 1.01 and 1.02 of this Schedule, escalated annually, effective January 1, 2006 and of each year thereafter, by a percentage amount equal to one-half the percentage increase in the CPI over the 12 month period ending on the September 30 immediately preceding each such year in the Renewal Period.

<u>Interpretation</u>. In this Schedule, "CPI" means the All-Items Consumer Price Index for Vancouver, British Columbia (time base 1986 = 100), as published by Statistics Canada in Consumer Price Index (catalogue no. 62-001).

JAN 25 1996

Accepted for filing: DEC - 8 1995
Effective: DEC 30 1995
Order No.: G-105-95 / G-108-95 & OIC 1510 G-4-96

SECRETARY
B.C. UTILITIES COMMISSION

SCHEDULE C

TO THE
TRANSPORTATION SERVICE AGREEMENT
DATED AS OF December 14th, 1995
BETWEEN
PACIFIC COAST ENERGY CORPORATION
AND
THE VANCOUVER ISLAND GAS JOINT VENTURE

DELIVERY POINTS

LOCATION	LEGAL DESCRIPTION
Woodfibre	District Lot 2351, New Westminster Group 1 Land District. PID 015-910-717
Port Mellon	District Lot 1366, except Lot A, New Westminster Group 1 Land District. PID 008-044-333
Powell River	Block 43, except those portions of Plans 12273 and 14778, District Lot 450, Plan 8096, Municipality of Powell River. PID 002-554-682
Elk Falls	Lot 1, District Lot 109, Sayward District Plan VIP 54479, District of Campbell River. PID 018-089-852
Port Alberni	Part of Lot 1, District Lot 1, Alberni District, Plan 15070, except that part in Plan 31593 included within Plan 51178. PID 016-994-281
Harmac	West 60 acres of Section 22, Range 1, Cedar District, except that part shown outlined in red on Plan 1499 R. PID 003-926-516
Crofton	Part of Lot 3, Section 3, Ranges 10 and 11, Chemainus District, Plan 3161 included within Plan VIP 54480 PID 017-832-951

JAN 25 1996
Accepted for filing: DEC - 8 1995
Effective: DEC 30 1995
Order No.: G-105-95/G-108-95 & OIC 1510 G-4-76

SECRETARY
B.C. UTILITIES COMMISSION

16407\31510\V22.HDD
12795/1319/WP51

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1224 *, Approved and Ordered* DEC 11 2004

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Special Direction is made.

Minister of Energy and Mines

Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section:- *Vancouver Island Natural Gas Pipeline Act*, R.S.B.C. 1996, c. 474, section 7 (3) and (4)

Other (specify):-

November 30, 2004

1527/2004/7

VANCOUVER ISLAND NATURAL GAS PIPELINE SPECIAL DIRECTION NO. 2 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Definitions

1 In this Special Direction:

"Act" means the *Vancouver Island Natural Gas Pipeline Act*;

"commission" means the British Columbia Utilities Commission;

"Contract Demand", **"Firm Transportation Service"** and **"Interruptible Offset Gas"** have the same meanings as they have in Article 3 of the TSA;

"Joint Venture" has the same meaning as in section 1.1 of Special Direction 1;

"letter agreement" means the letter agreement, dated October 27, 2004 and attached as Schedule "A" to this Special Direction, respecting the amendment to and extension of the TSA;

"Special Direction 1" means the Vancouver Island Natural Gas Pipeline Special Direction made under Order in Council 1510/95;

"Terasen" means Terasen Gas (Vancouver Island) Inc.;

"transportation tolls" has the same meaning as in Special Direction 1;

"TSA" means the Transportation Service Agreement dated as of the 14th day of December, 1995 and attached as Exhibit F to Special Direction 1.

Application

2 This Special Direction is issued to the commission under section 7 (3) and (4) of the Act.

Directions relating to the letter agreement

3 (1) Despite sections 3.6 and 3.7 of Special Direction 1 but without limiting any other power the commission may have, the commission must approve the letter agreement to the extent that it

(a) varies the transportation tolls or other amounts payable to Terasen for the services provided to the Joint Venture under the TSA, and

(b) increases or decreases

(i) the Contract Demand for Firm Transportation Service determined in accordance with the TSA, or

(ii) the quantities of Interruptible Offset Gas that the Joint Venture is entitled to receive under the TSA.

(2) Despite subsection (1), the direction contained in that subsection does not require the commission to approve any other agreements, including, without limitation, any further definitive amending agreements, whether or not those agreements do or purport to do either or both of the following:

(a) incorporate any or all of the terms of the letter agreement;

(b) replace or supersede the terms of the letter agreement.

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, BC V3S 2X7
Tel: 604-592-7784
Fax: 604-592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

December 21, 2004

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

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

Re: Terasen Gas (Vancouver Island) Inc.
Vancouver Island Gas Joint Venture ("VIGJV") Amending Agreement

Terasen Gas (Vancouver Island) Inc. ("TGVI") entered into an Amending Agreement to amend taxes of the VIGJV Transportation Service Agreement and Peaking Gas Management Agreement on October 27, 2004. Through Order of the Lieutenant Governor in Council, 1224 dated December 11, 2004 the Province, through the Vancouver Island Natural Gas Pipeline Special Direction No. 2, directed the British Columbia Utilities Commission ("the Commission") to approve the Amending Agreement. The Commission approved the Amending Agreement in Commission Order No. G-113-04, dated December 14, 2004 and directed TGVI to provide the filing in tariff format.

This submission represents TGVI's response to Commission Order No. G-113-04. TGVI respectfully requests Commission endorsement of the enclosed two (2) copies of the Amending Agreement and that one (1) complete set be returned to TGVI for its records.

If you have any questions please call Tom Loski at (604) 592-7464.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Scott A. Thomson

Attachments

cc: Karl Gustafson
Registered Intervenours / Interested Parties

Terasen Gas
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Tel: (604) 576-7000

Terasen Gas

DELIVERED BY COURIER AND E-MAIL
October 27, 2004

Dave Hargreaves
Manager, Central Services
HOWE SOUND PULP AND PAPER L.P.
Port Melon, B.C.
V0N 2S0

Dear Mr. Hargreaves :

Re : Amendment and Extension of Transportation Service Agreement and Peaking Gas Management Services Agreement between Terasen Gas (Vancouver Island) Inc. and the Vancouver Island Gas Joint Venture

This letter agreement is further to our recent discussions regarding the principal terms for the amendment and extension of the Terasen Gas (Vancouver Island) Inc. ("TGVI")/ Vancouver Island Joint Venture ("VIGJV") Transportation Service Agreement and Peaking Gas Management Services Agreement (collectively, the "Agreements"). The purpose of this letter agreement is to set out, as set forth herein and in Appendix 1 attached (together, the "Letter Agreement"), the terms upon which TGVI and VIGJV are prepared to amend and extend the Agreements. While it is intended that the terms of this Letter Agreement shall be binding on TGVI and VIGJV once executed by the parties hereto, the parties acknowledge that they shall be executing further definitive amending agreements ("Amending Agreements") to the Agreements which will incorporate the terms of this Letter Agreement. Once executed, such Amending Agreements shall replace and supersede the terms of this Letter Agreement.

Upon the execution of this Letter Agreement by the VIGJV and TGVI, the VIGJV shall:

1 promptly adjourn or cause to be adjourned generally the hearing of the Petition filed in the Vancouver Registry of the Supreme Court of British Columbia ("Petition") under #S045062 and hold all litigation relating to this matter in abeyance until the terms of the Amending Agreements have received all necessary regulatory, governmental and other approvals and have become effective in accordance with Article 11 of Appendix 1 to this Letter Agreement; and

2. agree not to renew the agreement with BC Hydro for the assignment of 4 TJ/day of transportation capacity upon the expiration of that agreement and, pending and following receipt of all necessary regulatory, governmental and other approvals to make this Letter Agreement effective, not to take further steps to require that TGVI consent to the assignment contemplated by that agreement.

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this day, of October, 2004

Pope and Talbot Ltd.

Per: ____________________
Name:
Title:

Western Pulp Limited

Per: ____________________
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ____________________
Name:
Title:

Norske Skog Canada Limited

Per: ____________________
Name:
Title:

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

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Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Sk/akl
Encl.

Accepted this 27 day of October, 2004

Pope and Talbot Ltd.

Per:
Name: PAUL G. SADLER
Title: GENERAL MANAGER P+T LTD

Western Pulp Limited

Per:
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per:
Name:
Title:

Norske Skog Canada Limited

Per:
Name:
Title:

...2

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

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Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this day, of October, 2004

Pope and Talbot Ltd.

Per: ______________________
Name:
Title:

Western Pulp Limited

Per: ______________________
Name: STEPHEN SUTHERLAND
Title: PURCHASING MANAGER

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name:
Title:

Norske Skog Canada Limited

Per: ______________________
Name:
Title:

...2

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

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Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this 27th day, of October, 2004

Pope and Talbot Ltd.

Per: ______________________
Name:
Title:

Western Pulp Limited

Per: ______________________
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name: DALE HARGREAVES
Title: MANAGER, CENTRAL SERVICES

Norske Skog Canada Limited

Per: ______________________
Name:
Title:

. 2

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this day, of October, 2004

Pope and Talbot Ltd.

Per: ______________________
Name:
Title:

Western Pulp Limited

Per: ______________________
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name:
Title:

Norske Skog Canada Limited

Per: ______________________
Name: R.H. LINDSTROM
Title: VICE PRESIDENT, STRATEGY

...2

TRANSPORTATION AND PEAKING GAS MANAGEMENT SERVICES

1. Parties

Vancouver Island Gas Joint Venture ("VIGJV") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (together, the "Parties").

2. Purpose

2.1 The VIGJV is seeking to extend and amend its existing Transportation Service Agreement ("TSA") and the Peaking Gas Management Agreement ("PGMA") with TGVI.

2.2 TGVI owns and operates the natural gas transmission system from Eagle Mountain to Vancouver Island and the transmission and distribution system on Vancouver Island, and proposes to expand its system with a phased combination of system upgrades and liquefied natural gas ("LNG") storage.

2.3 TGVI proposes to amend and extend each of the existing TSA and the PGMA with the VIGJV for service from Huntingdon to the VIGJV mills based on the principal terms outlined in this term sheet. The TSA and PGMA are collectively the "Agreements". Unless otherwise defined in this term sheet, all capitalized terms shall bear the meanings set out in the Agreements.

3. Term of TSA

3.1 The Renewal Period in the TSA will be amended and extended to be from January 1, 2005 to December 31, 2012.

3.2 The TSA may be extended for a five year term beyond the Renewal Period as mutually agreed by the Parties prior to October 1, 2011.

4. Quantity

4.1 Firm Contract Demand for the Renewal Period under the TSA will be:

4.1.1 20,000 gigajoules per day for the period January 1, 2005 to December 31, 2005.

4.1.2 12,500 gigajoules per day for the remainder of the Renewal Period.

4.2 Where a minimum Contract Demand is specified in the TSA as 30,000 gigajoules per day, it shall be amended to 8,000 gigajoules per day.

5. Toll

5.1 The firm demand toll shall be the Demand Toll as expressed in Schedule A of the TSA.

5.2 There will be three tiers of interruptible tolls for quantities each day in excess of the Contract Demand quantity.

5.2.1 For quantities of gas each day up to 20,000 gigajoules, the Interruptible Toll shall be paid on the positive difference between this quantity and the Contract Demand. The applicable Interruptible Toll for this gas shall be equivalent to the Demand Toll rate (firm demand rate). Quantities of gas delivered under this rate will be known as "Tier 1 IT".

5.2.2 For quantities of gas each day in excess of 20,000 gigajoules up to 30,000 gigajoules, the Interruptible Toll shall be paid as follows:

5.2.2.1On the 1st 20,000 gigajoules of gas, the Interruptible Toll shall be paid on the positive difference between 20,000 gigajoules and the Contract Demand at the Tier 1 IT rate; and

5.2.2.2On quantities between 20,000 gigajoules and 30,000 gigajoules the applicable Interruptible Toll payable on the quantity in excess of 20,000 gigajoules shall be as expressed in Schedule B of the TSA. Quantities of gas delivered under this rate will be known as "Tier 2 IT".

5.2.3 For quantities of gas each day in excess of 30,000 gigajoules, the Interruptible Toll shall be paid as follows:

5.2.3.1On the 1st 20,000 gigajoules of gas, the Interruptible Toll shall be paid on the positive difference between 20,000 gigajoules and the Contract Demand at the Tier 1 IT rate;

5.2.3.2On quantities between 20,000 gigajoules and 30,000 gigajoules the applicable Interruptible Toll payable on the quantity between 20,000 gigjoules and 30,000 gigajoules shall be at the Tier 2 IT rate; and

5.2.3.3The applicable Interruptible Toll paid on the quantities in excess of 30,000 gigajoules shall be equivalent to the Demand Toll rate (firm demand rate) multiplied by 1.1. Quantities of gas delivered under this rate will be known as "Tier 3 IT".

6. Future Contract Demand Reinstatement or Reduction

6.1 All articles related to Contract Demand reduction will be removed from the TSA except the following:

6.1.1 The VIGJV shall have the right to reduce Contract Demand by up to 4,500 gigajoules per day during the Renewal Period. The notice period for all such reductions shall be a minimum of one year and notice will not to be given prior to January 1, 2006.

Notwithstanding the above, the minimum Contract Demand during the Renewal Period shall be 8,000 gigajoules per day.

6.1.2 The right to reduce Contract Demand as a result of Expansion Projects will remain, but will be suspended for any Expansion Projects that, when announced, are projected to have in-service dates prior to November 1, 2010. For clarity, this means that the VIGJV will not be able to reduce its Contract Demand for any Expansion Projects put in service prior to November 1, 2010

6.2 The TSA will be amended such that any reinstatement of Contract Demand above 12,000 gigajoules per day will be on an annual renewal basis (effective November 1 of each year). TGVI will give the VIGJV a minimum of six months notice as to availability of reinstatement of Contract Demand in each year. For clarity, nothing in this amendment would compel TGVI to add facilities to meet a VIGJV request for reinstatement of Contract Demand.

7. Peaking Gas Management Agreement (PGMA)

7.1 The PGMA will be amended so that after January 1, 2006 TGVI will only be able to call for Curtailment in situations of mechanical failure of TGVI facilities that would otherwise cause it to be unable to meet core market demand.

7.2 Curtailment in these circumstances will be covered under the rate and terms for Supplemental Curtailment Units under the PGMA.

7.3 TGVI will also be able to request Emergency Gas under those provisions in the PGMA (namely, only if the VIGJV is able to provide it).

7.4 The term of the PGMA will be extended to reflect the extended term of the TSA as set out in this term sheet.

8. Interruptible Offset Gas

8.1 Limitations to the size of the Interruptible Offset Gas Account in the TSA shall be amended so that the total quantity of gas in the Interruptible Offset Account shall not exceed 25 times the then current Contract Demand in any year.

8.2 When quantities are delivered from the Interruptible Offset Account for Tier 1 IT, Tier 2 IT and Tier 3 IT, removal from the Interruptible Offset Account shall be on a 1 to 1 basis.

9. Right of Assignment

9.1 The TSA will be amended to remove any right of assignment except to the new owner in the case of a change in ownership of the Owner's Mills. For clarity, this means that there will be no right to assign or otherwise extend the rights under the TSA for use anywhere other than the Owner's Mills. The Agreements shall be amended to clarify that except for such assignment, the VIGJV shall not be entitled to add, replace or substitute any entity to the VIGJV and thereby purport to confer rights on such entity with respect to the Agreements notwithstanding any provision to the contrary in the Agreements.

9.2 The VIGJV shall promptly: (i) cause the VIGJV Petition to the Supreme Court of British Columbia, Vancouver Registry Number S045062, to be dismissed by way of consent dismissal order; or (ii) discontinue all further proceedings relating thereto; and in either case, each of TGVI and VIGJV shall bear its own costs and the parties will exchange a mutual release with respect to the claims set out therein.

9.3 There will be no other claims made to TGVI regarding any assignment of VIGJV Contract Demand under the Agreements.

10. Expansion Project Related to Service to ICP and CFT Outcome

The VIGJV agrees to not oppose TGVI's August 2004 CPCN application for an LNG facility for Vancouver Island.

11. Regulatory and Other Approvals

11.1 This term sheet and the amendments to the Agreements contemplated in this term sheet are subject to the approval by the British Columbia Utilities Commission ("BCUC") and receipt of other regulatory, governmental and other approvals as may be required.

11.2 TGVI shall proceed promptly and in good faith to apply to the BCUC for approval of this term sheet and the amendments and extension of the Agreements as contemplated in this term sheet and both parties shall support, through intervention, appearance of counsel, evidence and argument, such application. In addition, TGVI shall promptly and in good faith apply for and diligently seek all other regulatory, governmental and other regulatory approvals as my be required.

12. Requests by VIGJV for Additional Capacity which require Expansion Projects

The existing provisions in the TSA relating to Expansion Projects shall be amended to give effect to the following agreement between TGVI and the VIGJV with respect to Expansion Projects, including the provisions of Section 6.1.2 above. In the event the VIGJV requires additional firm capacity, which increase in firm capacity would require TGVI to undertake Expansion Projects, TGVI shall undertake such projects, subject to the approval of the BCUC, provided the following conditions are met:

12.1 **Ownership** – All Expansion Projects will remain the property of TGVI.

12.2 **Economic Test** – All requests for TGVI to undertake Expansion Projects will be subject to the Expansion Projects satisfying the following economic test. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Expansion Projects. Subject to the provisions of Section 12.5 below, Expansion Projects will be deemed to be economic and will be constructed if the results of the economic test indicate a zero or positive net present value.

Revenue – The projected revenue to be used in the economic test will be determined by TGVI by:

(a) establishing consumption estimates for the VIGJV; and,

(b) applying the appropriate revenue margins for such consumption.

Costs – The total costs to be used in the economic test include, without limitation, the following:

(a) the full labour, material, and other costs necessary to construct the Expansion Project and any related facilities;

(b) the appropriate allocation of TGVI's overheads associated with the construction of the Expansion Project; and,

(c) the incremental operating and maintenance expenses associated with the carrying out and implementation of the Expansion Project.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment to TGVI as approved by the BCUC.

12.5 **Contribution in Aid of Construction** – Notwithstanding the provisions of Section 12.2 above, if the economic test results indicate a negative net present value, TGVI will nonetheless proceed with the Expansion Project provided that the shortfall in projected revenue is eliminated by contributions in aid of construction made by the VIGJV. The total required contribution in aid of construction will be paid by the VIGJV prior to commencement of construction of the Expansion Project.

Scott A. Thomson
VP, Finance & Regulatory Affairs &
Chief Financial Officer

16705 Fraser Highway
Surrey, B.C. V3S 2X7
Tel: (604) 592-7784
Fax: (604) 592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

March 31, 2006

Lang Michener LLP
Barristers & Solicitors
1500 – 1055 West Georgia Street
P.O. Box 11117
Vancouver, BC V6E 4N7

Attention: Mr. Karl E. Gustafson, Q.C.

Dear Sir:

Re: Acknowledgement of Notice to Reduce Contract Demand

Terasen Gas (Vancouver Island) Inc. ("**TGVI**") hereby acknowledges receipt of your Notice to Reduce Contract Demand dated March 30, 2006 ("**Notice**"), given pursuant to the terms of the Transportation Service Agreement dated December 14, 1995 (the "**TSA**") between Pacific Coast Energy Corporation [now TGVI] and the participants in Vancouver Island Gas Joint Venture ("**VIGJV**"), and the Amendment and Extension Agreement related to the TSA dated October 27, 2004 (the "**Amendment**").

We confirm and accept the terms of the Notice, pursuant to section 6.1.1 of Appendix 1 of the Amendment, that VIGJV has exercised its right to reduce its Contract Demand by 3,400 gigajoules per day, thereby reducing VIGJV's Contract Demand from 12,500 gigajoules per day to 9,100 gigajoules per day effective as of March 31, 2007 for the remainder of the Renewal Period.

We further acknowledge VIGJV's reservation of its right, pursuant to section 6.1.1 of Appendix 1 of the Amendment, to further reduce its Contract Demand, upon notice, by up to an additional 1,100 gigajoules per day.

Sincerely,

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by:

Scott A. Thomson

Terasen Gas

Tom A. Loski
Director, Regulatory Affairs

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

August 16, 2007

Lang Michener LLP
Barristers & Solicitors
1500 – 1055 West Georgia Street
P.O. Box 11117
Vancouver, BC V6E 4N7

Attention: Mr. Karl E. Gustafson, Q.C.

Dear Sir:

Re: Acknowledgement of Notice to Reduce Contract Demand

Terasen Gas (Vancouver Island) Inc. ("**TGVI**") hereby acknowledges receipt of your Notice to Reduce Contract Demand dated August 16, 2007 ("**Notice**"), given pursuant to the terms of the Transportation Service Agreement dated December 14, 1995 (the "**TSA**") between Pacific Coast Energy Corporation [now TGVI] and the participants in the Vancouver Island Gas Joint Venture ("**VIGJV**"), and the Amendment and Extension Agreement related to the TSA dated October 27, 2004 (the "**Amendment**").

We confirm and accept the terms of the Notice, pursuant to section 6.1.1 of Appendix 1 of the Amendment, that VIGJV has exercised its right to reduce its Contract Demand by 1,100 gigajoules per day, thereby reducing VIGJV's Contract Demand from 9,100 gigajoules per day to 8,000 gigajoules per day effective as of August 16, 2008 for the remainder of the Renewal Period.

Sincerely,

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed

Tom Loski

PEAKING GAS MANAGEMENT AGREEMENT

THIS AGREEMENT dated as of the 14th day of December, 1995.

AMONG:

VANCOUVER ISLAND GAS JOINT VENTURE, a joint venture comprised of the following corporations and limited partnerships: **Fletcher Challenge Canada Limited, Howe Sound Pulp and Paper Limited, MacMillan Bloedel Limited, Western Pulp Limited Partnership** and **Harmac Pacific Inc.**, each of which has offices in Vancouver, British Columbia.

(the "Joint Venture")

AND:

CENTRA GAS BRITISH COLUMBIA INC., a corporation having offices in Victoria, British Columbia

("Centra")

AND:

SQUAMISH GAS CO. LTD., a corporation having offices in Vancouver, British Columbia.

("SG")

WHEREAS:

(A) The Joint Venture was formed for the purposes of coordinating the purchase and processing of Gas and the transportation and delivery of Residue Gas to 7 pulp and paper mills within the service area of PCEC;

(B) Each of the pulp and paper mills operated by members of the Joint Venture has alternative heavy fuel oil burning capability economically available which allows the Joint Venture to provide peak shaving capacity for the benefit of the LDU's;

(C) Centra and SG are involved in the purchase and processing of Gas and the transportation and delivery of Residue Gas for core market customers utilizing the PCEC system;

(D) The Joint Venture, Centra and SG are parties to the 1991 Peaking Gas Management Agreement under which the Joint Venture agreed to provide Residue Gas to Centra and SG on the terms and conditions set out in that agreement; and

(E) The Joint Venture, Centra and SG have agreed to terminate the 1991 Peaking Gas Management Agreement and to replace the 1991 Peaking Gas Management Agreement with this Agreement effective the Transition Time.

