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May 16, 2011

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

Attention: Ms. Alanna Gillis, Acting Commission Secretary

Dear Ms. Gillis:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy (Vancouver Island) Inc.) ("FEVI")

2012 and 2013 Revenue Requirements and Natural Gas Rates Application (the "Application")

Amendment to the Application dated May 16, 2011

On May 4, 2011, the FortisBC Energy Utilities' ("FEU" or the "Companies") submitted the above noted Application.

Attached please find an amendment to the Application (the "Amendment") that includes the following three categories of changes:

1. Amalgamated Financial Schedules;
2. Typographical or clerical corrections; and
3. Replacement tables and figures.

For ease of identification of the changes, the Companies have included a black-lined version of specific pages with revisions tracked to clearly identify what has changed. The following list identifies the relevant pages by category of change.

1. **Amalgamated Financial Schedules:**

   In support of the request to approve the determination of the amalgamated cost of service, as discussed in Section 3.3.5 and Section 8.1 (item 19) of the Application, the Companies have finalized the financial schedules for the amalgamated cost of service. The amalgamated financial schedules have been inserted as Section 7.5 of the Application.

2. **Typographical or Clerical Corrections:**

   The table of contents has been revised to correct page number references and accommodate the insertion of Section 7.5. Section 8 (Approvals Sought and Proposed Regulatory Process) has been reproduced with the new page numbering to accommodate the insertion of Section 7.5 In addition, the following pages have had narrative corrections made: 16, 17, 46, 70, 184, 185, 365, and 378.

3. **Replacement Tables and Figures:**

   - Page 67 – replacement of Figure 3.3-14 to reflect the correct series names for the chart: Customer & Stakeholder Expectations, Service Standards and Reliability and Capitalized Overhead.
   - Pages 69 and 70 – replacement Table 3.3-10 on Page 69 and corresponding narrative on Page 70 reflecting the amalgamated financial schedules included in Section 7.5. In finalizing the financial schedules for the amalgamated cost of service, further detail on the nature of the amalgamation adjustments has been obtained, requiring an update to Table 3.3-10. The total amalgamated delivery cost of service of $779.9 million is not impacted by this change. Please refer to Section 7.5, Schedules 1 through 6 for the determination of the amalgamated cost of service, rate base and earned return.
   - Appendix F-2 – changes have been made to the Tariff Continuity and Bill Impact Schedules for Rate Rider 8 in FEI and Rate Rider A in FEW. These commodity riders were inadvertently shown as reverting to zero in 2012. Both of these riders will be determined as a part of the fourth quarter gas cost report; therefore, for purposes of demonstrating the impacts of changes in delivery rates and riders relating to this Application, the Tariff Continuity and Bill Impact Schedules have been revised to exclude any changes in Rate Rider 8 and Rate Rider A.

Attached is an Amendment package which includes clean versions of all revised pages with the appropriate opposing pages for ease of insertion and replacement into the hardcopy binders. The filing instructions follow for the Amendment package to update the binder volumes.

Tab	Reference	Filing Instructions
VOLUME 1 - APPLICATION		
1.	Table of Contents	Remove and replace entire tab contents
2.	Section 1: Executive Summary and Introduction	Remove and replace pages 15-18
3.	Section 3: Revenue Requirements and Rates	Remove and replace pages 46 and 47
4.	Section 3: Revenue Requirements and Rates	Remove and replace pages 66 to 71
5.	Section 5: Cost of Service	Remove and replace pages 184 and 185
6.	Section 6: Rate Base	Remove and replace pages 365 and 366

Tab	Reference	Filing Instructions
7.	Section 6: Rate Base	Remove and replace pages 377 and 378
8.	Section 7: Financial Schedules	Insert new Tab "Amalgamated" Section 7.5 (pages 768 to 816) after page 767
9.	Section 8: Approvals Sought and Proposed Regulatory Process	Remove and replace entire tab contents
VOLUME 2 - APPENDICES		
10.	Appendix F-2	Remove and replace entire tab contents, note while only changes were made to FEI and FEW as noted above, the entire appendix has been reproduced to facilitate insertion.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed by: Michelle Carman

For: Diane Roy

Attachments

cc (email only): Registered Parties

Energy Services have been segregated and allocated to the Thermal Energy Services line of business. FEI activities in the area of Thermal Energy Services will continue to be captured in the approved non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. There is also a reduction in the O&M included in the natural gas cost of service (i.e. a benefit to natural gas customers) that is associated with the recovery of overheads from the Thermal Energy Services line of business. This is discussed further in Appendix G.

The growing prevalence of thermal solutions such as solar, DES and geo exchange, regardless of the provider of those services, will have an increasingly significant impact on the natural gas requirements over time. Thus, from the perspective of natural gas customers it is important to understand the growth of these energy alternatives over time and how they may impact the natural gas throughput and utilization. FEU sees this as an important issue to address in future filings such as the Long Term Resource Plan and future Rate Design applications. The need for additional resources to examine these impacts as part of the long term integrated resource planning process is discussed further in Section 5.3.8.

1.2.4 INCREASED FOCUS ON INVESTMENTS TO MAINTAIN THE SAFETY AND RELIABILITY OF OUR SYSTEM

In our 2010-2011 RRAs, we requested increases to O&M and capital budgets to ensure ongoing compliance to existing codes and anticipated new or changed codes and to allow us to continue to invest in the safety, integrity and reliability of the energy delivery system. To address these requirements, we received approval for additional O&M in the amount of $5.3 million in 2010 and a further $2.1 million in 2011. This funding allowed us to enhance safety messaging for customers, begin the long-range asset planning and address the specific code changes that were required. How each of these three areas has evolved since then is discussed below. The FEU believes that continued funding in these areas is necessary to ensure safe and reliable natural gas service.

1.2.4.1 Codes & Regulations

In addition to the codes and regulations that were addressed in 2010 and 2011, the FEU have identified new codes and regulations, and changes to existing codes and regulations that need to be addressed. A further discussion of these specific codes and regulations and incremental funding of $0.9 million in 2012 and a further $0.8 million in 2013 to address these requirements is included in O&M Section 5.3.

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Two other areas where the Utilities need funding to address safety and system integrity are:

- The BCOneCall project - a multi-stream two and a half year project that will automate a portion of the BCOneCall process and allow for the realization of significant benefits immediately upon completion of the project; and

- The Gas Assets Project - a four year project to move historic gas system asset compliance records into one system, with three distinct phases which will improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records, and the retention and disposal of compliance records no longer needed for operational, or other requirements.

Each of these two significant projects is discussed further in the Rate Base Deferrals Section 6.2.

1.2.4.2 Safety Messaging

In 2010 and 2011, the FEU spent approximately $1.0 million on safety awareness, primarily to increase the public's awareness of how to identify and respond to a gas leak. This initiative requires additional funding in 2012 and 2013 to fully implement our gas odour and action safety messaging, and also to increase public safety education around excavation diligence. The details regarding our plans to spend an additional $900 thousand in 2012 and a further $100 thousand in 2013 are included in O&M Section 5.3.8.5 Energy Solutions and External Relations.

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1.2.4.3 Long Term Asset Planning

FEU recognized the need to develop a long term life cycle view of gas assets when planning its sustainment capital and related asset management programs a number of years ago and first described these requirements in their 2010-2011 Revenue Requirements Application and 2010 Resource Plan. A long term view of gas assets is required primarily because of risks related to aging infrastructure. Complicating this planning requirement is the continual need to also address environmental responsibility, increased public expectations and increased regulations to maintain the safety, reliability and integrity of the distribution and transmission system used to provide gas delivery service. Critical in this regard is the concept of a "Long Term Sustainment Plan", which serves as a key component of FEU's approach for managing this challenge. This approach to long term planning is also important in order to ensure that any transmission and distribution system changes are cost effective so that their impact on customers' rates is kept to a minimum.

Today, FEU is responsible for managing gas transmission and distribution assets with a book value of approximately $3.0 billion and an approximate replacement value of $6.8 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40 to 55 years. These aging assets face an increasing rate of deterioration as they approach the end of their service life. FEU anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

To successfully manage this coming wave of asset replacements, FEU must also be cognizant of other interrelated factors. A long term view of asset management is therefore required due to a number of reasons:

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a non rate base deferral account to capture any differences that arise from the implementation of FIN 48.

3.2.2.3 Other US GAAP Items

A number of other adjustments are contemplated on transition to US GAAP that should not affect cost of service or rate base. These potential adjustments include the application of pushdown accounting, adjusting for how FEI accounts for Lease In/Lease Out transactions for external financial reporting, and others. None of these transactions are expected to affect regulatory accounting or reporting and would not affect the revenue requirement.

3.2.2.4 Costs Associated with the Adoption of US GAAP

In their US GAAP Application, the FEU outlined the expected costs of adopting both IFRS and US GAAP. The costs of adopting US GAAP were estimated to be incremental one-time costs of $1.8 million and incremental on-going costs of $0.9 million. These one-time costs are generally as a result of audit fees on the adoption of US GAAP. The higher on-going costs are as a result of higher audit fees including work required under Sarbanes-Oxley. These costs have not been included in this application. Under a US GAAP adoption scenario, the FEU would include the recovery of these costs through an evidentiary update to this RRA.

3.2.3 SUMMARY OF STATUS OF GAAP

In summary, upon receipt of a decision in the US GAAP Application, the FEU will provide an evidentiary update.

If the US GAAP Application is approved as proposed, the FEU will update their Application to include:

1. A total decrease in cost of service from pension and OPEBs (decrease of $782 thousand in 2012 and $2.24 million in 2013 as shown in Table 3.2-1 above) plus any associated income tax impacts;
2. The changes to rate base resulting from the pension and OPEB deferrals discussed in Section 3.2.2.1,
3. A total increase in O&M of $0.9 million in each of 2012 and 2013 for the ongoing costs of US GAAP compliance; and
4. A rate base deferral to capture the estimated $1.8 million in one-time US GAAP conversion costs.

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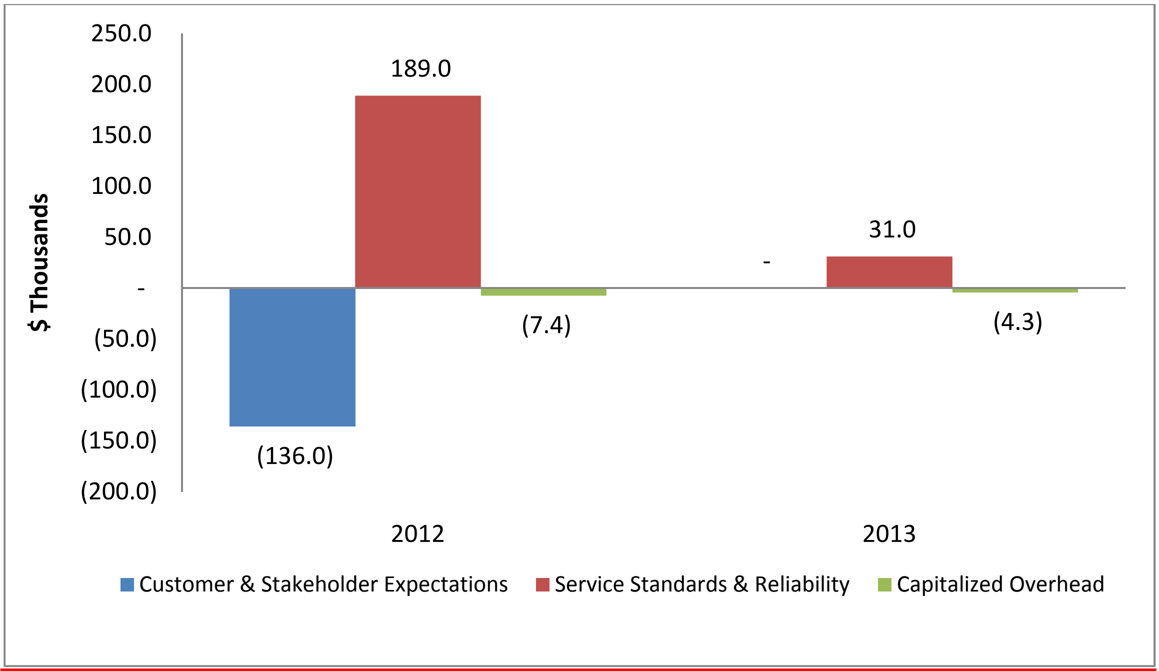
In the event that the FEU are ordered to implement accounting policies other than US GAAP, the FEU will update their Application to include the impacts of those changes.

Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements[46]



The items in the chart above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

Depreciation and Amortization Expense

A full year of depreciation associated with the Muskwa River Crossing Project, as well as additions in 2012 and 2013, have resulted in higher depreciation expense of $68 thousand in 2012 and a further $10 thousand in 2013. This increase is offset by the impacts of the changes in depreciation rates which reduce the expense by $30 thousand. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of depreciation changes is an increase of $50 thousand in 2012 and a further $13 thousand in 2013.

In addition, amortization expense has decreased $37 thousand in 2012 with no further changes in 2013. This amount is after-tax, so the impact to revenue requirements is as stated.

[46] Please refer to Section 5.3, Table 5.3-12 and Table 5.3-13

and going forward. The efficiency rationale for proceeding in this fashion is also discussed in Section 1.2.5.

In Section 3.3.5.1, the FEU provide a summary of the amalgamated cost of service. The amalgamated cost of service represents the summation of the Mainland, Vancouver Island, Whistler and Fort Nelson cost of service as described above, as well as adjustments to account for cost of service line items that will eliminate or change upon amalgamation.

3.3.5.1 FEU Amalgamated Cost of Service

The FEU amalgamated cost of service of $1.509 billion ($779.9 million delivery margin) is determined in Section 7.5, Schedule 2 as follows:

Table 3.3-10: Amalgamated 2013 Cost of Service

($ thousands)	Reference	2013 Total	2013 Cost of Gas	2013 Cost of Service[1]
Mainland	*Section 7, Tab 7.1, Schedule 6, Column 5*	$ 1,282,763	$ 658,568	$ 624,195
Vancouver Island	*Section 7, Tab 7.2, Schedule 6, Column 5*	214,087	76,399	137,688
Whistler	*Section 7, Tab 7.3, Schedule 6, Column 5*	12,173	3,455	8,718
Fort Nelson	*Section 7, Tab 7.4, Schedule 6, Column 5*	5,001	2,945	2,056
		1,514,024	741,367	772,657
Add (Deduct):				
FEI (LNG Mitigation fee to FEVI)		-	(12,024)	12,024
Other Cost of Service & Rate Base		(2,158)	-	(2,158)
FEW Transportation Charge		(2,585)	-	(2,585)
Squamish Transportation Charge		(416)	(416)	-
Total Amalgamation Adjustments		(5,159)	(12,440)	7,281
Amalgamated FEU Cost of Service		**$ 1,508,865**	**$ 728,927**	**$ 779,938**

[1] *Cost of service excluding cost of gas*

AMALGAMATION ADJUSTMENTS

The cost of service must be adjusted to reflect intercompany items that will be eliminated upon amalgamation and rate harmonization. In the case of shared services and wheeling or transportation charges between the Regions, the amalgamation of the entities results in the inter-company agreements ceasing to be in effect, and the need to retain them for regulatory purposes disappears upon amalgamation. In the case of the three items below, an adjustment must be made to the cost of service.

- The LNG mitigation revenues are included in the Vancouver Island delivery cost of service with the offset cost residing in the Mainland midstream costs. For purposes of this analysis, FEU has taken the approach of showing this $12 million adjustment to the delivery cost of service and cost of gas; however, the allocation of the LNG mitigation revenues as between midstream and delivery will be reviewed in the Fall 2011 Amalgamation and Rate Design Phase 'A' Application and may result in changes from what has been presented in this RRA.

- Other cost of service impacts from changes in interest expense and cash working capital occur. The short term interest expense for the amalgamated cost of service is determined using the FEI short term debt rate, which results in a reduction to the cost of service of approximately $2.2 million. The cash working capital for the amalgamated cost of service is determined using the FEI approved Lead and Lag days.
- The FEW Transport charges are accounted for as a cost in FEW but as a revenue FEVI; therefore the delivery cost of service has been adjusted to remove these costs.
- The Squamish Transport charges are accounted for as commodity costs in FEI but as revenue in FEVI; therefore the cost of gas has been adjusted to remove these costs.

The Companies do not expect that there will be material cost savings as a result of the amalgamation, since the operations and management of the utilities are already fully integrated and the savings have been captured for the benefit of customers over the 2004 through 2011 period; however, some small annual savings will be realized. These savings would be limited to reporting efficiencies such as financial, legal and regulatory reporting and debt issuance requirements. There will also be costs incurred to effect a future legal amalgamation of the Companies, if approved. For the one year of amalgamated cost of service (2013) relevant to this RRA, the costs and savings are expected to offset each other, and therefore the FEU have not forecast a change to the cost of service for this item. The FEU will capture any variances from the forecast of zero in a deferral account for future recovery from/return to customers. Although the costs related to the legal amalgamation are one-time in nature, any efficiency savings, although not large, will be ongoing, and will be included in future RRAs.

3.4 Rate Proposals

3.4.1 DELIVERY RATES

The proposed delivery rates reflect the revenue requirements for each Utility as discussed in Section 3.3. Preliminary bill impacts and tariff continuity schedules for all customers are provided in Appendix F-2, showing the annual bill impacts below. The following summary for each Utility provides the delivery rate change required and a summary of the annual bill impact of the rate proposals for an average residential customer in Mainland, Whistler, and Fort Nelson.

Deleted: <#>The unaccounted for gas associated with the FEVI Wheeling Agreement with FEI resides in the delivery cost of service in FEI, but as a cost of gas in FEVI, and has been adjusted accordingly.¶

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Deleted: The capitalized overhead rate for the determination of tax expense and UCC additions is assumed to be FEI's rate of 8 percent.

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employees anticipated to retire by the end of 2012 is reflected in the decrease that is expected for 2013.

SERVICE STANDARDS AND RELIABILITY

Transmission requires an additional $1.005 million in O&M funding in 2012 and an additional $1.048 million is needed in 2013 to meet service standards and reliability. These amounts are comprised of standard inflation on materials for a total of $180 thousand in 2012 and an additional $185 thousand in 2013, and the need for additional system sustainment resources for a total of $1.1 million in 2012 and an additional $803 thousand in 2013. These increases are offset by a forecast savings in Own Use Fuel.

The system sustainment resources include the additional level of staffing described above in the discussion on employee changes in Section 5.3.5.11, as well as consulting resources needed to help with the further refinement of asset management processes and for the completion of project feasibility investigations. These additional O&M costs need to be incurred to plan for increased asset renewals as a large portion of the Company's gas system assets approach the end of their useful life. The incremental O&M funding is required to complete feasibility studies and early stage planning, and to prepare budget requests for a variety of potential projects required to provide a long term view of asset management and system sustainability. Please refer to the discussion about system sustainment and asset management in Section 2 of the Application and to the discussion of capital requirements in Section 6.2 for information about this critical requirement.

These cost increases are offset by a forecast reduction in Own Use Fuel required to operate the Company's compressors and the Tilbury LNG facility (savings of $275 thousand in 2012 followed an increase of $61 thousand in 2013). The changes in Own Use Fuel costs are based on current forward market prices, which are lower than those forecast for 2011, but increase in 2013 from the cost estimated for 2012.

5.3.5.15 Transmission 2012 and 2013 Forecast - Vancouver Island

Transmission requires $621 thousand in incremental O&M funding in 2012 and a further $308 thousand in 2013 for Vancouver Island Transmission system operating and maintenance activities. A discussion of these increases by cost driver follows.

Table 5.3-24: Incremental Transmission O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	6,134	(41)	62	(92)	-	-	693	621	6,755
2013	6,755	-	63	45	-	-	201	308	7,064

CODES AND REGULATIONS

A number of non-recurring activities in 2011 that resulted from CSA Z662 are no longer required. In particular, aerial recoating, inline inspection activities, and seismic inspection activities required by CSA Z662 are complete for the 2012 and 2013 period, which results in an O&M reduction of $187 thousand in 2012. This savings is offset in 2012 by primarily two items:

(1) a $20 thousand cost increase driven by the need to ensure that transmission pipeline signage meets CSA Z662 code to clearly identify the presence of pipelines in order to reduce the possibility of damage and interference and (2) an additional $75 thousand to manage the existing condition of vegetation growing on transmission rights of way on the Vancouver Island system.

In 2013, a cost increase of $45 thousand is forecast for the recertification of pressure safety valves used in Transmission's compressors. This recertification requirement reoccurs on a three year cycle.

SERVICE STANDARDS AND RELIABILITY

Transmission needs an additional $693 thousand in incremental O&M in 2012 and an additional $201 thousand in 2013 on Vancouver Island to meet its objectives related to Service Standards and Reliability. These amounts are comprised of standard inflation on materials for a total of $65 thousand in 2012 and an additional $66 thousand in 2013, and the need for additional Transmission pipeline employees for a total of $170 thousand in 2012 and an additional $95 thousand in 2013. An additional $166 thousand is required in 2012 for Mt. Hayes LNG plant operators who were able to capitalize a portion of their labour costs in 2011 while assisting with the construction of the LNG facility. The access road leading to the new Mt. Hayes LNG facility requires an additional $50 thousand in 2012 for ongoing annual maintenance. Additionally, Mt. Hayes will incur incremental electricity costs required for ongoing liquefaction and vaporization activities. In 2012 Mt. Hayes is forecast to incur additional electricity costs, net of a minor fuel gas savings, totalling $242 thousand. In 2013 electricity costs are expected to increase a further $40 thousand.

5.3.5.16 Operations Summary

Outside of inflationary pressures, the main contributors to the increase in 2012 and 2013 forecast O&M expenditures for the Operations department relate to demographics, service standards and reliability, and code and regulations compliance.

Having effective asset, distribution and transmission system management is necessary to help ensure reliable, secure, and cost effective supplies of natural gas and propane to customers. The Operations department believes the costs it has presented are prudent and necessary to meet the above objectives and customer priorities.

5.3.6 ENERGY SUPPLY AND RESOURCE DEVELOPMENT

5.3.6.1 Departmental Overview

The Energy Supply and Resource Development department is responsible for two broad functional areas of activity – Energy Supply, and Resource Development. The purpose of each of these two functional areas and the scope of their activities are described in the following section.

ENERGY SUPPLY AND RESOURCE DEVELOPMENT ORGANIZATIONAL STRUCTURE

The organizational chart for the Energy Supply and Resource Development department is presented below.

NGV

Capital invested in NGV fueling assets, subject to approval of the NGV Application presently before the Commission, is forecast to be $4 million in 2012 and $3.8 million in 2013. These projects will be accompanied by contracts that provide for their forecast incremental costs of service to be recovered through dedicated take-or-pay incremental revenues from the incremental NGV fueling customers. Further detail on this capital investment is provided in Appendix I.

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6.2.3.6 Vancouver Island Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Vancouver Island are summarized in Table 6.2-16 below.

Table 6.2-16: Approved, Actual and Forecast Vancouver Island Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	2,725	1,836	2,966	2,553	2,757	2,922
New Customer Services	5,940	5,309	6,459	4,517	4,926	5,270
New Customer Meters	540	430	582	440	480	513
	9,206	**7,575**	**10,006**	**7,510**	**8,163**	**8,705**

6.2.3.7 Mains – Vancouver Island

Forecast new mains activity, together with unit costs and capital expenditure levels are summarized in Table 6.2-17 below.

Table 6.2-17: Approved, Actual and Forecast Vancouver Island Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	30,116	18,282	31,610	24,927	26,393	27,415
Unit Costs ($/meter)	$ 90	$ 100	$ 94	$ 102	$ 104	$ 107
Expenditures ($000's)	$ 2,725	$ 1,836	$ 2,966	$ 2,553	$ 2,757	$ 2,922

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are described in the following three sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year or more of the Company's strategic goals, and each project is required to demonstrate how it supports the achievement of organizational goals and priorities. PPM compares and prioritizes potential IT project investments based on the project's value contribution to the organization's goals, irrespective of where the initiative originated. Those projects with the greatest contribution and alignment will receive highest priority. The priority of each project guides the financial and resource allocation for the portfolio. Prioritization ideally assures projects with the greatest value to the Company will be considered first when allocating finite resources. PPM ultimately drives the establishment of the IT Project Portfolio which must be reviewed and accepted by the Utility Operating Committee Capital Management group consisting of the key representatives from IT, Finance, Regulatory, Distribution, Transmission, Marketing, and Engineering Services. This activity takes place annually following the corporate budgeting process and in advance of initiation of the targeted fiscal year. Prior to execution, all approved IT Project Portfolio projects must still acquire formal authorization for capital investment through written justification (business casing) which reconfirms the business value of undertaking the project and validates the assumptions made in the initial establishment of the IT Project Portfolio.

2012 AND 2013 FORECASTS

The Company is forecasting an increase of $2.0 million for the Mainland and $500 thousand for Vancouver Island for 2012 from the 2011 total of $16.0 million and $1.5 million respectively, with 2013 held at that level. This increase is based on enabling several robust technology roadmaps created in 2010 and 2011 in addition to satisfying pent-up demand from restrictions on the execution of several IT projects other than the CCE CPCN. Effective execution of this increased forecast will be managed through the employment of PPM, management of inter-project dependencies and risk mitigation within the IT Project Portfolio and the optimal usage of IT and business resources freed up from the cessation of the CCE CPCN. For projects that require significant business involvement, the business must prioritize between IT project commitments and other business imperatives. Over the years, the Company has invested time and effort on technology that enables operational efficiencies and the integration of business processes spanning multiple business units. Consequently, the IT Project Portfolio management team must work to ensure that all affected groups are coordinated and have the same ability to commit resources to projects that impact them all.

The capital request for IT investment is forecast at an amount in 2012 and 2013 that FEU believes is the appropriate amount that can prudently be executed while meeting the top priorities of the business. The incremental $2.5 million from 2011 to a total of $20 million for the in each of 2012 and 2013 reflects the costs anticipated to ensure a balanced IT Project Portfolio that will address the requirements of technology sustainment, security and risk mitigation and meet the priority demands of the Company's further IT enablement.

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7.5 Amalgamated Financial Schedules

UTILITY INCOME AND EARNED RETURN CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Cost of Gas Sold (Including Gas Lost)	$ 659,338	$ 74,337	$ 3,493	$ 2,900	$ 740,068	$ (12,440) [1]	$ 727,627	
2	GCVA Amortization	-	(8,124)	-	-	(8,124)	-	(8,124)	- Sect 7-TAB 7.5, Schedule 7
3	Net Cost of Gas	659,338	66,213	3,493	2,900	731,944	(12,440)	719,503	
4									
5	Operation and Maintenance	192,742	30,303	779	744	224,568	-	224,568	- Sect 7-TAB 7.5, Schedule 11
6	Transportation Costs	-	4,483	2,585	-	7,068	(6,041) [2]	1,027	- Sect 7-TAB 7.5, Schedule 7
7	Property and Sundry Taxes	49,656	9,895	236	172	59,959	-	59,959	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	133,920	35,896	1,062	360	171,238	(41) [3]	171,197	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(27,203)	(12,651)	(16)	(24)	(39,894)	15,522 [4]	(24,373)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	24,478	3,878	336	56	28,748	17 [5]	28,765	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	212,179	57,074	2,906	688	272,847	(1,376) [6]	271,470	- Sect 7-TAB 7.5, Schedule 5
12	Delivery Cost of Service	585,772	128,878	7,888	1,996	724,534	8,081	732,613	
13									
14	Total Cost of Service	1,245,110	195,091	11,381	4,896	1,456,478	(4,358)	1,452,116	
15									
16		Notes							
17		1 FEI LNG Mitigation to FEVI ($12) MM, FEVI Squamish Wheeling from FEI ($0.4) MM							
18		2 FEVI Wheeling ($3.5) MM to FEI, FEW Wheeling ($2.5) MM to FEVI							
19		3 FEVI amortization of Whistler Contribution $0.25 MM offset by FEW amortization of Contribution deferral ($0.29) MM							
20		4 FEVI Wheeling $3.5 MM to FEI, FEVI LNG Mitigation $12 MM from FEI, Late Payment Ratio applied to FEU Revenues $0.02 MM							
21		5 Change in Rate Base impact on Income Taxes							
22		6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes							

UTILITY INCOME AND EARNED RETURN CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Cost of Gas Sold (Including Gas Lost)	$ 658,568	$ 76,399	$ 3,455	$ 2,945	$ 741,367	$ (12,440) [1]	$ 728,927	
2	GCVA Amortization	-	-	-	-	-	-	-	
3	Net Cost of Gas	658,568	76,399	3,455	2,945	741,367	(12,440)	728,927	
4									
5	Operation and Maintenance	203,365	30,515	787	771	235,438	-	235,438	- Sect 7-TAB 7.5, Schedule 11
6	Transportation Costs	-	4,494	2,585	-	7,079	(6,049) [2]	1,029	- Sect 7-TAB 7.5, Schedule 7
7	Property and Sundry Taxes	51,239	10,263	244	178	61,924	-	61,924	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	152,235	37,334	1,661	370	191,600	(35) [3]	191,565	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(28,883)	(12,662)	(16)	(24)	(41,585)	15,513 [4]	(26,074)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	30,160	7,440	542	55	38,197	10 [5]	38,207	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	216,079	60,304	2,915	706	280,004	(2,155) [6]	277,849	- Sect 7-TAB 7.5, Schedule 6
12	Delivery Cost of Service	624,195	137,688	8,718	2,056	772,657	7,283	779,938	
13									
14	Total Cost of Service	1,282,763	214,087	12,173	5,001	1,514,024	(5,156)	1,508,865	
15									

16 Notes

17 1 FEI LNG Mitigation to FEVI ($12) MM, FEVI Squamish Wheeling from FEI ($0.4) MM

18 2 FEVI Wheeling ($3.5) MM to FEI, FEW Wheeling ($2.5) MM to FEVI

19 3 FEVI amortization of Whistler Contribution $0.25 MM offset by FEW amortization of Contribution deferral ($0.29) MM

20 4 FEVI Wheeling $3.5 MM to FEI, FEVI LNG Mitigation $12 MM from FEI, Late Payment Ratio applied to FEU Revenues $0.02 MM

21 5 Change in Rate Base impact on Income Taxes

22 6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes

UTILITY RATE BASE CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2012
($000s)

May 16, 2011

Section 7
TAB 7.5
Schedule 3

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Gas Plant in Service, Beginning	$ 3,542,280	$ 1,263,155	$ 16,216	$ 11,799	$ 4,833,450		$ 4,833,448	- Sect 7-TAB 7.5, Schedule 22
2	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
3	Gas Plant in Service, Ending	3,770,188	1,317,524	17,203	12,525	5,117,440		5,117,445	- Sect 7-TAB 7.5, Schedule 22
4									
5	Accumulated Depreciation Beginning - Plant	$ (923,722)	$ (295,740)	$ (2,588)	$ (2,366)	$ (1,224,416)		$ (1,224,413)	- Sect 7-TAB 7.5, Schedule 28
6	Adjustment - CPCNs / Opening Bal Adjt	4,405	9,193	-	-	13,598		13,597	- Sect 7-TAB 7.5, Schedule 28
7	Accumulated Depreciation Ending - Plant	(1,014,039)	(318,482)	(2,933)	(2,718)	(1,338,172)		(1,338,167)	- Sect 7-TAB 7.5, Schedule 28
8									
9	Negative Salvage Depreciation Beginning - Plant	$ -	$ -	$ -	$ -	$ -		$ -	- Sect 7-TAB 7.5, Schedule 32
10	Adjustment - CPCNs / Opening Bal Adjt	(4,405)	(9,193)	-	-	(13,598)		(13,597)	- Sect 7-TAB 7.5, Schedule 32
11	Negative Salvage Depreciation Ending - Plant	(7,994)	(12,476)	(74)	-	(20,544)		(20,543)	- Sect 7-TAB 7.5, Schedule 32
12									
13	CIAC, Beginning	$ (171,372)	$ (276,364)	$ (186)	$ (1,287)	$ (449,209)	17,034 [1]	$ (432,176)	- Sect 7-TAB 7.5, Schedule 34
14	Adjustment - Opening Bal Adjt	-	2,484	-	-	2,484	(2,484) [1]	-	
15	CIAC, Ending	(183,107)	(254,306)	(186)	(1,287)	(438,886)	14,550 [1]	(424,337)	- Sect 7-TAB 7.5, Schedule 34
16									
17	Accumulated Amortization Beginning - CIAC	$ 48,742	$ 59,227	$ 17	$ 490	$ 108,476	(592) [1]	$ 107,884	- Sect 7-TAB 7.5, Schedule 34
18	Adjustment - Opening Bal Adjt	-	(86)	-	-	(86)	86 [1]	-	
19	Accumulated Amortization Ending - CIAC	49,913	63,319	22	490	113,744	(760) [1]	112,986	- Sect 7-TAB 7.5, Schedule 34
20									
21	Allocated Plant Adjustment, Mid-Year	-	-	-	-	-		-	
22									
23	Net Plant in Service, Mid-Year	$ 2,555,445	$ 774,128	$ 13,746	$ 8,823	$ 3,352,141	$ 13,917	$ 3,366,064	
24									
25	Adjustment to 13-Month Average	40,567	1,210	111	-	41,888		41,888	
26	Work in Progress, No AFUDC	17,110	2,285	23	-	19,418		19,418	
27	Unamortized Deferred Charges	27,407	(1,096)	27,584	54	53,949	(13,724) [2]	40,223	- Sect 7-TAB 7.5, Schedule 37
28	Cash Working Capital	(3,445)	295	42	8	(3,100)	704 [3]	(2,398)	- Sect 7-TAB 7.5, Schedule 40
29	Other Working Capital	100,905	11,042	633	4	112,584		112,584	- Sect 7-TAB 7.5, Schedule 40
30	Future Income Taxes Regulatory Asset	271,465	72,524	2,172	-	346,161		346,161	- Sect 7-TAB 7.5, Schedule 43
31	Future Income Taxes Regulatory Liability	(271,465)	(72,524)	(2,172)	-	(346,161)		(346,161)	- Sect 7-TAB 7.5, Schedule 43
32	LILO Benefit	(1,482)	-	-	-	(1,482)		(1,482)	
33	Utility Rate Base	$ 2,736,507	$ 787,864	$ 42,139	$ 8,889	$ 3,575,399	$ 897	$ 3,576,297	- Sect 7-TAB 7.5, Schedule 44
34									
35	Notes								
36	1 FEVI CIAC - Pipeline Contribution from FEW								
37	2 FEW's contribution deferral to FEVI for pipeline								
38	3 Applying FEI Lead/Lag days to FEVI and FEW expense/revenue								

($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Gas Plant in Service, Beginning	$ 3,770,188	$ 1,317,524	$ 17,203	$ 12,525	$ 5,117,440		$ 5,117,445	- Sect 7-TAB 7.5, Schedule 25
2	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
3	Gas Plant in Service, Ending	3,904,928	1,344,362	17,637	12,919	5,279,846		5,279,855	- Sect 7-TAB 7.5, Schedule 25
4									
5	Accumulated Depreciation Beginning - Plant	$ (1,014,039)	$ (318,482)	$ (2,933)	$ (2,718)	$ (1,338,172)		$ (1,338,167)	- Sect 7-TAB 7.5, Schedule 31
6	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
7	Accumulated Depreciation Ending - Plant	(1,105,609)	(346,979)	(3,200)	(3,076)	(1,458,864)		(1,458,860)	- Sect 7-TAB 7.5, Schedule 31
8									
9	Negative Salvage Depreciation Beginning - Plant	$ (7,994)	$ (12,476)	$ (74)	$ -	$ (20,544)		$ (20,543)	- Sect 7-TAB 7.5, Schedule 33
10	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
11	Negative Salvage Depreciation Ending - Plant	(11,805)	(15,874)	(150)	-	(27,829)		(27,825)	- Sect 7-TAB 7.5, Schedule 33
12									
13	CIAC, Beginning	$ (183,107)	$ (254,306)	$ (186)	$ (1,287)	$ (438,886)	$ 14,550 [1]	$ (424,337)	- Sect 7-TAB 7.5, Schedule 35
14	Adjustment - Opening Bal Adjt	-	-	-	-	-		-	
15	CIAC, Ending	(189,803)	(250,614)	(186)	(1,287)	(441,890)	14,550 [1]	(427,341)	- Sect 7-TAB 7.5, Schedule 35
16									
17	Accumulated Amortization Beginning - CIAC	$ 49,913	$ 63,319	$ 22	$ 490	$ 113,744	$ (755) [1]	$ 112,986	- Sect 7-TAB 7.5, Schedule 35
18	Adjustment - Opening Bal Adjt	-	-	-	-	-		-	
19	Accumulated Amortization Ending - CIAC	55,928	67,506	27	490	123,951	(1,007) [1]	122,940	- Sect 7-TAB 7.5, Schedule 35
20									
21	Allocated Plant Adjustment, Mid-Year	-	-	-	-	-		-	
22									
23	Net Plant in Service, Mid-Year	$ 2,634,300	$ 796,990	$ 14,080	$ 9,028	$ 3,454,398	$ 13,669	$ 3,468,077	
24									
25	Adjustment to 13-Month Average	-	-	-	-	-		-	
26	Work in Progress, No AFUDC	17,110	2,285	23	-	19,418		19,418	
27	Unamortized Deferred Charges	38,574	3,891	26,703	82	69,250	(13,435) [2]	55,814	- Sect 7-TAB 7.5, Schedule 39
28	Cash Working Capital	(1,963)	476	61	12	(1,414)	328 [3]	(1,086)	- Sect 7-TAB 7.5, Schedule 40
29	Other Working Capital	101,622	10,436	635	4	112,697		112,697	- Sect 7-TAB 7.5, Schedule 40
30	Future Income Taxes Regulatory Asset	282,359	76,663	2,319	-	361,341		361,341	- Sect 7-TAB 7.5, Schedule 43
31	Future Income Taxes Regulatory Liability	(282,359)	(76,663)	(2,319)	-	(361,341)		(361,341)	- Sect 7-TAB 7.5, Schedule 43
32	LILO Benefit	(1,316)	-	-	-	(1,316)		(1,316)	
33	Utility Rate Base	$ 2,788,327	$ 814,078	$ 41,502	$ 9,126	$ 3,653,033	$ 562	$ 3,653,604	- Sect 7-TAB 7.5, Schedule 45
34									
35		Notes							
36		1 FEVI CIAC - Pipeline Contribution from FEW							
37		2 FEW's contribution deferral to FEVI for pipeline							
38		3 Applying FEI Lead/Lag days to FEVI and FEW expense/revenue							