THIS AGREEMENT WITNESSES that in consideration of the premises and the mutual covenants and agreements herein, the parties hereto agree and covenant as follows:

ARTICLE I - INTERPRETATION

1.1 Definitions

In this Agreement, unless the context otherwise requires, each of the following words, phrases and expressions has the following meaning:

"**Agreement Term**" means the period commencing at the Transition Time and ending on the date of termination or expiration of the PCEC Transportation Agreement;

"**Agreement Year**" means each period of 12 consecutive Months during the Agreement Term, beginning at 0800 PST on the first Day of November and ending at 0800 PST on the next succeeding first Day of November, except that the first Agreement Year shall be the period commencing at the Transition Time and ending at 0800 PST on November 1, 1996;

"**BC Gas**" means BC Gas Utility Ltd.;

"**Basic Supply Agreements**" means all LDU long-term gas supply and storage contracts and Winter Peaking Supply Contracts but does not include back-up, temporary peaking or emergency supply contracts;

"**BCUC**" means the British Columbia Utilities Commission;

"**Canadian Border Price**" means in respect of any Month the first of the Month spot gas price in United States dollars per million British Thermal Units of Residue Gas for "Canadian Border" gas listed for "Northwest Pipeline Corp." under the "Index" column in the McGraw-Hill publication entitled "Inside F.E.R.C.'s Gas Market Report", published for each such Month or, if that price is no longer published, an equivalent reference price agreed to by the parties, converted to Canadian dollars per GJ at the Exchange Rate and by using an energy conversion factor of 1.055056 GJ per million British Thermal Units;

"**Centra Distribution System**" means the property and assets used by Centra and its subsidiaries in the gas distribution business carried on in the areas served by the PCEC pipeline, both as of the date of this Agreement and following any transfer of all such property and assets to PCEC whether by conveyance, assignment, merger, amalgamation or otherwise.

"**Core Market**" means, subject to §7.13, residential, institutional, commercial and industrial customers who form part of British Columbia's core market as defined by the British Columbia Ministry of Energy, Mines and Petroleum Resources or the BCUC from time to time provided that, if there is any conflict or inconsistency between those two definitions, that of the Ministry will prevail;

"**Curtailment**" means a reduction by the Joint Venture in the amount of Residue Gas it would otherwise be entitled to take for the purpose of redirecting the supply of that Residue Gas to an LDU in increments equal to Curtailment Units when requested hereunder by an LDU to maintain firm service to its Core Market customers;

"**Curtailment Unit**" means one half of the Joint Venture's Firm Daily Contract Demand divided by the number of Joint Venture Participants in an Agreement Year, or part thereof;

"**Day**" means a period of 24 consecutive hours beginning and ending at 0800 PST and the reference date for any Day will be the calendar date upon which the 24 hour period commences;

"**Emergency Gas**" has the meaning set forth in §3.8;

"**Exchange Rate**" means for each calendar month the average of the Bank of Canada daily noon exchange rates for the conversion of U.S. dollars to Canadian dollars;

"**Firm Daily Contract Demand**" means in respect of each Agreement Year the weighted average Contract Demand for Firm Transportation Service in effect during each such Agreement Year under the PCEC Transportation Agreement, which average Contract Demand shall be that quantity of Residue Gas, in GJ per Day, equal to one-twelfth of the sum of such Contract Demands in effect in each Month in each such Agreement Year;

"**Force Majeure**" means any event or circumstance beyond the reasonable control of a party, except those caused by its own lack of funds, which prevents, hinders or frustrates the ability of a party to fully perform any obligation hereunder including, without limiting the generality of the foregoing:

(i) acts of God, including lightning, earthquakes, storms, epidemics, landslides, floods, fires, explosions or washouts;

(ii) acts of the Queen's enemies, sabotage, wars, blockades, insurrections, riots, civil disturbances, arrests or restraints;

(iii) freezing of wells or delivery facilities, well blowouts, craterings, inability to obtain pipe materials or equipment, or pipeline or compressor failure;

(iv) orders of any court or government authority; and

(v) failure or refusal for any reason (other than the default of the Joint Venture) by a supplier, processor or transporter (other than PCEC) of Gas or Residue Gas to or for the Joint Venture to supply, process or transport Gas or Residue Gas to or for the Joint Venture;

or any other causes, whether of the kind herein enumerated or otherwise, not within the reasonable control of the party claiming suspension and which, by the exercise of due diligence, such party could not have prevented or is unable to overcome;

"**Gas**" means raw natural gas which meets Westcoast's specifications and delivery pressure for raw natural gas;

"**Gas Manager**" means the person or corporation engaged by the Joint Venture to manage the business of the Joint Venture;

"**GJ**" means gigajoule;

"**Incremental Fuel Cost**" has the meaning and shall be determined in accordance with Schedule "A";

"**Incremental Fuel Cost Statement**" has the meaning set forth in §5.2;

"**Huntingdon**" means the point of interconnection between the Westcoast system and the BC Gas system near Huntingdon, British Columbia;

"**Joint Venture Participants**" means those large industrial customers served by PCEC who are from time to time participants in the Vancouver Island Gas Joint Venture, such customers being as at the date hereof, the 7 pulp and paper mills at Crofton, Elk Falls, Harmac, Port Alberni, Port Mellon, Powell River and Woodfibre.

"**Joint Venture Agreement**" means the Restated Joint Venture Agreement made effective November 1, 1995 among the Joint Venture Participants;

"**LDU**" means Centra (or, following the transfer of the Centra Distribution System to PCEC, the Centra Distribution System as distinct from the other business and operations of PCEC) or SG, and LDU's means both Centra and SG (or, if applicable, the Centra Distribution System);

"**Maximum Daily Curtailment**" means one half of the Joint Venture's Firm Daily Contract Demand;

"**Month**" means the period beginning at 0800 PST on the first Day of each calendar month and ending at 0800 PST on the first Day of the next succeeding calendar month;

"**1991 Peaking Gas Management Agreement**" means the agreement made effective the 1st day of November, 1991 among the Joint Venture, Centra and SG;

"**PCEC**" means Pacific Coast Energy Corporation;

"**PCEC Transportation Agreement**" means the Transportation Service Agreement dated as of December 14, 1995 between PCEC and the Joint Venture;

"**PST**" means Pacific Standard Time;

"**Residue Gas**" means the residue remaining after Gas has been processed to meet Westcoast's specifications for Residue Gas at Huntingdon;

"**Service Area**" means a geographic area ordinarily served by an LDU with Residue Gas delivered to the LDU through the PCEC pipeline;

"**Standard Annual Curtailment**" means 5 times the Maximum Daily Curtailment;

"**Standard Annual Curtailment Units**" means 5 times the number of Joint Venture Participants;

"**Supplemental Annual Curtailment**" means Residue Gas that may be accessed by the LDU from the Joint Venture, in addition to the Standard Annual Curtailment, in a quantity not to exceed the amount of the Standard Annual Curtailment;

"**Supplemental Annual Curtailment Units**" means Curtailment Units in addition to the Standard Annual Curtailment up to 5 times the number of Joint Venture Participants;

"**Transition and Release Agreement**" means the agreement dated as of December 14, 1995 among PCEC, the Joint Venture and Her Majesty the Queen in Right of British Columbia as represented by the Minister of Energy, Mines and Petroleum Resources;

"**Transition Time**" means the Transition Time as defined in the Transition and Release Agreement;

"**Westcoast**" means Westcoast Energy Inc.; and

"**Winter Peaking Supply Contracts**" means contracts of 3 months or greater duration (including consecutive or essentially consecutive shorter term contracts with any one supplier) entered into by an LDU to provide any peaking supplies of Residue Gas between November 1 and April 1 in each Agreement Year.

1.2 Interpretation

In this Agreement, except as otherwise expressly provided or unless the context otherwise requires,

(a) "this Agreement" means this agreement as from time to time supplemented or amended by one or more agreements entered into pursuant to the applicable provisions of this Agreement;

(b) the headings are for convenience only and are not intended as a guide to interpretation of this Agreement or any portion thereof;

(c) the word "including", when following any general statement or term, is not to be construed as limiting the general statement or term to the specific or similar items or matters set forth, but rather as permitting the general statement or term to refer to all other items or matters that could reasonably fall within its broadest possible scope;

(d) all accounting terms not otherwise defined herein have the meanings assigned to them, and all calculations to be made hereunder are to be made in accordance with generally accepted accounting principles applied on a consistent basis;

(e) all references to currency mean Canadian currency unless otherwise expressly stated;

(f) a reference to a statute includes all regulations made thereunder, all amendments to the statute or regulations in force from time to time, and any statute or regulation that supplements or supersedes such statute or regulation;

(g) a reference to an entity includes any successor to that entity;

(h) words importing the masculine gender include the feminine or neuter, and vice versa; words in the singular include the plural, and vice versa; and words importing a corporate entity include individuals, and vice versa;

(i) a reference to "approval", "authorization", "consent" or "notice" means written approval, authorization, consent or notice;

(j) references herein to words or phrases commonly used in the oil and gas industry not otherwise specifically defined herein, will have the meaning generally accorded thereto by the custom of the trade and usage in the oil and gas industry; and

(k) the division of this Agreement into articles, paragraphs, clauses and subclauses and the insertion of headings, and any table of contents, are for convenience of reference only and will not affect the construction or interpretation hereof.

ARTICLE II - TERM

2.1 Agreement Term

Subject to §7.21, this Agreement will have effect and be binding upon the parties for the Agreement Term unless terminated by one of the parties in accordance with Article VI.

ARTICLE III - CURTAILMENT PROVISIONS

3.1 Notice of Curtailment

(a) Each LDU seeking to impose a Curtailment by way of Standard Annual Curtailment or Supplemental Annual Curtailment will notify the Gas Manager and other LDU's by telephone, or by such other method as may be agreed upon from time to time by the parties, not less than 24 hours before the beginning of the Day on which the Curtailment is required and consistent with PCEC operating procedures, and state the number of Curtailment Units required and the Days on which those Curtailment Units will be taken. Under no circumstance, except as provided in §3.8, will the LDU's notify the Gas Manager of a request for a daily Curtailment quantity in excess of the Maximum Daily Curtailment. Except as provided in §3.8, under no circumstance will the Joint Venture be obligated to curtail its take of Residue Gas on more occasions than the number of Standard Annual Curtailment Units plus the number of Supplemental Annual Curtailment Units;

(b) Each LDU having instituted a Curtailment will immediately notify the Gas Manager when a Curtailment is no longer in effect or if any change to a notice of Curtailment is required;

(c) If a Curtailment Unit is shared by 2 or more LDU's, the LDU's will advise the Joint Venture of their respective interests in the Curtailment Unit within 48 hours after the Curtailment Unit is received;

(d) Notwithstanding any other provision of this Agreement, except §3.8, unless the Joint Venture is in default of its obligations under §3.3 or §7.16, it will at all times and under all circumstances have the right to take Residue Gas up to 50% of its Firm Daily Contract Demand; and

(e) If for any reason other than a default by the Joint Venture of its obligations under §3.3 or §7.16, there is a shortfall in the amount of Residue Gas available to meet the Firm Daily Contract Demand, the number of Curtailment Units available on that Day may, at the option of the Joint Venture, be reduced accordingly.

3.2 Curtailment Obligations of the LDU's

An LDU may invoke a Curtailment only under the following conditions:

(a) the Curtailment is initiated by the LDU in good faith to satisfy its Core Market requirements for firm Residue Gas; and

(b) when the LDU, acting reasonably, determines that a Curtailment may be required, the LDU has promptly and diligently exercised all rights to

(i) stop the sale or delivery of Residue Gas pursuant to all interruptible contracts with its customers before and during the period of Curtailment and, in addition,

(ii) curtail the sale or delivery of Residue Gas to industrial customers under all contracts for the sale or delivery of 100,000 GJ or more per Agreement Year and which allow for curtailment, and curtail the sale or delivery of Residue Gas under all contracts with other customers for the sale or delivery of 100,000 GJ or more per Agreement Year if the terms of the contracts permit curtailments in aggregate of 100,000 GJ or more in any Agreement Year, provided, in any case under this §3.2(b)(ii), that such curtailment of the customers of the LDU and Curtailment of the Joint Venture will have the same priority and the LDU will use all reasonable efforts to apportion such curtailments equitably over the course of each Agreement Year; and

(c) the LDU has utilized all Residue Gas available to it under its Basic Supply Agreements for its Service Area and no such Residue Gas is diverted to alternative markets,

(i) after such time as the LDU, acting reasonably, determines that a Curtailment may be required, and

(ii) during the period of Curtailment.

3.3 Curtailment Obligations of Joint Venture

Upon receipt of a notice of Curtailment as provided in §3.1(a), the Joint Venture will:

(a) provide at Huntingdon the amount of Residue Gas requested in the notice of Curtailment, in increments equal to Curtailment Units, to the LDU requesting Curtailment up to the Maximum Daily Curtailment,

(b) direct PCEC to deliver Residue Gas in aggregate, up to the Standard Annual Curtailment plus the Supplemental Annual Curtailment as may be requested by the LDU's hereunder and, subject to §3.1 (d), direct PCEC to deliver that Residue Gas to the LDU's in priority to other deliveries to the Joint Venture,

(c) to the extent necessary to satisfy the Curtailment requested, increase its nomination with Westcoast for delivery at Huntingdon of Residue Gas up to the Firm Daily Contract Demand, and

(d) provide a copy of the notice of Curtailment to PCEC and authorize PCEC to transport such Residue Gas to the LDU from Huntingdon,

provided that nothing herein will require the Joint Venture to deliver or authorize the transportation of Residue Gas for or to an LDU at times or in quantities other than as specifically provided in this Agreement.

3.4 Force Majeure

In the event of a Force Majeure, all obligations of the Joint Venture under this Agreement will be suspended hereunder in whole or in part as may be appropriate during the period of Force Majeure provided that the Joint Venture provides notice of the Force Majeure event to the LDU's at its first reasonable opportunity.

Nothing in this Agreement shall be deemed to limit any right that PCEC may have in the event of a "Force Majeure" as defined in PCEC's General Terms and Conditions for Gas Transportation Service.

3.5 Obligations Non-cumulative

The obligations of the Joint Venture under this Article III are not cumulative and will not be carried forward from Agreement Year to Agreement Year.

3.6 Notice of Size of Curtailment Units

The Joint Venture will use reasonable efforts to notify the LDU's as to the number of GJ's available in each Curtailment Unit by April 15th in the Agreement Year immediately preceding the Agreement Year for which such Curtailment Unit is to be in effect. If a final figure as to the number of GJ's per Curtailment Unit is not available by April 15th, the Joint Venture will by September 10th in the Agreement Year provide to the LDU's its best reasonable estimate of that number and will provide the final number to be in effect during an Agreement Year before the start of that Agreement Year.

3.7 Notice of Remaining Curtailments

The Joint Venture will keep a record of the number of Curtailment Units utilized in each Agreement Year by each of the LDU's and will, upon request, notify the LDU's as to the number of Standard Annual Curtailments and Supplemental Annual Curtailments remaining available during an Agreement Year.

3.8 Emergency Assistance

Notwithstanding any other condition herein, whenever, for reasons beyond the control of the LDU, the supply of Residue Gas available to an LDU is insufficient to meet the total demands of all Core Market customers in its Service Area, the Joint Venture will, subject to §3.9, cooperate reasonably with the LDU to deliver to the LDU such Residue Gas ("Emergency Gas") as is necessary to meet the essential requirements of those customers up to the Firm Daily Contract Demand, provided the LDU has first

(a) utilized all Curtailment Units otherwise available to it under this Agreement on that Day,

(b) curtailed or interrupted all non-essential use by other customers in its Service Area in accordance with an emergency priority list filed with and approved by the BCUC, and

(c) requested that PCEC confirm to the Joint Venture that, to the best of PCEC's knowledge, the LDU has insufficient Residue Gas to meet the requirements of its Core Market customers and that confirmation has been received by the Joint Venture.

To request Emergency Gas, the LDU will give notice to the Joint Venture regarding the cause and expected duration of the emergency, and the amount of Emergency Gas requested and will confirm that the conditions set out in §3.8 (a), (b) and (c) have all been satisfied.

If the LDU determines reasonably that the shortfall in the supply of Residue Gas for Core Market customers in its Service Area is likely to continue over 2 or more successive Days, it may declare a continuing emergency by giving notice thereof to the Joint Venture and it will not be required, on any Day other than the first Day and after such notice is given, during the period of that continuing emergency, to first utilize Curtailment Units otherwise available each Day as required by §3.8(a), provided that the LDU must issue a general appeal to the public advising of the problems being experienced and urging immediate reduction in the use of Residue Gas and must, throughout the continuing emergency, fulfil the requirements of §3.8(b).

3.9 Limitation of Emergency Gas

Nothing in this Agreement will be construed to require the Joint Venture to deliver Emergency Gas, if and to the extent, in the absolute discretion of the Joint Venture, such Emergency Gas is required to preserve safety in, or to prevent damage to, any of the plant, equipment or facilities of any of the Joint Venture Participants.

3.10 Report of Interruptions and Curtailments

Within 30 days following the end of each Agreement Year, each LDU having exercised a right of Curtailment in that Agreement Year will deliver to the Joint Venture a written report to set forth in reasonable detail, including relevant dates, amounts and customers involved, for all

(i) interruptions of sales or deliveries of Residue Gas required pursuant to §3.2(b)(i), and

(ii) curtailments of the sale or delivery of Residue Gas required pursuant to §3.2(b)(ii).

3.11 Report Regarding Emergency Gas

In each instance when an LDU requests Emergency Gas it will, as soon as practicable following the request, provide an explanation, in reasonable detail and in writing, to the Joint Venture of the circumstances giving rise to the request and, as appropriate, the plans and measures to be taken by the LDU to ensure that circumstances will not occur again.

ARTICLE IV - PRICE

4.1 Standard Annual Curtailment

The price to be paid by an LDU to the Joint Venture for Residue Gas taken as Standard Annual Curtailments in any Month in the Agreement Term shall be an amount, per GJ of Residue Gas delivered, equal to the Canadian Border Price, plus $5.26 per GJ.

4.2 Supplemental Annual Curtailment

The price to be paid by an LDU to the Joint Venture for Residue Gas taken as Supplemental Annual Curtailments in any Month in the Agreement Term shall be an amount, per GJ of Residue Gas delivered, equal to the Canadian Border Price, plus $18.42 per GJ.

4.3 Emergency Gas

The price to be paid by an LDU to the Joint Venture for Residue Gas taken as Emergency Gas in any Month in the Agreement Term shall be an amount, per GJ of Residue Gas delivered, equal to 5 times the sum of

(a) the Incremental Fuel Cost plus

(b) the Canadian Border Price.

4.4 Not Divisible

For purposes of administering this Agreement, a Curtailment Unit will not be divisible. Any amount of Residue Gas that is supplied as Standard Annual Curtailment or Supplemental Annual Curtailment that is less than a Curtailment Unit will be rounded up to the next whole number and will be deemed to be a full Curtailment Unit. For greater certainty, this Section will not apply with regard to the supply of Emergency Gas.

ARTICLE V - STATEMENTS

5.1 Statements and Payments

The Joint Venture shall within 15 days following the end of each Month in which a Curtailment was in effect or in which Emergency Gas was supplied by the Joint Venture, deliver to each LDU a statement setting out the number of Curtailment Units provided to the LDU and, if applicable, the quantity of Emergency Gas supplied and the amount payable therefor in accordance with §4.1, §4.2 and §4.3. The LDU shall within 10 days of the receipt of the statement for any Month pursuant to this Section or within 25 days following the end of such Month, whichever is the later, pay the amount specified therein to the Joint Venture. If the Curtailment has been divided between the two LDU's, the notice of Curtailment setting forth the respective shares of the LDU's will be used as the basis for calculating the amount to be paid by each of the LDU's. Payments not made by the due date provided herein will bear interest in each Month at the prime annual interest rate in effect on the first day of each calendar month charged by the Royal Bank of Canada for Canadian dollar loans plus 2% from the due date until paid in full.

5.2 Incremental Fuel Costs

The Joint Venture will deliver to the LDU's a statement (the "Incremental Fuel Cost Statement") setting forth the calculation of the Incremental Fuel Cost to be utilized in calculating all payments due under §4.3. The Incremental Fuel Cost Statement will remain in effect until amended by the Joint Venture upon not less than 30 days' notice to the LDU's as provided in Schedule "A".

5.3 Revisions to Incremental Fuel Cost

Upon receipt of a revised Incremental Fuel Cost Statement as provided in §5.2, any LDU objecting to the calculation of the Incremental Fuel Cost will, within 15 days of the receipt of the revised Incremental Fuel Cost Statement, deliver a written notice of objection to the Joint Venture. The Joint Venture will, within 15 days of its receipt of a notice of objection, provide such additional information as may be reasonable and appropriate to justify the calculation but under no circumstances will the Joint Venture be obligated to disclose information that it considers to be confidential. If the parties fail to agree upon a mutually acceptable revision of the Incremental Fuel Cost within 30 days of the delivery of the revised Incremental Fuel Cost Statement, the dispute will be referred to an arbitrator for determination pursuant to §7.13. Pending the decision of the arbitrator, the existing Incremental Fuel Cost will remain in effect.

5.4 Correction of Errors

If any error is discovered in a statement rendered by the Joint Venture pursuant to §5.1, such error shall be corrected within 60 days of the discovery of the error provided, however, that no adjustment shall be made for any error in a statement which is discovered more than 24 months after the receipt of that statement by the LDU's.

ARTICLE VI - TERMINATION

6.1 Automatic Termination

Notwithstanding any other provision herein, this Agreement will automatically terminate upon the expiration or termination of the PCEC Transportation Agreement.

6.2 LDU Right to Cancel

Each LDU may at its election, subject to §6.7, cancel its participation under this Agreement provided that this Agreement will remain in effect between the Joint Venture and any remaining LDU.

6.3 Joint Venture Right to Cancel for Cause

If an LDU breaches any material provision of §3.2, §3.8 or §5.1 of this Agreement and fails, after receiving notice thereof to immediately commence and diligently seek to remedy such breach, the Joint Venture may by notice in writing suspend all its obligations hereunder to the LDU in breach until the breach is remedied. If the breach relates to the payment of a money obligation and is not remedied within 10 business days of the delivery of the notice of breach, the Joint Venture may upon a further 5 business days notice specifically setting forth its intention, cancel the right of the LDU to participate in this Agreement. If the LDU, commits a breach of the same provision of this Agreement on more than 2 occasions in an Agreement Year in respect of which notice of such breach has been given, the Joint Venture may elect, upon notice to the LDU to suspend all rights of the LDU hereunder until such time as the LDU provides evidences or assurances to the reasonable satisfaction of the Joint Venture that the breach will not occur again.