($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Rate Base	$ 2,736,507	$ 787,864	$ 42,139	$ 8,889	$ 3,575,399	$ 897	$ 3,576,297	- Sect 7-TAB 7.5, Schedule 18
2									
3	Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%		40.00%	- Sect 7-TAB 7.5, Schedule 44
4	Common Equity	1,094,603	315,146	16,856	3,556	1,430,160	359	1,430,519	- Sect 7-TAB 7.5, Schedule 44
5	ROE	9.50%	10.00%	10.00%	9.50%	9.62% [1]		9.62%	- Sect 7-TAB 7.5, Schedule 44
6	Equity Earned Return	103,987	31,515	1,686	338	137,525	91 [2]	137,616	- Sect 7-TAB 7.5, Schedule 44
7									
8	Long Term Debt % of Capital Structure	57.82%	46.39%	47.46%	57.30%	55.18%		55.22%	- Sect 7-TAB 7.5, Schedule 44
9	Long Term Debt	1,582,117	365,526	20,000	5,094	1,972,737	1,935	1,974,672	- Sect 7-TAB 7.5, Schedule 44
10	Average Rate	6.73%	5.75%	5.11%	6.73%	6.53%		6.54%	- Sect 7-TAB 7.5, Schedule 44
11	LTD Earned Return	106,548	21,003	1,022	343	128,916	233	129,149	- Sect 7-TAB 7.5, Schedule 44
12									
13	Short Term Debt % of Capital Structure	2.18%	13.61%	12.54%	2.69%	4.82%		4.78%	- Sect 7-TAB 7.5, Schedule 44
14	Short Term Debt	59,787	107,192	5,283	239	172,501	(1,395)	171,106	- Sect 7-TAB 7.5, Schedule 44
15	Average Rate	2.75%	4.25%	3.75%	2.93%	3.71%		2.75%	- Sect 7-TAB 7.5, Schedule 44
16	STD Earned Return	1,644	4,556	198	7	6,405	(1,700)	4,705	- Sect 7-TAB 7.5, Schedule 44
17									
18	Total Earned Return	$ 212,179	$ 57,074	$ 2,906	$ 688	$ 272,846	$ (1,376)	$ 271,470	- Sect 7-TAB 7.5, Schedule 44
19									
20	Notes								
21	1 Calculation of Weigted Average ROE								
22	Total Equity Return					137,525	(Line 6, Column 6)		
23	Equity Portion of Rate Base					1,430,160	(Line 4, Column 6)		
24	Weighted Average ROE					9.62%	(Line 22 / Line 23)		
25	2 Impact of Rate Base Change \$0.04 MM, Impact of rounding Weighted Average ROE to 2 decimals \$0.05 MM								

($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Rate Base	$ 2,788,327	$ 814,078	$ 41,502	$ 9,126	$ 3,653,033	$ 562	$ 3,653,604	- Sect 7-TAB 7.5, Schedule 18
2									
3	Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%		40.00%	- Sect 7-TAB 7.5, Schedule 45
4	Common Equity	1,115,331	325,631	16,601	3,650	1,461,213	229	1,461,442	- Sect 7-TAB 7.5, Schedule 45
5	ROE	9.50%	10.00%	10.00%	9.50%	9.62% [1]		9.62%	- Sect 7-TAB 7.5, Schedule 45
6	Equity Earned Return	105,956	32,563	1,660	347	140,526	64 [2]	140,591	- Sect 7-TAB 7.5, Schedule 45
7									
8	Long Term Debt % of Capital Structure	56.76%	42.99%	48.19%	56.25%	53.59%		53.64%	- Sect 7-TAB 7.5, Schedule 45
9	Long Term Debt	1,582,515	350,000	20,000	5,134	1,957,649	2,210	1,959,859	- Sect 7-TAB 7.5, Schedule 45
10	Average Rate	6.74%	5.85%	5.11%	6.74%	6.57%		6.56%	- Sect 7-TAB 7.5, Schedule 45
11	LTD Earned Return	106,730	20,473	1,022	346	128,571	(24)	128,547	- Sect 7-TAB 7.5, Schedule 45
12									
13	Short Term Debt % of Capital Structure	3.24%	17.01%	11.81%	3.75%	6.41%		6.36%	- Sect 7-TAB 7.5, Schedule 45
14	Short Term Debt	90,481	138,447	4,901	342	234,171	(1,868)	232,303	- Sect 7-TAB 7.5, Schedule 45
15	Average Rate	3.75%	5.25%	4.75%	3.80%	4.66%		3.75%	- Sect 7-TAB 7.5, Schedule 45
16	STD Earned Return	3,393	7,268	233	13	10,907	(2,196)	8,711	- Sect 7-TAB 7.5, Schedule 45
17									
18	Total Earned Return	$ 216,079	$ 60,304	$ 2,915	$ 706	$ 280,004	$ (2,156)	$ 277,849	- Sect 7-TAB 7.5, Schedule 45

Line No.	Notes			
19				
20	Notes			
21	1 Calculation of Weigted Average ROE			
22		Total Equity Return	140,526	(Line 6, Column 6)
23		Equity Portion of Rate Base	1,461,213	(Line 4, Column 6)
24		Weighted Average ROE	9.62%	(Line 22 / Line 23)
25	2 Impact of Rate Base Change $0.02 MM, Impact of rounding Weighted Average ROE to 2 decimals $0.04 MM			

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Cost of Gas Sold (Including Gas Lost)	727,627	728,927	1,300	
2	GCVA Amortization	(8,124)	-	8,124	
3	Net Cost of Gas	719,503	728,927	9,424	
4					
5	Operation and Maintenance	224,568	235,438	10,870	- Sect 7-TAB 7.5, Schedule 9
6	Transportation Costs	1,027	1,029	2	
7	Property and Sundry Taxes	59,959	61,924	1,965	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	171,197	191,565	20,368	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(24,373)	(26,074)	(1,701)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	28,765	38,207	9,442	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	271,470	277,849	6,379	- Sect 7-TAB 7.5, Schedule 44 & 45
12	Delivery Cost of Service	732,613	779,938	47,325	
13					
14	Total Cost of Service	1,452,116	1,508,865	56,749	

OTHER OPERATING REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,557	$ 2,560	$3	
4					
5	Connection Charge	3,075	3,108	33	
6					
7	NSF Returned Cheque Charges	83	83	-	
8					
9	Other Recoveries	124	127	3	
10					
11	Total Other Utility Revenue	5,839	5,878	39	
12					
13	**Miscellaneous Revenue**				
14					
15	SCP Third Party Revenue	14,852	14,827	(25)	
16					
17	Biomethane Other Revenue	(62)	(29)	33	
18					
19	CNG & LNG Service Revenues	3,744	5,398	1,654	
20					
21					
22	Total Miscellaneous	18,534	20,196	1,662	
23					
24	**Total Other Operating Revenue**	$ 24,373	$ 26,074	$ 1,701	- Sect 7-TAB 7.5, Schedule 7

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)
1	M&E Costs	$ 58,567	$ 60,697	
2	COPE Costs	36,133	38,131	
3	COPE Customer Services Costs	11,824	11,177	
4	IBEW Costs	33,159	34,931	
5				
6	**Labour Costs**	**139,683**	**144,935**	
7				
8	Vehicle Costs	4,484	4,544	
9	Employee Expenses	6,172	6,351	
10	Materials and Supplies	8,117	8,490	
11	Computer Costs	14,734	15,306	
12	Fees and Administration Costs	74,264	79,629	
13	Contractor Costs	23,920	26,386	
14	Facilities	18,511	16,344	
15	Recoveries & Revenue	(28,758)	(28,220)	
16				
17	**Non-Labour Costs**	**121,444**	**128,831**	
18				
19				
20	**Total Gross O&M Expenses**	**261,127**	**273,766**	
21				
22	Less: Capitalized Overhead	(36,558)	(38,327)	
23				
24	**Total O&M Expenses**	**$ 224,569**	**$ 235,438**	- Sect 7-TAB 7.5, Schedule 7

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Distribution Supervision	100-11	$ 13,305	$ 13,825	
2					
3	Operation Centre - Distribution	100-21	12,743	13,443	
4	Asset Management - Distribution	100-22	3,259	4,587	
5	Preventative Maintenance - Distribution	100-23	3,202	3,483	
6	Distribution Operations - General	100-24	7,003	7,355	
7	Meter Exchange	100-25	-	-	
8	Emergency Management	100-26	5,938	6,134	
9	Distribution Operations Total	100-20	32,145	35,002	
10					
11	Distribution Corrective - Meters	100-31	1,886	1,945	
12	Distribution Corrective - Propane	100-32	-	-	
13	Distribution Corrective - Leak Repair	100-33	1,374	1,415	
14	Distribution Corrective - Stations	100-34	773	793	
15	Distribution Corrective - General	100-35	638	987	
16	Distribution Maintenance Total	100-30	4,671	5,140	
17					
18	**Distribution Total**	**100**	**50,121**	**53,966**	
19					
20	Transmission Supervision	200-11	5,497	6,453	
21					
22	Pipeline Operation	200-21	3,622	3,766	
23	Right of Way	200-22	730	808	
24	Compression	200-23	2,171	2,239	
25	Gas Control	200-24	2,848	3,000	
26	Transmission Pipeline Integrity Project (TPIP)	200-25	2,611	2,797	
27	Transmission Operations Total	200-20	11,983	12,610	
28					
29	Pipeline - Maintenance	200-31	2,830	2,684	
30	Compression - Maintenance	200-32	1,624	1,764	
31	TPIP - Maintenance	200-33	1,567	1,587	
32	Transmission Maintenance Total	200-30	6,021	6,035	
33					
34	**Transmission Total**	**200**	**23,502**	**25,098**	
35					
36	LNG Plant Operations	300-11	2,780	2,937	
37	LNG Plant Maintenance	300-21	797	824	
38					
39	**LNG Plant Total**	**300**	**3,577**	**3,761**	
40					
41	Measurement Operations	400-11	4,951	5,261	
42	Measurement Maintenance	400-21	2,539	2,601	
43					
44	**Measurement Total**	**400**	**7,491**	**7,861**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Facilities Management	500-10	$ 10,433	$ 9,451	
2	Shops & Stores	500-20	4,677	4,783	
3	Operations Engineering	500-30	10,621	11,092	
4	Property Services	500-40	1,411	1,453	
5	System Integrity	500-50	2,567	2,608	
6	Environmental Health & Safety	500-60	2,893	3,057	
7	Operations Governance	500-70	1,649	1,705	
8	Energy Supply & Resource Development	500-80	-	-	
9	**General Operations Total**	**500**	**34,251**	**34,149**	
10					
11	Energy Efficiency	600-10	0	(0)	
12	Marketing - Supervision	600-20	(807)	(785)	
13	Corporate & Marketing Communications	600-30	3,887	4,103	
14	Marketing Planning & Development	600-40	955	981	
15	**Marketing Total**	**600**	**4,035**	**4,298**	
16					
17	Customer Care - Supervision	700-10	2,793	2,883	
18	Customer Contact	700-20	45,431	48,917	
19	Bad Debt Management and Administration	700-30	5,445	5,494	
20	Customer Management & Sales	700-40	8,189	8,545	
21	**Customer Care Total**	**700**	**61,859**	**65,839**	
22					
23	Business & IT Services - Supervision	800-10	0	-	
24	Application Management	800-20	16,540	17,297	
25	Infrastructure Management	800-30	8,760	9,154	
26	Procurement Services	800-40	1,265	1,412	
27	**Business & IT Services Total**	**800**	**26,564**	**27,863**	
28					
29	Administration & General	900-11	2,748	3,273	
30	Insurance	900-12	5,437	5,257	
31	Finance and Regulatory Affairs	900-13	11,564	11,892	
32	Shared Services Agreement	900-14	11,095	11,410	
33	Corporate Administration Total	900-10	30,844	31,833	
34	Forecasting	900-20	3,036	3,335	
35	Public Affairs	900-30	2,253	2,309	
36	Business Development	900-40	3,979	4,113	
37	Human Resources	900-50	8,152	8,457	
38	Other Post Employment Benefits (OPEB)	900-60	1,464	883	
39	**Administration & General Total**	**900**	**49,727**	**50,930**	
40					
41	**Total Gross O&M Expenses**		**261,127**	**273,766**	
42					
43	Less: Capitalized Overhead		(36,558)	(38,327)	
44					
45	**Total O&M Expenses**		**$ 224,569**	**$ 235,438**	- Sect 7-TAB 7.5, Schedule 7
46					

PROPERTY AND SUNDRY TAXES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Property Taxes				
2					
3	1% in Lieu of General Municipal Tax	$ 15,452	$ 15,452	$ -	
4					
5	General, School and Other	44,507	46,472	1,965	
6					
7		59,959	61,924	1,965	
8					
9	Add / Less: Deferred Property Taxes	-	-	-	
10					
11	Total	$ 59,959	$ 61,924	$ 1,965	- Sect 7-TAB 7.5, Schedule 7

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 152,890	$ 159,498	$ 6,608	- Sect 7-TAB 7.5, Schedule 28 & 31
4					
5	Less: Amortization of Contributions in Aid of Construction	(10,208)	(10,158)	50	- Sect 7-TAB 7.5, Schedule 34 & 35
6		142,682	149,340	6,658	
7					
8	Add: Removal Cost Provision	20,192	20,868	676	
9		162,874	170,208	7,334	- Sect 7-TAB 7.5, Schedule 15
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ 199	$ 21,357	$ 21,158	- Sect 7-TAB 7.5, Schedule 37 & 39
14	Less: GCVA Amortization	8,124	-	(8,124)	- Sect 7-TAB 7.5, Schedule 7
15		8,323	21,357	13,034	
16					
17	TOTAL	$ 171,197	$ 191,565	$ 20,368	- Sect 7-TAB 7.5, Schedule 7

INCOME TAXES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	CALCULATION OF INCOME TAXES				
2	EARNED RETURN after VINGPA Adjustment	$ 271,470	$ 277,849	$ 6,379	- Sect 7-TAB 7.5, Schedule 7
3	Deduct - Interest on Debt	(133,854)	(137,258)	(3,404)	- Sect 7-TAB 7.5, Schedule 44 & 45
4	Net Additions (Deductions)	(51,320)	(25,970)	25,350	- Sect 7-TAB 7.5, Schedule 15
5	Adjusted Taxable Income After Tax	86,296	114,621	28,325	
6					
7	Current Income Tax Rate	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	0.00%	
9					
10	Taxable Income	115,061	$ 152,828	$ 37,767	
11					
12					
13	Income Tax - Current	$ 28,765	$ 38,207	$ 9,442	
14	Previous Year Adjustment	-		-	
15					
16	**Total Income Tax**	$ 28,765	$ 38,207	$ 9,442	- Sect 7-TAB 7.5, Schedule 7

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 765	765	$ -	
3	Depreciation	162,874	170,208	7,334	- Sect 7-TAB 7.5, Schedule 13
4	Amortization of Debt Issue Expenses	1,019	797	(222)	
5	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,056	2,190	134	
6	Pension Expense	9,479	9,066	(413)	
7	OPEB Expense	4,495	4,752	257	
8	Amortization of Decommissioning of Propane Assets	232	232	-	
9	Amortization of 75% Direct Appliance Conversion Costs	331	331	-	
10					
11	Deductions:				
12	Amortization of Deferred Charges	199	21,357	21,158	- Sect 7-TAB 7.5, Schedule 13
13	Less: Amortization of Decommissioning of Propane Assets (TGW)	(232)	(232)	-	
14	Less: Amortization of 75% Direct Appliance Conversion Costs (FEW)	(331)	(331)	-	
15	Capital Cost Allowance	(176,598)	(179,622)	(3,024)	- Sect 7-TAB 7.5, Schedule 16 & 17
16	Cumulative Eligible Capital Allowance	(2,174)	(2,046)	128	
17	Debt Issue Costs	(1,531)	(702)	829	
18	Vehicle Lease Payment	(3,776)	(4,006)	(230)	
19	Pension Contributions	(13,835)	(13,636)	199	
20	OPEB Contributions	(2,550)	(2,677)	(127)	
21	Overheads Capitalized Expensed for Tax Purposes	(16,752)	(17,517)	(765)	
22	Removal Costs	(13,247)	(13,586)	(339)	
23	Major Inspection Costs	(1,806)	(1,342)	464	
24	Biomethane Other Revenue	62	29	(33)	
25					
26	TOTAL	$ (51,320)	$ (25,970)	$ 25,350	- Sect 7-TAB 7.5, Schedule 14

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	12/31/2011 UCC Balance	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,374,427	$ -	$ 60	$ (54,978)	$ 1,319,509
2	1(b)	6%	27,103	-	22,657	(2,306)	47,454
3	2	6%	151,899	-	-	(9,113)	142,786
4	3	5%	2,695	-	-	(135)	2,560
5	6	10%	172	1	-	(18)	155
6	7	15%	21,070	(1)	8,911	(3,828)	26,152
7	8	20%	27,030	-	12,417	(6,648)	32,799
8	10	30%	3,742	2	3,398	(1,633)	5,509
9	12	100%	7,097	(1)	66,233	(40,213)	33,116
10	13	manual	345	-	3,504	(3,027)	822
11	14	manual	275	-	-	(25)	250
12	17	8%	190	-	-	(15)	175
13	38	30%	967	-	360	(344)	983
14	39	25%	-	-	-	-	-
15	45	45%	405	-	-	(183)	222
16	47	8%	158,860	1	3,439	(12,847)	149,453
17	49	8%	126,340	-	27,790	(11,220)	142,910
18	50	55%	5,394	-	11,548	(6,143)	10,799
19	51	6%	335,722	-	84,610	(22,681)	397,651
20	43.2	50%	1,450	1	2,063	(1,241)	2,273
21							
22		Total	$ 2,245,183	$ 3	$ 246,990	$ (176,598)	$ 2,315,578
23							
24	Cross Reference					- Sect 7-TAB 7.5, Schedule 15	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,319,509	$ -	$ -	$ (52,780)	$ 1,266,729
2	1(b)	6%	47,454	-	3,559	(2,955)	48,058
3	2	6%	142,786	(2)	-	(8,567)	134,217
4	3	5%	2,560	(1)	-	(128)	2,431
5	6	10%	155	1	-	(15)	141
6	7	15%	26,152	-	6,184	(4,387)	27,949
7	8	20%	32,799	-	7,613	(7,321)	33,091
8	10	30%	5,509	(1)	3,646	(2,199)	6,955
9	12	100%	33,116	1	12,000	(39,117)	6,000
10	13	manual	822	1	130	(446)	507
11	14	manual	250	-	-	(25)	225
12	17	8%	175	(1)	-	(14)	160
13	38	30%	983	-	360	(349)	994
14	39	25%	-	-	-	-	-
15	45	45%	222	2	-	(101)	123
16	47	8%	149,453	(1)	1,516	(12,017)	138,951
17	49	8%	142,910	-	20,234	(12,242)	150,902
18	50	55%	10,799	-	8,000	(8,139)	10,660
19	51	6%	397,651	(1)	106,120	(27,043)	476,727
20	43.2	50%	2,273	(1)	2,563	(1,777)	3,058
21							
22		Total	$ 2,315,578	$ (3)	$ 171,925	$ (179,622)	$ 2,307,878
23							
24	Cross Reference					- Sect 7-TAB 7.5, Schedule 15	