6.4 Joint Venture Right to Reduce Curtailment

If following the date of this Agreement there is a material change in circumstances such that it becomes impracticable or uneconomic for a Joint Venture Participant to purchase, transport, store or utilize heavy fuel oil at its facilities in substantially the same manner as it does at the date of this Agreement, the Joint Venture may, upon not less than 12 months' notice to the LDU's, such notice not to be effective before the expiration of the last day of any Agreement Year, reduce the number of Curtailment Units to be available hereunder. The notice will provide reasonable particulars regarding the reasons for the reduction and the calculation of the amount of the reduction. If a notice is given under this provision, the Joint Venture will, upon request by the LDU's, cooperate reasonably with the LDU's to examine and develop alternatives whereby it becomes reasonably practicable and economic for the Joint Venture to minimize or avoid a reduction in the Curtailment Units available to the LDU's. Nothing herein will be construed to require the expenditure of funds by any Joint Venture Participant to provide Curtailment Units to the LDU's other than such expenditures as would be made by such participant prudently in the ordinary course of conducting its business.

6.5 Unavailability of Heavy Fuel Oil

The parties expressly acknowledge that this Agreement and the ability of the Joint Venture to curtail its consumption of Residue Gas is based upon the capability of the Joint Venture Participants to continue to purchase, transport, store and utilize heavy fuel oil on reasonably practicable and economic terms. If and to the extent any of the Joint Venture Participants is unable for any reason beyond its reasonable control to purchase, transport, store or utilize heavy fuel oil, the obligations of the Joint Venture hereunder related to Curtailment will be suspended or reduced as appropriate to reflect these circumstances. The Joint Venture will endeavour to provide as much notice as may be practicable of any suspension or reduction of Curtailment rights under this Section but will in any event provide not less than 12 months' notice thereof. Nothing herein will relieve the Joint Venture Participants of any obligation to exercise reasonable diligence and prudent financial judgement in purchasing, transporting, storing or utilizing heavy fuel oil. Nothing in this Agreement will be interpreted to impose upon any of the Joint Venture Participants any obligation to make any capital investment in facilities or equipment for the storage, transportation or use of any alternate fuel.

6.6 Notice of Termination

The Joint Venture will give to the LDU's as much notice as is reasonably possible if this Agreement is to be terminated pursuant to §6.1. Each LDU wishing to cancel its participation under this Agreement will give notice thereof to the Joint Venture and to each other LDU not less than one month in advance of the effective date of such cancellation.

6.7 Accrued Rights

The termination of this Agreement and the cancellation by any LDU of its participation hereunder will be without prejudice to any rights that may accrue hereunder before the effective date of such termination or cancellation.

6.8 Replacement Agreement

If this Agreement is to be cancelled or is terminated for any reason other than as provided in §6.2 or §6.3, the parties will, if requested by one of the parties before effective date of the cancellation or termination, negotiate in good faith the basis upon which this Agreement might be replaced by a new agreement to provide Residue Gas by way of Curtailment to one or more of the LDU's. Nothing herein will be interpreted to impose upon the parties an obligation to enter into any such replacement agreement.

6.9 Ramp Down

If this Agreement is to be cancelled or terminated for any reason other than as provided in §6.2 or §6.3, and the parties fail to agree upon a replacement agreement pursuant to §6.8, the parties will negotiate in good faith the basis upon which the availability of Curtailments may be reduced in stages, to the extent practicable and upon terms which fairly compensates the Joint Venture for any related loss or cost.

ARTICLE VII - MISCELLANEOUS

7.1 Enurement

This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the parties.

7.2 Notices

Any notice with respect to this Agreement, except Curtailment notices under §3.1(a) and except for requests for Emergency Gas under §3.8, must be in writing and shall be deemed validly given to and received by the addressee if served personally on the date of personal service or, if delivered by facsimile copier, when received as follows:

If to the Joint Venture, to:

Vancouver Island Gas Joint Venture
c/o Inland Pacific Energy Services Ltd.
Suite 1600, 1095 West Pender Street
Vancouver, British Columbia V6E 2M6

Attention: Gas Manager
Telecopier: (604) 895-3524

with a copy to:

Fletcher Challenge Canada Limited
9th Floor, Toronto Dominion Bank Tower
700 West Georgia Street
Vancouver, British Columbia V7H 1J7

Attention: General Counsel
Telecopier: (604) 654-4132

to:

Howe Sound Pulp and Paper Limited
30th Floor - 1055 Dunsmuir Street
Vancouver, British Columbia V7X 1B5

Attention: Vice President, Environment and Energy
Telecopier: (604) 661-5464

to:

MacMillan Bloedel Limited
22nd Floor - 925 West Georgia Street
Vancouver, British Columbia V6C 3L2

Attention: General Counsel
Telecopier: (604) 687-2314

to:

Western Pulp Limited Partnership
c/o Western Pulp Inc.
Suite 2300, 1111 West Georgia Street
Vancouver, British Columbia V6E 4M3

Attention: Secretary-Treasurer
Telecopier: (604) 665-8806

and to:

Harmac Pacific Inc.
980 MacMillan Road
P.O. Box 1800
Nanaimo, British Columbia V9R 5M5

Attention: Vice-President, Manufacturing
Telecopier: (604) 722-4310

If to the LDU's, to:

Squamish Gas Co. Ltd.
1111 West Georgia Street
Vancouver, British Columbia V6E 4M6

Attention: Vice-President, Gas Supply
Telecopier: (604) 443-6476

and to:

Centra Gas British Columbia Inc.
1675 Douglas Street
Victoria, British Columbia V8W 3V3

Attention: President
Telecopier: (604) 480-4450

or to such other address in British Columbia as may be specified from time to time by the particular party by notice to the others.

7.3 Entire Agreement

As of the date hereof, this Agreement constitutes the entire agreement among the parties and supersedes every previous agreement, communication, expectation, negotiation, representation or understanding, whether oral or written, express or implied, statutory or otherwise, among the parties with respect to the subject matter of this Agreement.

7.4 Records and Audit

The LDU's and the Joint Venture will keep and maintain at all times, true and accurate books, records and accounts in accordance with good industry practices, distinguishable from all other books and records, in respect of all Residue Gas curtailed and accounts will be preserved by the parties for a period of at not less than 36 months after the termination or expiration of the Agreement Term.

During normal business hours and through to the expiration of 24 months following the termination or expiration of the Agreement Term, the parties to this Agreement have the right, at their sole cost, to have a third party auditor, who will be a member of a national Canadian chartered accounting firm audit on such party's behalf, the relevant accounts, books, records and charts of the other party to the extent necessary in order to verify the accuracy of any statement, charge, computation or demand made under or pursuant to any of the provisions of this Agreement.

If any error is discovered in any statement rendered hereunder, such error will be adjusted within 60 days from the date of discovery, but no adjustment will be made for any error discovered more than 24 months after delivery and receipt of such statements.

7.5 Modification

There will be no modification of the terms and provisions of this Agreement except by the agreement of all the parties in writing.

7.6 Governing Laws

This Agreement will be interpreted and construed in accordance with the laws of the Province of British Columbia and the parties irrevocably attorn to the jurisdiction of the Courts of British Columbia.

7.7 Compliance With Laws

This Agreement and the respective obligations of the parties hereunder are subject to present and future valid laws and valid orders, rules, and regulations of duly constituted authorities having jurisdiction.

7.8 Confidentiality

Except as required by law in the event of litigation in respect of this Agreement, and except as may be required by a valid order or direction of the British Columbia Utilities Commission or other regulatory body having jurisdiction, the parties hereto, and their officers, directors, employees and co-venturers will hold in confidence during the Agreement Term and after its termination, and will not use to the detriment of any other party hereto, all information contained hereunder and all matters concerning the transactions herein contemplated.

7.9 Cumulative Remedies

Unless specifically provided herein, the rights, powers and remedies of each of the parties provided herein are cumulative and do not affect any right, power or remedy that may be available to either party at law or in equity.

7.10 Not Assignable

None of the parties may transfer, convey or assign this Agreement or any right, benefit or interest in this Agreement without the prior written consent of the others (such consent not to be unreasonably withhold or delayed), and any such transfer, conveyance or assignment made without such consent will be void. Notwithstanding the foregoing, if Centra transfers to PCEC all the property and assets used by Centra and its subsidiaries in the gas distribution business carried on in the areas served by the PCEC pipeline, Centra may, upon notice in writing to the other parties without the prior consent of any other party to this Agreement, transfer, convey and assign this Agreement to PCEC. Upon the assumption by PCEC of:

(a) the obligations and liabilities of Centra under the 1991 Peaking Gas Management Agreement which have accrued under the that agreement prior to the Transition Time; and

(b) the covenants, obligations and any liabilities of Centra under and pursuant to this Agreement, including any obligations and liabilities which have occurred prior to the effective date of such assumption by PCEC,

Centra shall, without further act or formality, be absolutely released and forever discharged by the Joint Venture of and from all of the covenants, obligations and any liabilities whatsoever of Centra under and pursuant to both this Agreement and the 1991 Peaking Gas Management Agreement, and the Joint Venture shall, without further act or formality, be absolutely released and forever discharged by Centra of and from all of the covenants, obligations and any liabilities whatsoever of Centra under and pursuant to both this Agreement and the 1991 Peaking Management Agreement.

7.11 Termination of 1991 Peaking Gas Management Agreement

Effective the Transition Time, and without act or formality, the 1991 Peaking Gas Management Agreement shall be terminated and, subject to §6.7 of the 1991 Peaking Gas Management Agreement:

(a) the Joint Venture and each of the Joint Venture Participants shall be released and forever discharged by Centra and by SG, respectively, of and from all of the covenants, obligations and any liability whatsoever of the Joint Venture under and pursuant to the 1991 Peaking Gas Management Agreement; and

(b) Centra and SG, respectively, shall be released and forever discharged by the Joint Venture of and from all of the covenants, obligations and any liability whatsoever of Centra and of SG, respectively, under and pursuant to the 1991 Peaking Gas Management Agreement.

7.12 Several Liability

The parties acknowledge and agree that for all purposes the obligations of the Joint Venture and the Joint Venture Participants hereunder are not joint but are several only in accordance with the respective interests of each of the Joint Venture Participants from time to time pursuant to the Joint Venture Agreement.

7.13 Core Market Exceptions

If the Joint Venture believes reasonably that its interests are or may be unfairly prejudiced by the inclusion of any particular customer of an LDU as a Core Market customer or that the treatment of a particular customer as a Core Market customer confers an unfair advantage or undue preference to that customer, the Joint Venture will have the right to complain to the BCUC. If the BCUC determines that there is an unfair advantage or undue preference or that the interests of the Joint Venture are unfairly prejudiced, that customer will, for all purposes of this Agreement, be excluded from the Core Market.

7.14 Arbitration

Any dispute between the Joint Venture and one or more LDU regarding the calculation of the Incremental Fuel Cost will be determined by a single arbitrator appointed, if the parties fail to agree upon an arbitrator within 10 days of the date of a demand for arbitration, pursuant to the provisions of the Commercial Arbitration Act (British Columbia). The arbitrator will, depending on the nature of the dispute, be a chartered accountant or a professional engineer having appropriate experience and expertise and the arbitration will be held in Vancouver, British Columbia with all proceedings governed by the Commercial Arbitration Act (British Columbia). The arbitrator's decision will be made effective retroactive to the date 30 days from the date of delivery of the revised Incremental Fuel Cost Statement.

7.15 Exchange of Information

The parties will, upon request, provide such additional information as may be reasonably required to allow the parties to efficiently and effectively carry out their respective obligations hereunder and to determine and enforce individual or collective rights under this Agreement.

7.16 Contracting for Gas Supply

Each party will contract prudently for Gas supply consistent with good business practices in their respective business activities. Without limiting the generality of the foregoing, each of the LDU's will contract for Gas supply on a basis that, utilizing a forecast peak demand based on the coldest winter over the past 20 years, or such other period of time as the BCUC may approve, it will not require access to Supplemental Curtailment Units or Emergency Gas. If any LDU seeks to change the period of time upon which its peak demand forecast is based from the 20 years contemplated herein, it will give notice in advance to the Joint Venture of the proposed change and the reasons therefor. Each party will provide on a confidential basis, copies of its proposed Gas supply contracts for each gas year with the BCUC for approval. Acceptance by the BCUC of such contracts will be deemed conclusively to evidence prudent contracting as required by this §7.16.

7.17 Approval of BCUC

This Agreement will not become effective unless and until it is approved by an order of the BCUC. Nothing in this Agreement will be deemed to confer jurisdiction or authority upon the BCUC to vary or amend this Agreement, and any such purported variation or amendment by the BCUC without the consent of the parties will automatically terminate this Agreement.

7.18 Joint Venture Not a Public Utility

Nothing in this Agreement, and no delivery of Residue Gas by the Joint Venture or any Joint Venture Participant by virtue of this Agreement, will be construed to constitute the Joint Venture or any of the Joint Venture Participants, jointly or severally, as a public utility within the meaning of the Utilities Commission Act (British Columbia) or otherwise by operation of law.

7.19 Counterpart Execution

This Agreement may be executed in any number of counterparts, and all of those counterparts shall, for all purposes, constitute one agreement binding upon the parties notwithstanding that all parties are not signatory to the same counterpart.

7.20 First Agreement Year

For the first Agreement Year, the LDU's shall be entitled to that number of Curtailment Units and Supplemental Annual Curtailment Units equal to those available under this Agreement in any other Agreement Year less the number of such units utilized by the LDU's under the 1991 Peaking Gas Management Agreement during the period from 0800 PST on November 1, 1995 until the Transition Time.

7.21 Condition Precedent

This Agreement shall not come into force and effect unless Her Majesty the Queen in Right of the Province of British Columbia and PCEC have delivered written notice to the Joint Venture pursuant to paragraph 2 of the Transition and Release Agreement.

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

FLETCHER CHALLENGE CANADA LIMITED

Per:________________________

Per:________________________

HOWE SOUND PULP AND PAPER LIMITED

Per:________________________

Per:________________________

MACMILLAN BLOEDEL LIMITED

Per:________________________

Per:________________________

WESTERN PULP INC. as General Partner of WESTERN PULP LIMITED PARTNERSHIP

Per: J. Waldie Manion

Per:________________________

HARMAC PACIFIC INC.

Per:________________________

Per:________________________

For the LDU's:

SQUAMISH GAS CO. LTD.

Per:________________________

Per:________________________

CENTRA GAS BRITISH COLUMBIA INC.

Per:________________________

Per:________________________

SCHEDULE "A"

Incremental Fuel Cost

"Incremental Fuel Cost" means, on a comparative burner-tip basis in dollars per GJ, the difference between:

(a) the cost of Residue Gas to the Joint Venture for the current month of billing in Canadian dollars per GJ at the Huntingdon delivery point on the Westcoast System, and

(b) the Canadian dollar per GJ equivalent for the current month of billing of the weighted monthly average price of one month forward prices for WTI (West Texas Intermediate) and ANS (Alaska North Slope) crude oil spot prices CFI, U.S. dollars per barrel (the "Crude Oil Reference Price") plus $1.00 U.S. per barrel in respect of all ancillary costs related to the acquisition, storage, handling and use of the amount of fuel oil used to replace Residue Gas subject to Curtailment (the "Administration Fee"), plus

(c) all other adjustments as may be appropriate to fairly compensate the Joint Venture for any consequent increase in the unit cost it incurs for uncurtailed Residue Gas service (including, without limitation, odourant, fuel gas and lost and unaccounted for gas charges) and for any other incremental costs or expenses incurred by the Joint Venture as a consequence of Curtailments as set forth from time to time in the Incremental Fuel Cost Statement.

If at any time the Crude Oil Reference Price (or any alternative index or reference price in effect hereunder) is not adequate as a proxy for the actual costs incurred by the Joint Venture Participants in purchasing fuel oil to replace Residue Gas subject to Curtailment, the Joint Venture may, upon not less than 30 days' notice and subject to the consent of the LDU's (such consent not to be unreasonably withheld or delayed) , substitute an alternative index or reference price for that purpose.

If the Joint Venture at any time wishes to increase the Administration Fee, or if following an increase in the Administration Fee the LDU's wish to reduce the Administration Fee, the Joint Venture or the LDU's, as the case may be, will give at least 30 days' notice of the proposed change together with such reasonable information as may be required to justify the change.

At no time will the Administration Fee be less than the Canadian dollar per GJ equivalent of $1.00 U.S. per barrel.

At no time will the Incremental Fuel Cost be less than the Canadian dollar per GJ equivalent of $1.00 U.S. per barrel.

For purposes of classification, the Canadian dollar per GJ equivalent of U.S. dollars per barrel shall be calculated by multiplying the value in U.S. dollars per barrel by the current Exchange Rate and dividing by 6.838.

ASSIGNMENT AND ASSUMPTION AGREEMENT

THIS AGREEMENT made as of the 20th day of February, 1996

BETWEEN:

CGBC HOLDINGS INC., a company having offices in the City of Victoria, in the Province of British Columbia

("CGBC")

OF THE FIRST PART

AND:

CENTRA GAS BRITISH COLUMBIA INC., a company having offices in the City of Victoria, in the Province of British Columbia

("CENTRA")

OF THE SECOND PART

WHEREAS:

A. The Joint Venture, Squamish Gas and CGBC were parties to the 1991 PGMA;

B. The Joint Venture, Squamish Gas and CGBC entered into the 1995 PGMA under which the parties agreed to terminate the 1991 PGMA and replace it with the 1995 PGMA, effective the Transition Time;

C. Section 7.10 of the 1995 PGMA provides that if all the property and assets used by CGBC and its subsidiaries in the gas distribution business carried on in the areas served by the Vancouver Island Pipeline are transferred to Centra, CGBC may, upon notice to and without the consent of the Joint Venture or Squamish Gas, transfer, convey and assign the 1995 PGMA to Centra;

D. Section 7.10 of the 1995 PGMA also provides that if Centra assumes the obligations and liabilities of CGBC which accrued under the 1991 PGMA prior to the Transition Time and under the 1995 PGMA prior to the Effective Time, CGBC will be released and absolutely discharged from both agreements;

E. On January 1, 1996, the properties, assets, business and undertaking of Centra and its subsidiaries, Centra Gas Vancouver Island Inc. and Centra Gas Victoria Inc., relating to the gas distribution systems carried on in the areas served by the Vancouver Island Pipeline were transferred and conveyed to Centra;

F. On January 3, 1996, the corporate name of CGBC was changed from Centra Gas British Columbia Inc. to CGBC Holdings Inc., and the corporate name of Centra was changed from Pacific Coast Energy Corporation to Centra Gas British Columbia Inc.;

THIS AGREEMENT WITNESSES THAT, in consideration of the premises and the mutual covenants and agreements herein contained, the parties hereto agree and covenant as follows:

1. In this Agreement,

   (a) "Effective Time" means 0800 Pacific Standard Time on February 23, 1996;

   (b) "Joint Venture" means the Vancouver Island Gas Joint Venture comprised of Fletcher Challenge Canada Limited, Howe Sound Pulp and Paper Limited, MacMillan Bloedel Limited, Western Pulp Limited Partnership and Harmac Pacific Inc.;

   (c) "1991 PGMA" means the Peaking Gas Management Agreement made effective November 1, 1991 among the Joint Venture, Squamish Gas and CGBC;

   (d) "1995 PGMA" means the Peaking Gas Management Agreement dated as of December 14, 1995 among the Joint Venture, Squamish Gas and CGBC;

   (e) "Squamish Gas" means Squamish Gas Co. Ltd., a company having offices in the City of Vancouver, in the Province of British Columbia; and

   (f) "Transition Time" means 0800 Pacific Standard Time on December 30, 1995.

2. As at the Effective Time, CGBC assigns, sets over and transfers to Centra absolutely all of its right, title and interest in, to and under the 1995 PGMA.

3. As of the Effective Time, Centra accepts the assignment of all CGBC's right, title and interest in, to and under the 1995 PGMA, and agrees from and after the Effective Time and to the full exoneration and discharge of CGBC:

   (a) to perform the 1995 PGMA, and to be bound by all the terms and conditions of the 1995 PGMA to the same extent as if Centra was named therein in the place and stead of CGBC;

   (b) to assume all the obligations and liabilities of CGBC under the 1991 PGMA which accrued under that agreement prior to the Transition Time; and

   (c) to assume all the obligations and liabilities of CGBC under the 1995 PGMA which accrued under that agreement prior to the Effective Time.

IN WITNESS WHEREOF, this Agreement has been executed by the parties hereto as of the date first above written.

CGBC HOLDINGS INC.

By: ______________________________

By: ______________________________

CENTRA GAS BRITISH COLUMBIA INC.

By: ______________________________

By: ______________________________

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 1224 *, Approved and Ordered* DEC 11 2004

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the attached Special Direction is made.

Minister of Energy and Mines

Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section:- *Vancouver Island Natural Gas Pipeline Act*, R.S.B.C. 1996, c. 474, section 7 (3) and (4)

Other (specify):-

November 30, 2004 1527/2004/7

VANCOUVER ISLAND NATURAL GAS PIPELINE SPECIAL DIRECTION NO. 2 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Definitions

1 In this Special Direction:

"Act" means the *Vancouver Island Natural Gas Pipeline Act*;

"commission" means the British Columbia Utilities Commission;

"Contract Demand", **"Firm Transportation Service"** and **"Interruptible Offset Gas"** have the same meanings as they have in Article 3 of the TSA;

"Joint Venture" has the same meaning as in section 1.1 of Special Direction 1;

"letter agreement" means the letter agreement, dated October 27, 2004 and attached as Schedule "A" to this Special Direction, respecting the amendment to and extension of the TSA;

"Special Direction 1" means the Vancouver Island Natural Gas Pipeline Special Direction made under Order in Council 1510/95;

"Terasen" means Terasen Gas (Vancouver Island) Inc.;

"transportation tolls" has the same meaning as in Special Direction 1;

"TSA" means the Transportation Service Agreement dated as of the 14th day of December, 1995 and attached as Exhibit F to Special Direction 1.

Application

2 This Special Direction is issued to the commission under section 7 (3) and (4) of the Act.

Directions relating to the letter agreement

3 (1) Despite sections 3.6 and 3.7 of Special Direction 1 but without limiting any other power the commission may have, the commission must approve the letter agreement to the extent that it

(a) varies the transportation tolls or other amounts payable to Terasen for the services provided to the Joint Venture under the TSA, and

(b) increases or decreases

(i) the Contract Demand for Firm Transportation Service determined in accordance with the TSA, or

(ii) the quantities of Interruptible Offset Gas that the Joint Venture is entitled to receive under the TSA.

(2) Despite subsection (1), the direction contained in that subsection does not require the commission to approve any other agreements, including, without limitation, any further definitive amending agreements, whether or not those agreements do or purport to do either or both of the following:

(a) incorporate any or all of the terms of the letter agreement;

(b) replace or supersede the terms of the letter agreement.

Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

16705 Fraser Highway
Surrey, BC V3S 2X7
Tel: 604-592-7784
Fax: 604-592-7890
Email: scott.thomson@terasengas.com
www.terasengas.com

December 21, 2004

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

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

Re: Terasen Gas (Vancouver Island) Inc.
Vancouver Island Gas Joint Venture ("VIGJV") Amending Agreement

Terasen Gas (Vancouver Island) Inc. ("TGVI") entered into an Amending Agreement to amend taxes of the VIGJV Transportation Service Agreement and Peaking Gas Management Agreement on October 27, 2004. Through Order of the Lieutenant Governor in Council, 1224 dated December 11, 2004 the Province, through the Vancouver Island Natural Gas Pipeline Special Direction No. 2, directed the British Columbia Utilities Commission ("the Commission") to approve the Amending Agreement. The Commission approved the Amending Agreement in Commission Order No. G-113-04, dated December 14, 2004 and directed TGVI to provide the filing in tariff format.

This submission represents TGVI's response to Commission Order No. G-113-04. TGVI respectfully requests Commission endorsement of the enclosed two (2) copies of the Amending Agreement and that one (1) complete set be returned to TGVI for its records.

If you have any questions please call Tom Loski at (604) 592-7464.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Scott A. Thomson

Attachments

cc: Karl Gustafson
Registered Intervenours / Interested Parties

Terasen Gas
16705 Fraser Highway
Surrey, B.C.
V3S 2X7

Tel: (604) 576-7000

Terasen Gas

DELIVERED BY COURIER AND E-MAIL
October 27, 2004

Dave Hargreaves
Manager, Central Services
HOWE SOUND PULP AND PAPER L.P.
Port Melon, B.C.
V0N 2S0

Dear Mr. Hargreaves :

Re : Amendment and Extension of Transportation Service Agreement and Peaking Gas Management Services Agreement between Terasen Gas (Vancouver Island) Inc. and the Vancouver Island Gas Joint Venture

This letter agreement is further to our recent discussions regarding the principal terms for the amendment and extension of the Terasen Gas (Vancouver Island) Inc. ("TGVI")/ Vancouver Island Joint Venture ("VIGJV") Transportation Service Agreement and Peaking Gas Management Services Agreement (collectively, the "Agreements"). The purpose of this letter agreement is to set out, as set forth herein and in Appendix 1 attached (together, the "Letter Agreement"), the terms upon which TGVI and VIGJV are prepared to amend and extend the Agreements. While it is intended that the terms of this Letter Agreement shall be binding on TGVI and VIGJV once executed by the parties hereto, the parties acknowledge that they shall be executing further definitive amending agreements ("Amending Agreements") to the Agreements which will incorporate the terms of this Letter Agreement. Once executed, such Amending Agreements shall replace and supersede the terms of this Letter Agreement.

Upon the execution of this Letter Agreement by the VIGJV and TGVI, the VIGJV shall:

1 promptly adjourn or cause to be adjourned generally the hearing of the Petition filed in the Vancouver Registry of the Supreme Court of British Columbia ("Petition") under #S045062 and hold all litigation relating to this matter in abeyance until the terms of the Amending Agreements have received all necessary regulatory, governmental and other approvals and have become effective in accordance with Article 11 of Appendix 1 to this Letter Agreement; and

2. agree not to renew the agreement with BC Hydro for the assignment of 4 TJ/day of transportation capacity upon the expiration of that agreement and, pending and following receipt of all necessary regulatory, governmental and other approvals to make this Letter Agreement effective, not to take further steps to require that TGVI consent to the assignment contemplated by that agreement.

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this day, of October, 2004

Pope and Talbot Ltd.

Per: ____________________
Name:
Title:

Western Pulp Limited

Per: ____________________
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ____________________
Name:
Title:

Norske Skog Canada Limited

Per: ____________________
Name:
Title:

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Ak/ak
Encl.

Accepted this 27 day of October, 2004

Pope and Talbot Ltd.
Per:
Name: PAUL G. SADLER
Title: GENERAL MANAGER
P+T LTD

Western Pulp Limited
Per:
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership
Per:
Name:
Title:

Norske Skog Canada Limited
Per:
Name:
Title:

...2

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this day, of October, 2004

Pope and Talbot Ltd.

Per: ______________________
Name:
Title:

Western Pulp Limited

Per:
Name: STEPHEN SUTHERLAND
Title: PURCHASING MANAGER

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name:
Title:

Norske Skog Canada Limited

Per: ______________________
Name:
Title:

...2

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

As set out above, once executed by both parties, the terms set out in this Letter Agreement are intended to constitute a legally binding agreement amongst the parties hereto. By their respective signatures hereto, the parties acknowledge that they have all requisite corporate and other authority to enter into, execute and be bound by the terms of this Letter Agreement. Please sign below where indicated and return a fully executed copy to my attention. This Letter Agreement may be executed by facsimile and by counterparty.

Yours very truly,
TERASEN GAS (VANCOUVER ISLAND) INC.
Per:

Scott Thomson
Vice President Finance
Akf/akf
Encl.

Accepted this 27th day, of October, 2004

Pope and Talbot Ltd.

Per: ______________________
Name:
Title:

Western Pulp Limited

Per: ______________________
Name:
Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name: DALE HARLESAKES
Title: MANAGER, CENTRAL SERVICES

Norske Skog Canada Limited

Per: ______________________
Name:
Title:

Once the requisite regulatory, governmental and other approvals have been obtained, VIGJV shall promptly cause the dismissal or discontinuance of the Petition as contemplated in Section 9.2 of Appendix 1 to this Letter Agreement.

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Title:

Howe Sound Pulp and Paper Limited Partnership

Per: ______________________
Name:
Title:

Norske Skog Canada Limited

Per: ______________________
Name: R.H. LINDSTROM
Title: VICE PRESIDENT, STRATEGY

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TRANSPORTATION AND PEAKING GAS MANAGEMENT SERVICES

1. Parties

Vancouver Island Gas Joint Venture ("VIGJV") and Terasen Gas (Vancouver Island) Inc. ("TGVI") (together, the "Parties").

2. Purpose

2.1 The VIGJV is seeking to extend and amend its existing Transportation Service Agreement ("TSA") and the Peaking Gas Management Agreement ("PGMA") with TGVI.

2.2 TGVI owns and operates the natural gas transmission system from Eagle Mountain to Vancouver Island and the transmission and distribution system on Vancouver Island, and proposes to expand its system with a phased combination of system upgrades and liquefied natural gas ("LNG") storage.

2.3 TGVI proposes to amend and extend each of the existing TSA and the PGMA with the VIGJV for service from Huntingdon to the VIGJV mills based on the principal terms outlined in this term sheet. The TSA and PGMA are collectively the "Agreements". Unless otherwise defined in this term sheet, all capitalized terms shall bear the meanings set out in the Agreements.

3. Term of TSA

3.1 The Renewal Period in the TSA will be amended and extended to be from January 1, 2005 to December 31, 2012.

3.2 The TSA may be extended for a five year term beyond the Renewal Period as mutually agreed by the Parties prior to October 1, 2011.

4. Quantity

4.1 Firm Contract Demand for the Renewal Period under the TSA will be:

4.1.1 20,000 gigajoules per day for the period January 1, 2005 to December 31, 2005.

4.1.2 12,500 gigajoules per day for the remainder of the Renewal Period.

4.2 Where a minimum Contract Demand is specified in the TSA as 30,000 gigajoules per day, it shall be amended to 8,000 gigajoules per day.

5. Toll

5.1 The firm demand toll shall be the Demand Toll as expressed in Schedule A of the TSA.

5.2 There will be three tiers of interruptible tolls for quantities each day in excess of the Contract Demand quantity.

5.2.1 For quantities of gas each day up to 20,000 gigajoules, the Interruptible Toll shall be paid on the positive difference between this quantity and the Contract Demand. The applicable Interruptible Toll for this gas shall be equivalent to the Demand Toll rate (firm demand rate). Quantities of gas delivered under this rate will be known as "Tier 1 IT".

5.2.2 For quantities of gas each day in excess of 20,000 gigajoules up to 30,000 gigajoules, the Interruptible Toll shall be paid as follows:

5.2.2.1On the 1st 20,000 gigajoules of gas, the Interruptible Toll shall be paid on the positive difference between 20,000 gigajoules and the Contract Demand at the Tier 1 IT rate; and

5.2.2.2On quantities between 20,000 gigajoules and 30,000 gigajoules the applicable Interruptible Toll payable on the quantity in excess of 20,000 gigajoules shall be as expressed in Schedule B of the TSA. Quantities of gas delivered under this rate will be known as "Tier 2 IT".

5.2.3 For quantities of gas each day in excess of 30,000 gigajoules, the Interruptible Toll shall be paid as follows:

5.2.3.1On the 1st 20,000 gigajoules of gas, the Interruptible Toll shall be paid on the positive difference between 20,000 gigajoules and the Contract Demand at the Tier 1 IT rate;

5.2.3.2On quantities between 20,000 gigajoules and 30,000 gigajoules the applicable Interruptible Toll payable on the quantity between 20,000 gigjoules and 30,000 gigajoules shall be at the Tier 2 IT rate; and

5.2.3.3The applicable Interruptible Toll paid on the quantities in excess of 30,000 gigajoules shall be equivalent to the Demand Toll rate (firm demand rate) multiplied by 1.1. Quantities of gas delivered under this rate will be known as "Tier 3 IT".

6. Future Contract Demand Reinstatement or Reduction

6.1 All articles related to Contract Demand reduction will be removed from the TSA except the following:

6.1.1 The VIGJV shall have the right to reduce Contract Demand by up to 4,500 gigajoules per day during the Renewal Period. The notice period for all such reductions shall be a minimum of one year and notice will not to be given prior to January 1, 2006.

Notwithstanding the above, the minimum Contract Demand during the Renewal Period shall be 8,000 gigajoules per day.

6.1.2 The right to reduce Contract Demand as a result of Expansion Projects will remain, but will be suspended for any Expansion Projects that, when announced, are projected to have in-service dates prior to November 1, 2010. For clarity, this means that the VIGJV will not be able to reduce its Contract Demand for any Expansion Projects put in service prior to November 1, 2010

6.2 The TSA will be amended such that any reinstatement of Contract Demand above 12,000 gigajoules per day will be on an annual renewal basis (effective November 1 of each year). TGVI will give the VIGJV a minimum of six months notice as to availability of reinstatement of Contract Demand in each year. For clarity, nothing in this amendment would compel TGVI to add facilities to meet a VIGJV request for reinstatement of Contract Demand.

7. Peaking Gas Management Agreement (PGMA)

7.1 The PGMA will be amended so that after January 1, 2006 TGVI will only be able to call for Curtailment in situations of mechanical failure of TGVI facilities that would otherwise cause it to be unable to meet core market demand.

7.2 Curtailment in these circumstances will be covered under the rate and terms for Supplemental Curtailment Units under the PGMA.

7.3 TGVI will also be able to request Emergency Gas under those provisions in the PGMA (namely, only if the VIGJV is able to provide it).

7.4 The term of the PGMA will be extended to reflect the extended term of the TSA as set out in this term sheet.

8. Interruptible Offset Gas

8.1 Limitations to the size of the Interruptible Offset Gas Account in the TSA shall be amended so that the total quantity of gas in the Interruptible Offset Account shall not exceed 25 times the then current Contract Demand in any year.

8.2 When quantities are delivered from the Interruptible Offset Account for Tier 1 IT, Tier 2 IT and Tier 3 IT, removal from the Interruptible Offset Account shall be on a 1 to 1 basis.

9. Right of Assignment

9.1 The TSA will be amended to remove any right of assignment except to the new owner in the case of a change in ownership of the Owner's Mills. For clarity, this means that there will be no right to assign or otherwise extend the rights under the TSA for use anywhere other than the Owner's Mills. The Agreements shall be amended to clarify that except for such assignment, the VIGJV shall not be entitled to add, replace or substitute any entity to the VIGJV and thereby purport to confer rights on such entity with respect to the Agreements notwithstanding any provision to the contrary in the Agreements.

9.2 The VIGJV shall promptly: (i) cause the VIGJV Petition to the Supreme Court of British Columbia, Vancouver Registry Number S045062, to be dismissed by way of consent dismissal order; or (ii) discontinue all further proceedings relating thereto; and in either case, each of TGVI and VIGJV shall bear its own costs and the parties will exchange a mutual release with respect to the claims set out therein.

9.3 There will be no other claims made to TGVI regarding any assignment of VIGJV Contract Demand under the Agreements.

10. Expansion Project Related to Service to ICP and CFT Outcome

The VIGJV agrees to not oppose TGVI's August 2004 CPCN application for an LNG facility for Vancouver Island.

11. Regulatory and Other Approvals

11.1 This term sheet and the amendments to the Agreements contemplated in this term sheet are subject to the approval by the British Columbia Utilities Commission ("BCUC") and receipt of other regulatory, governmental and other approvals as may be required.

11.2 TGVI shall proceed promptly and in good faith to apply to the BCUC for approval of this term sheet and the amendments and extension of the Agreements as contemplated in this term sheet and both parties shall support, through intervention, appearance of counsel, evidence and argument, such application. In addition, TGVI shall promptly and in good faith apply for and diligently seek all other regulatory, governmental and other regulatory approvals as my be required.

12. Requests by VIGJV for Additional Capacity which require Expansion Projects

The existing provisions in the TSA relating to Expansion Projects shall be amended to give effect to the following agreement between TGVI and the VIGJV with respect to Expansion Projects, including the provisions of Section 6.1.2 above. In the event the VIGJV requires additional firm capacity, which increase in firm capacity would require TGVI to undertake Expansion Projects, TGVI shall undertake such projects, subject to the approval of the BCUC, provided the following conditions are met:

12.1 **Ownership** – All Expansion Projects will remain the property of TGVI.

12.2 **Economic Test** – All requests for TGVI to undertake Expansion Projects will be subject to the Expansion Projects satisfying the following economic test. The economic test will be a discounted cash flow analysis of the projected revenue and costs associated with the Expansion Projects. Subject to the provisions of Section 12.5 below, Expansion Projects will be deemed to be economic and will be constructed if the results of the economic test indicate a zero or positive net present value.

Revenue – The projected revenue to be used in the economic test will be determined by TGVI by:

(a) establishing consumption estimates for the VIGJV; and,

(b) applying the appropriate revenue margins for such consumption.

Costs – The total costs to be used in the economic test include, without limitation, the following:

(a) the full labour, material, and other costs necessary to construct the Expansion Project and any related facilities;

(b) the appropriate allocation of TGVI's overheads associated with the construction of the Expansion Project; and,

(c) the incremental operating and maintenance expenses associated with the carrying out and implementation of the Expansion Project.

In addition to the costs identified, the economic test will include applicable taxes and the appropriate return on investment to TGVI as approved by the BCUC.

12.5 **Contribution in Aid of Construction** – Notwithstanding the provisions of Section 12.2 above, if the economic test results indicate a negative net present value, TGVI will nonetheless proceed with the Expansion Project provided that the shortfall in projected revenue is eliminated by contributions in aid of construction made by the VIGJV. The total required contribution in aid of construction will be paid by the VIGJV prior to commencement of construction of the Expansion Project.

TARIFF SUPPLEMENT NO. 1

TRANSPORTATION SERVICE AGREEMENT

BETWEEN

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)

AND

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Effective January 1, 2008

This TRANSPORTATION SERVICE AGREEMENT is made as of September 19, 2007.

BETWEEN:

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

(hereinafter called "TGVI")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation established pursuant to an Act of the Province of British Columbia and continued under BC Hydro and Power Authority Act, R.S.B.C. 1996, c.212.

(hereinafter called "BC Hydro")

WHEREAS:

A. TGVI owns and operates a natural gas transmission and distribution system on the Sunshine Coast and Vancouver Island; and

B. BC Hydro requires natural gas transportation service to transport the fuel requirements for the Island Cogeneration Project ("ICP") at Campbell River on Vancouver Island; and

C. TGVI has agreed to provide such gas transportation services to BC Hydro in accordance with and subject to the terms and conditions hereinafter set forth.

NOW THEREFORE in consideration of the mutual agreements herein contained the parties covenant and agree as follows:

ARTICLE 1
GENERAL TERMS AND CONDITIONS

1.1 Incorporation. The provisions of the General Terms and Conditions for Gas Transportation Service (the "GT&Cs") are incorporated herein by reference and constitute part of this Agreement. Unless otherwise defined in this Agreement, the terms and expressions used in this Agreement have the same meaning as the corresponding terms and expressions used in the GT&Cs. If there is any conflict or inconsistency between the provisions of this Agreement and the provisions of the GT&Cs, then the provisions of this Agreement prevail.

ARTICLE 2
INTERPRETATION

2.1 Definitions. In this Agreement, the following terms have the following meanings:

(1) "Alternate Delivery Point" means any "Delivery Point" as defined in the GT&Cs, other than the Delivery Point specified in this Agreement, which is specified for a Shipper in its Service Agreement;

(2) "BCUC" means British Columbia Utilities Commission and any successor regulatory agency thereto;

(3) "Capacity Assignment Agreement" means the Capacity Assignment Agreement dated as of September 19, 2007 between TGVI, BC Hydro and Terasen Gas Inc., as amended and in effect from time to time;

(4) "Capacity Right" has the meaning as set out in the Peaking Agreement;

(5) "Certificate of Public Convenience and Necessity" (or "CPCN") means a certificate issued by the BCUC under section 45 of the *Utilities Commission Act* (British Columbia) or if section 45 is amended or replaced, any approval of similar effect required from the BCUC under section 45 as amended or under any statutory provision of similar effect that replaces section 45.

(6) "Commencement Date" is the later of January 1, 2008 and the date immediately following the date the conditions precedent under section 11.10 are satisfied;

(7) "Commodity Toll" means, in respect of each Month of the Service Period of this Agreement, the amount, expressed in dollars per GJ, as approved and amended from time to time by the BCUC, and determined by TGVI for such Month and allocated to BC Hydro, in respect of:

(a) taxes payable by TGVI in respect of System Gas, including taxes payable under the *Motor Fuel Tax Act* (British Columbia);

(b) any excise or other taxes payable by TGVI in respect of gas transported and delivered through the TGVI System; and

(c) odorant costs payable by TGVI to Terasen Gas Inc. in accordance with the Wheeling Agreement;

(8) "Connecting Facilities" means the pipeline, metering and related facilities installed by TGVI to connect ICP to the TGVI System;

(9) "Contract Demand" (or "CD") has the meaning as set out in section 6.2, as adjusted from time to time in accordance with section 4.3 and/or section 6.3;

(10) "Delivery Point" means the point where the Connecting Facilities connect to the facilities of ICP;

(11) "Demand Toll" means, in respect of each Month of the Service Period of this Agreement, the toll for Firm Transportation Service as approved and amended from time to time by the BCUC, expressed in dollars per GJ of Contract Demand per day, and as set out from time to time in Schedule 1;

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

(13) "Expansion Facility" or "Expansion Facilities" means a material facility or facilities that TGVI proposes to construct on the TGVI System after the Commencement

Date in respect of which TGVI has provided BC Hydro an Expansion Notice pursuant to section 4.2, but excluding the proposed Mt. Hayes Storage Facility and excluding any replacement of, or upgrade to, a facility in existence at the Commencement Date except to the extent that replacement facility or upgrade causes a material increase in the capacity of the TGVI System;

(14) “Excess Capacity Period” means, for each Expansion Facility, the period of time, measured in months and based on the most recent TGVI demand forecast filed with the BCUC, from the effective date of termination of this Agreement to the earlier of (a) the date the Expansion Facility is forecast to be required to meet design day requirements on the TGVI System, and (b) the end of the Initial Term or, if the Service Period has been extended, the end of the Renewal Term;

(15) “Expansion Notice” has the meaning as set out in section 4.1;

(16) “Forced Outage” means a total or partial outage of ICP of a temporary nature resulting from an unplanned component failure or other condition, which requires, either immediately, or prior to the weekend if the condition arose on a weekday, a generator or other component to be removed from service or the load on a generator or reliance on the component to be reduced and includes a total or partial outage of ICP resulting from an unplanned component failure or other condition of the electrical transmission system which causes ICP to be incapable of delivering electricity at the point of interconnection of ICP to the electrical transmission system.

(17) “General Terms and Conditions for Gas Transportation Service” (or “GT&Cs”) means the TGVI Tariff, Part B, Transmission Transportation Service, as amended and approved by the BCUC and in effect from time to time;

(18) “ICP” means the Island Cogeneration Project located in Campbell River on Vancouver Island;

(19) “Initial Term” has the meaning as set out in 3.1;

(20) “Interruptible Toll” means, in respect of each Month of the Service Period of this Agreement, the toll for Interruptible Transportation Service as approved and amended from time to time by the BCUC, expressed in dollars per GJ, and as set out from time to time in Schedule 1;

(21) “Maintenance Outage” means a total or partial outage of ICP of a temporary nature resulting from the removal of a generator or other component from service, or a reduction of load on a generator, in order to perform work on specific components that can be deferred such that it does not constitute a Forced Outage, but requires a generator or other component to be removed from service before the next Planned Outage;

(22) “Mt. Hayes Storage Facility” means TGVI’s proposed natural gas storage facility and associated transmission facilities as more fully described as System Facilities in the application dated June 5, 2007 filed by TGVI with the BCUC;

(23) “Outage Event” means, in respect of ICP, a Forced Outage, a Maintenance Outage, or a Planned Outage;

(24) "Pacific Clock Time" means PST or DST as in effect on the relevant day;

(25) "Peaking Agreement" means the Peaking Agreement dated as of September 19, 2007 between TGVI and BC Hydro, as amended and in effect from time to time;

(26) "Planned Outage" means a total or partial outage of ICP of a temporary nature resulting from the removal of a generator or other component from service, or a reduction of load on a generator, in order to perform work on specific components that is scheduled in accordance with a planned outage schedule;

(27) "Receipt Point" has the meaning as set out in the GT&Cs;

(28) "Renewal Term" has the meaning as set out in 3.2;

(29) "Service Period" means the period from 08:00 Pacific Clock Time on the Commencement Date to the earlier of: (i) the expiry of the Initial Term or, if a right of renewal is exercised, the expiry of the Renewal Term; and (ii) the effective date of termination of this Agreement in accordance with its terms;

(30) "TGVI System" means the gas transmission pipeline and related facilities owned and operated by TGVI extending from a point of connection with the Terasen Gas Inc. system in Coquitlam, British Columbia to various delivery points on the Sunshine Coast and Vancouver Island and for clarity excludes any distribution facilities; and

(31) "TJ" means terajoule.

2.2 Interpretation. For the purposes of this Agreement, except as otherwise expressly provided:

(1) "Agreement" means this Agreement, together with the Schedule 1 attached hereto;

(2) all references in this Agreement to a designated "Article", "section", "subsection" or other subdivision or to a Schedule are to the designated Article, section, subsection or other subdivisions of, or Schedule to, this Agreement;

(3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision;

(4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof; and

(5) the singular of any term includes the plural, and vice versa, the use of any term is equally applicable to any gender and, where applicable, a body corporate and the word "including" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto.

2.3 Schedule. The following is the Schedule to this Agreement:

Schedule 1 Demand Tolls for Firm Transportation Service and nterruptible Tolls for Interruptible Transportation Service

ARTICLE 3
TERM

3.1 Initial Term. The initial term (the "Initial Term") for Firm Transportation Service and Interruptible Service under this Agreement will commence at 08:00 Pacific Clock Time on the Commencement Date and will expire at 08:00 Pacific Clock Time on April 12, 2022.

3.2 Renewal Term. Subject to section 3.4, BC Hydro may extend the Service Period for successive renewal terms (each a "Renewal Term") of one or more years ending at 08:00 Pacific Clock Time on November 1 (except for the first Renewal Term which may be for a period ending at 08:00 Pacific Clock Time on November 1, 2022) by giving prior written notice (a "Renewal Notice") to TGVI as follows:

(1) the Renewal Notice must be given not less than 730 days prior to the end of the applicable Initial Term or Renewal Term, as the case may be, and must specify the length of the Renewal Term; and

(2) if material facility additions or upgrades are required to be added to the TGVI System to enable TGVI to continue to provide Firm Transportation Service in accordance with this Agreement during the Renewal Term specified in the Renewal Notice, then TGVI will, within 30 days after receipt of a Renewal Notice from BC Hydro, provide BC Hydro with reasonable details of any required facility additions and/or upgrades and associated costs and any minimum Renewal Term requirements in accordance with section 3.3, and within 30 days of receipt of that advice from TGVI, BC Hydro will notify TGVI whether or not BC Hydro will withdraw the Renewal Notice.

3.3 Renewal Facility Requirements. If TGVI requires material facility additions or upgrades to the TGVI System in order to provide Firm Transportation Service under this Agreement during any Renewal Term, then TGVI may require that, as a condition of the renewal, the Renewal Term be extended for a reasonable renewal period not exceeding in any event 10 years, provided that TGVI has so advised BC Hydro of the required minimum Renewal Term in TGVI's notice under subsection 3.2(2).

3.4 Withdrawal of Renewal Notice. If BC Hydro withdraws a Renewal Notice, the Agreement will terminate at the end of the Service Period. If a Renewal Notice is not withdrawn the Service Period will be extended by the Renewal Term pursuant to section 3.2 and 3.3.

3.5 Maximum Term. The Service Period will not exceed 35 years except if as a result of a TGVI requirement for material facility additions or upgrades to the TGVI System a Renewal Term has been extended pursuant to section 3.3, in which event the Service Period will be to the end of that Renewal Term.

ARTICLE 4
FUTURE EXPANSION

4.1 Notice Period. At any time after the Commencement Date including during a Renewal Term, TGVI may give written notice (an "Expansion Notice") to BC Hydro in accordance with section 4.2 of its proposed construction and installation of an Expansion Facility. Any such notice must be provided in writing to BC Hydro prior to filing an application with the BCUC for a CPCN in respect of the Expansion Facility and not less than 24 months or greater than 36 months prior to the date the Expansion Facility is required to be in service.

4.2 Expansion Notice. In each Expansion Notice TGVI will provide BC Hydro reasonable detail regarding the need for the proposed Expansion Facility based on the most recent demand forecast filed with the BCUC and the expected costs for the Expansion Facility including the incremental revenue requirement for the Expansion Facility, alternatives to the proposed Expansion Facility and associated costs of such alternatives, the date the Expansion Facility is expected to be in service, the amount by which the Contract Demand must be reduced to defer the in-service date of the Expansion Facility by at least one year, and the estimated deferral of the in-service date for the Expansion Facility if the Contract Demand is reduced by 25%, 50% and 100%. In addition to the foregoing, TGVI will disclose in each Expansion Notice any additional Expansion Facilities that TGVI is aware may be required to be added to the TGVI System and which TGVI expects to commence construction of within 4 complete calendar years after the date of delivery to BC Hydro of that Expansion Notice. The foregoing requirement does not limit TGVI's obligation to deliver an Expansion Notice to BC Hydro in respect of any future Expansion Facility in accordance with section 4.1.

4.3 Deferral of Future Expansion. Within 60 days after receipt of an Expansion Notice, BC Hydro may by written notice to TGVI elect to: (i) reduce its Contract Demand by an amount sufficient to allow deferral of the Expansion Facility by at least one year; (ii) increase the Maximum Curtailment Volume under section 3.6 of the Peaking Agreement; or (iii) terminate this Agreement. The effective date of any termination of this Agreement, reduction in Contract Demand or increase in Maximum Curtailment Volume will be the date the Expansion Facility is expected to be in service as provided in the Expansion Notice.

4.4 Termination arising from Expansion Requirements:

(1) If BC Hydro elects to terminate the Agreement pursuant to section 4.3, and no Expansion Facilities have been added to, or are under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination, BC Hydro will not be responsible for any termination payment.

(2) If BC Hydro elects to terminate the Agreement pursuant to section 4.3, and Expansion Facilities have been added to, or are under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination, BC Hydro will make a termination payment to TGVI pursuant to section 5.3.

4.5 BCUC Application. If upon receipt of an Expansion Notice, BC Hydro chooses not to reduce its Contract Demand, increase the Maximum Curtailment Volume pursuant to section 3.6 of the Peaking Agreement, or terminate this Agreement pursuant to section

4.3, BC Hydro will not oppose any application by TGVI to the BCUC for a CPCN for the Expansion Facility that is the subject of that Expansion Notice. If the BCUC does not issue a CPCN for the Expansion Facility, then at TGVI's written request the parties will use commercially reasonable efforts to determine if a peaking gas agreement or other alternative arrangements can reasonably be expected to defer or avoid such Expansion Facility. Any such agreement or arrangement entered into by the parties will be subject to BCUC approval.

ARTICLE 5
TERMINATION

5.1 Early Termination. In addition to BC Hydro's right to terminate this Agreement under Article 4, BC Hydro may terminate the Agreement effective on or after November 1, 2015 provided BC Hydro gives TGVI not less than 24 months prior written notice. In the event that BC Hydro exercises this right to terminate the Agreement:

(1) the termination will occur at 08:00 Pacific Clock Time on November 1 following the expiration of the 24 month minimum notice period or such later November 1 designated by BC Hydro; and

(2) if Expansion Facilities have been added to, or are under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination, BC Hydro will make a termination payment to TGVI pursuant to Section 5.3. If no Expansion Facilities have been added to, or are under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination, BC Hydro will not be responsible for any termination payment.

5.2 Expansion Facilities. Within 30 days of receipt of a notice of termination pursuant to sections 4.3 or 5.1, from BC Hydro, TGVI will provide BC Hydro with a forecast of the annual incremental revenue requirements associated with each Expansion Facility, if any, for the Excess Capacity Period for that Expansion Facility. BC Hydro will then have 30 days to provide written comment on the forecast and TGVI will consider those comments prior to filing an application to the BCUC for approval of the termination payment pursuant to section 5.6.

5.3 Termination Payment. Subject to section 5.4 and 5.6, if BC Hydro exercises its right to terminate the Agreement in accordance with section 4.3 or section 5.1, and if Expansion Facilities have been added to, or are under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination, BC Hydro will pay either:

(1) a series of annual payments that for each year would be equal to the sum of the forecast incremental revenue requirement for that year for each Expansion Facility described above that has an Excess Capacity Period in effect for that year plus or minus any adjustments determined as appropriate and approved by the BCUC, provided that neither of the parties shall apply for any adjustments that are not expressly contemplated under this Agreement; or

(2) a payment equal to the present value of the sum of the forecast incremental revenue requirement associated with each Expansion Facility described above during the Excess Capacity Period for that Expansion Facility where the discount

rate is TGVI's then-current after tax weighted average cost of capital as approved by the BCUC plus or minus any adjustments determined as appropriate and approved by the BCUC, provided that neither of the parties shall apply for any adjustments that are not expressly contemplated under this Agreement.

If BC Hydro elects to make annual payments pursuant to subsection 5.3(1), BC Hydro may elect at any time on written notice to TGVI to make a payment under subsection 5.3(2) based on the then outstanding period of the Excess Capacity Period for each Expansion Facility and upon making such payment, BC Hydro will have no further obligation under this section 5.3.

For the purpose of this section 5.3, the calculation of the forecast incremental revenue requirement for each Expansion Facility that has been added to, or that is under construction for, the TGVI System after the Commencement Date and prior to delivery of BC Hydro's notice of termination will be based on the calculation of the incremental revenue requirement for that Expansion Facility as set out in the application for the CPCN for that Expansion Facility which will include reasonably estimated incremental costs of operation, maintenance, property tax and other taxes applicable to that Expansion Facility, costs of depreciation and amortization, income tax, return on equity and interest on debt. BC Hydro acknowledges that the incremental revenue requirement in the application for the CPCN will be based on estimates and will be adjusted to reflect actual costs in effect at the time the termination fee is calculated.

For the purposes of this section 5.3, the forecast incremental revenue requirement will be determined for the entire period of the estimated Excess Capacity Period at the time the notice of termination is delivered. Payments under either subsection 5.3(1) or subsection 5.3(2) will be based on the termination payment approved by the BCUC, which is based on the forecast incremental requirement and will not be subject to further review or approval.

5.4 Replacement of Existing Facilities. If an Expansion Facility is a facility that replaces or upgrades an existing facility in a manner that results in a material increase in the capacity of the TGVI System, the termination payment for that Expansion Facility will be calculated in the manner set out in section 5.3 except that the termination payment will be limited to a prorated share of the incremental revenue requirement which share will be determined as the ratio of the increase in capacity relative to the total capacity provided by the Expansion Facility .

5.5 Expiry. BC Hydro is not required to pay any termination payment if this Agreement expires at the end of the Initial Term or a Renewal Term.

5.6 BCUC Approval: The parties agree and recognise that the termination payment or payments are subject to approval by the BCUC. Within 90 days of receipt of the termination notice from BC Hydro, TGVI will apply to the BCUC for approval of the termination payment. If the BCUC approves the termination payment before the effective date of termination, the termination payment will be payable by BC Hydro on the date when the termination comes into effect. If the BCUC has not approved the termination payment before the effective date of termination, BC Hydro will make a termination payment calculated pursuant to sections 5.3 and 5.4 (based on the forecast provided by TGVI pursuant to section 5.2) on the date when the termination comes into effect (without prejudice to BC Hydro's right to dispute the forecast of the incremental revenue requirement provided by TGVI to BC Hydro pursuant to section 5.2), and if the termination payment as approved by the BCUC differs from the termination payment made by BC Hydro pursuant to this section, the difference will be adjusted between the parties with the appropriate party making an adjustment payment to the other within 30 days of the date of the BCUC's approval. Subject to the foregoing, if BC Hydro elects to make annual payments pursuant to subsection 5.3 (1), payment will be made each October 31 until the Excess Capacity Period for all Expansion Facilities has expired. Nothing in this Agreement, including the provisions of sections 5.2, 5.3 and 5.4, shall prevent BC Hydro from disputing the forecast of the incremental revenue requirement provided by TGVI to BC Hydro pursuant to section 5.2 or from seeking approval from the BCUC for an alternate termination payment in respect of any Expansion Facility that is under construction on the date of delivery of a notice of termination by BC Hydro from the termination payment that would otherwise be calculated in accordance with sections 5.3 and 5.4.

5.7 Right of Inspection. BC Hydro will have the right at all reasonable times to examine the applicable books and records of TGVI to the extent necessary to verify the accuracy of any termination payment pursuant to section 5.4.

ARTICLE 6
FIRM TRANSPORTATION SERVICE

6.1 Firm Transportation Service. Subject to the provisions of this Agreement, TGVI will, on each Day during the Service Period, provide BC Hydro with Firm Transportation Service from the Receipt Point to the Delivery Point in respect of that quantity of gas not exceeding the Contract Demand as requested and supplied at the Receipt Point by BC Hydro.

6.2 Contract Demand. The Contact Demand under this Agreement is 50 TJ per Day. C

6.3 Changes to Contract Demand. Subject to the availability of capacity, BC Hydro may increase or decrease its Contract Demand by up to 5 TJ per Day to a maximum of 50 TJ and minimum of 40 TJ per day with a minimum 365 days prior written notice to TGVI. The change in the Contract Demand will be effective as of 08:00 Pacific Clock Time on the first November 1st following the expiration of the 365 day minimum notice period or such later November 1 as designated by BC Hydro.

6.4 Rate of Delivery. If BC Hydro anticipates that the hourly delivery rate on any Day to the Delivery Point will exceed 5% of the Authorized Quantity for such Day, then BC Hydro will notify TGVI of the anticipated hourly deliveries. TGVI will authorize such deliveries, except in circumstances where TGVI, acting reasonably, considers that such rates of delivery would adversely impact the operational stability and integrity of TGVI's natural gas transmission and distribution system. If TGVI does not authorize the delivery rates requested by BC Hydro, then BC Hydro will be required to reduce the hourly rate of flow at which it takes delivery of gas at the Delivery Point to amounts not greater than 5% of the Authorized Quantity for such Day for the Delivery Point. Notwithstanding any prior delivery authorizations made by TGVI, TGVI will not be required to deliver gas at the Delivery Point in any hour of a Day in an amount greater than 5% of the Authorized Quantity if TGVI, acting reasonably, considers that the rate of delivery should be so limited to maintain the operational stability and integrity of TGVI's natural gas transmission and distribution system.

6.5 Coordination. BC Hydro and TGVI shall make reasonable efforts to coordinate and cooperate in the delivery of notices, filing of nominations and other communications (including with respect to the timing for all of the foregoing) to allow BC Hydro reasonable flexibility in fuel switching and dispatch at ICP to the extent consistent with maintenance of operational stability and integrity of the TGVI System.

ARTICLE 7
INTERRUPTIBLE TRANSPORTATION SERVICE

7.1 Interruptible Service. Subject to the provisions of this Agreement and the GT&Cs, TGVI will, on each Day during the Service Period, provide BC Hydro with Interruptible Transportation Service from the Receipt Point to the Delivery Point in respect of that quantity of gas in excess of the Contract Demand as requested and supplied at the Receipt Point by BC Hydro.

ARTICLE 8
TOLLS

8.1 Tolls - Firm Transportation Service. Subject to section 7 of the GT&Cs in respect of Demand Toll Credits, BC Hydro will pay to TGVI in respect of the Firm Transportation Service provided hereunder in each Month of the Service Period of this Agreement an amount equal to the sum of:

(1) the amount obtained by multiplying the Demand Toll for such Month by the product obtained by multiplying the Contract Demand by the number of Days in such Month; and

(2) the amount obtained by multiplying the Commodity Toll for such Month by the total quantity of gas delivered to BC Hydro under such service at the Delivery Point and the Alternate Delivery Point(s), if any, in such Month.

If the Service Period commences on a Day other than the first Day of a Month, or expires other than on the last Day of a Month, the Demand Toll will be prorated day-for-day in respect of that Month.

8.2 Tolls - Interruptible Transportation Service. BC Hydro will pay to TGVI in respect of the Interruptible Transportation Service provided to BC Hydro in each Month of the Service Period of this Agreement an amount equal to the sum of:

(1) the amount obtained by multiplying the Interruptible Toll for such Month by the total quantity of gas delivered to BC Hydro under such service at the Delivery Point in such Month; and

(2) the amount obtained by multiplying the Commodity Toll for such Month by the total quantity of gas delivered to BC Hydro under such service at the Delivery Point in such Month.

8.3 Intra-Month Toll Change. If the Demand Toll or Interruptible Toll changes during a Month, then the Demand Toll and the Interruptible Toll chargeable under this Agreement for that Month will be calculated to the date of the change using the Demand Toll and Interruptible Toll in effect prior to the change, and thereafter at the changed Demand Toll and Interruptible Toll.

ARTICLE 9
RECEIPT POINTS, DELIVERY POINTS AND DELIVERY PRESSURE

9.1 Receipt Point. BC Hydro will, in respect of the Firm Transportation Service and Interruptible Transportation Service to be provided by TGVI hereunder, deliver gas to TGVI at the Receipt Point.

9.2 Delivery Point. TGVI will, in respect of the Firm Transportation Service and Interruptible Transportation Service to be provided by TGVI hereunder, deliver gas to BC Hydro at the Delivery Point.

9.3 Alternate Delivery Points. If an Outage Event occurs and as a result ICP is unable to use the full Contract Demand, BC Hydro will, in respect of the Firm Transportation Service being provided by TGVI hereunder, have the right to nominate gas for delivery to one or more Alternate Delivery Points specified by BC Hydro for each Day during the period of the Outage Event without incurring any Interruptible Tolls, provided that:

(1) BC Hydro provides to TGVI notice of the Outage Event describing the nature, extent and estimated duration of the Outage Event (including whether the Outage Event is a Forced Outage, a Maintenance Outage or a Planned Outage), as soon as reasonably practicable after becoming aware of the Outage Event;

(2) the nomination will only be authorized by TGVI if and to the extent there is available capacity on the TGVI System to the Alternate Delivery Point(s) specified by BC Hydro, and only to the extent that TGVI, acting reasonably, does not determine that such authorization will adversely impact the operational stability and integrity of TGVI's natural gas transmission and distribution system; and

(3) the nomination will only be authorized by TGVI on an interruptible basis with the same priority as Interruptible Transportation Service.

9.4 Dispatch Event. If BC Hydro initiates a Dispatch Event, BC Hydro may use its Firm Transportation Service under this Agreement to nominate and deliver gas for delivery to the Elk Falls Mill during such period, provided that:

(1) ICP is not operating;

(2) facilities are installed downstream of the ICP meter to allow BC Hydro to divert gas to the Elk Falls Mill;

(3) BC Hydro continues to be responsible for all obligations under the Agreement; and

(4) volumes delivered to the Elk Falls Mill pursuant to this clause do not exceed 7000 GJ per Day.

9.5 Delivery Pressure. Gas delivered by TGVI to BC Hydro at the Delivery Point will be at a pressure of not less than 500 psig.

ARTICLE 10
ARBITRATION

10.1 Arbitration. All disputes arising under or relating to this Agreement, except only disputes with respect to which the BCUC has jurisdiction, which the BCUC is prepared to exercise, will, after the parties have attempted for a period not exceeding 15 days in good faith to settle the dispute between themselves, be submitted to and finally settled by arbitration under the Commercial Arbitration Act. The arbitration will take place in Vancouver, British Columbia before a single arbitrator and will be administered by the British Columbia International Commercial Arbitration Centre ("BCICAC") in accordance with its "Procedures for Cases under the BCICAC Rules". If a dispute arises under the Peaking Agreement and is pending concurrently with a dispute pending under this Agreement, based on the same or similar facts and circumstances, the parties shall consent to the consolidation of those disputes in a single arbitration proceeding, with the intent of avoiding any unnecessary multiplicity of proceedings.

ARTICLE 11
GENERAL

11.1 Notices. Any notice or other communication required or permitted to be given under this Agreement, or those notices given under the General Terms and Conditions for Gas Transportation Service, will be effective only if in writing and when it is actually delivered (which delivery may be by facsimile) to the party for whom it is intended at the following address or such other address in British Columbia as such party may designate to the other party by notice in writing delivered in accordance with this 11.1:

to TGVI:

Terasen Gas (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, British Columbia
V3S 2X7

Attention: Director, Customer Management and Sales
Facsimile: 604-592-7894

to BC Hydro:

British Columbia Hydro and Power Authority
333 Dunsmuir Street
Vancouver, B.C.
V6B 5R3

Attention: Manager, Contracts and Evaluation
Facsimile: (604) 623-4335

11.2 Severability. If any provision of this Agreement is found or determined to be invalid, illegal or unenforceable it will be construed to be separate and severable from this Agreement and will not impair the validity, legality or enforceability of any other provisions of this Agreement, and the remainder of this Agreement will continue to be binding on the parties as if such provision had been deleted.

11.3 No Waiver. No waiver by either party of any default by the other in the performance of any of the provisions of this Agreement will operate or be construed as a waiver of any other or future default or defaults hereunder, whether of a like or a different character.

11.4 Assignment. This Agreement may be assigned by either party provided that the prior written consent of the other party has been obtained, such consent not to be unreasonably withheld, delayed or conditioned. This Agreement may not be assigned unless it is assigned in its entirety, the Peaking Agreement is assigned to the same assignee, and the assignee assumes the obligations of the assignor under this Agreement and under the Peaking Agreement.

11.5 Burden and Benefit. This Agreement will enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns.

11.6 Governing Law. This Agreement and all matters arising hereunder will be governed by the laws of British Columbia and the federal laws of Canada applicable in British Columbia.

11.7 Entire Agreement. This Agreement (together with the Peaking Agreement between the parties and the Capacity Assignment Agreement among the parties and Terasen Gas Inc (while such agreement remains in effect), all made as of the same date as the date of this Agreement) contains the whole agreement between the parties in respect of the subject matter hereof and there are no terms, conditions or collateral agreements express, implied or statutory other than as expressly set forth in the aforesaid agreements and the aforesaid agreements supersede all of the terms of any written or oral agreement or understanding between the parties in respect of the subject matter hereof.

11.8 Effect of Termination. Notwithstanding the termination of this Agreement, whether at the end of the Initial Term or otherwise, provisions respecting liabilities which have arisen or accrued prior to the date of termination will continue in full force and effect in accordance with their respective terms.

11.9 Without Prejudice. Except with respect to those matters that have been expressly agreed to by the Parties pursuant to this Agreement, nothing in this Agreement, or in any of the other agreements referenced in section 11.7, shall prejudice any positions that any of the parties may take in the future on any and all matters brought before the BCUC in regard to TGVI's services, tolls and GT&Cs, whether those matters are initiated by BC Hydro, TGVI or any other person.

11.10 Conditions Precedent. This Agreement is subject to the approval of this Agreement and each of the other agreements referenced in section 11.7 by the BCUC on terms and conditions, if any, acceptable in respect of this Agreement and the Peaking Agreement to TGVI and BC Hydro, and acceptable in respect of the Capacity Assignment Agreement to Terasen Gas Inc., TGVI and BC Hydro provided that if a party has not provided written notice of rejection of the terms and conditions included in the BCUC decision, if any, by 30 days after the date of issuance of the BCUC decision, the party will be deemed to have accepted those terms and conditions.

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

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by Randy Jespersen
Signature

RANDY JESPERSEN President and CEO
Print Name and Office

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Original signed by Bob Elton
Signature

BOB ELTON President and CEO
Print Name and Office

SCHEDULE 1

Demand Tolls for Firm Transportation Service and

Interruptible Tolls for Interruptible Transportation Service

Demand Toll	$0.858 per GJ per Day	
Interruptible Toll (summer)	$0.858 per GJ per Day	R
Interruptible Toll (winter)	$1.358 per GJ per Day	

TARIFF SUPPLEMENT NO. 2

PEAKING AGREEMENT

BETWEEN

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)

AND

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Effective January 1, 2008

PEAKING AGREEMENT

This PEAKING AGREEMENT is made as September 19, 2007.