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Gas Plant in Service, Beginning	$ 4,833,448	$ 5,117,445	$ 283,997	- Sect 7-TAB 7.5, Schedule 22 & 25
2	Opening Balance Adjustment	-	-	-	
3	Gas Plant in Service, Ending	5,117,445	5,279,855	162,410	- Sect 7-TAB 7.5, Schedule 22 & 25
4					
5	Accumulated Depreciation Beginning - Plant	$ (1,224,413)	$ (1,338,167)	$ (113,754)	- Sect 7-TAB 7.5, Schedule 28 & 31
6	Opening Balance Adjustment	13,597	-	(13,597)	
7	Accumulated Depreciation Ending - Plant	(1,338,167)	(1,458,860)	(120,693)	- Sect 7-TAB 7.5, Schedule 28 & 31
8					
9	Negative Salvage Beginning	$ -	$ (20,543)	$ (20,543)	- Sect 7-TAB 7.5, Schedule 32 & 33
10	Opening Balance Adjustment	(13,597)	-	13,597	
11	Negative Salvage Ending	(20,543)	(27,825)	(7,282)	- Sect 7-TAB 7.5, Schedule 32 & 33
12					
13	CIAC, Beginning	$ (432,176)	$ (424,337)	$ 7,839	- Sect 7-TAB 7.5, Schedule 34 & 35
14	Opening Balance Adjustment	-	-	-	
15	CIAC, Ending	(424,337)	(427,341)	(3,004)	- Sect 7-TAB 7.5, Schedule 34 & 35
16					
17	Accumulated Amortization Beginning - CIAC	$ 107,884	$ 112,986	$ 5,102	- Sect 7-TAB 7.5, Schedule 34 & 35
18	Opening Balance Adjustment	-	-	-	
19	Accumulated Amortization Ending - CIAC	112,986	122,940	9,954	- Sect 7-TAB 7.5, Schedule 34 & 35
20					
21	Net Plant in Service, Mid-Year	$ 3,366,064	$ 3,468,077	$ 102,013	
22					
23	Adjustment to 13-Month Average	41,888	-	(41,888)	
24	Work in Progress, No AFUDC	19,418	19,418	-	
25	Unamortized Deferred Charges	40,223	55,814	15,591	- Sect 7-TAB 7.5, Schedule 37 & 39
26	Cash Working Capital	(2,398)	(1,086)	1,312	- Sect 7-TAB 7.5, Schedule 40
27	Other Working Capital	112,584	112,697	113	- Sect 7-TAB 7.5, Schedule 40
28	Future Income Taxes Regulatory Asset	346,161	361,341	15,180	- Sect 7-TAB 7.5, Schedule 43
29	Future Income Taxes Regulatory Liability	(346,161)	(361,341)	(15,180)	- Sect 7-TAB 7.5, Schedule 43
30	LILO Benefit	(1,482)	(1,316)	166	
31	**Utility Rate Base**	$ 3,576,297	$ 3,653,604	$ 77,307	- Sect 7-TAB 7.5, Schedule 44 & 45

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 Forecast	2013 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 153,750	$ 158,898	
6	Gateway Project	11,500	1,750	
7				
8	Total Regular Capital Expenditures	$ 165,250	$ 160,648	
9				
10	Special Projects - CPCN's			
11	Customer Care Enhancement	14,916	-	
12	Kootenay River Xing	1,223	-	
13	Victoria Regional Office	4,782	-	
14	Total CPCN's	$ 20,921	$ -	
15				
16				
17	TOTAL CAPITAL EXPENDITURES	$ 186,171	$ 160,648	
18				
19				
20	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
21				
22	Regular Capital			
23	Regular Capital Expenditures	$ 165,250	$ 160,648	
24	Add - Opening WIP	38,957	38,957	
25	Less - Closing WIP	(38,957)	(38,957)	
26	Capital Vehicle Lease Addition	3,180	2,860	
27	Add - AFUDC	2,088	1,916	
28	Add - Overhead Capitalized	36,556	38,329	- Sect 7-TAB 7.5, Schedule 22 & 25
29				
30	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 207,073	$ 203,753	
31				
32	Special Projects - CPCN's			
33	CPCN Expenditures	20,921	-	
34	Add - Opening WIP	68,412	(26)	
35	Less - Closing WIP	26	26	
36	Add: Projects transferred from Deferral Accounts	14,700	-	
37	Less: Adjustments	(512)	-	
38	Add - AFUDC	1,042	-	
39				
40	TOTAL CPCN ADDITIONS	$ 104,589	$ -	- Sect 7-TAB 7.5, Schedule 22 & 25
41				
42	TOTAL PLANT ADDITIONS	$ 311,662	$ 203,753	

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	297	-	-	-	-	-	-	297	297
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	1,907	-	-	-	-	-	-	1,907	1,907
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	51,023	-	325	-	-	-	-	51,348	51,186
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
14	471-00 Distribution Land Rights	3,184	-	-	-	-	-	-	3,184	3,184
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	56,692	56,325	6,000	149	-	(3,653)	-	115,513	117,715
17	402-02 Application Software - 20%	19,942	-	6,000	95	-	(2,045)	-	23,992	21,967
18	TOTAL INTANGIBLE	134,760	56,325	12,325	244	-	(5,698)	-	197,956	197,970
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	146	-	50	-	17	-	-	213	180
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	14,112	-	-	-	-	-	15,040	7,984
30	442-00 Structures & Improvements (Tilbury)	4,959	588	-	-	-	-	-	5,547	5,253
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,658	-	2,050	63	714	(681)	-	28,804	27,731
36	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	1,012	-	-	-	-	-	-	1,012	1,012
37	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
38	443-00 Gas Holders - Storage (Mount Hayes)	60,757	-	750	-	-	-	-	61,507	61,132
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
43	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
44	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
45	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
46	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
47	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
48	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
49	TOTAL MANUFACTURED	251,039	14,700	2,850	63	731	(681)	-	268,702	259,871

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 10,244	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,244	$ 10,244
3	461-00 Transmission Land Rights	290	-	80	-	-	-	-	370	330
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	26,434	-	-	-	-	-	-	26,434	26,434
6	463-00 Measuring Structures	12,897	-	-	-	-	-	-	12,897	12,897
7	464-00 Other Structures & Improvements	6,144	-	-	-	-	-	-	6,144	6,144
8	465-00 Mains	1,116,780	1,223	25,597	999	8,507	(1,065)	-	1,152,041	1,134,411
9	465-00 Mains - INSPECTION	7,523	-	1,806	-	595	-	-	9,924	8,724
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	170,447	-	6,478	223	1,954	(547)	-	178,555	174,501
14	466-00 Compressor Equipment - OVERHAUL	8,145	-	1,450	-	326	-	-	9,921	9,033
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
16	467-10 Measuring & Regulating Equipment	42,903	-	-	-	-	-	-	42,903	42,903
17	467-20 Telemetering	6,619	-	736	32	257	(481)	-	7,163	6,891
18	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	4,126	-	-	-	-	-	-	4,126	4,126
21	TOTAL TRANSMISSION	1,468,127	1,223	36,147	1,254	11,639	(2,093)	-	1,516,297	1,492,212
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	4,213	-	-	-	-	-	-	4,213	4,213
25	471-00 Distribution Land Rights	2	-	50	-	-	-	-	52	27
26	472-00 Structures & Improvements	18,194	-	-	-	-	-	-	18,194	18,194
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	869,678	-	22,878	-	7,255	(3,109)	-	896,702	883,190
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	176,159	-	246	-	85	(1,783)	-	174,707	175,433
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	-	-	11,944	-	3,857	-	-	15,801	7,901
33	475-00 Mains	1,190,478	-	31,791	177	10,028	(2,963)	-	1,229,511	1,209,995
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	97,304	-	3,305	139	1,107	(571)	-	101,284	99,294
37	477-00 Telemetering	6,617	-	750	5	249	(120)	-	7,501	7,059
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	214,345	-	12,190	-	-	(4,370)	-	222,165	218,255
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,698,625	-	83,154	321	22,581	(12,916)	-	2,791,765	2,745,195
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	187	-	203	-	71	-	-	461	324
49	418-10 Bio Gas Purification Overhaul	402	-	413	-	-	-	-	815	609
50	418-20 Bio Gas Purification Upgrader	1,607	-	1,650	-	-	-	-	3,257	2,432
51	474-10 Bio Gas Reg & Meter Installations	1,681	-	406	-	141	-	-	2,228	1,955
52	478-30 Bio Gas Meters	40	-	406	-	-	-	-	446	243
53	TOTAL BIO-GAS	3,917	-	3,078	-	212	-	-	7,207	5,562

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,040	$ -	$ 1,540	$ -	$ 536	$ -	$ -	$ 4,116	$ 3,078
3	476-20 NG Transportation LNG Dispensing Equipment	1,737	-	1,180	-	411	-	-	3,328	2,533
4	476-30 NG Transportation CNG Foundations	450	-	340	-	118	-	-	908	679
5	476-40 NG Transportation LNG Foundations	383	-	260	-	91	-	-	734	559
6	476-50 NG Transportation LNG Pumps	824	-	560	-	195	-	-	1,579	1,202
7	476-60 NG Transportation CNG Dehydrator	159	-	120	-	42	-	-	321	240
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,593	-	4,000	-	1,393	-	-	10,986	8,290
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	21,540	6,355	2,000	-	-	-	-	29,895	25,718
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	12,110	-	-	-	-	-	-	12,110	12,110
16	- Masonry Buildings	87,558	15,752	4,471	-	-	-	-	107,781	97,670
17	- Leasehold Improvement	766	3,429	200	-	-	(313)	-	4,082	5,854
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	4,246	443	513	-	-	-	-	5,202	4,901
20	483-40 GP Furniture	19,847	2,829	1,571	-	-	(567)	-	23,680	23,250
21	483-10 GP Computer Hardware	23,677	3,533	8,000	206	-	(1,517)	-	33,899	30,647
22	483-20 GP Computer Software	2,211	-	-	-	-	(475)	-	1,736	1,974
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
25	484-00 Vehicles	7,410	-	3,398	-	-	(262)	-	10,546	8,978
26	484-00 Vehicles - Leased	28,481	-	3,180	-	-	(1,908)	-	29,753	29,117
27	485-10 Heavy Work Equipment	689	-	-	-	-	(11)	-	678	684
28	485-20 Heavy Mobile Equipment	2,291	-	360	-	-	-	-	2,651	2,471
29	486-00 Small Tools & Equipment	47,553	-	3,022	-	-	(1,207)	-	49,368	48,461
30	487-00 Equipment on Customer's Premises	9	-	-	-	-	-	-	9	9
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	8,404	-	115	-	-	(10)	-	8,509	8,457
34	- Radio	4,546	-	45	-	-	(7)	-	4,584	4,565
35	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
36	TOTAL GENERAL	271,387	32,341	26,875	206	-	(6,277)	-	324,532	304,912
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 4,833,448	$ 104,589	$ 168,429	$ 2,088	$ 36,556	$ (27,665)	$ -	$ 5,117,445	$ 5,014,011
43										
44	Cross Reference	- Sect 7-TAB 7.5, Schedule 18							- Sect 7-TAB 7.5, Schedule 18	
45			- Sect 7-TAB 7.5, Schedule 19							

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	297	-	-	-	-	-	-	297	297
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	1,907	-	-	-	-	-	-	1,907	1,907
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	51,348	-	328	-	-	-	-	51,676	51,512
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
14	471-00 Distribution Land Rights	3,184	-	-	-	-	-	-	3,184	3,184
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	115,513	-	6,000	149	-	(8,758)	-	112,904	114,209
17	402-02 Application Software - 20%	23,992	-	6,000	95	-	(4,268)	-	25,819	24,906
18	TOTAL INTANGIBLE	197,956	-	12,328	244	-	(13,026)	-	197,502	197,729
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	213	-	-	-	-	-	-	213	213
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,040	-	-	-	-	-	-	15,040	15,040
30	442-00 Structures & Improvements (Tilbury)	5,547	-	-	-	-	-	-	5,547	5,547
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	28,804	-	450	14	164	(149)	-	29,283	29,044
36	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	1,012	-	-	-	-	-	-	1,012	1,012
37	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
38	443-00 Gas Holders - Storage (Mount Hayes)	61,507	-	603	-	-	-	-	62,110	61,809
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
43	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
44	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
45	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
46	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
47	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
48	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
49	TOTAL MANUFACTURED	268,702	-	1,053	14	164	(149)	-	269,784	269,243

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 10,244	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,244	$ 10,244
3	461-00 Transmission Land Rights	370	-	82	-	-	-	-	452	411
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	26,434	-	-	-	-	-	-	26,434	26,434
6	463-00 Measuring Structures	12,897	-	-	-	-	-	-	12,897	12,897
7	464-00 Other Structures & Improvements	6,144	-	-	-	-	-	-	6,144	6,144
8	465-00 Mains	1,152,041	-	22,422	867	7,734	(899)	-	1,182,165	1,167,103
9	465-00 Mains - INSPECTION	9,924	-	1,342	-	490	-	-	11,756	10,840
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	178,555	-	5,347	186	1,711	(458)	-	185,341	181,948
14	466-00 Compressor Equipment - OVERHAUL	9,921	-	-	-	-	-	-	9,921	9,921
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
16	467-10 Measuring & Regulating Equipment	42,903	-	-	-	-	-	-	42,903	42,903
17	467-20 Telemetering	7,163	-	935	40	341	(611)	-	7,868	7,516
18	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	4,126	-	-	-	-	-	-	4,126	4,126
21	TOTAL TRANSMISSION	1,516,297	-	30,128	1,093	10,276	(1,968)	-	1,555,826	1,536,062
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	4,213	-	-	-	-	-	-	4,213	4,213
25	471-00 Distribution Land Rights	52	-	50	-	-	-	-	102	77
26	472-00 Structures & Improvements	18,194	-	-	-	-	-	-	18,194	18,194
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	896,702	-	25,321	-	8,464	(2,965)	-	927,522	912,112
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	174,707	-	193	-	71	(852)	-	174,119	174,413
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	15,801	-	12,405	-	4,197	-	-	32,403	24,102
33	475-00 Mains	1,229,511	-	35,920	213	12,168	(3,526)	-	1,274,286	1,251,899
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	101,284	-	3,380	142	1,191	(585)	-	105,412	103,348
37	477-00 Telemetering	7,501	-	550	4	189	(83)	-	8,161	7,831
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	222,165	-	12,598	-	-	(4,370)	-	230,393	226,279
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,791,765	-	90,417	359	26,280	(12,381)	-	2,896,440	2,844,103
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	461	-	203	-	74	-	-	738	600
49	418-10 Bio Gas Purification Overhaul	815	-	513	-	-	-	-	1,328	1,072
50	418-20 Bio Gas Purification Upgrader	3,257	-	2,050	-	-	-	-	5,307	4,282
51	474-10 Bio Gas Reg & Meter Installations	2,228	-	406	-	148	-	-	2,782	2,505
52	478-30 Bio Gas Meters	446	-	406	-	-	-	-	852	649
53	TOTAL BIO-GAS	7,207	-	3,578	-	222	-	-	11,007	9,107

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 4,116	$ -	$ 1,386	$ -	$ 506	$ -	$ -	$ 6,008	$ 5,062
3	476-20 NG Transportation LNG Dispensing Equipment	3,328	-	1,180	-	431	-	-	4,939	4,134
4	476-30 NG Transportation CNG Foundations	908	-	306	-	112	-	-	1,326	1,117
5	476-40 NG Transportation LNG Foundations	734	-	260	-	95	-	-	1,089	912
6	476-50 NG Transportation LNG Pumps	1,579	-	560	-	204	-	-	2,343	1,961
7	476-60 NG Transportation CNG Dehydrator	321	-	108	-	39	-	-	468	395
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	10,986	-	3,800	-	1,387	-	-	16,173	13,580
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	29,895	-	400	-	-	-	-	30,295	30,095
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	12,110	-	-	-	-	(3)	-	12,107	12,109
16	- Masonry Buildings	107,781	-	2,995	-	-	-	-	110,776	109,279
17	- Leasehold Improvement	4,082	-	130	-	-	(146)	-	4,066	4,074
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	5,202	-	113	-	-	-	-	5,315	5,259
20	483-40 GP Furniture	23,680	-	465	-	-	(1,954)	-	22,191	22,936
21	483-10 GP Computer Hardware	33,899	-	8,000	206	-	(6,581)	-	35,524	34,712
22	483-20 GP Computer Software	1,736	-	-	-	-	(211)	-	1,525	1,631
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
25	484-00 Vehicles	10,546	-	3,646	-	-	(1,409)	-	12,783	11,665
26	484-00 Vehicles - Leased	29,753	-	2,860	-	-	(1,716)	-	30,897	30,325
27	485-10 Heavy Work Equipment	678	-	-	-	-	-	-	678	678
28	485-20 Heavy Mobile Equipment	2,651	-	360	-	-	-	-	3,011	2,831
29	486-00 Small Tools & Equipment	49,368	-	3,160	-	-	(1,357)	-	51,171	50,270
30	487-00 Equipment on Customer's Premises	9	-	-	-	-	-	-	9	9
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	8,509	-	30	-	-	(408)	-	8,131	8,320
34	- Radio	4,584	-	45	-	-	(34)	-	4,595	4,590
35	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
36	TOTAL GENERAL	324,532	-	22,204	206	-	(13,819)	-	333,123	328,828
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 5,117,445	$ -	$ 163,508	$ 1,916	$ 38,329	$ (41,343)	$ -	$ 5,279,855	$ 5,198,650
43										
44	Cross Reference	- Sect 7-TAB 7.5, Schedule 18							- Sect 7-TAB 7.5, Schedule 18	
45			- Sect 7-TAB 7.5, Schedule 19							

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**INTANGIBLE PLANT**					
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	1	-	-	531	532
4	175-00 Unamortized Conversion Expense - Squamish	78	-	-	78	156
5	178-00 Organization Expense	7	-	-	383	390
6	179-01 Other Deferred Charges	-	-	-	-	-
7	401-00 Franchise and Consents	55	-	-	164	219
8	402-00 Utility Plant Acquisition Adjustment	36	-	-	57	93
9	402-00 Other Intangible Plant	39	-	-	821	860
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-
11	461-00 Transmission Land Rights	-	-	-	1,751	1,751
12	461-10 Transmission Land Rights - Byron Creek	-	-	-	19	$ 19
13	461-13 IP Land Rights Whistler	-	-	-	-	-
14	471-00 Distribution Land Rights	-	-	-	249	249
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	1	1
16	402-01 Application Software - 12.5%	14,283	-	(3,653)	25,431	36,061
17	402-02 Application Software - 20%	4,393	-	(2,045)	7,989	10,337
18	TOTAL INTANGIBLE	18,892	-	(5,698)	37,474	50,668
19						
20	**MANUFACTURED GAS / LOCAL STORAGE**					
21	430-00 Manufact'd Gas - Land	-	-	-	(899)	(899)
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	16	-	-	120	136
24	433-00 Manufact'd Gas - Equipment	12	-	-	70	82
25	434-00 Manufact'd Gas - Gas Holders	8	-	-	201	209
26	436-00 Manufact'd Gas - Compressor Equipment	3	-	-	29	32
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	49	-	-	272	321
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	188	-	-	2,612	2,800
31	443-00 Gas Holders - Storage (Tilbury)	318	-	-	10,403	10,721
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	1,176	-	(681)	9,189	9,684
36	440/441-00 Land in Fee Simple and Land Rights (Mount Hayes)	-	-	-	-	-
37	442-00 Structures & Improvements (Mount Hayes)	698	-	-	407	1,105
38	443-00 Gas Holders - Storage (Mount Hayes)	1,021	-	-	592	1,613
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	290	-	-	169	459
43	448-20 Pre-treatment (Mount Hayes)	1,160	-	-	677	1,837
44	448-30 Liquefaction Equipment (Mount Hayes)	725	-	-	423	1,148
45	448-40 Send out Equipment (Mount Hayes)	581	-	-	290	871
46	448-50 Sub-station and Electric (Mount Hayes)	562	-	-	281	843
47	448-60 Control Room (Mount Hayes)	395	-	-	198	593
48	449-00 Local Storage Equipment (Mount Hayes)	5	-	-	3	8
49	TOTAL MANUFACTURED	7,207	-	(681)	25,038	31,564

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**TRANSMISSION PLANT**					
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-
5	462-00 Compressor Structures	968	(219)	-	10,655	11,404
6	463-00 Measuring Structures	431	(95)	-	4,609	4,945
7	464-00 Other Structures & Improvements	174	-	-	1,742	1,916
8	465-00 Mains	16,691	(2,672)	(1,065)	303,997	316,951
9	465-00 Mains - INSPECTION	1,276	-	-	1,939	3,215
10	465-11 IP Transmission Pipeline - Whistler	600	-	-	1,511	2,111
11	465-30 Mt Hayes - Mains	93	-	-	54	147
12	465-10 Mains - Byron Creek	49	-	-	889	938
13	466-00 Compressor Equipment	5,027	(404)	(547)	60,620	64,696
14	466-00 Compressor Equipment - OVERHAUL	1,908	-	-	3,154	5,062
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	204	-	-	119	323
16	467-10 Measuring & Regulating Equipment	1,836	(72)	-	13,993	15,757
17	467-20 Telemetering	23	-	(481)	6,280	5,822
18	467-31 IP Intermediate Pressure Whistler	13	-	-	32	45
19	467-20 Measuring & Regulating Equipment - Byron Creek	-	-	-	4	4
20	468-00 Communication Structures & Equipment	468	-	-	2,786	3,254
21	TOTAL TRANSMISSION	29,761	(3,462)	(2,093)	412,785	436,991
22						
23	**DISTRIBUTION PLANT**					
24	470-00 Land in Fee Simple	-	-	-	26	26
25	471-00 Distribution Land Rights	-	-	-	-	-
26	472-00 Structures & Improvements	600	(22)	-	5,362	5,940
27	472-10 Structures & Improvements - Byron Creek	5	-	-	27	32
28	473-00 Services	19,684	(3,009)	(3,109)	167,256	180,822
29	473-00 Services - LILO	2,543	-	-	1,820	4,363
30	474-00 House Regulators & Meter Installations	12,619	(5,354)	(1,783)	19,116	24,598
31	474-00 House Regulators & Meter Installations - LILO	598	-	-	704	1,302
32	477-00 Meters/Regulators Installations	359	-	-	-	359
33	475-00 Mains	17,940	(2,845)	(2,963)	362,762	374,894
34	475-00 Mains - LILO	1,803	-	-	1,560	3,363
35	476-00 Compressor Equipment	272	-	-	706	978
36	477-00 Measuring & Regulating Equipment	4,675	(75)	(571)	26,356	30,385
37	477-00 Telemetering	17	-	(120)	6,362	6,259
38	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	204	204
39	478-10 Meters	16,994	1,169	(4,370)	66,199	79,992
40	478-11 Meters - LILO	524	-	-	660	1,184
41	478-20 Instruments	362	-	-	926	1,288
42	479-00 Other Distribution Equipment	-	-	-	-	-
43	TOTAL DISTRIBUTION	78,995	(10,136)	(12,916)	660,046	715,989
44						
45	**BIO GAS**					
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	5	-	-	2	7
49	418-10 Bio Gas Purification Overhaul	81	-	-	-	81
50	418-20 Bio Gas Purification Upgrader	162	-	-	-	162
51	474-10 Bio Gas Reg & Meter Installations	145	-	-	44	189
52	478-30 Bio Gas Meters	19	-	-	1	20
53	TOTAL BIO-GAS	412	-	-	47	459

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Natural Gas for Transportation**					
2	476-10 NG Transportation CNG Dispensing Equipment	$ 154	$ -	$ -	$ 51	$ 205
3	476-20 NG Transportation LNG Dispensing Equipment	127	-	-	43	170
4	476-30 NG Transportation CNG Foundations	34	-	-	11	45
5	476-40 NG Transportation LNG Foundations	28	-	-	10	38
6	476-50 NG Transportation LNG Pumps	120	-	-	41	161
7	476-60 NG Transportation CNG Dehydrator	12	-	-	4	16
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-
9	TOTAL NG FOR TRANSP	475	-	-	160	635
10						
11	**GENERAL PLANT & EQUIPMENT**					
12	480-00 Land in Fee Simple	-	-	-	30	30
13	481-00 Land Rights	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-
15	- Frame Buildings	648	-	-	3,331	3,979
16	- Masonry Buildings	2,180	-	-	13,825	16,005
17	- Leasehold Improvement	374	-	(313)	501	562
18	Office Equipment & Furniture	-	-	-	-	-
19	483-30 GP Office Equipment	326	-	-	433	759
20	483-40 GP Furniture	1,159	-	(567)	14,395	14,987
21	483-10 GP Computer Hardware	6,111	-	(1,517)	9,766	14,360
22	483-20 GP Computer Software	247	-	(475)	956	728
23	483-21 GP Computer Software	-	-	-	-	-
24	483-22 GP Computer Software	10	-	-	39	49
25	484-00 Vehicles	1,393	-	(262)	3,050	4,181
26	484-00 Vehicles - Leased	3,086	-	(1,908)	14,746	15,924
27	485-10 Heavy Work Equipment	46	-	(11)	(13)	22
28	485-20 Heavy Mobile Equipment	402	-	-	780	1,182
29	486-00 Small Tools & Equipment	2,423	-	(1,207)	20,120	21,336
30	487-00 Equipment on Customer's Premises	1	-	-	(6)	(5)
31	- VRA Compressor Installation Costs	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-
33	- Telephone	564	-	(10)	4,515	5,069
34	- Radio	305	-	(7)	2,397	2,695
35	489-00 Other General Equipment	-	-	-	(2)	(2)
36	TOTAL GENERAL	19,275	-	(6,277)	88,863	101,861
37						
38	**UNCLASSIFIED PLANT**					
39	499 Plant Suspense	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-
41						
42	TOTALS	$ 155,017	$ (13,598)	$ (27,665)	$ 1,224,413	$ 1,338,167
43						
44	Less: Vehicle Depreciation Allocated To Capital Projects	(1,884)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA	(243)				
46	**Net Depreciation Expense**	$ 152,890				
47						
48	Cross Reference	- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	**INTANGIBLE PLANT**					
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	1	-	-	532	533
4	175-00 Unamortized Conversion Expense - Squamish	78	-	-	156	234
5	178-00 Organization Expense	7	-	-	390	397
6	179-01 Other Deferred Charges	-	-	-	-	-
7	401-00 Franchise and Consents	55	-	-	219	274
8	402-00 Utility Plant Acquisition Adjustment	36	-	-	93	129
9	402-00 Other Intangible Plant	39	-	-	860	899
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-
11	461-00 Transmission Land Rights	-	-	-	1,751	1,751
12	461-10 Transmission Land Rights - Byron Creek	-	-	-	$ 19	19
13	461-13 IP Land Rights Whistler	-	-	-	-	-
14	471-00 Distribution Land Rights	-	-	-	249	249
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	1	1
16	402-01 Application Software - 12.5%	14,276	-	(8,758)	36,061	41,579
17	402-02 Application Software - 20%	4,981	-	(4,268)	10,337	11,050
18	TOTAL INTANGIBLE	19,473	-	(13,026)	50,668	57,115
19						
20	**MANUFACTURED GAS / LOCAL STORAGE**					
21	430-00 Manufact'd Gas - Land	-	-	-	(899)	(899)
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	16	-	-	136	152
24	433-00 Manufact'd Gas - Equipment	14	-	-	82	96
25	434-00 Manufact'd Gas - Gas Holders	8	-	-	209	217
26	436-00 Manufact'd Gas - Compressor Equipment	3	-	-	32	35
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	49	-	-	321	370
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	198	-	-	2,800	2,998
31	443-00 Gas Holders - Storage (Tilbury)	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	1,231	-	(149)	9,684	10,766
36	440/441-00 Land in Fee Simple and Land Rights (Mount Hayes)	-	-	-	-	-
37	442-00 Structures & Improvements (Mount Hayes)	698	-	-	1,105	1,803
38	443-00 Gas Holders - Storage (Mount Hayes)	1,032	-	-	1,613	2,645
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	290	-	-	459	749
43	448-20 Pre-treatment (Mount Hayes)	1,160	-	-	1,837	2,997
44	448-30 Liquefaction Equipment (Mount Hayes)	725	-	-	1,148	1,873
45	448-40 Send out Equipment (Mount Hayes)	581	-	-	871	1,452
46	448-50 Sub-station and Electric (Mount Hayes)	562	-	-	843	1,405
47	448-60 Control Room (Mount Hayes)	395	-	-	593	988
48	449-00 Local Storage Equipment (Mount Hayes)	5	-	-	8	13
49	TOTAL MANUFACTURED	7,285	-	(149)	31,564	38,700

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account (1)	Provision 2013 (Cr.) (2)	Provision Adjust-ments (3)	Retirements (4)	Accumulated 12/31/2012 (5)	Accumulated 12/31/2013 (6)
1	**TRANSMISSION PLANT**					
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-
5	462-00 Compressor Structures	968	-	-	11,404	12,372
6	463-00 Measuring Structures	431	-	-	4,945	5,376
7	464-00 Other Structures & Improvements	174	-	-	1,916	2,090
8	465-00 Mains	17,174	-	(899)	316,951	333,226
9	465-00 Mains - INSPECTION	1,590	-	-	3,215	4,805
10	465-11 IP Transmission Pipeline - Whistler	600	-	-	2,111	2,711
11	465-30 Mt Hayes - Mains	93	-	-	147	240
12	465-10 Mains - Byron Creek	49	-	-	938	987
13	466-00 Compressor Equipment	5,241	-	(458)	64,696	69,479
14	466-00 Compressor Equipment - OVERHAUL	2,146	-	-	5,062	7,208
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	204	-	-	323	527
16	467-10 Measuring & Regulating Equipment	1,836	-	-	15,757	17,593
17	467-20 Telemetering	25	-	(611)	5,822	5,236
18	467-31 IP Intermediate Pressure Whistler	13	-	-	45	58
19	467-20 Measuring & Regulating Equipment - Byron Creek	-	-	-	4	4
20	468-00 Communication Structures & Equipment	468	-	-	3,254	3,722
21	TOTAL TRANSMISSION	31,012	-	(1,968)	436,991	466,035
22						
23	**DISTRIBUTION PLANT**					
24	470-00 Land in Fee Simple	-	-	-	26	26
25	471-00 Distribution Land Rights	-	-	-	-	-
26	472-00 Structures & Improvements	600	-	-	5,940	6,540
27	472-10 Structures & Improvements - Byron Creek	5	-	-	32	37
28	473-00 Services	20,325	-	(2,965)	180,822	198,182
29	473-00 Services - LILO	2,543	-	-	4,363	6,906
30	474-00 House Regulators & Meter Installations	12,549	-	(852)	24,598	36,295
31	474-00 House Regulators & Meter Installations - LILO	598	-	-	1,302	1,900
32	477-00 Meters/Regulators Installations	1,097	-	-	359	1,456
33	475-00 Mains	18,561	-	(3,526)	374,894	389,929
34	475-00 Mains - LILO	1,803	-	-	3,363	5,166
35	476-00 Compressor Equipment	272	-	-	978	1,250
36	477-00 Measuring & Regulating Equipment	4,866	-	(585)	30,385	34,666
37	477-00 Telemetering	19	-	(83)	6,259	6,195
38	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	204	204
39	478-10 Meters	17,621	-	(4,370)	79,992	93,243
40	478-11 Meters - LILO	524	-	-	1,184	1,708
41	478-20 Instruments	362	-	-	1,288	1,650
42	479-00 Other Distribution Equipment	-	-	-	-	-
43	TOTAL DISTRIBUTION	81,745	-	(12,381)	715,989	785,353
44						
45	**BIO GAS**					
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	9	-	-	7	16
49	418-10 Bio Gas Purification Overhaul	143	-	-	81	224
50	418-20 Bio Gas Purification Upgrader	286	-	-	162	448
51	474-10 Bio Gas Reg & Meter Installations	186	-	-	189	375
52	478-30 Bio Gas Meters	51	-	-	20	71
53	TOTAL BIO-GAS	675	-	-	459	1,134

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Natural Gas for Transportation**					
2	476-10 NG Transportation CNG Dispensing Equipment	$ 253	$ -	$ -	$ 205	$ 458
3	476-20 NG Transportation LNG Dispensing Equipment	207	-	-	170	377
4	476-30 NG Transportation CNG Foundations	56	-	-	45	101
5	476-40 NG Transportation LNG Foundations	46	-	-	38	84
6	476-50 NG Transportation LNG Pumps	196	-	-	161	357
7	476-60 NG Transportation CNG Dehydrator	20	-	-	16	36
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-
9	TOTAL NG FOR TRANSP	778	-	-	635	1,413
10						
11	**GENERAL PLANT & EQUIPMENT**					
12	480-00 Land in Fee Simple	-	-	-	30	30
13	481-00 Land Rights	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-
15	- Frame Buildings	648	-	(3)	3,979	4,624
16	- Masonry Buildings	2,440	-	-	16,005	18,445
17	- Leasehold Improvement	373	-	(146)	562	789
18	Office Equipment & Furniture	-	-	-	-	-
19	483-30 GP Office Equipment	351	-	-	759	1,110
20	483-40 GP Furniture	1,147	-	(1,954)	14,987	14,180
21	483-10 GP Computer Hardware	6,942	-	(6,581)	14,360	14,721
22	483-20 GP Computer Software	204	-	(211)	728	721
23	483-21 GP Computer Software	-	-	-	-	-
24	483-22 GP Computer Software	10	-	-	49	59
25	484-00 Vehicles	1,832	-	(1,409)	4,181	4,604
26	484-00 Vehicles - Leased	3,239	-	(1,716)	15,924	17,447
27	485-10 Heavy Work Equipment	46	-	-	22	68
28	485-20 Heavy Mobile Equipment	461	-	-	1,182	1,643
29	486-00 Small Tools & Equipment	2,513	-	(1,357)	21,336	22,492
30	487-00 Equipment on Customer's Premises	1	-	-	(5)	(4)
31	- VRA Compressor Installation Costs	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-
33	- Telephone	555	-	(408)	5,069	5,216
34	- Radio	306	-	(34)	2,695	2,967
35	489-00 Other General Equipment	-	-	-	(2)	(2)
36	TOTAL GENERAL	21,068	-	(13,819)	101,861	109,110
37						
38	**UNCLASSIFIED PLANT**					
39	499 Plant Suspense	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-
41						
42	TOTALS	$ 162,036	$ -	$ (41,343)	$ 1,338,167	$ 1,458,860
43						
44	Less: Vehicle Depreciation Allocated To Capital Projects	(2,109)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA	(429)				
46	**Net Depreciation Expense**	$ 159,498				
47						
48	Cross Reference	- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**MANUFACTURED GAS / LOCAL STORAGE**						
2	442-00 Structures & Improvements (Tilbury)	$ 19	$ -	$ -	$ -	$ -	$ 19
3	443-00 Gas Holders - Storage (Tilbury)	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	103	-	-	-	-	103
5	TOTAL MANUFACTURED	188	-	-	-	-	188
6							
7	**TRANSMISSION PLANT**						
8	462-00 Compressor Structures	48	219	-	-	-	267
9	463-00 Measuring Structures	10	95	-	-	-	105
10	464-00 Other Structures & Improvements	9	-	-	-	-	9
11	465-00 Mains	1,691	2,672	-	-	-	4,363
12	466-00 Compressor Equipment	501	404	-	-	-	905
13	467-10 Measuring & Regulating Equipment	80	72	-	-	-	152
14	468-00 Communication Structures & Equipment	87	-	-	-	-	87
15	TOTAL TRANSMISSION	2,426	3,462	-	-	-	5,888
16							
17	**DISTRIBUTION PLANT**						
18	472-00 Structures & Improvements	29	22	-	-	-	51
19	473-00 Services	9,330	3,009	(9,464)	-	-	2,875
20	473-00 Services - LILO	1,230	-	-	-	-	1,230
21	474-00 House Regulators & Meter Installations	1,315	5,354	(2,700)	-	-	3,969
22	477-00 Meters/Regulators Installations	59	-	-	-	-	59
23	475-00 Mains	3,562	2,845	(908)	-	-	5,499
24	475-00 Mains - LILO	389	-	-	-	-	389
25	476-00 Compressor Equipment	117	-	-	-	-	117
26	477-00 Measuring & Regulating Equipment	461	75	(175)	-	-	361
27	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	-	-	-
28	478-10 Meters	1,084	(1,169)	-	-	-	(85)
29	TOTAL DISTRIBUTION	17,576	10,136	(13,247)	-	-	14,465
30							
31	**BIO GAS**						
32	475-20 Bio Gas Mains – Private Land	1	-	-	-	-	1
33	478-30 Bio Gas Meters	1	-	-	-	-	1
34	TOTAL BIO-GAS	2	-	-	-	-	2
35							
36	TOTALS	$ 20,192	$ 13,598	$ (13,247)	$ -	$ -	$ 20,543
37							
38	Cross Reference	- Sect 7-TAB 7.5, Schedule 13				- Sect 7-TAB 7.5, Schedule 18	
39							