BETWEEN:

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

(hereinafter called "TGVI")

AND:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation established pursuant to an Act of the Province of British Columbia and continued under BC Hydro and Power Authority Act, R.S.B.C. 1996, c.212.

(hereinafter called "BC Hydro")

WHEREAS:

A. TGVI owns and operates a natural gas transmission and distribution system on the Sunshine Coast and Vancouver Island; and

B. BC Hydro and TGVI have entered into a Transportation Service Agreement (the "TSA") made September 19, 2007 under which TGVI will provide gas transportation service to BC Hydro from a receipt point at Huntingdon to a delivery point on Vancouver Island; and

C. TGVI and BC Hydro wish to enter into a Peaking Agreement pursuant to which BC Hydro agrees to provide capacity rights to TGVI for the purpose of serving TGVI's Core Market.

NOW THEREFORE in consideration of the mutual agreements herein contained the parties covenant and agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Incorporation. Unless otherwise defined in this Agreement, the terms defined in the TSA, including the General Terms and Conditions for Gas Transportation Service (the "GT&Cs"), and used in this Agreement have the meanings assigned to those terms in the TSA and the GT&Cs. If there is any conflict or inconsistency between the provisions of this Agreement and the TSA or the GT&Cs, the provisions of this Agreement shall prevail.

1.2 Definitions. In this Agreement, the following terms have the following meanings:

(1) "Capacity Right" has the meaning assigned to that term in subsection 3.1;

(2) "Commencement Date" means the later of January 1, 2008 and the date immediately following the date the conditions precedent in section 13.10 are satisfied;

(3) "Contract Demand" has the meaning under the TSA;

(4) "Converted Sumas Daily Index Price" means in respect of the Sumas Daily Index Price for any Day, a unit cost (expressed in dollars per GJ) equal to the quotient obtained by dividing (i) the product obtained by multiplying the Sumas Daily Index Price (reported in U.S. dollars per MMBtu) for such Day by the Exchange Rate for such Day, by (ii) 1.055056;

(5) "Converted Sumas Monthly Index Price" means, in respect of the Sumas Monthly Index Price for any Month, a unit cost (expressed in dollars per GJ) equal to the quotient obtained by dividing (i) the product obtained by multiplying the Sumas Monthly Index Price (reported in U.S. dollars per MMBtu) for such Month by the Exchange Rate for such Month, by (ii) 1.055056;

(6) "Core Market" means residential, institutional, commercial and industrial customers who form part of TGVI's core market for gas in British Columbia;

(7) "CPI" means the Consumer Price Index for Canada, All-items (not seasonally adjusted), as published by Statistics Canada in Catalogue No. 62-001-XIE;

(8) "Distillate Index Price" means a unit cost (expressed in Canadian dollars per GJ) equal to the energy replacement cost for Light Fuel Oil as determined by the average of the weekly Vancouver Rack Price for Light Fuel Oil (expressed in Canadian dollars per litre) for the month of November of each year, plus delivery/handling charges and Provincial Fuel Tax. The price calculated for each November will become effective on November 1st of that year. For January 1st to October 31st, 2008, the price calculated for November 2007 will be used.;

(9) "Exchange Rate" means:

(a) in respect of any Day, the rate of exchange for converting U.S. dollars into Canadian dollars equal to the noon spot exchange rate for the U.S. dollar in terms of the Canadian dollar for that Day as published by the Bank of Canada; and

(b) in respect of any Month, the rate of exchange for converting U.S. dollars into Canadian dollars equal to the average of the noon spot exchange rates for the U.S. dollar in terms of the Canadian dollar for that Month as published by the Bank of Canada;

(10) "Expiry Date" means the date on which the Service Period of the TSA ends;

(11) "Firm Capacity" means that portion of BC Hydro's Contract Demand, expressed in GJ per day, for which TGVI has a Capacity Right pursuant to Article 3 of this Agreement;

(12) "Intra-Day Additional Right" has the meaning assigned to that term in section 4.1;

(13) "Light Fuel Oil" means fuel oil meeting the specifications of seasonal Diesel Fuel in accordance with Standard CAN/CGSB-3.517-93, or the latest version, having a heating value of 38.68 GJs per cubic meter;

(14) "Maximum Curtailment Volume" means the total curtailment volume TGVI may use in aggregate in a Winter Period as specified in section 3.5 or in the applicable notice delivered by BC Hydro in accordance with section 3.6 for that Winter Period;

(15) "Mt. Hayes Storage Facility" means TGVI's proposed natural gas storage facility and associated transmission facilities as more fully described as System Facilities in the application dated June 5, 2007 filed by TGVI with the BCUC;

(16) "Purchase Point" has the same meaning as Receipt Point under the GT&Cs;

(17) "Sumas Daily Index Price" means, in respect of any Day, the midpoint price for "NW Sumas" located under the column "Midpoint" under the heading "Canadian Gas" in the "Daily Price Survey" section in the issue of the publication *Gas Daily* (reported in U.S. dollars per MMBTU) in which such price is reported for such Day;

(18) "Sumas Monthly Index Price" means, in respect of any Month, the price for "Northwest Pipeline Corp., Canadian border" located under the column "Index" in the "Prices of Spot Gas Delivered to Pipelines" section in the issue of the publication *Inside FERC's Gas Market Report* (reported in U.S. dollars per MMBtu) in which such price is reported for such Month;

(19) "TSA Demand Toll" is the Demand Toll associated with the Firm Transportation Service under the TSA;

(20) "Term" has the meaning assigned to that term in section 2.1;

(21) "WEI" means Westcoast Energy Inc., a Spectra Energy Company; and

(22) "Winter Period" means the period from 08:00 Pacific Clock Time November 1 to 08:00 Pacific Clock Time April 1.

1.3 Interpretation. For the purposes of this Agreement, except as otherwise expressly provided:

(1) "this Agreement" means this Agreement as it may from time to time be supplemented or amended and in effect;

(2) all references in this Agreement to a designated "Article", "section", "subsection" or other subdivision or to a Schedule are to the designated Article, section, subsection or other subdivisions of, or Schedule to, this Agreement;

(3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision;

(4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof;

(5) the singular of any term includes the plural, and vice versa, the use of any term is equally applicable to any gender and, where applicable, a body corporate and the word "including" is not limiting whether or not non-limiting language (such as

"without limitation" or "but not limited to" or words of similar import) is used with reference thereto; and

(6) if any index, tariff or price quotation referred to in this Agreement ceases to be published, or if the basis therefor is changed materially, there will be substituted an available replacement index, tariff or price quotation that most nearly, of those publicly available, approximates the intent and purpose of the index, tariff or price quotation that has so ceased or changed.

ARTICLE 2
TERM

2.1 Term. This Agreement shall be effective from the Commencement Date and shall continue in effect until the Expiry Date (the "Term").

ARTICLE 3
CAPACITY RIGHT

3.1 Capacity Right. Subject to the provisions of this Agreement TGVI shall have the right (the "Capacity Right") to use the Firm Capacity up to the quantity specified in section 3.2. The Capacity Right is subject to the following conditions:

(1) TGVI requires the use of all or a portion of the Firm Capacity for the purpose of supplying gas to its Core Market customers;

(2) TGVI has curtailed all Interruptible Transportation Service and intends to use all the TGVI System capacity available to it after provision of Firm Transportation Service to its other Shippers. For clarity, provision of Firm Transportation Service to other Shippers will be on the basis of the Contract Demand which is specified for a Shipper in its Service Agreements.

3.2 Firm Capacity. After having satisfied the conditions in section 3.1 and subject to the limit in section 3.5, during the Term of this Agreement TGVI may exercise its Capacity Right on any Day during a Winter Period for up to:

(1) 19,000 GJs per Day during the period beginning 08:00 Pacific Clock Time January 1, 2008 and ending 0800 Pacific Clock Time April1, 2008; and

(2) 27,000 GJs per Day during the Winter Period beginning November 1, 2008.

TGVI will provide not less than 365 days prior written notice of the Firm Capacity associated with the Capacity Right effective on November 1, 2009 and each Winter Period thereafter, but in each case such amount shall not exceed the Contract Demand.

3.3 Notices. If in respect of any Day TGVI wishes to exercise its Capacity Right, TGVI will give a notice (the "Capacity Notice") to BC Hydro specifying the quantity of Firm Capacity TGVI requires from BC Hydro on such Day. TGVI will provide the Capacity Notice to BC Hydro not later than 05:45 Pacific Clock Time on the day that precedes the Day the capacity is required, (or such later time as may be agreed upon between the parties from time to time to enable TGVI to better assess the requirements of its Core Market customers for such Day).

3.4 Obligations. If in respect of any Day TGVI gives a Capacity Notice to BC Hydro pursuant to section 3.3, then:

(1) BC Hydro's nomination for such Day pursuant to section 3.1 of the GT&Cs will not be greater than the quantity equal to the Contract Demand less the quantity specified in the Capacity Notice;

(2) BC Hydro's right to increase its nomination for such Day pursuant to section 3.5 of the GT&Cs is limited to the quantity equal to the Contract Demand less the quantity specified in the Capacity Notice unless TGVI provides notice to BC Hydro (the "Release Notice") specifying the additional capacity available for use by BC Hydro. If TGVI has provided such Release Notice, BC Hydro may increase its nomination pursuant to section 3.5 of the GT&Cs, up to the quantity equal to the Contract Demand less the quantity specified in the Capacity Notice, plus the quantity TGVI specified in the Release Notice; and

(3) TGVI will use reasonable efforts in accordance with section 6.5 of the TSA to permit fuel switching during continguous hours such that hourly curtailments of output from ICP can be minimised.

3.5 Limited Usage. The Maximum Curtailment Volume that TGVI may use under the Capacity Right may not, in aggregate, exceed:

(1) 100,000 GJs for the period January 1, 2008 to April 1, 2008.

(2) 100,000 GJs for the Winter Periods from November 1, 2008 to April 1, 2010; and

(3) 150,000 GJs for the Winter Period from November 1, 2010 to April 1, 2011.

TGVI will provide not less than 365 days prior written notice of the Maximum Curtailment Volume effective on November 1, 2011 and each Winter Period thereafter, but in each case, such amount shall not exceed 100,000 GJs. If TGVI fails to deliver notice for any Winter Period, the Maximum Curtailment Volume for that Winter Period is 100,000 GJs.

3.6 Increase in Maximum Curtailment Volume. If TGVI delivers an Expansion Notice to BC Hydro in accordance with Article 4 of the TSA, BC Hydro may elect to increase the Maximum Curtailment Volume up to a maximum of 150,000 GJs if such increase will allow a deferral of the Expansion Facility for at least one year.

3.7 On-System Storage. TGVI will make reasonable efforts on a day-to-day basis over each Winter Period to limit the exercise of the Capacity Right by using the capacity provided by the Mt. Hayes Storage Facility that TGVI has reserved for its own use during that Winter Period. For clarity, this condition does not restrict TGVI's right to contract with third parties, including Terasen Gas Inc., for use of the Mt. Hayes Storage Facility.

ARTICLE 4
INTRA-DAY ASSISTANCE

4.1 Intra-Day Assistance. If at any time either (a) TGVI's system capacity is less than the demand for Firm Transportation Service due to a temporary reduction in system capacity, or (b) TGVI's Core Market load is expected to exceed TGVI's forecast at the time of the Capacity Notice, or (c) TGVI has exercised its rights to all Firm Capacity available on any

Day pursuant to section 3.2 or over a 12 month period pursuant to section 3.5, then TGVI shall have the right (the "Intra-Day Additional Right") to purchase from BC Hydro at the Purchase Point, upon the terms and conditions hereof, the quantity of gas as determined in accordance with section 4.3, to receive from BC Hydro the quantity of gas specified in the notice given by TGVI to BC Hydro pursuant to section 4.2 and to use an equal amount of BC Hydro's Firm Capacity under the TSA, provided that:

(1) the number of hours over which TGVI may require BC Hydro to deliver such gas to TGVI may not be less than 4 consecutive hours and not greater than 48 consecutive hours;

(2) in the case where the period of time over which TGVI requires BC Hydro to deliver such gas to TGVI does not extend beyond one Day, the quantity of such gas shall be equal to the product obtained by multiplying (i) the quotient obtained by dividing BC Hydro's Authorized Quantity for that Day by 24, by (ii) the number of hours during the Day over which TGVI requires BC Hydro to deliver such gas to TGVI;

(3) in the case where the period of time over which TGVI requires BC Hydro to deliver such gas to TGVI does extend beyond one Day into the next succeeding Day, the quantity of such gas shall be equal to the sum of:

  (a) the product obtained by multiplying (i) the quotient obtained by dividing BC Hydro's Authorized Quantity for the first Day by 24, by (ii) the number of hours during that Day over which TGVI requests BC Hydro to deliver such gas to TGVI; and

  (b) the product obtained by multiplying (i) the quotient obtained by dividing BC Hydro's Authorized Quantity under the TSA for the next succeeding Day by 24, by (ii) the number of hours during the next succeeding Day over which TGVI requests BC Hydro to deliver such gas to TGVI;

(4) the quantity of such gas that TGVI may require BC Hydro to deliver to TGVI pursuant to the Intra-Day Additional Right is further limited to the greater of (i) 30,000 GJs, and (ii) a quantity having the energy equivalent of the inventory of distillate on hand in the distillate storage tank at ICP as of each November 1 during the Service Period, provided that BC Hydro shall use reasonable efforts to maintain a full inventory of distillate to the extent commercially reasonable;

(5) the aggregate number of hours over which TGVI may require BC Hydro to deliver such gas to TGVI may not exceed 240 hours in any continuous 12 Month period; and

(6) TGVI shall not, without the consent of BC Hydro, be entitled after it has given a notice to BC Hydro pursuant to section 4.2, to give another notice to BC Hydro pursuant to section 4.2 within a period of 96 hours after the expiry of the period of time over which TGVI requires BC Hydro to deliver gas to TGVI as specified in such first notice.

4.2 Notice. To exercise the Intra-Day Additional Right TGVI shall, not less than 2 hours prior to the time that TGVI requires BC Hydro to commence the delivery of such gas to TGVI, give a notice to BC Hydro specifying:

(1) the time that TGVI requires BC Hydro to commence the delivery of such gas to TGVI and the number of consecutive hours over which TGVI requires BC Hydro to deliver such gas to TGVI; and

(2) the quantity of gas that TGVI requires from BC Hydro during such hours.

4.3 Delivery of Gas by BC Hydro. If TGVI gives a notice to BC Hydro pursuant to section 4.2, then:

(1) BC Hydro shall sell and deliver to TGVI, and TGVI shall purchase and accept delivery from BC Hydro, during the hours specified by TGVI in such notice:

(a) the quantity of gas specified by TGVI in such notice; and

(b) gas being an allowance for System Gas in respect of the quantity of gas specified by TGVI in such notice, based upon the percentage requirements specified monthly by TGVI pursuant to subsection 3.01(b) of the GT&Cs; and

(2) BC Hydro shall not take delivery of gas under the TSA during the period of time specified by TGVI in such notice.

ARTICLE 5
PRICE

5.1 Capacity Right Payment. For each month during the Term, TGVI will pay BC Hydro an amount equal to the sum of:

(1) Capacity Payment - an amount equal to one-twelfth of the product obtained by multiplying the TSA Demand Toll for such month by the Maximum Curtailment Volume; and

(2) Distillate Carrying Charge - an amount equal to one -twelth of the product obtained by multiplying the Distillate Index Price by the Maximum Curtailment Volume and further multiplying by 0.08.

For the purposes of this section 5.1, the Maximum Curtailment Volume in each month is the amount in effect the immediately preceding November 1 other than in the period January 1 to October 31, 2008 where it is 100,000 GJs. If the Term commences on a Day other than the first Day of a Month, or expires other than on the last Day of a Month, the amounts payable under this section will be prorated day-for-day in respect of that Month.

5.2 Intra-Day Right Payment. For each Month during which TGVI has exercised the Intra-Day Additional Right, TGVI shall pay to BC Hydro under this Agreement the following amounts:

(1) the sum of the amounts for each Day in such Month equal to the product obtained by multiplying the TSA Demand Toll for such Month, expressed on the basis of $ per GJ per Day, by the quantity of gas sold and delivered by BC Hydro to TGVI during such Month pursuant to subsection 4.3(1)(a); and

(2) in respect of the total quantity of gas, including System Gas, sold and delivered by BC Hydro to TGVI pursuant to section 4.3 during such Month, an amount equal to the higher of:

(a) the sum of the amounts for each day in such Month equal to the product obtained by multiplying the Converted Sumas Daily Index Price for such Day by the quantity of gas, including System Gas sold and delivered by BC Hydro to TGVI on such Day; and

(b) an amount equal to the sum of (i) the product obtained by multiplying the sum of the Distillate Index Price and $1.00 for such month by the quantity of gas sold and delivered by BC Hydro to TGVI during such month, (ii) $12,065 (in January 2007$ adjusted annually commencing as of January 1, 2008 and each January 1 thereafter to account for the cumulative increase in CPI since January 1, 2007) for each notice given by TGVI to BC Hydro pursuant to section 4.2 in such Month and in respect of which BC Hydro delivered gas to TGVI as requested by TGVI in such notice; and (iii) $1,086 (in January 2007$ adjusted annually commencing as of January 1, 2008 and each January 1 thereafter to account for the cumulative increase in CPI since January 1, 2007) for each hour in such Month during which BC Hydro delivered gas to TGVI as requested in each notice given by TGVI to BC Hydro pursuant to section 4.2 in such Month.

ARTICLE 6
TITLE TRANSFER

6.1 Possession and Title. Possession and title to all gas sold and delivered hereunder by BC Hydro to TGVI shall pass from BC Hydro to TGVI at the Purchase Point. Until passage of possession and title BC Hydro shall be deemed to be in exclusive control and possession of, and responsible for, such gas until such gas is delivered to the Purchase Point at which time TGVI shall be deemed to be in exclusive control and possession of, and responsible for, such gas.

ARTICLE 7
QUALITY AND MEASUREMENT

7.1 Quality. All gas delivered hereunder by BC Hydro to TGVI at the Purchase Point shall meet or exceed the minimum and not exceed the maximum heating value, delivery pressure and temperature standards and other quality specifications set out in WEI's General Terms and Conditions for gas delivered by WEI to the Receipt Point.

7.2 Measurement. All gas delivered hereunder by BC Hydro to TGVI at the Purchase Point shall be measured as to volume, quality, heating value, delivery pressure and temperature by WEI using the metering, measuring, monitoring and sampling equipment installed, maintained and operated by WEI at the Purchase Point, in accordance with the standards, procedures and specifications set out in WEI's General Terms and Conditions.

ARTICLE 8
STATEMENTS AND PAYMENT

8.1 Statements. BC Hydro shall, within 15 days following the end of each Month deliver to TGVI a statement setting out the charges payable by TGVI to BC Hydro for that Month pursuant to section 5.1 and any amount payable by TGVI for that Month pursuant to section 5.2.

8.2 Payment. TGVI shall, within 10 days of the receipt of a statement for any Month pursuant to section 8.1 or within 25 days following the end of such Month, whichever is later, pay the amount specified therein to BC Hydro. If TGVI fails to make any payment to BC Hydro when due then interest thereon shall accrue at the rate of interest which is equal to the floating annual rate of interest established from time to time by Royal Bank of Canada as a reference rate for purposes of determining the rate of interest Royal Bank of Canada will charge on Canadian dollar loans made in Canada and designated as its "prime rate", plus 2%, from the date when such payment was due until the same is paid.

8.3 Right of Inspection. TGVI shall have the right at all reasonable times to examine the books and records of BC Hydro to the extent necessary to verify the accuracy of any statement rendered by BC Hydro pursuant to section 8.1.

ARTICLE 9
TERMINATION

9.1 Termination of Transportation Service Agreement. If the TSA is terminated or expires pursuant to the provisions thereof, then this Agreement shall, without further act or formality, terminate on the effective date of termination or expiry of the TSA.

ARTICLE 10
INDEMNITY

10.1 Shortfall in the Delivery of Gas. Subject to Article 11, if BC Hydro fails to deliver on any Day the quantity of gas required to be delivered by BC Hydro to TGVI on such Day pursuant to Article 4, then TGVI shall have the immediate right to obtain gas from other sources to replace the gas which BC Hydro failed to deliver and BC Hydro shall reimburse TGVI for 115% of all reasonable third party costs and expenses incurred by TGVI to obtain such gas (including, without limitation, the cost and expense of obtaining and transporting such gas to the Purchase Point) that are incremental to the price otherwise payable to BC Hydro under this Agreement if BC Hydro had not failed to deliver such gas, which shall be TGVI's sole and exclusive remedy for any such failure to deliver by BC Hydro.

ARTICLE 11
FORCE MAJEURE

11.1 Suspension. Subject to the other provisions of this Article 11, if BC Hydro is unable by reason of Force Majeure to perform in whole or in part its obligation to sell and deliver gas under this Agreement that obligation shall be suspended to the extent necessary during the continuation of any inability so caused by such Force Majeure. Notwithstanding the foregoing, TGVI will continue to have the right to use the Firm Capacity associated with its Capacity Right pursuant to section 3.1.

11.2 Exception. BC Hydro shall not be entitled to the benefit of section 11.1 unless, as soon as possible after the happening of the occurrence relied upon or as soon as possible after determining that the occurrence was in the nature of Force Majeure and would affect BC Hydro's ability to deliver gas to the Purchase Point, BC Hydro has given notice to TGVI that BC Hydro's ability to deliver gas to the Purchase Point has been affected.

11.3 Resumption of Obligations. BC Hydro shall give notice to TGVI, as soon as possible after the Force Majeure has been remedied, that the same has been remedied and that BC Hydro's ability to deliver gas to the Purchase Point is no longer affected.

ARTICLE 12
ARBITRATION

12.1 Arbitration. All disputes arising under or relating to this Agreement, except only disputes with respect to which the BCUC has jurisdiction, which the BCUC is prepared to exercise, will, after the parties have attempted for a period not exceeding 15 days in good faith to settle the dispute between themselves, be submitted to and finally settled by arbitration under the Commercial Arbitration Act. The arbitration will take place in Vancouver, British Columbia before a single arbitrator and will be administered by the British Columbia International Commercial Arbitration Centre ("BCICAC") in accordance with its "Procedures for Cases under the BCICAC Rules". If a dispute arises under the TSA and is pending concurrently with a dispute pending under this Agreement, based on the same or similar facts and circumstances, the parties shall consent to the consolidation of those disputes in a single arbitration proceeding, with the intent of avoiding any unnecessary multiplicity of proceedings

ARTICLE 13
GENERAL

13.1 Notices. Any notice or other communication required or permitted to be given under this Agreement will be effective only if in writing and when it is actually delivered (which delivery may be by facsimile) to the party for whom it is intended at the address indicated in the TSA.