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**MANUFACTURED GAS / LOCAL STORAGE**						
2	442-00 Structures & Improvements (Tilbury)	$ 20	$ -	$ -	$ -	$ 19	$ 39
3	443-00 Gas Holders - Storage (Tilbury)	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	107	-	-	-	103	210
5	TOTAL MANUFACTURED	193	-	-	-	188	381
6							
7	**TRANSMISSION PLANT**						
8	462-00 Compressor Structures	48	-	-	-	267	315
9	463-00 Measuring Structures	10	-	-	-	105	115
10	464-00 Other Structures & Improvements	9	-	-	-	9	18
11	465-00 Mains	1,738	-	-	-	4,363	6,101
12	466-00 Compressor Equipment	522	-	-	-	905	1,427
13	467-10 Measuring & Regulating Equipment	80	-	-	-	152	232
14	468-00 Communication Structures & Equipment	87	-	-	-	87	174
15	TOTAL TRANSMISSION	2,494	-	-	-	5,888	8,382
16							
17	**DISTRIBUTION PLANT**						
18	472-00 Structures & Improvements	29	-	-	-	51	80
19	473-00 Services	9,635	-	(9,487)	-	2,875	3,023
20	473-00 Services - LILO	1,230	-	-	-	1,230	2,460
21	474-00 House Regulators & Meter Installations	1,307	-	(2,700)	-	3,969	2,576
22	477-00 Meters/Regulators Installations	181	-	-	-	59	240
23	475-00 Mains	3,685	-	(1,224)	-	5,499	7,960
24	475-00 Mains - LILO	389	-	-	-	389	778
25	476-00 Compressor Equipment	117	-	-	-	117	234
26	477-00 Measuring & Regulating Equipment	480	-	(175)	-	361	666
27	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	-	-	-
28	478-10 Meters	1,123	-	-	-	(85)	1,038
29	TOTAL DISTRIBUTION	18,176	-	(13,586)	-	14,465	19,055
30							
31	**BIO GAS**						
32	475-20 Bio Gas Mains – Private Land	2	-	-	-	1	3
33	478-30 Bio Gas Meters	3	-	-	-	1	4
34	TOTAL BIO-GAS	5	-	-	-	2	7
35							
36	TOTALS	$ 20,868	$ -	$ (13,586)	$ -	$ 20,543	$ 27,825
37							
38	Cross Reference	- Sect 7-TAB 7.5, Schedule 13					- Sect 7-TAB 7.5, Schedule 18
39							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 FORECAST Additions	Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 250,340	$ -	$ 6,517	$ -	$ 256,857	
4							
5	Transmission Contributions	116,849	-	10,750	-	127,599	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	15,864	-	-	(5,106)	10,758	
11							
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13	Government Loans Contribution	49,123	-	-	(20,000)	29,123	
14							
15	Biomethane	-	-	-	-	-	
16							
17	TOTAL Contributions	432,176	-	17,267	(25,106)	424,337	- Sect 7-TAB 7.5, Schedule 18
18							
19							
20							
21	**Amortization**						
22							
23	Distribution Contributions	(65,154)	-	(6,351)	-	(71,505)	
24							
25	Transmission Contributions	(33,438)	-	(2,203)	-	(35,641)	
26							
27	Others	10	-	10	-	20	
28							
29	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
30	- Infrastructure/Custom	(9,302)	-	(1,664)	5,106	(5,860)	
31							
32	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
33	Government Loans Contribution	-	-	-	-	-	
34							
35	Biomethane	-	-	-	-	-	
36							
37	TOTAL CIAC Amortization	(107,884)	-	(10,208)	5,106	(112,986)	- Sect 7-TAB 7.5, Schedule 18
38							
39	**NET CONTRIBUTIONS**	$ 324,292	$ -	$ 7,059	$ (20,000)	$ 311,351	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars (1)	Balance 12/31/2012 (2)	Adjustment (3)	2013 FORECAST Additions (4)	Retirements (5)	Balance 12/31/2013 (6)	Cross Reference (7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 256,857	$ -	$ 6,581	$ -	$ 263,438	
4							
5	Transmission Contributions	127,599	-	750	-	128,349	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,758	-	-	(204)	10,554	
11							
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13	Government Loans Contribution	29,123	-	-	(4,123)	25,000	
14							
15	Biomethane	-	-	-	-	-	
16							
17	TOTAL Contributions	424,337	-	7,331	(4,327)	427,341	- Sect 7-TAB 7.5, Schedule 18
18							
19							
20							
21	**Amortization**						
22							
23	Distribution Contributions	(71,505)	-	(6,537)	-	(78,042)	
24							
25	Transmission Contributions	(35,641)	-	(2,299)	-	(37,940)	
26							
27	Others	20	-	10	-	30	
28							
29	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
30	- Infrastructure/Custom	(5,860)	-	(1,332)	204	(6,988)	
31							
32	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
33	Government Loans Contribution	-	-	-	-	-	
34							
35	Biomethane	-	-	-	-	-	
36							
37	TOTAL CIAC Amortization	(112,986)	-	(10,158)	204	(122,940)	- Sect 7-TAB 7.5, Schedule 18
38							
39	**NET CONTRIBUTIONS**	$ 311,351	$ -	$ (2,827)	$ (4,123)	$ 304,401	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (23,385)	$ -	$ 31,179	$ (7,795)	$ 23,385	$ -	$ -	$ -	$ (0)	$ (11,692)
3	Midstream Cost Reconciliation Account (MCRA)	18,725	-	-	-	-	-	(8,322)	2,081	12,484	15,604
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,964)	464	-	-	-	-	3,333	(833)	(5,000)	(6,250)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(3,006)	-	3,953	(988)	2,965	2	15	(4)	(28)	(1,517)
6	Revelstoke Propane Cost Deferral Account	189	-	(252)	63	(189)	-	-	-	0	94
7	SCP Mitigation Revenues Variance Account	(6,180)	-	-	-	-	2,515	-	-	(3,665)	(4,922)
8	Gas Cost Variance Account (GCVA)	(8,124)	-	-	-	-	8,124	-	-	(0)	(4,062)
9	Gas Cost Reconciliation Account (GCRA)	11,435	(11,492)	76	(19)	57	-	-	-	(0)	(28)
10	Cost of Gas - Rate Rider A	(11,492)	11,492	-	-	-	-	-	-	(0)	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	23,714	-	20,000	(5,000)	15,000	(2,842)	-	-	35,871	29,793
14	NGV Conversion Grants	101	-	82	(20)	61	(27)	-	-	135	118
15	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
16	2010-2011 Biomethane Program Costs	-	897	-	-	-	(299)	-	-	598	748
17	2011 CNG and LNG Service Costs and Recoveries	-	-	(95)	24	(71)	24	-	-	(48)	(24)
18	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
19											
20	Non-Controllable Items										
21	Property Tax Deferral	(1,799)	-	-	-	-	1,074	-	-	(724)	(1,262)
22	Insurance Variance	(1,197)	-	-	-	-	1,197	-	-	-	(598)
23	Pension & OPEB Variance	9,574	-	-	-	-	(3,191)	-	-	6,383	7,978
24	BCUC Levies Variance	235	-	-	-	-	(234)	-	-	0	118
25	Interest Variance	(6,227)	-	-	-	-	2,820	-	-	(3,408)	(4,817)
26	Interest Variance - Funding benefits via Customer Deposits	917	-	-	-	-	(387)	-	-	530	723
27	Tax Variance Account	(7,029)	-	-	-	-	7,029	-	-	0	(3,514)
28	Olympics Security Costs Deferral	475	-	-	-	-	(244)	-	-	232	353
29	IFRS Conversion Costs	572	-	-	-	-	(286)	-	-	285	428
30	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
31	Vancouver Island Joint Venture Litigation Costs	-	137	-	-	-	(137)	-	-	-	68
32	Vancouver Island HST Implementation	(133)	-	-	-	-	133	-	-	-	(66)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 713	$ -	$ -	$ -	$ -	$ (184)	$ -	$ -	$ 529	$ 621
3	2010-2011 Revenue Requirement Application	100	-	-	-	-	(100)	-	-	0	50
4	2012-2013 Revenue Requirement Application	979	-	-	-	-	(489)	-	-	489	734
5	CCE CPCN Application	228	-	-	-	-	(63)	-	-	165	197
6	NGV for Transportation Application	-	147	-	-	-	(49)	-	-	98	123
7	Long Term Resource Plan Application	136	-	70	(18)	53	-	-	-	188	162
8	Victoria Regional Centre CPCN Application	69	-	-	-	-	(69)	-	-	-	35
9											
10	Whistler Pipeline										
11	Whistler Pipeline Conversion	13,288	-	-	-	-	(740)	-	-	12,548	12,918
12	Capital Contribution to FEVI	-	-	-	-	-	-	-	-	-	-
13	Pipeline Contribution Costs Variance Account	-	(434)	-	-	-	434	-	-	-	(217)
14											
15	Other										
16	Pension & OPEB Funding	(30,602)	-	(76,859)	-	(76,859)	-	-	-	(107,461)	(69,032)
17	Deferred Removal Costs	3,363	-	-	-	-	(1,682)	-	-	1,682	2,522
18	Gains and Losses on Asset Disposition	18,739	(6,176)	-	-	-	(628)	-	-	11,935	12,249
19	PCEC Start Up Costs	1,052	-	-	-	-	(44)	-	-	1,008	1,030
20	2010-2011 Customer Service O&M and COS	-	26,025	4,973	(1,243)	3,730	(3,253)	-	-	26,502	26,264
21	2011 Kootney River Crossing COS	-	120	-	-	-	(40)	-	-	80	100
22	Gas Asset Records Project	-	-	2,000	(500)	1,500	(300)	-	-	1,200	600
23	BC OneCall Project	-	-	1,250	(313)	938	(188)	-	-	750	375
24	IFRS Transitional Costs	(6,176)	6,176	75,131	-	75,131	(8,066)	-	-	67,065	33,533
25											
26	Residual Deferred Charges										
27	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
28	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
29	Carbon Tax Cost of Service	(66)	-	-	-	-	66	-	-	-	(33)
30	OSC Certification Compliance	(59)	-	-	-	-	59	-	-	-	(30)
31	Deferred ROE Variance	(47)	-	-	-	-	47	-	-	0	(24)
32	Sales Margin Differential	464	(464)	-	-	-	-	-	-	-	-
33	FEW 2009 Revenue Requirement Application	1	-	-	-	-	(1)	-	-	-	1
34	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
35	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
36	Residual Rider Disposition	-	179	-	-	-	(179)	-	-	-	89
37											
38	Total Deferred Charges for Rate Base	$ (7,733)	$ 27,071	$ 61,507	$ (15,809)	$ 45,699	$ (199)	$ (4,974)	$ 1,243	$ 61,107	$ 40,223
39											
40	Cross Reference						- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -
3	Midstream Cost Reconciliation Account (MCRA)	12,484	-	-	-	-	-	(8,322)	2,081	6,242	9,363
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(5,000)	-	-	-	-	-	3,333	(833)	(2,500)	(3,750)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(28)	-	(0)	-	(0)	2	10	(3)	(18)	(23)
6	Revelstoke Propane Cost Deferral Account	0	-	-	-	-	-	-	-	0	0
7	SCP Mitigation Revenues Variance Account	(3,665)	-	-	-	-	2,150	-	-	(1,514)	(2,590)
8	Gas Cost Variance Account (GCVA)	(0)	-	-	-	-	-	-	-	(0)	-
9	Gas Cost Reconciliation Account (GCRA)	(0)	-	-	-	-	-	-	-	(0)	-
10	Cost of Gas - Rate Rider A	(0)	-	-	-	-	-	-	-	(0)	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	35,871	-	20,000	(5,000)	15,000	(4,396)	-	-	46,475	41,173
14	NGV Conversion Grants	135	-	82	(20)	61	(42)	-	-	154	145
15	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
16	2010-2011 Biomethane Program Costs	598	-	-	-	-	(299)	-	-	299	449
17	2011 CNG and LNG Service Costs and Recoveries	(48)	-	-	-	-	24	-	-	(24)	(36)
18	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
19											
20	Non-Controllable Items										
21	Property Tax Deferral	(724)	-	-	-	-	362	-	-	(362)	(543)
22	Insurance Variance	-	-	-	-	-	-	-	-	-	-
23	Pension & OPEB Variance	6,383	-	-	-	-	(3,191)	-	-	3,191	4,787
24	BCUC Levies Variance	0	-	-	-	-	-	-	-	0	0
25	Interest Variance	(3,408)	-	-	-	-	1,704	-	-	(1,704)	(2,556)
26	Interest Variance - Funding benefits via Customer Deposits	530	-	-	-	-	(265)	-	-	265	397
27	Tax Variance Account	0	-	-	-	-	-	-	-	0	-
28	Olympics Security Costs Deferral	232	-	-	-	-	(236)	-	-	(4)	114
29	IFRS Conversion Costs	285	-	-	-	-	(285)	-	-	0	143
30	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
31	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
32	Vancouver Island HST Implementation	-	-	-	-	-	-	-	-	-	-

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 529	$ -	$ -	$ -	$ -	$ (184)	$ -	$ -	$ 345	$ 437
3	2010-2011 Revenue Requirement Application	0	-	-	-	-	-	-	-	0	-
4	2012-2013 Revenue Requirement Application	489	-	-	-	-	(489)	-	-	(0)	245
5	CCE CPCN Application	165	-	-	-	-	(63)	-	-	102	134
6	NGV for Transportation Application	98	-	-	-	-	(49)	-	-	49	74
7	Long Term Resource Plan Application	188	-	200	(50)	150	(168)	-	-	171	180
8	Victoria Regional Centre CPCN Application	-	-	-	-	-	-	-	-	-	-
9											
10	Whistler Pipeline										
11	Whistler Pipeline Conversion	12,548	-	-	-	-	(740)	-	-	11,808	12,178
12	Capital Contribution to FEVI	-	-	-	-	-	-	-	-	-	-
13	Pipeline Contribution Costs Variance Account	-	-	-	-	-	-	-	-	-	-
14											
15	Other										
16	Pension & OPEB Funding	(107,461)	-	(3,332)	-	(3,332)	-	-	-	(110,793)	(109,127)
17	Deferred Removal Costs	1,682	-	-	-	-	(1,682)	-	-	0	841
18	Gains and Losses on Asset Disposition	11,935	-	-	-	-	(628)	-	-	11,307	11,621
19	PCEC Start Up Costs	1,008	-	-	-	-	(44)	-	-	964	986
20	2010-2011 Customer Service O&M and COS	26,502	-	-	-	-	(3,719)	-	-	22,783	24,642
21	2011 Kootney River Crossing COS	80	-	-	-	-	(40)	-	-	40	60
22	Gas Asset Records Project	1,200	-	2,250	(563)	1,688	(638)	-	-	2,250	1,725
23	BC OneCall Project	750	-	1,250	(313)	938	(375)	-	-	1,313	1,031
24	IFRS Transitional Costs	67,065	-	-	-	-	(8,066)	-	-	58,999	63,032
25											
26	Residual Deferred Charges										
27	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
28	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
29	Carbon Tax Cost of Service	-	-	-	-	-	-	-	-	-	-
30	OSC Certification Compliance	-	-	-	-	-	-	-	-	-	-
31	Deferred ROE Variance	0	-	-	-	-	-	-	-	0	-
32	Sales Margin Differential	-	-	-	-	-	-	-	-	-	-
33	FEW 2009 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
34	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
35	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
36	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-
37											
38	Total Deferred Charges for Rate Base	$ 61,107	$ -	$ 20,449	$ (5,945)	$ 14,504	$ (21,357)	$ (4,979)	$ 1,244	$ 50,520	$ 55,814
39											
40	Cross Reference						- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Required for				
3	Operating Expenses	$ 8,850	$ 10,191	$ 1,341	- Sect 7-TAB 7.5, Schedule 41
4					
5					
6	Less - Funds Available:				
7					
8	Reserve for Bad Debts	(5,871)	(5,815)	56	
9					
10	Withholdings From Employees	(5,377)	(5,462)	(85)	
11					
12	Subtotal	(2,398)	(1,086)	1,312	- Sect 7-TAB 7.5, Schedule 18
13					
14	**Other Working Capital Items**				
15	Construction Advances	(633)	(633)	-	
16	Transmission Line Pack Gas	3,571	4,381	810	
17	Gas in Storage	108,527	107,802	(725)	
18	Inventory - Materials & Supplies	1,410	1,438	28	
19					
20	Subtotal	112,584	112,697	113	- Sect 7-TAB 7.5, Schedule 18
21					
22	Total	$ 110,186	$ 111,611	$ 1,425	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 Days	2012 Expenses	2012 Cash Working Capital	2013 Days	2013 Expenses	2013 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASHWORKING CAPITAL, REVISED RATES**							
2								
3	Revenue Lag Days	39.0			39.0			
4	Expense Lead Days	36.4			36.1			- Sect 7-TAB 7.5, Schedule 42
5								
6	Net Lead/(Lag) Days	2.6	$ 1,242,412	$ 8,850	2.9	$ 1,282,647	$ 10,191	- Sect 7-TAB 7.5, Schedule 40
7								
8								
9								
10								
11	Cash working capital = Col. 2 x Col. 3 / 365 days							

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

		2012			2013			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**							
2								
3	Operating And Maintenance							
4	Expenses	$ 224,568	25.5	$ 5,726,484	$ 235,438	25.5	$ 6,003,669	- Sect 7-TAB 7.5, Schedule 7
5	Transportation Costs	1,027	40.2	41,285	1,029	40.2	41,366	- Sect 7-TAB 7.5, Schedule 7
6	Gas Purchases (excl Royalty Credits)	727,627	40.2	29,250,605	728,927	40.2	29,302,866	- Sect 7-TAB 7.5, Schedule 7
7								
8	Taxes Other Than Income							
9	Property Taxes	59,959	2.0	119,918	61,924	2.0	123,848	- Sect 7-TAB 7.5, Schedule 12
10	Franchise Fees	9,156	420.3	3,848,267	9,498	420.3	3,992,009	
11	Carbon Tax	171,423	29.1	4,988,404	186,944	29.1	5,440,061	
12	HST - Net	30,240	38.9	1,176,379	31,439	38.9	1,222,993	
13	PST Component of HST (REC)	(10,353)	33.9	(350,652)	(10,758)	33.9	(364,390)	
14	Income Tax	28,765	15.2	437,228	38,207	15.2	580,746	- Sect 7-TAB 7.5, Schedule 14
15								
16	Total	$ 1,242,412	36.4	$ 45,237,918	$ 1,282,647	36.1	$ 46,343,168	

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	$ (3,511,931)	$ (3,556,636)	
3	Less: Undepreciated Capital Cost	(2,473,819)	(2,461,553)	
4		(1,038,112)	(1,095,083)	
5	Weighted Average Future Tax Rate	25.00%	25.00%	
6		(259,528)	(273,771)	
7				
8	Total FIT Liability- After Tax (PP&E)	(259,528)	(273,771)	
9	Total FIT Liability- After Tax (Non-PP&E)	(6,294)	(2,420)	
10	Total FIT Liability- After Tax	(265,822)	(276,191)	
11				
12	Tax Gross Up	(88,607)	(92,064)	
13				
14	FIT Liability/Asset - End of Year	(354,429)	(368,254)	
15				
16	FIT Liability/Asset - Opening Balance	(337,894)	(354,428)	
17				
18	FIT Liability/Asset - Mid Year	(346,162)	(361,341)	- Sect 7-TAB 7.5, Schedule 18
19				
20				
21	Note: * Excludes Land, Software CIAC, and WIP.			