13.2 Severability. If any provision of this Agreement is found or determined to be invalid, illegal or unenforceable it shall be construed to be separate and severable from this Agreement and shall not impair the validity, legality or enforceability of any other provisions of this Agreement, and the remainder of this Agreement shall continue to be binding on the parties as if such provision had been deleted.

13.3 No Waiver. No waiver by either party of any default by the other in the performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any other or future default or defaults hereunder, whether of a like or a different character.

13.4 Assignment. This Agreement may be assigned by either party provided that the prior written consent of the other party has been obtained, such consent not to be unreasonably withheld, delayed or conditioned. This Agreement may not be assigned unless it is assigned in its entirety, the TSA is assigned to the same assignee, and the assignee assumes the obligations of the assignor under this Agreement and under the TSA.

13.5 Burden and Benefit. This Agreement shall enure to the benefit of and be binding upon the parties and their respective successors and permitted assigns.

13.6 Governing Law. This Agreement and all matters arising hereunder shall be governed by the laws of British Columbia and the federal laws of Canada applicable in British Columbia.

13.7 Entire Agreement. This Agreement (together with the Transportation Service Agreement between the parties and the Capacity Assignment Agreement (while that Agreement remains in effect) among the parties and Terasen Gas Inc., all made as of the same date as the date of this Agreement) contains the whole agreement between the parties in respect of the subject matter hereof and there are no terms, conditions or collateral agreements express, implied or statutory other than as expressly set forth in the aforesaid agreements and the aforesaid agreements supersede all of the terms of any written or oral agreement or understanding between the parties in respect of the subject matter hereof.

13.8 Effect of Termination. Notwithstanding the termination of this Agreement, whether at the end of the Initial Term or otherwise, provisions respecting liabilities which have arisen or accrued prior to the date of termination will continue in full force and effect in accordance with their respective terms.

13.9 Without Prejudice. Except with respect to those matters that have been expressly agreed to by the Parties pursuant to this Agreement, nothing in this Agreement, or in any of the other agreements referenced in section 13.7, shall prejudice any positions that any of the parties may take in the future on any and all matters brought before the BCUC in regard to TGVI's services, tolls and GT&Cs, whether those matters are initiated by BC Hydro, TGVI or any other person.

13.10 Conditions Precedent. This Agreement is subject to the approval of this Agreement and each of the agreements referenced in section 13.7 by the BCUC on terms and conditions, if any, acceptable in respect of this Agreement and the Transportation Service Agreement to TGVI and BC Hydro, and acceptable in respect of the Capacity Assignment Agreement to Terasen Gas Inc., TGVI and BC Hydro, provided that if a party has not provided written notice of rejection of the terms and conditions included in the BCUC decision, if any, by 30 days after the date of issuance of the BCUC decision, the party will be deemed to have accepted those terms and conditions.

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

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by Randy Jespersen
Signature

RANDY JESPERSEN President and CEO
Print Name and Office

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Original signed by Bob Elton
Signature

BOB ELTON President and CEO
Print Name and Office

TARIFF SUPPLEMENT NO. 3

CAPACITY ASSIGNMENT AGREEMENT

BETWEEN

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)

AND

FORTISBC ENERGY INC.
(formerly Terasen Gas Inc.)

AND

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Effective January 1, 2008

CAPACITY ASSIGNMENT

This Capacity Assignment Agreement is made as of September 19, 2007.

AMONG:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY, a crown corporation established pursuant to an Act of the Province of British Columbia and continued under the BC Hydro and Power Authority Act, R.S.B.C. 1996, c.212.

(hereinafter called "BC Hydro")

AND:

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

(hereinafter called "TGVI")

AND:

TERASEN GAS INC., a company incorporated under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia

(hereinafter called "Terasen")

WITNESSES THAT WHEREAS:

A. Terasen and BC Hydro entered into a Bypass Transportation Agreement ("the BTA") for the provision by Terasen to BC Hydro of daily non-recallable firm gas transportation service on the Coastal Transmission System;

B. BC Hydro and TGVI have entered into (i) a Transportation Service Agreement (the "TSA"), and (ii) a Peaking Agreement (the "Peaking Agreement"), both dated as of September 19, 2007;

C. Terasen and TGVI have entered into a Wheeling Agreement for the provision by Terasen to TGVI of transportation service on the Coastal Transmission System; and

D. Terasen, TGVI and BC Hydro have agreed that BC Hydro may assign to TGVI firm gas transportation capacity available to BC Hydro under the BTA on the terms and conditions of this Agreement to be used by TGVI to provide firm gas transportation service to BC Hydro under the TSA.

NOW THEREFORE this Agreement witnesses that in consideration of the premises, the covenants and agreements herein contained, and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree that:

ARTICLE 1
INTERPRETATION

1.1 **BTA Definitions:** Words and phrases defined in the BTA and used in this Agreement have the meanings given in the BTA, unless otherwise defined herein.

1.2 **Definitions:** In this Agreement, the following terms have the following meanings:

(a) “Assigned Service” means a quantity of Daily Firm Service available to BC Hydro under the BTA from a receipt point at Huntingdon to a delivery point at Eagle Mountain in an amount equal to the Contract Demand plus an allowance for BC Hydro’s share of System Gas on the TGVI System under the TSA;

(b) "Assignment Term" means the period commencing on the Commencement Date and ending on the earlier of (i) the expiry or termination of the TSA; (ii) the expiry or termination of the BTA; and (iii) the effective date of termination of this Agreement pursuant to section 2.12;

(c) “BTA” means the Bypass Transportation Agreement made as of November 27, 1998 and executed on July 13, 1999 between Terasen and BC Hydro, as amended from time to time;

(d) “Commencement Date” means the later of January 1, 2008 and the date immediately following the date the conditions precedent under section 6.6 are satisfied;

(e) “Contract Demand” means the “Contract Demand” in effect from time to time pursuant to the TSA;

(f) “Pacific Clock Time” has the meaning given in the TSA;

(g) “Peaking Agreement” means the Peaking Agreement dated as of September 19, 2007 between TGVI and BC Hydro, as amended and in effect from time to time;

(h) “System Gas” has the meaning as set out in in the TGVI Tariff, Part B, Transmission Transportation Service , as amended and approved by the BCUC for time to time;

(i) “TSA” means the Transportation Service Agreement dated as of September 19, 2007 between TGVI and BC Hydro, as amended and in effect from time to time; and

(j) ”Wheeling Agreement" means the Wheeling Agreement dated for reference July 3, 1989 between Terasen and TGVI, as amended from time to time.

1.3 **Interpretation:** For the purpose of this Agreement, except otherwise expressly provided:

(a) "this Agreement" means this agreement as it may from time to time be supplemented or amended and in effect;

(b) all references to this Agreement to a designated "Article", "Section", "Subsection" or other subdivision are to the designated Article, Section, Subsection or other subdivisions of this Agreement;

(c) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision;

(d) the headings are for convenience only and are not intended to interpret, define or limit the scope, extent or intent of this Agreement or any provision hereof; and

(e) the singular of any term includes the plural, and vice versa, and the word "including" is not limiting whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto.

ARTICLE 2
ASSIGNMENT

2.1 **Assigned Service**: Subject to the terms and conditions of this Agreement, BC Hydro hereby assigns to TGVI during the Assignment Term all rights of BC Hydro under the BTA to the Assigned Service, including the right to use and enforce and to make separate nominations for the Assigned Service, under and subject to the terms of the BTA (including the Terms and Conditions of the Transportation Schedule). BC Hydro shall not during the Assignment Term use or exercise any rights under the BTA in respect of the Assigned Service or any part thereof.

2.2 **Coordination Agreement:** Terasen agrees to increase the minimum delivery pressure under the Wheeling Agreement and the BTA to 300 psig. BC Hydro, Terasen, and TGVI will coordinate deliveries under the TSA and the BTA such that if on any Day during the Assignment Term BC Hydro has made a nomination for deliveries under the TSA, and if that nomination together with the nominations for deliveries to Burrard Thermal for that Day are such that the delivery pressure at Eagle Mountain would be less than 300 psig, on notice from Terasen or TGVI, BC Hydro may, by return notice, elect to either:

(1) allow Terasen to reduce deliveries at Burrard Thermal to the extent necessary to maintain a minimum pressure of 300 psig at Eagle Mountain; or

(2) allow TGVI to reduce deliveries under the TSA to the extent necessary but not exceeding the total Assigned Service to allow Terasen to reduce delivery pressure at Eagle Mountain below 300 psig and still meet the remaining firm requirements of TGVI and Burrard Thermal.

If BC Hydro does not make a request as required under this section, Terasen or TGVI may, on notice to BC Hydro, reduce deliveries in accordance with either subsection 2.2(1) or (2) as selected by Terasen and/or TGVI.

2.3 **Exercise of Contractual Rights by TGVI**: Subject to the terms and conditions of this Agreement, TGVI may exercise and enforce all rights of BC Hydro under the BTA, including the right to use and enforce and to make separate nominations for the Assigned Service to the extent, but only to the extent, necessary to enable TGVI to use the Assigned Service in accordance with the terms and conditions of the BTA, including the Terms and Conditions of the Transportation Schedule, and for greater certainty, TGVI shall not, and has no right to:

(a) agree to any amendment of, or supplement to, the BTA or any rights or obligations of BC Hydro thereunder, including any right to change or agree upon any alternate Receipt Point or Delivery Point or any change in the Contract Quantity;

(b) exercise any right to cancel or terminate the BTA in whole or in part, or to give any notice or take any action that would entitle Terasen to cancel or terminate the BTA in whole or in part;

(c) grant to Terasen any waiver of performance that would impair any right of BC Hydro to exercise its rights under the BTA during or after the Assignment Term;

(d) assign, in whole or in part, any of its rights in respect of the Assigned Service or otherwise acquired under this Agreement, without the prior written consent of BC Hydro and Terasen, which consent may be granted or withheld in the sole discretion of either of them; or

(e) otherwise take any act, or omit to take any act, that has the effect of impairing the exercise of the rights of BC Hydro under the BTA during the Assignment Term in accordance with section 2.8 or the reversion of rights to BC Hydro on expiry of the Assignment Term in accordance with section 2.9.

2.4 **BC Hydro Covenants**: Except as otherwise expressly contemplated in this Agreement, BC Hydro shall not, during the Assignment Term, without the prior written consent of TGVI, which consent may be granted or withheld in the sole discretion of TGVI:

(a) agree to any amendment of, or supplement to, the BTA or any rights or obligations of BC Hydro thereunder, including any right to change or agree upon any alternate Receipt Point or Delivery Point or any change in the Contract Quantity that would in any way affect the exercise by TGVI of its rights in respect of the Assigned Service acquired under this Agreement;

(b) with the exception of its rights under sections 8.01 and 8.03 of the BTA, exercise any right to cancel or terminate the BTA in whole or in part, or to give any notice or take any action that would entitle Terasen to cancel or terminate the BTA in whole or in part;

(c) exercise its rights to cancel or terminate the BTA under sections 8.01 or 8.03 unless (i) BC Hydro has received confirmation from Terasen that new facilities are not required to provide TGVI with the equivalent amount of capacity as provided by the Assigned Service, or (ii) BC Hydro has provided written notice to TGVI at least 12 months before the effective date of the cancellation or termination;

(d) grant to Terasen any waiver of performance that would impair any right of TGVI to exercise its rights in respect of the Assigned Service or otherwise acquired under this Agreement;

(e) assign, in whole or in part, any of its rights in respect of the Assigned Service; or

(f) otherwise take any act, or omit to take any act, that has the effect of impairing the exercise of the rights of TGVI in respect of the Assigned Service or otherwise acquired under this Agreement.

2.5 **Assumption of Obligations**: TGVI hereby assumes and covenants and agrees with BC Hydro and Terasen to perform and discharge the obligations of BC Hydro, and to comply with the terms and conditions, under the BTA, including the Terms and Conditions of the Transportation Schedule, in connection only with the Assigned Service and the exercise by TGVI of the contractual rights hereby assigned, save and except only the payment of amounts due by BC Hydro under Article 4 of the BTA. TGVI acknowledges that it has received and reviewed the BTA and the Terms and Conditions of the Transportation Schedule.

2.6 **Curtailment and Imbalances**: Subject to section 2.2 of this Agreement and notwithstanding any provisions in the BTA, BC Hydro, Terasen and TGVI agree each with the others that:

(a) if at any time after Terasen has authorized Daily Firm Service under the BTA for any Day Terasen curtails Daily Firm Service for that Day by a quantity less than the aggregate Authorized Quantity authorized by Terasen for both BC Hydro and TGVI for that Day, then the amount of Daily Firm Service for that Day which is not curtailed will be allocated between BC Hydro and TGVI pro rata in proportion to their respective Authorized Quantities for that Day; and

(b) if at any time before Terasen has authorized Daily Firm Service under the BTA for any Day Terasen determines that it will be unable to provide all of the Daily Firm Service for that Day, then the amount of Daily Firm Service that Terasen is able to provide on that Day will be allocated between BC Hydro and TGVI pro rata in proportion to the amount of Daily Firm Service to which they are each entitled (which, for greater certainty, in the case of TGVI is the Assigned Service and in the case of BC Hydro is the amount equal to the difference between the Contract Quantity under the BTA and the Assigned Service under this Agreement).

Gas imbalances and applicable penalties, if any, will be attributed to, and borne by, the party creating them, as determined by Terasen, acting reasonably.

2.7 **Concurrent Exercise of Contractual Rights by BC Hydro**: It is acknowledged and agreed that, notwithstanding this Agreement, BC Hydro shall continue to be entitled to exercise all contractual rights under the BTA, including the Terms and Conditions of the Transportation Schedule, during the Assignment Term, including the right to use and make separate nominations for the difference between the Contract Quantity under the BTA and the Assigned Service under this Agreement, save and except only to the extent as limited by the rights assigned hereby, provided, however, nothing in this Agreement shall obligate Terasen to provide firm transportation service to BC Hydro and/or TGVI in a quantity greater that the Contract Quantity or for a term greater than the term of the BTA or upon terms and conditions other than those specified in the BTA including the Terms and Conditions of the Transportation Schedule.

2.8 **Reversion of Contractual Rights**: It is acknowledged and agreed that upon expiry of the Assignment Term, this Agreement shall terminate (subject to provisions of Section

2.6) and upon termination of this Agreement, however so arising, TGVI shall have no further or continuing rights to use the Assigned Service, and all rights assigned hereunder shall revert in full, and without impairment to, and thereafter be exercisable by, BC Hydro in accordance with the terms of the BTA, including the Terms and Conditions of the Transportation Schedule.

2.9 **No Agreement Assignment**: It is acknowledged and agreed that this Agreement constitutes an assignment of certain contractual rights and benefits only under the BTA, and does not constitute an assignment of that agreement.

2.10 **No Release**: Notwithstanding any other provision of this Agreement, it is acknowledged and agreed that nothing in this Agreement will release BC Hydro from its obligations to Terasen under the BTA, including the Terms and Conditions of the Transportation Schedule.

2.11 **No Amendment to BTA**: It is acknowledged and agreed that except as otherwise specifically provided herein, nothing in this Agreement shall operate or be construed as an amendment to the BTA or the Terms and Conditions of the Transportation Schedule, all of which terms and conditions shall remain in full force and effect.

2.12 **Termination by BC Hydro:** BC Hydro may terminate this Agreement at any time provided BC Hydro gives TGVI not less than 24 months prior written notice. In the event that BC Hydro exercises its right to terminate the Agreement, the termination will occur at 08:00 Pacific Clock Time on November 1 immediately following the expiration of the 24 month minimum notice period or such later November 1 as designated by BC Hydro in the notice delivered under this section.

ARTICLE 3
PAYMENT

3.1 **Assigned Service:** TGVI is not obliged to pay to BC Hydro any fee or other charge for or in respect of the assignment of the Assigned Service provided herein.

3.2 **Allocation of Wheeling Agreement Costs**: The parties acknowledge that TGVI will apply for Demand Tolls for BC Hydro under the TSA on the basis that the costs allocated by TGVI to BC Hydro as a shipper on the TGVI System on account of the costs payable by TGVI to Terasen pursuant to the Wheeling Agreement shall be based on BC Hydro's Contract Demand under the TSA plus its share of System Gas less the quantity of Assigned Service.

3.3 **By BC Hydro**: Nothing in this Agreement releases BC Hydro from its obligations to make payment to Terasen of all amounts becoming due and payable under Article 4 of the BTA, including for greater certainty any and all payments attributable to the Assigned Service. TGVI is not liable to Terasen for any amount owing by BC Hydro to Terasen under the BTA.

ARTICLE 4
TERASEN CONSENT

4.1 **Consent:** Pursuant to section 23.3 of the Terms and Conditions of the Transportation Schedule, Terasen hereby consents to the assignment herein provided upon the terms and conditions specified herein. Terasen acknowledges that during the Assignment Term TGVI shall be entitled to hold and enforce all of the rights, benefits and privileges of BC Hydro under the BTA with respect to the Assigned Service, on the terms and conditions herein set out to the same extent as TGVI had entered into a Transportation Agreement with Terasen, on the same terms and conditions as the BTA, in respect of the Assigned Service and with a receipt point at Huntingdon and a delivery point at Eagle Mountain.

ARTICLE 5
ARBITRATION

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

ARTICLE 6
MISCELLANEOUS

6.1 **Notices:** All notices required or permitted to be given hereunder shall be in writing and shall be considered as having been given if delivered personally, or by facsimile in the manner provided for notices in the BTA, to BC Hydro or to Terasen (in either case with a copy to TGVI) at the addresses and facsimile numbers set out in, or notified under, the BTA, and to TGVI as follows:

Terasen Gas (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, British Columbia, V3S 2X7
Attention: Director, Customer Management and Sales

6.2 **Choice of Law**: This Agreement is governed by British Columbia law and subject to Article 5.1, the parties attorn to the exclusive jurisdiction of the courts of British Columbia.

6.3 **Amendment:** This Agreement may be amended only by an instrument in writing signed by the parties.

6.4 **Enurement:** This Agreement enures to the benefit of and is binding upon the parties and their respective successors and permitted assigns.

6.5 **Entire Agreement**: This Agreement between the parties and the TSA and Peaking Agreement between TGVI and BC Hydro, all made as of the same date as the date of this Agreement) contains the whole agreement between the parties in respect of the subject matter hereof and there are no terms, conditions or collateral agreements express, implied or statutory other than as expressly set forth in the aforesaid agreements and the aforesaid agreements supersede all of the terms of any written or oral agreement or understanding between the parties in respect of the subject matter hereof.

6.6 **Conditions Precedent:** This Agreement is subject to the approval of this Agreement and each of the other agreements referenced in section 6.5 by the BCUC on terms and conditions, if any, acceptable in respect of this Agreement to TGVI, BC Hydro and Terasen Gas Inc. and acceptable in respect of the TSA and the Peaking Agreement to TGVI and BC Hydro, provided that if a party has not provided written notice of rejection of the terms and conditions included in the BCUC decision, if any, by 30 days after the date of issuance of the BCUC decision, the party will be deemed to have accepted those terms and conditions.

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

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

Original signed by Bob Elton
Signature

BOB ELTON, President and CEO
Print Name and Office

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by Randy Jespersen
Signature

RANDY JESPERSEN, President and CEO
Print Name and Office

TERASEN GAS INC.

Original signed by Scott Thomson
Signature

SCOTT THOMSON, VP Regulatory Affairs & CEO
Print Name and Office

Attachment 79.1

PROPOSED FORM OF AGREEMENT FOR AMALCO (REVISED JULY 18, 2012)

THIS AGREEMENT is made effective January 1, 2013 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY INC., a corporation formed under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia

(**"FEI**")

AND:

FORTISBC HOLDINGS INC., a corporation formed under the laws of British Columbia, having an office at 10th Floor, 1111 West Georgia Street, Vancouver, British Columbia

("**FHI**")

WHEREAS

A. FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. were amalgamated into FEI;

B. FEI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of the Lower Mainland, Vancouver Island, Whistler and the Interior;

C. FEI maintains administrative offices throughout British Columbia; and

D. FEI wishes to retain FHI to provide certain professional and management services to it in respect to the ownership and operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

Deleted: FHI and Amalco Proposed Corporate Services Contract - REVISED July 18.doc

(b) “**Force Majeure**” has the meaning assigned to such term in Section 9.1;

(c) “**Governmental Authority**” means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) “**Laws**” means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) “**Person**” includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) “**Services**” means the professional and management services to be provided to FEI by FHI as more particularly described in Section 2.1.

1.2 Schedules

Schedule "A" is attached to, and is incorporated by reference into, this Agreement.

1.3 Interpretation

In and for the purpose of this Agreement

1) this “Agreement” means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated “Article”, “section” or other subdivision is to the designated Article, section or other subdivision of this Agreement,

3) the words “herein”, “hereof” and “hereunder” and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word “or” is not exclusive and the word “including” is not limiting (whether or not non-limiting language (such as “without limitation” or “but not limited to” or words of similar import) is used with reference thereto), and

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6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

1.5 Prior Agreements

The parties agree that any prior agreements between the parties pertaining to the subject matter hereof, including the agreement between FEI and FHI dated January 1, 2010 and amended on January 1, 2012, agreement between FortisBC Energy (Vancouver Island) Inc. and FHI, dated January 1, 2010 and amended on January 1, 2012 and agreement between FortisBC Energy (Whistler) Inc. and FHI dated January 1, 2010 and amended on January 1, 2012 are hereby cancelled and of no further effect.

PART 2

SERVICES

2.1 Services

FHI hereby agrees to provide to FEI those professional and management services described in Schedule "A" which Services shall include certain professional and management services provided to FHI by its parent company, Fortis Inc. which professional and management services also benefit FEI.

2.2 No Obligation to Provide Additional Services

FHI shall not perform, and FHI shall have no obligation to perform, any services on behalf of FEI other than as set out in this Agreement or any similar agreement.

2.3 Consultation with FEI

FHI will consult with FEI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between FHI and FEI. In performing the Services, FHI shall be an independent contractor. FHI employees shall not be considered employees of FEI for any purpose.

2.5 Compliance

In performing the Services, FHI will comply with all Applicable Laws.

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PART 3

COMPENSATION

3.1 Compensation for Services and Shared Costs

FEI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $12,277,400 per annum on a take-or-pay basis.

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3.2 Amendment to Costs

The amounts set out in Section 3.1 may be amended annually by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of FEI and to reflect annual inflationary adjustments. Any services to be provided that are not contemplated under this Agreement will be subject to additional compensation as agreed between the parties and form an amendment to this agreement in accordance with Section 10.3 below.