WEIGHTED AVERAGE RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1							
2	2012 FORECAST						
3	Long-Term Debt	$ 1,974,672	55.22%	6.54%	3.61%	$ 129,149	- Sect 7-TAB 7.5, Schedule 46
4	Unfunded Debt						
5	Adjustment, Revised Rates	171,106	4.78%	2.75%	0.13%	4,705	
6	Common Equity	1,430,519	40.00%	9.62%	3.85%	137,616	- Sect 7-TAB 7.5, Schedule 5
7							
8		$ 3,576,297	100.00%		7.59%	$ 271,470	- Sect 7-TAB 7.5, Schedule 18

WEIGHTED AVERAGE RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1							
2	2013 FORECAST						
3	Long-Term Debt	$ 1,959,859	53.64%	6.56%	3.52%	$ 128,547	- Sect 7-TAB 7.5, Schedule 47
4	Unfunded Debt						
5	Adjustment, Revised Rates	232,303	6.36%	3.75%	0.24%	8,711	
6	Common Equity	1,461,442	40.00%	9.62%	3.85%	140,591	- Sect 7-TAB 7.5, Schedule 6
7							
8		$ 3,653,604	100.00%		7.60%	$ 277,849	- Sect 7-TAB 7.5, Schedule 18

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 73,843	*	12.054%	$ 74,698	$ 9,004
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	**	10.461%	157,274	16,452
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999		6.109%	250,000	15,273
15	FEVI L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000		5.200%	100,000	5,200
16	FEVI PCEPA - 2012	1-Jan-2008	1-Jan-2013	3.416%	15,526	-	15,526		3.416%	15,526	530
17											
18	FEW Intercompany Loan 2009	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000		5.110%	20,000	1,022
19											
20											
21											
22	LILO Obligations - Kelowna								6.398%	24,678	1,579
23	LILO Obligations - Nelson								7.606%	3,931	299
24	LILO Obligations - Vernon								8.833%	11,752	1,038
25	LILO Obligations - Prince George								7.769%	30,171	2,344
26	LILO Obligations - Creston								6.958%	2,860	199
27											
28	Vehicle Lease Obligation								5.007%	13,782	690
29											
30	Total									$ 1,974,672	$ 129,149
31											
32	*Includes adjustment of $15,755 for BC Hydro Premium (Series A), using weighted average capital structure.									Average Embedded Cost	6.54%
33	**Includes adjustment of $0 for BC Hydro Premium (Series B), using weighted average capital structure.										
34	Cross Reference									- Sect 7-TAB 7.5, Schedule 44	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100 *	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	158,262 **	10.230%	160,490	16,418
3										
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588	5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627
11										
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000	4.878%	100,000	2,860
13										
14	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
15	FEVI L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000	5.200%	100,000	5,200
16	FEVI PCEPA - 2013	1-Jan-2008	1-Jan-2013	4.413%	15,526	-	15,526	4.413%	-	-
17										
18	FEW Intercompany Loan 2009	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000	5.110%	20,000	1,022
19										
20										
21										
22	LILO Obligations - Kelowna							6.413%	23,749	1,523
23	LILO Obligations - Nelson							7.696%	3,794	292
24	LILO Obligations - Vernon							8.929%	11,323	1,011
25	LILO Obligations - Prince George							7.862%	29,142	2,291
26	LILO Obligations - Creston							7.050%	2,766	195
27										
28	Vehicle Lease Obligation							5.630%	13,640	768
29										
30	Total								$ 1,959,859	$ 128,547
31										
32	*Includes adjustment of $16,012 for BC Hydro Premium (Series A), using weighted average capital structure.								Average Embedded Cost	6.56%
33	**Includes adjustment of $3,216 for BC Hydro Premium (Series B), using weighted average capital structure.									
34	Cross Reference								- Sect 7-TAB 7.5, Schedule 45	

Appendix F-2

BILL IMPACT AND TARIFF CONTINUITIES

DRAFT BILL IMPACT SCHEDULES AND TARIFF CONTINUITIES

This appendix includes draft bill impact schedules and tariff continuities that result from the financial schedules contained in Section 7 of this Application and the corresponding rate proposals contained in Section 3 of this Application.

This appendix includes fourteen tabs as follows:

Utility/Region		Appendix F-2 Tabs	Application Reference
Mainland	January 1, 2012 January 1, 2013	1.1.1 / 1.1.2 1.2.1 / 1.2.2	Section 7, Tab 7.1
Vancouver Island	January 1, 2012 January 1, 2013	2.1.1 / 2.1.2 2.2.1 / 2.2.2	Section 7, Tab 7.2
Whistler	January 1, 2012 January 1, 2013	3.1 3.2	Section 7, Tab 7.3
Fort Nelson	January 1, 2012 January 1, 2013	4.1.1 / 4.1.2 4.2.1 / 4.2.2	Section 7, Tab 7.4

	RATE SCHEDULE 1: RESIDENTIAL SERVICE	**EXISTING JANUARY 1, 2011 RATES**			**DELIVERY MARGIN RELATED CHARGES CHANGES**			**PROPOSED JANUARY 1, 2012 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.275	$3.275	$3.275	$0.256	$0.256	$0.256	$3.531	$3.531	$3.531
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.207**	**$3.207**	**$3.207**	**$0.292**	**$0.292**	**$0.292**	**$3.499**	**$3.499**	**$3.499**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009
14	Subtotal **Midstream Related Charges per GJ**	**$1.349**	**$1.324**	**$1.364**	**$0.000**	**$0.000**	**$0.000**	**$1.349**	**$1.324**	**$1.364**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Revised May 16, 2011

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.714	$2.714	$2.714	$0.193	$0.193	$0.193	$2.907	$2.907	$2.907
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.036)	($0.036)	($0.036)	$0.036	$0.036	$0.036	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.658**	**$2.658**	**$2.658**	**$0.217**	**$0.217**	**$0.217**	**$2.875**	**$2.875**	**$2.875**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.270**	**$2.270**	**$2.270**	**$0.165**	**$0.165**	**$0.165**	**$2.435**	**$2.435**	**$2.435**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.854	$0.854	$0.854	$0.081	$0.081	$0.081	$0.935	$0.935	$0.935
6	(b) Extension Period	$1.631	$1.631	$1.631	$0.081	$0.081	$0.081	$1.712	$1.712	$1.712
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.014)	($0.014)	($0.014)	$0.014	$0.014	$0.014	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.172	$6.157	$6.193	$0.095	$0.095	$0.095	$6.267	$6.252	$6.288
33	(b) Extension Period	$6.949	$6.934	$6.970	$0.095	$0.095	$0.095	$7.044	$7.029	$7.065

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
5										
6	**Delivery Charge per GJ**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$5.956	$5.941	$5.977	$0.072	$0.072	$0.072	$6.028	$6.013	$6.049

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.530	$8.523	$8.523	$0.252	$0.252	$0.252	$8.782	$8.775	$8.775

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JANUARY 1, 2011 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.608	$0.213	$3.821
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	($0.039)	$0.039	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$13.770	$0.252	$14.022

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.392	$6.377	$6.413	$0.080	$0.080	$0.080	$6.472	$6.457	$6.493

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	EFFECTIVE JANUARY 1, 2011			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.790	$0.790	$0.790	$0.048	$0.048	$0.048	$0.838	$0.838	$0.838
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	($0.009)	($0.009)	($0.009)	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.781	$0.781	$0.781	$0.057	$0.057	$0.057	$0.838	$0.838	$0.838

Line No.	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$12.673	$0.734	$13.407
7	(b) Firm MTQ	$0.088	$0.005	$0.093
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.003	$0.058	$1.061
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	($0.009)	$0.009	$0.000
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.079	$0.014	$0.093
35	(b) Interruptible MTQ	$0.994	$0.067	$1.061

Line No.	**RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE** Particulars	**EFFECTIVE JANUARY 1, 2011** Columbia Except Elkview	Elkview Coal	**DELIVERY MARGIN RELATED CHARGES CHANGES** Columbia Except Elkview	Elkview Coal	**PROPOSED JANUARY 1, 2012 RATES** Columbia Except Elkview	Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.048	$1.827	$0.530	$0.120	$8.578	$1.947
7	(b) Firm MTQ	$0.086	$0.086	$0.006	$0.006	$0.092	$0.092
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.802	$0.201	$0.053	$0.013	$0.855	$0.214
11	(b) between and including Nov. 1 and Mar.31	$1.155	$0.287	$0.076	$0.019	$1.231	$0.306
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	($0.006)	($0.002)	$0.006	$0.002	$0.000	$0.000
15							
16							
17	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22							
23	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.080	$0.084	$0.012	$0.008	$0.092	$0.092
31	(b) Interruptible MTQ - Summer	$0.796	$0.199	$0.059	$0.015	$0.855	$0.214
32	- Winter	$1.149	$0.285	$0.082	$0.021	$1.231	$0.306

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.270	$2.270	$2.270	$0.165	$0.165	$0.165	$2.435	$2.435	$2.435

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.624	$0.624	$0.624	$0.072	$0.072	$0.072	$0.696	$0.696	$0.696

Line No.	RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.609	$3.609	$3.609	$0.252	$0.252	$0.252	$3.861	$3.861	$3.861

RATE SCHEDULE 27:
INTERRUPTIBLE T-SERVICE

Line No.	Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.060	$1.060	$1.060	$0.080	$0.080	$0.080	$1.140	$1.140	$1.140