3.3 Invoicing

FHI will invoice FEI in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

FEI will, within thirty (30) days of receipt of an invoice from FHI, pay to FHI the amount specified in such invoice. Any amount to be remitted by FEI to FHI and not remitted on or before the date on which it is due shall thereafter bear interest. A late payment charge of 1.5% per month (18% per annum) shall be payable to FHI on any unpaid balance after thirty (30) days of the date of invoice.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by FEI

Subject to Section 4.4, FEI will indemnify, defend and hold harmless FHI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including

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4.2 Limitation of Liability of FHI

Neither FHI nor any of its directors, officers, employees, agents or contractors will be liable to FEI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which FEI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FHI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FHI.

4.3 Indemnity by FHI

Subject to Section 4.4, FHI will indemnify, defend and hold harmless FEI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which FEI may suffer or incur as a result of any act or omission or error of judgement as a result of which FHI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF FEI

5.1 Covenants by FEI

FEI covenants and agrees to:

(a) fully co-operate with FHI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by FEI to FHI or any other Person pursuant to or as contemplated by this Agreement.

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PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of FHI

FHI hereby represents and warrants to FEI as representations and warranties which are true as at the date hereof and which will be true during the term of FHI's appointment hereunder:

(a) FHI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FHI has full power and authority to perform its obligations hereunder;

(b) this Agreement constitutes a valid and binding obligation of FHI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) FHI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of FEI

FEI hereby represents and warrants to FHI as representations and warranties which are true as at the date hereof and which will be true during the term of FHI's appointment hereunder

(a) FEI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FEI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2013 and will end on December 31, 2013, unless earlier terminated pursuant to the provisions hereof. Thereafter this Agreement will automatically be renewed for further one (1) year terms subject to Section 7.2 below.

7.2 Termination

FHI's appointment hereunder may be terminated at any time:

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(a) by FHI giving FEI six (6) months' written notice of such termination:

(i) if FEI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FEI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FEI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FEI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FEI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event FEI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FEI of written notice thereof from FHI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FHI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FHI that FEI is in breach is conceded to be correct by FEI or found to be correct by an arbitrator pursuant to section 8.1;

(b) by FEI giving FHI six (6) months' written notice of such termination:

(i) if FHI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FHI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FHI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FHI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FHI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event FHI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FHI of written notice thereof from FEI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FEI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FEI that FHI is in breach is conceded to be

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correct by FHI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, FHI will have no further obligations under Article 2 and will promptly deliver to FEI any material documents in the possession of FHI pertaining to the business of FEI.

7.4 Compensation of FHI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, FEI will pay to FHI all amounts owing to FHI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Article 3 which are payable to FHI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between FHI and FEI regarding any allegation that FEI or FHI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

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PART 9
FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

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PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

[Execution page follows]

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10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this on the Effective Date.

FORTISBC ENERGY INC.

By: ___________________________

Title: ___________________________

FORTISBC HOLDINGS INC.

By: ______________________________

Title: ______________________________

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Schedule "A"

Description of Services

<u>SERVICES PROVIDED BY FHI</u>

<u>General Governance & Oversight Services</u>

In addition to the specific services described below, FEI receives the benefit of the expert advice and experience of FHI executives, who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of FHI as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

<u>Treasury and Cash Management</u>

(1) Execute Financings
  a. Develop financing plans
    i. Provide assessments of financing alternatives
    ii. Determine timing, term, rate, structure
  b. Obtain BCUC approvals
  c. Execute financings
    i. Negotiation, preparation of legal documentation
    ii. Prepare disclosure documentation
    iii. Investor presentations
    iv. Due diligence process
    v. Deal execution

(2) Cash Management
  a. Prepare and maintain short-term cash forecasting
  b. Execute short-term borrowing
    i. Commercial paper issuance
    ii. Bank borrowing
  c. Execute short-term investing of excess funds
  d. Negotiation of letters of credit
  e. Execution of manual wire transfers
  f. Establish and maintain internet based banking platform for cp issuance, fund transfers and reporting

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g. Payment of interest, principal and fees on outstanding debt

(3) Arrange operating credit facilities

a. Negotiate credit agreements

i. Determine terms and conditions

ii. Negotiate pricing and term

b. Manage syndication process

c. Obtain BCUC approval

(4) Negotiate bank-service fees

(5) Treasury-related controls and compliance

a. Develop and monitor control and compliance procedures for key Treasury procedures

(6) Compliance reporting

a. Prepare and file required compliance reports with third parties

i. Lenders, securities commissions, BCUC

(7) Hedging of interest rate and foreign exchange risks

a. Develop financial hedging plans as required

b. Negotiation of required documentation

c. Execution of derivative transaction

(8) Prepare Derivatives Policies and Procedures;

(9) Counterparty Credit Risk Management;

a. Review credit worthiness of counterparties

b. Determine appropriate credit limits for counterparties

c. Determine requirement for credit support

d. Negotiate appropriate credit support documentation

(10) Interest rate and foreign exchange rate forecasting;

(11) Regulatory submissions with respect to ROE, capital structure and financing matters;

(12) Capital structure review and maintenance; and

(13) Provide education and related materials from training courses and seminars attended by Treasury staff.

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Investor Relations

(1) Manage the Rating Agency Process;

(2) Maintain investment banker and debt investor relationships;

(3) Maintain banking and money market dealer relationships;

(4) Investor and Shareholder communication;

(5) Assist in preparation of annual/quarterly disclosure documents; and

(6) Prepare annual report.

Corporate Development and Capital Management

(1) Manage the annual strategic planning cycle;

(2) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process;

(3) Provide financial analysis and evaluation of new projects and new initiatives;

(4) Manage the acquisition and divestiture activity;

(5) Provide project management and/or due diligence support where required; and

(6) Contract negotiation in support of business development initiatives.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for FEI and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required from prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly and annual report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada, the US and under International Financial Reporting ("IFRS");

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(7) Direct response to accounting authorities in both Canada, the US and IFRS with respect to exposure drafts and pronouncements;

(8) Project lead for FHI on the implementation of IFRS;

(9) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with General Accepted Accounting Principles;

(10) Accounting advice and assistance as required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current tax expense, providing information for the calculation of FIT expense and reviewing FIT calculations, preparing or reviewing the necessary journal entries, assisting auditors with external audit review, preparing tax disclosures to the financial statements and analyzing Balance Sheet tax accounts;

(2) Prepare tax returns and all tax compliance work for FEI, including identification and research of technical issues, filing necessary elections, agreements and information returns, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax instalments and arrange payment;

(4) Prepare or review tax information and calculations in support of rate cases, annual reviews and annual reports to the BCUC; participate in regulatory working groups to provide information and guidance on tax issues;

(5) Provide tax support for planning and forecasting groups; provide a strategic tax perspective into planning processes to optimize tax advantages for the Gas companies;

(6) Provide leadership, guidance and consultation to finance and operations leaders on income tax and commodity tax issues; find tax solutions to complex business issues;

(7) Monitor, identify and research tax issues resulting from tax law changes, accounting changes (such as IFRS) or business opportunities to make sound recommendations to management;

(8) Interpret impact of industry issues on tax; participate in industry group tax committees such as Canadian Gas Association and make submissions to government bodies on issues relevant to the industry;

(9) Monitor HST, GST and PST (including Social Services Tax, Carbon Tax, ICE levy), including identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of HST, GST or PST to particular transactions, training employees on the application of commodity taxes to

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revenues, disbursements and transactions, advising employees of commodity tax changes; advising in the implementation of new taxes;

(10) Monitor tax implications of payroll and employee benefits including advising on taxable benefits and related calculations, payroll tax issues, and pension plan tax issues;

(11) Coordinate tax audits (federal income tax, LCT, HST, GST , various PST), provide auditors access to data, research and provide answers to auditor's requests and negotiable beneficial resolution of proposed adjustments;

(12) Prepare and file Notices of Objection and Appeal letters and coordinate legal appeals with internal and external counsel; negotiate with tax authorities with a view to minimizing ultimate liabilities;

(13) Establish and monitor tax department controls and ensure adherence to tax policies;

(14) Provide ongoing training, guidance and support to tax group employees to enhance their performance levels and career development.

Internal Audit

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the FEI Code of Business Conduct compliance management is effective by conducting the annual compliance reviews and acting as a resource when issues arise with respect to the Code of Business Conduct;

(5) Monitor the Whistle Blower Ethics line and address issues as they arise;

(6) Participate on various committees in the capacity of ex-officio to provide oversight and value add;

(7) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of FEI.

(8) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance;

(9) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(10) Provide assistance to the external auditors in completing their external financial audits; and

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(11) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts.

Risk Management and Insurance Services

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of business that FEI is engaged in, and ensuring that there are systems in place that effectively manage and monitor those risks with a view to the long term viability of the FEI;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold and payment of same;

(9) Conduct of review of contractual agreements to protect FEI from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

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Corporate Secretary's Office

(1) Ensure all continuous disclosure and governance activities required by external regulators and third parties are appropriately carried out, including Securities filings and BC Business Corporations Act requirements; and

(2) Manage the relationship and corporate activities of the Board of Directors.

(3) Prepare materials for Board of Directors and minutes.

(4) Track and maintain corporate records.

(5) Assist in preparation of corporate documentation and providing corporate information to internal and external parties.

Legal Department

(1) Provide all legal services to FEI other than those outsourced to outside legal counsel;

(2) Direct the provision and management of outside legal services, primarily litigation, to FEI;

(3) Provide management of all litigation;

(4) Provide legal counsel on regulatory, environmental, marketing, employment, and intellectual property;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Advise FEI on legal issues that may arise including claims, actions, real estate and other property transactions, and contracts, including the purchase of goods and services by FEI; and

(7) Provide general miscellaneous legal support and advice to management.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employees and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

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(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required; and

(8) Corporate governance of salary and benefit administration, including executive and management compensation.

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SERVICES PROVIDED BY FORTIS INC. (“FORTIS”)

Deleted: WHICH BENEFIT FEI

Deleted: In addition to the specific services described above, FEI receives the benefit of the expert advice and experience of Fortis executives.

Executive Function

President & CEO

A. Strategic Direction

1. Present annually to the Board of Directors of Fortis (the “Board”) a strategic plan and a business plan which must (a) be designed to achieve the corporate objectives together with an appropriate set of performance measures, (b) identify the principal strategic and operational risks of the business, and (c) include appropriate methods to manage the risks;
2. Obtain Board approval for the strategic plan and the business plans of Fortis as a precondition to the implementation of such plans;
3. Obtain Board approval for the procurement, allocation, and disposition of corporate resources for Fortis as a precondition to such procurement, allocation or disposition of such resources either;
   a. in the approved Business Plan; or
   b. by specific authorization of an asset transaction consistent with current business activities in an amount in excess of $XX [insert amount] million ($XX [insert amount] million annual aggregate) and for any share transaction (other than increased investment in an existing affiliate within the transaction size parameters noted above); and
4. Communicate the principal objectives and strategic plan for Fortis throughout Fortis.

B. Leadership and Management of Fortis

1. Lead Fortis with vision and values that are well understood, widely supported and consistently followed;
2. Foster a corporate culture which promotes ethical practices, personal integrity and the fulfilment of social responsibilities;
3. Create the appropriate environment to stimulate employee morale and productivity;
4. Manage change proactively;
5. Ensure continuous improvement in the quality and value of the products and services provided by Fortis;

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6. Ensure that Fortis achieves and maintains satisfactory competitive positions within its industries; and
7. Serve as a director of Fortis.

C. *Management and Organization Structure*

1. Provide advice to the Board on the appointment of all officers of Fortis;
2. Assist the Board in establishing the limits of delegated authority and responsibility in conducting Fortis's business;
3. Provide annually to the Board, an evaluation of the performance of each senior manager who reports to the CEO;
4. Present for approval to the Board, an annual plan which will provide for the development and succession of senior managers of Fortis in a timely fashion;
5. Generally develop, attract, and retain a highly motivated, effective management team; and
6. Obtain Board approval for any proposed significant or material change in the organizational structure of Fortis as a precondition to the implementation of such changes.

D. *Finances, Controls and Internal Systems*

1. Consistently strive to achieve Fortis's annual and long-term financial goals and objectives;
2. Assist the Board in establishing an appropriate capital structure for Fortis;
3. Ensure that Fortis has systems in place to effectively monitor and manage the principal risks related to the operation of the business(es);
4. Establish and maintain the integrity of Fortis's financial controls and reporting systems and compliance of the financial information with appropriate accounting principles;
5. Establish and monitor processes and systems designed to ensure compliance with all applicable laws by Fortis, its officers and employees; and
6. Provide certification of financial matters, including the completeness and accuracy of Fortis's financial statements and, where necessary, matters relating to internal controls over financial reporting.

E. *Employee Relations*

1. Ensure that a process is in place to monitor compliance with the ethical standards to be observed by all officers and employees of Fortis, and ensure that a process is in place to monitor divergence from the ethical standards to be observed by all employees; and
2. Establish and maintain effective communications with employees of Fortis.

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F. External Communication

1. Assist the Board in establishing and maintaining an effective communications policy with shareholders, the financial community, the media, the community at large and other stakeholders;
2. Ensure that Fortis contributes, and is perceived to contribute, to the well-being of the communities it serves; and
3. Serve as the principal representative and spokesperson of Fortis.

G. Board Relations

1. Keep the Board adequately informed, on a timely basis, with respect to all events and information which the CEO believes might materially affect Fortis, its performance, prospects, and image;
2. Provide the assistance necessary for the Chair of the Board and committees of the Board to carry out their duties;
3. Be entitled to attend all meetings of Board committees and provide Board committees the assistance necessary to carry out their mandates;
4. Assist the Board in reviewing and maintaining an up-to-date position description for the President and CEO of Fortis; and
5. Report to the Board on material use of outside consultants.

VP Finance and CFO

1. Advise and assist the Chairman of the Board and President and CEO in the development of strategies and goals in the financial planning and structure of the Group and in the control of the Company's business operations.
2. Keep the CEO informed of all relevant financial information and report on the financial status and performance of all companies in the group to the Board of Directors of Fortis Inc.
3. Responsible for all aspects of investor relations program, including shareholder communications and shareholder meetings.
4. Liaison with the investment community and market surveillance.
5. Ensure that procedures and systems necessary to maintain proper records and to afford adequate accounting controls and services are implemented throughout the organization.

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6. Ensure that uniform financial policies and procedures are adhered to throughout the organization.
7. Ensure the development and maintenance of timely financial information systems.
8. Develop and maintain effective internal and external audit activities and recommend proper financial controls.
9. Develop and maintain suitable budgeting procedures and reviews.
10. Direct the planning and control of corporate cash requirements and major banking relationships.
11. Review capital expenditure plans and budgeting.
12. Plan and direct corporate financing.
13. Recommend guidelines for financial transactions between companies in the Fortis Group.
14. Ensure that adequate financial personnel resources are retained and appropriately assigned throughout the group.
15. Appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions. As demanded, manage external financial consulting resources.
16. Maintain an awareness of changes in practice and procedure within the professional accounting field.
17. Act as CFO of subsidiary organizations when required.

General Counsel & Corporate Secretary

1. Prepare schedules, notices, agendas, resolutions, and minutes for the Boards of Directors of Fortis Inc. and selected subsidiaries and affiliates.
2. Coordination of all communications to Board of Directors.
3. Operation of share purchase plans.
4. Preparation of security documents including Management Information Circulars, Annual Information Forms and prospectuses.
5. Responsible for regulatory compliance, including annual returns to the registries of companies, dividend disclosure, filing of annual and quarterly reports, reports to stock exchanges, notices of Material Change, and Insider Reports.
6. Provide legal services to all corporations in the Fortis Group including, when necessary, engagement of outside legal services.

Treasury and Taxation Function

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1. Manage equity financing, including both common and preference shares, and related prospectuses
2. Manage debt financing, including long-term debt and credit facility borrowings as well as borrowing rates
3. Maintaining the capital structure
4. Assist the VP finance and CFO appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions
5. Cash management and forecasting activities – including dividend and interest payments and equity injections required by subsidiaries
6. Managing cash requirements of subsidiaries, as required, as it relates to intercompany loans and required equity injections
7. Debt covenant calculations and monitoring
8. Managing hedging activities related to US dollar debt
9. Preparation of annual corporate tax returns and related foreign affiliate corporate tax returns
10. Calculation of quarterly and annual Fortis Inc. corporate tax provision
11. Responsibility for utilization of non-capital and capital loss carryforwards of Fortis Inc. and coordination of tax utilization plans with applicable subsidiaries
12. Managing corporate reorganizations and tax planning
13. Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, EI and payroll tax issues
14. Preparing Fortis Inc. employee T4's, including preparing taxable benefit calculations
15. Coordination of Fortis Inc. corporate income tax or HST audits
16. Tax research associated with tax issues and changes in tax laws

Investor Relations Function

1. Manage analyst communications – including review of analysts' commentaries/research reports, conduct quarterly conference calls and respond to general analyst research inquiries.
2. Manage investor communications – including the preparation and delivery of investor presentations, road shows, web casts, teleconferences and one-on-one meetings with existing and prospective shareholders
3. Manage shareholder communications – including responding to general shareholder inquiries and the preparation, delivery and filing of documentation for

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quarterly and annual mailings (i.e., quarterly reports, annual report, proxy, management information circular and annual information form).

4. Coordination and preparation of Fortis's Annual Meeting including preparation of the Executive's presentation to shareholders.
5. Coordination of solicitation of proxies.
6. Preparation of Quarterly Investor Relations Reports to the Board of Directors.
7. Preparation, coordination and dissemination of media releases to newswire agencies, websites and distribution lists.
8. Monitor and maintain Fortis's media coverage.
9. Develop, host and maintain the Fortis Inc. website.
10. Monitor the websites of the Fortis Group of Companies.
11. Monitor and research the market and investment community through Bloomberg, ThomsonOne, TSX, etc.
12. Manage and maintain the Fortis Inc. dividend reinvestment and share purchase plans (i.e., Dividend Reinvestment and Share Purchase Plan, Consumer Share Purchase Plan and Employee Share Purchase Plan)
13. Coordination and preparation of Fortis's consolidated Strategic Issues document and presentation to the Board of Directors.
14. Preparation of Fortis's consolidated Business Plan presentation to the Board of Directors.
15. Manage public relations – including conference participation, the preparation of Executive speeches and responding to media inquiries.

<u>Financial Reporting Function</u>

1. Preparation of quarterly and annual consolidated financial statements and notes to the financial statements and the related management discussion and analysis
2. Preparation of monthly internal consolidated and non-consolidated financial statements of Fortis Inc.
3. Coordination with external auditors of the annual audit of the consolidated financial statements and quarterly review of consolidated financial statements.
4. Preparation and analysis of financial information required for prospectus and other security filing documents
5. Preparation of the Annual Information Form and providing assistance in the preparation of the Management Information Circular

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6. Assisting in responding to reviews and queries of securities regulators related to continuous disclosure reporting
7. Research current and emerging accounting policies in Canada, US and that related to IFRS
8. Coordinate consistent accounting policy treatment across the Fortis group of companies related to presentation, alternative treatments and resolution of complex accounting policies to ensure compliance with GAAP
9. Oversight and coordination of conversion to International Financial Reporting Standards across the Fortis Group of companies – including coordinating research, organizing working group and steering committee sessions to discuss and resolve ongoing issues and progress, monitoring and directing progress of the overall conversion and coordination with the external auditors
10. Coordination and preparation of consolidated Business Plan document and reporting to the Board of Directors
11. Preparation of quarterly forecasted consolidated earnings and EPS
12. Responsibility for maintaining internal controls over financial reporting at Fortis Inc.

Internal Audit Function

1. Performs internal audit activities at Fortis Inc including:
   a. coordinating the Fortis Inc. CEO and CFO internal controls certification process through maintenance of financial process documentation and annual evaluation of internal controls over financial reporting and disclosure controls. Involves ensuring that all Fortis subsidiaries are fully compliant in order to support certification by the parent company;
   b. performing quality assurance reviews of Fortis Inc. continuous disclosures documents prior to public filing;
   c. performing annual reviews of Fortis Inc. statutory obligations and executive expenditures;
   d. reporting internal audit activities to the Fortis Inc. Audit Committee on a regular basis; and
   e. coordinating compliance with corporate governance requirements

2. Provides oversight over the internal audit function at the Fortis subsidiary companies to:

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a. ensure corporate-wide consistency in the application of internal audit methodologies and practices and in the reporting of audit results to management and audit committees;

b. coordinate annual audit program planning to ensure critical risk areas are addressed;

c. coordinate corporate-wide audit projects;

d. identify opportunities for audit resource and information sharing between the subsidiary internal audit groups;

e. oversees audit program planning and reviews internal audit reports to management and Audit Committees for these subsidiaries with limited internal audit resources;

3. Administers and monitors reports of allegations of suspected improper conduct or wrong doing via Fortis's ethics reporting system

4. Development of a company-wide Enterprise Risk Management program approach

<u>Board of Directors</u>

The Board of Directors of Fortis Inc. is responsible for the stewardship of Fortis. The Board will supervise the management of the business and affairs of Fortis and, in particular, will:

A. Strategic Planning and Risk Management

1. Adopt a strategic planning process and approve, on an annual basis, a strategic plan for Fortis which considers, among other things, the opportunities and risks of the business;
2. Monitor the implementation and effectiveness of the approved strategic and business plan;
3. Assist the CEO in identifying the principal risks of Fortis's business and the implementation of appropriate systems to manage such risks;

B. Management and Human Resources

1. Select, appoint and evaluate the CEO, and determine the terms of the CEO's employment with Fortis;
2. In consultation with the CEO, appoint all officers of Fortis and determine the terms of employment, training, development and succession of senior management (including the processes for appointing, training and evaluating senior management);
3. To the extent feasible, satisfy itself as to the integrity of the CEO and other officers and the creation of a culture of integrity throughout Fortis;

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C. Finances, Controls and Internal Systems

1. Review and approve all material transactions including acquisitions, divestitures, dividends, capital allocations, expenditures and other transactions which exceed threshold amounts set by the Board (including equity contributions to subsidiaries to support the investment in rate base to serve customers;
2. Evaluate Fortis's internal controls relating to financial and management information systems;

D. Communications

1. Adopt a communication policy that seeks to ensure that effective communications, including statutory communication and disclosure, are established and maintained with employees, shareholders, the financial community, the media, the community at large and other security holders of Fortis;
2. Establish procedures to receive feedback from stakeholders of Fortis and communications to the independent directors as a group;

E. Governance

1. Develop Fortis's approach to corporate governance issues, principles practices and disclosure;
2. Establish appropriate procedures to evaluate director independence standards and allow the Board to function independently of management;
3. Appoint from among the directors an audit committee and such other committees of the Board as deemed appropriate and delegate responsibilities thereto in accordance with their mandates;
4. Develop and monitor policies governing the operation of subsidiaries through exercise of Fortis's shareholder positions in such subsidiaries;
5. Develop and monitor compliance with Fortis's code of conduct;
6. Set expectations and responsibilities of directors, including attendance at, preparation for and participation in meetings; and
7. Evaluate and review the performance of the Board, each of its committees and its members.

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