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	95.0	GJ x	$3.275 =	$311.1250	95.0	GJ x	$3.531 =	$335.4450	$0.256	$24.3200	2.41%
6	Rider 2 2009 ROE Rate Rider	95.0	GJ x	$0.000 =	$0.0000	95.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0	GJ x	($0.048) =	($4.5600)	95.0	GJ x	$0.000 =	$0.0000	$0.048	$4.5600	0.45%
8	Rider 5 RSAM	95.0	GJ x	($0.020) =	($1.9000)	95.0	GJ x	($0.032) =	($3.0400)	($0.012)	($1.1400)	-0.11%
9	Subtotal Delivery Margin Related Charges				**$446.75**				**$474.49**		**$27.74**	**2.75%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	95.0	GJ x	$1.340 =	$127.3000	95.0	GJ x	$1.340 =	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	$0.009 =	$0.8550	95.0	GJ x	$0.009 =	0.8550	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$128.16				$128.16		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	$4.568 =	$433.96	95.0	GJ x	$4.568 =	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$562.12**				**$562.12**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	95.0		*$10.620*	**$1,008.87**	95.0		*$10.912*	**$1,036.61**	*$0.292*	**$27.74**	**2.75%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days	$0.389 =	$142.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	75.0	GJ x	$3.275 =	$245.6250	75.0	GJ x	$3.531 =	$264.8250	$0.256	$19.2000	2.33%
26	Rider 2 2009 ROE Rate Rider	75.0	GJ x	$0.000 =	$0.0000	75.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0	GJ x	($0.048) =	($3.6000)	75.0	GJ x	$0.000 =	$0.0000	$0.048	$3.6000	0.44%
28	Rider 5 RSAM	75.0	GJ x	($0.020) =	($1.5000)	75.0	GJ x	($0.032) =	($2.4000)	($0.012)	($0.9000)	-0.11%
29	Subtotal Delivery Margin Related Charges				**$382.61**				**$404.51**		**$21.90**	**2.66%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	75.0	GJ x	$1.315 =	$98.6250	75.0	GJ x	$1.315 =	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	$0.009 =	$0.6750	75.0	GJ x	$0.009 =	$0.6750	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$99.30				$99.30		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	$4.568 =	$342.60	75.0	GJ x	$4.568 =	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$441.90**				**$441.90**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	75.0		*$10.993*	**$824.51**	75.0		*$11.285*	**$846.41**	*$0.292*	**$21.90**	**2.66%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	80.0	GJ x	$3.275 =	$262.0000	80.0	GJ x	$3.531 =	$282.4800	$0.256	$20.4800	2.35%
46	Rider 2 2009 ROE Rate Rider	80.0	GJ x	$0.000 =	$0.0000	80.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0	GJ x	($0.048) =	($3.8400)	80.0	GJ x	$0.000 =	$0.0000	$0.048	$3.8400	0.44%
48	Rider 5 RSAM	80.0	GJ x	($0.020) =	($1.6000)	80.0	GJ x	($0.032) =	($2.5600)	($0.012)	($0.9600)	-0.11%
49	Subtotal Delivery Margin Related Charges				**$398.64**				**$422.00**		**$23.36**	**2.68%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	80.0	GJ x	$1.355 =	$108.4000	80.0	GJ x	$1.355 =	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0	GJ x	$0.009 =	$0.7200	80.0	GJ x	$0.009 =	$0.7200	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$109.12				$109.12		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	$4.568	$365.44	80.0	GJ x	$4.568 =	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$474.56**	80.0			**$474.56**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	80.0		*$10.915*	**$873.20**	80.0		*$11.207*	**$896.56**	*$0.292*	**$23.36**	**2.68%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	300.0	GJ x	$2.714 =	$814.2000	300.0	GJ x	$2.907 =	$872.1000	$0.193	$57.9000	2.02%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	($0.036) =	($10.8000)	300.0	GJ x	$0.000 =	$0.0000	$0.036	$10.8000	0.38%
8	Rider 5 RSAM	300.0	GJ x	($0.020) =	($6.0000)	300.0	GJ x	($0.032) =	($9.6000)	($0.012)	($3.6000)	-0.13%
9	Subtotal Delivery Margin Related Charges				**$1,095.48**				**$1,160.58**		**$65.10**	**2.27%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327 =	$398.1000	300.0	GJ x	$1.327 =	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$398.10				$398.10		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568 =	$1,370.40	300.0	GJ x	$4.568 =	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$1,768.50**				**$1,768.50**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	300.0		*$9.547*	**$2,863.98**	300.0		*$9.764*	**$2,929.08**	*$0.217*	**$65.10**	**2.27%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	250.0	GJ x	$2.714 =	$678.5000	250.0	GJ x	$2.907 =	$726.7500	$0.193	$48.2500	1.99%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	($0.036) =	($9.0000)	250.0	GJ x	$0.000 =	$0.0000	$0.036	$9.0000	0.37%
28	Rider 5 RSAM	250.0	GJ x	($0.020) =	($5.0000)	250.0	GJ x	($0.032) =	($8.0000)	($0.012)	($3.0000)	-0.12%
29	Subtotal Delivery Margin Related Charges				**$962.58**				**$1,016.83**		**$54.25**	**2.23%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301 =	$325.2500	250.0	GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$325.25				$325.25		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568 =	$1,142.00	250.0	GJ x	$4.568 =	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$1,467.25**				**$1,467.25**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	250.0		*$9.719*	**$2,429.83**	250.0		*$9.936*	**$2,484.08**	*$0.217*	**$54.25**	**2.23%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	320.0	GJ x	$2.714 =	$868.4800	320.0	GJ x	$2.907 =	$930.2400	$0.193	$61.7600	2.03%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	($0.036) =	($11.5200)	320.0	GJ x	$0.000 =	$0.0000	$0.036	$11.5200	0.38%
48	Rider 5 RSAM	320.0	GJ x	($0.020) =	($6.4000)	320.0	GJ x	($0.032) =	($10.2400)	($0.012)	($3.8400)	-0.13%
49	Subtotal Delivery Margin Related Charges				**$1,148.64**				**$1,218.08**		**$69.44**	**2.28%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342 =	$429.4400	320.0	GJ x	$1.342 =	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$429.44				$429.44		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568 =	$1,461.76	320.0	GJ x	$4.568 =	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$1,891.20**				**$1,891.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	320.0		*$9.500*	**$3,039.84**	320.0		*$9.717*	**$3,109.28**	*$0.217*	**$69.44**	**2.28%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
4												
5	Delivery Charge	2,800.0	GJ x	$2.318 =	$6,490.4000	2,800.0	GJ x	$2.467 =	$6,907.6000	$0.149	$417.2000	1.77%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	($0.028) =	($78.4000)	2,800.0	GJ x	$0.000 =	$0.0000	$0.028	$78.4000	0.33%
8	Rider 5 RSAM	2,800.0	GJ x	($0.020) =	($56.0000)	2,800.0	GJ x	($0.032) =	($89.6000)	($0.012)	($33.6000)	-0.14%
9	Subtotal Delivery Margin Related Charges				**$7,946.24**				**$8,408.24**		**$462.00**	**1.96%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018 =	$2,850.4000	2,800.0	GJ x	$1.018 =	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$2,850.40				$2,850.40		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568 =	$12,790.40	2,800.0	GJ x	$4.568 =	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$15,640.80**				**$15,640.80**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.424*	**$23,587.04**	2,800.0		*$8.589*	**$24,049.04**	*$0.165*	**$462.00**	**1.96%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
24												
25	Delivery Charge	2,600.0	GJ x	$2.318 =	$6,026.8000	2,600.0	GJ x	$2.467 =	$6,414.2000	$0.149	$387.4000	1.76%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	($0.028) =	($72.8000)	2,600.0	GJ x	$0.000 =	$0.0000	$0.028	$72.8000	0.33%
28	Rider 5 RSAM	2,600.0	GJ x	($0.020) =	($52.0000)	2,600.0	GJ x	($0.032) =	($83.2000)	($0.012)	($31.2000)	-0.14%
29	Subtotal Delivery Margin Related Charges				**$7,492.24**				**$7,921.24**		**$429.00**	**1.95%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999 =	$2,597.4000	2,600.0	GJ x	$0.999 =	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$2,597.40				$2,597.40		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568 =	$11,876.80	2,600.0	GJ x	$4.568 =	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$14,474.20**				**$14,474.20**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.449*	**$21,966.44**	2,600.0		*$8.614*	**$22,395.44**	*$0.165*	**$429.00**	**1.95%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
44												
45	Delivery Charge	3,300.0	GJ x	$2.318 =	$7,649.4000	3,300.0	GJ x	$2.467 =	$8,141.1000	$0.149	$491.7000	1.78%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	($0.028) =	($92.4000)	3,300.0	GJ x	$0.000 =	$0.0000	$0.028	$92.4000	0.34%
48	Rider 5 RSAM	3,300.0	GJ x	($0.020) =	($66.0000)	3,300.0	GJ x	($0.032) =	($105.6000)	($0.012)	($39.6000)	-0.14%
49	Subtotal Delivery Margin Related Charges				**$9,081.24**				**$9,625.74**		**$544.50**	**1.97%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036 =	$3,418.8000	3,300.0	GJ x	$1.036 =	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$3,418.80				$3,418.80		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568 =	$15,074.40	3,300.0	GJ x	$4.568 =	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$18,493.20**				**$18,493.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.356*	**$27,574.44**	3,300.0		*$8.521*	**$28,118.94**	*$0.165*	**$544.50**	**1.97%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
5												
6	Delivery Charge											
7	(a) Off-Peak Period	5,400.0	GJ x	$0.854 =	$4,611.6000	5,400.0	GJ x	$0.935 =	$5,049.0000	$0.081	$437.4000	1.20%
8	(b) Extension Period	0.0	GJ x	$1.631 =	$0.0000	0.0	GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0	GJ x	$0.000 =	$0.0000	5,400.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0	GJ x	($0.014) =	($75.6000)	5,400.0	GJ x	$0.000 =	$0.0000	$0.014	$75.6000	0.21%
11	Subtotal Delivery Margin Related Charges				**$7,622.52**				**$8,135.52**		**$513.00**	**1.41%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge											
15	(a) Off-Peak Period	5,400.0	GJ x	$0.764 =	$4,125.6000	5,400.0	GJ x	$0.764 =	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.764 =	$0.0000	0.0	GJ x	$0.764 =	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge											
18	(a) Off-Peak Period	5,400.0	GJ x	$4.568 =	24,667.2000	5,400.0	GJ x	$4.568 =	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
20												
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$28,792.80**				**$28,792.80**		**$0.00**	**0.00%**
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24												
25	Total during Off-Peak Period	5,400.0			**$36,415.32**	5,400.0			**$36,928.32**		**$513.00**	**1.41%**
26												
27												
28	**INLAND SERVICE AREA**											
29	Delivery Margin Related Charges											
30	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
31												
32	Delivery Charge											
33	(a) Off-Peak Period	9,300.0	GJ x	$0.854 =	$7,942.2000	9,300.0	GJ x	$0.935 =	$8,695.5000	$0.081	$753.3000	1.25%
34	(b) Extension Period	0.0	GJ x	$1.631 =	$0.0000	0.0	GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0	GJ x	$0.000 =	$0.0000	9,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0	GJ x	($0.014) =	($130.2000)	9,300.0	GJ x	$0.000 =	$0.0000	$0.014	$130.2000	0.22%
37	Subtotal Delivery Margin Related Charges				**$10,898.52**				**$11,782.02**		**$883.50**	**1.46%**
38												
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge											
41	(a) Off-Peak Period	9,300.0	GJ x	$0.749 =	$6,965.7000	9,300.0	GJ x	$0.749 =	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.749 =	$0.0000	0.0	GJ x	$0.749 =	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge											
44	(a) Off-Peak Period	9,300.0	GJ x	$4.568 =	$42,482.4000	9,300.0	GJ x	$4.568 =	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
46												
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$49,448.10**				**$49,448.10**		**$0.00**	**0.00%**
48												
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
51	Total during Off-Peak Period	9,300.0			**$60,346.62**	9,300.0			**$61,230.12**		**$883.50**	**1.46%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1												
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$15.943 =	**$11,191.99**	58.5	GJ x	$16.996 =	**$11,931.19**	$1.053	**$739.20**	**0.97%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.645 =	$6,256.5000	9,700.0	GJ x	$0.696 =	$6,751.2000	$0.051	$494.7000	0.65%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000 =	$0.0000	9,700.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	($0.021) =	($203.7000)	9,700.0	GJ x	$0.000 =	$0.0000	$0.021	$203.7000	0.27%
11	Subtotal Delivery Margin Related Charges				**$6,052.80**				**$6,751.20**		**$698.40**	**0.92%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764 =	$7,410.8000	9,700.0	GJ x	$0.764 =	$7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568 =	$44,309.6000	9,700.0	GJ x	$4.568 =	$44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$51,720.40**				**$51,720.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.836*	**$76,009.19**	9,700.0		*$7.984*	**$77,446.79**	*$0.148*	**$1,437.60**	**1.89%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$15.943 =	**$15,687.91**	82.0	GJ x	$16.996 =	**$16,724.06**	$1.053	**$1,036.15**	**1.05%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.645 =	$8,256.0000	12,800.0	GJ x	$0.696 =	$8,908.8000	$0.051	$652.8000	0.66%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000 =	$0.0000	12,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	($0.021) =	($268.8000)	12,800.0	GJ x	$0.000 =	$0.0000	$0.021	$268.8000	0.27%
29	Subtotal Delivery Margin Related Charges				**$7,987.20**				**$8,908.80**		**$921.60**	**0.93%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749 =	$9,587.2000	12,800.0	GJ x	$0.749 =	$9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568 =	$58,470.4000	12,800.0	GJ x	$4.568 =	$58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$68,057.60**				**$68,057.60**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.717*	**$98,776.71**	12,800.0		*$7.870*	**$100,734.46**	*$0.153*	**$1,957.75**	**1.98%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$15.943 =	**$10,598.91**	55.4	GJ x	$16.996 =	**$11,298.94**	$1.053	**$700.03**	**0.97%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.645 =	$5,869.5000	9,100.0	GJ x	$0.696 =	$6,333.6000	$0.051	$464.1000	0.64%
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000 =	$0.0000	9,100.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	($0.021) =	($191.1000)	9,100.0	GJ x	$0.000 =	$0.0000	$0.021	$191.1000	0.27%
47	Subtotal Delivery Margin Related Charges				**$5,678.40**				**$6,333.60**		**$655.20**	**0.91%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785 =	$7,143.5000	9,100.0	GJ x	$0.785 =	$7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568 =	$41,568.8000	9,100.0	GJ x	$4.568 =	$41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,712.30**				**$48,712.30**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$7.916	**$72,033.61**	9,100.0		$8.065	**$73,388.84**	*$0.149*	**$1,355.23**	**1.88%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
5														
6	Delivery Charge	2,900.0	GJ x	$3.648	=	$10,579.2000	2,900.0	GJ x	$3.861	=	$11,196.9000	$0.213	$617.7000	2.43%
7	Rider 2 2009 ROE Rate Rider	2,900.0	GJ x	$0.000	=	$0.0000	2,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0	GJ x	($0.039)	=	($113.1000)	2,900.0	GJ x	$0.000	=	$0.0000	$0.039	$113.1000	0.44%
9	Subtotal Delivery Margin Related Charges					**$11,198.10**					**$11,928.90**		**$730.80**	**2.87%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.353	=	$1,023.7000	2,900.0	GJ x	$0.353	=	$1,023.7000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$4.568	=	$13,247.2000	2,900.0	GJ x	$4.568	=	$13,247.2000	$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$14,270.90**					**$14,270.90**		**$0.00**	**0.00%**
15														
16	Total *(with effective $/GJ rate)*	2,900.0		*$8.782*		**$25,469.00**	2,900.0		*$9.034*		**$26,199.80**	*$0.252*	**$730.80**	**2.87%**
17														
18														
19	**INLAND SERVICE AREA**													
20	Delivery Margin Related Charges													
21	Basic Charge	365.25	days x	$2.004	=	$732.00	365.25	days x	$2.004	=	$732.00	$0.00	$0.00	0.00%
22														
23	Delivery Charge	11,900.0	GJ x	$3.648	=	$43,411.2000	11,900.0	GJ x	$3.861	=	$45,945.9000	$0.213	$2,534.7000	2.48%
24	Rider 2 2009 ROE Rate Rider	11,900.0	GJ x	$0.000	=	$0.0000	11,900.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0	GJ x	($0.039)	=	($464.1000)	11,900.0	GJ x	$0.000	=	$0.0000	$0.039	$464.1000	0.45%
26	Subtotal Delivery Margin Related Charges					**$43,679.10**					**$46,677.90**		**$2,998.80**	**2.94%**
27														
28	Commodity Related Charges													
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.346	=	$4,117.4000	11,900.0	GJ x	$0.346	=	$4,117.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$4.568	=	$54,359.2000	11,900.0	GJ x	$4.568	=	$54,359.2000	$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$58,476.60**					**$58,476.60**		**$0.00**	**0.00%**
32														
33	Total *(with effective $/GJ rate)*	11,900.0		*$8.585*		**$102,155.70**	11,900.0		*$8.837*		**$105,154.50**	*$0.252*	**$2,998.80**	**2.94%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$1.073 =	$8,691.3000	8,100.0 GJ x	$1.140 =	$9,234.0000	$0.067	$542.7000	0.87%
7	Rider 2 2009 ROE Rate Rider	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0 GJ x	($0.013) =	($105.3000)	8,100.0 GJ x	$0.000 =	$0.0000	$0.013	$105.3000	0.17%
9	Rider 4 Reserve for Future Use	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges			**$8,586.00**			**$9,234.00**		**$648.00**	**1.04%**
11										
12	Commodity Related Charges									
13	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.764 =	$6,188.4000	8,100.0 GJ x	$0.764 =	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0 GJ x	$4.568 =	$37,000.8000	8,100.0 GJ x	$4.568 =	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$43,189.20**			**$43,189.20**		**$0.00**	**0.00%**
16										
17	Non-Standard Charges (not forecast)									
18	Index Pricing Option, UOR									
19										
20	Total *(with effective $/GJ rate)*	8,100.0	*$7.696*	**$62,335.20**	8,100.0	*$7.776*	**$62,983.20**	*$0.080*	**$648.00**	**1.04%**
21										
22										
23	**INLAND SERVICE AREA**									
24	Delivery Margin Related Charges									
25	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26										
27	Delivery Charge	4,000.0 GJ x	$1.073 =	$4,292.0000	4,000.0 GJ x	$1.140 =	$4,560.0000	$0.067	$268.0000	0.74%
28	Rider 2 2009 ROE Rate Rider	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0 GJ x	($0.013) =	($52.0000)	4,000.0 GJ x	$0.000 =	$0.0000	$0.013	$52.0000	0.14%
30	Rider 4 Reserve for Future Use	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges			**$4,240.00**			**$4,560.00**		**$320.00**	**0.89%**
32										
33	Commodity Related Charges									
34	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.749 =	$2,996.0000	4,000.0 GJ x	$0.749 =	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0 GJ x	$4.568 =	$18,272.0000	4,000.0 GJ x	$4.568 =	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$21,268.00**			**$21,268.00**		**$0.00**	**0.00%**
37										
38	Non-Standard Charges (not forecast)									
39	Index Pricing Option, UOR									
40										
41	Total *(with effective $/GJ rate)*	4,000.0	*$9.017*	**$36,068.00**	4,000.0	*$9.097*	**$36,388.00**	*$0.080*	**$320.00**	**0.89%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011						PROPOSED JANUARY 1, 2012 RATES						Annual Increase/Decrease		
1		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**															
3	Basic Charge	12	months x	$3,664.00	=	**$43,968.00**		12	months x	$3,664.00	=	**$43,968.00**		$0.00	**$0.00**	**0.00%**
4																
5																
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ x	$0.790	=	$369,171.4240		467,305.6	GJ x	$0.838	=	$391,602.0928		$0.048	$22,430.6688	5.47%
7	Rider 2 2009 ROE Rate Rider	467,305.6	GJ x	$0.000	=	$0.0000		467,305.6	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6	GJ x	($0.009)	=	($4,205.7504)		467,305.6	GJ x	$0.000	=	$0.0000		$0.009	$4,205.7504	1.03%
9	Transportation - Interruptible					**$364,965.67**						**$391,602.09**			**$26,636.42**	**6.50%**
10																
11																
12	Non-Standard Charges (not forecast)															
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas															
14																
15																
16	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
17																
18																
19	Total *(with effective $/GJ rate)*	467,305.6		*$0.877*		**$409,869.67**		467,305.6		*$0.934*		**$436,506.09**		*$0.057*	**$26,636.42**	**6.50%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**INLAND SERVICE AREA**													
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**	12	months x	$4,810.00	=	**$57,720.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$12.673	=	**$394,698.00**	2,595.4	GJ x	$13.407	=	**$417,558.36**	$0.734	**$22,860.36**	**4.33%**
7														
8														
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.088	=	$51,433.8704	584,475.8	GJ x	$0.093	=	$54,356.2494	$0.005	$2,922.3790	0.55%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	($0.009)	=	($5,260.2822)	584,475.8	GJ x	$0.000	=	$0.0000	$0.009	$5,260.2822	1.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$46,173.59**					**$54,356.25**		**$8,182.66**	**1.55%**
13														
14														
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.003	=	$28,693.7237	28,607.9	GJ x	$1.061	=	$30,352.9819	$0.058	$1,659.2582	0.31%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	($0.009)	=	($257.4711)	28,607.9	GJ x	$0.000	=	$0.0000	$0.009	$257.4711	0.05%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$28,436.25**					**$30,352.98**		**$1,916.73**	**0.36%**
19														
20														
21	Non-Standard Charges (not forecast)													
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
23														
24														
25	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
26														
27														
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.903*		**$527,963.84**	584,475.8		*$0.960*		**$560,923.59**	*$0.057*	**$32,959.75**	**6.24%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**													
3	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
4														
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.048	=	**$213,606.84**	2,211.8	GJ x	$8.578	=	**$227,673.84**	$0.530	**$14,067.00**	**4.52%**
6														
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.086	=	$39,331.7388	457,345.8	GJ x	$0.092	=	$42,075.8136	$0.006	$2,744.0748	0.88%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	=	$0.0000	457,345.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	($0.006)	=	($2,744.0748)	457,345.8	GJ x	$0.000	=	$0.0000	$0.006	$2,744.0748	0.88%
10	Transportation - Firm (Delivery Charge Firm MTQ)					**$36,587.66**					**$42,075.81**		**$5,488.15**	**1.77%**
11														
12	Delivery Charge - Interruptible MTQ													
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.802	=	$5,399.3848	6,732.4	GJ x	$0.855	=	$5,756.2020	$0.053	$356.8172	0.11%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.155	=	$0.0000	0.0	GJ x	$1.231	=	$0.0000	$0.076	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	=	$0.0000	6,732.4	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	($0.006)	=	($40.3944)	6,732.4	GJ x	$0.000	=	$0.0000	$0.006	$40.3944	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$5,358.99**					**$5,756.20**		**$397.21**	**0.13%**
18														
19	Non-Standard Charges (not forecast)													
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
21														
22	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
23														
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.670*		**$310,933.49**	464,078.2		*$0.713*		**$330,885.85**	*$0.043*	**$19,952.36**	**6.42%**
25														
26														
27	**COLUMBIA SERVICE - ELKVIEW COAL**													
28	Basic Charge	12	months x	$4,537.00	=	**$54,444.00**	12	months x	$4,537.00	=	**$54,444.00**	$0.00	**$0.00**	**0.00%**
29														
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.827	=	**$58,537.08**	2,670.0	GJ x	$1.947	=	**$62,381.88**	$0.120	**$3,844.80**	**2.25%**
31														
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.086	=	$54,313.6010	631,553.5	GJ x	$0.092	=	$58,102.9220	$0.006	$3,789.3210	2.21%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	=	$0.0000	631,553.5	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	($0.002)	=	($1,263.1070)	631,553.5	GJ x	$0.000	=	$0.0000	$0.002	$1,263.1070	0.74%
35	Transportation - Firm (Delivery Charge Firm MTQ)					**$53,050.49**					**$58,102.92**		**$5,052.43**	**2.95%**
36														
37	Delivery Charge - Interruptible MTQ													
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.201	=	$0.0000	0.0	GJ x	$0.214	=	$0.0000	$0.013	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.287	=	$4,162.3897	14,503.1	GJ x	$0.306	=	$4,437.9486	$0.019	$275.5589	0.16%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	($0.002)	=	($29.0062)	14,503.1	GJ x	$0.000	=	$0.0000	$0.002	$29.0062	0.02%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	=	$0.0000	14,503.1	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$4,133.38**					**$4,437.95**		**$304.57**	**0.18%**
44														
45	Non-Standard Charges (not forecast)													
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
47														
48	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
49														
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.265*		**$171,100.95**	646,056.6		*$0.279*		**$180,302.75**	*$0.014*	**$9,201.80**	**5.38%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	4,100.0	GJ x	$2.318 =	$9,503.8000	4,100.0	GJ x	$2.467 =	$10,114.7000	$0.149	$610.9000	5.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0	GJ x	$0.000 =	$0.0000	4,100.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0	GJ x	($0.028) =	($114.8000)	4,100.0	GJ x	$0.000 =	$0.0000	$0.028	$114.8000	0.97%
10	Rider 5 RSAM	4,100.0	GJ x	($0.020) =	($82.0000)	4,100.0	GJ x	($0.032) =	($131.2000)	($0.012)	($49.2000)	-0.42%
11	Transportation - Firm				**$9,307.00**				**$9,983.50**		**$676.50**	**5.72%**
12												
13	Non-Standard Charges (not forecast)											
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
15												
16	Total *(with effective $/GJ rate)*	4,100.0		*$2.886*	**$11,833.24**	4,100.0		*$3.051*	**$12,509.74**	*$0.165*	**$676.50**	**5.72%**
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	4,700.0	GJ x	$2.318 =	$10,894.6000	4,700.0	GJ x	$2.467 =	$11,594.9000	$0.149	$700.3000	5.31%
24	Rider 2 2009 ROE Rate Rider	4,700.0	GJ x	$0.000 =	$0.0000	4,700.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0	GJ x	($0.028) =	($131.6000)	4,700.0	GJ x	$0.000 =	$0.0000	$0.028	$131.6000	1.00%
26	Rider 5 RSAM	4,700.0	GJ x	($0.020) =	($94.0000)	4,700.0	GJ x	($0.032) =	($150.4000)	($0.012)	($56.4000)	-0.43%
27	Transportation - Firm				**$10,669.00**				**$11,444.50**		**$775.50**	**5.88%**
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
31												
32	Total *(with effective $/GJ rate)*	4,700.0		*$2.807*	**$13,195.24**	4,700.0		*$2.972*	**$13,970.74**	*$0.165*	**$775.50**	**5.88%**
33												
34	**COLUMBIA SERVICE AREA**											
35	Basic Charge	12	months x	$132.52 =	**$1,590.24**	12	months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36												
37	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
38												
39	Delivery Charge	4,200.0	GJ x	$2.318 =	$9,735.6000	4,200.0	GJ x	$2.467 =	$10,361.4000	$0.149	$625.8000	5.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0	GJ x	$0.000 =	$0.0000	4,200.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0	GJ x	($0.028) =	($117.6000)	4,200.0	GJ x	$0.000 =	$0.0000	$0.028	$117.6000	0.98%
42	Rider 5 RSAM	4,200.0	GJ x	($0.020) =	($84.0000)	4,200.0	GJ x	($0.032) =	($134.4000)	($0.012)	($50.4000)	-0.42%
43	Transportation - Firm				**$9,534.00**				**$10,227.00**		**$693.00**	**5.75%**
44												
45	Non-Standard Charges (not forecast)											
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
47												
48	Total *(with effective $/GJ rate)*	4,200.0		*$2.871*	**$12,060.24**	4,200.0		*$3.036*	**$12,753.24**	*$0.165*	**$693.00**	**5.75%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Transportation - Firm Demand	97.2 GJ x	$15.943 =	**$18,595.92**	97.2 GJ x	$16.996 =	**$19,824.12**	$1.053	**$1,228.20**	**3.19%**
8										
9	Delivery Charge	19,086.2 GJ x	$0.645 =	$12,310.5990	19,086.2 GJ x	$0.696 =	$13,283.9952	$0.051	$973.3962	2.53%
10	Rider 2 2009 ROE Rate Rider	19,086.2 GJ x	$0.000 =	$0.0000	19,086.2 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2 GJ x	($0.021) =	($400.8102)	19,086.2 GJ x	$0.000 =	$0.0000	$0.021	$400.8102	1.04%
12	Transportation - Firm			**$11,909.79**			**$13,284.00**		**$1,374.21**	**3.57%**
13										
14	Non-Standard Charges (not forecast)									
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16										
17	Total *(with effective $/GJ rate)*	19,086.2	*$2.016*	**$38,485.71**	19,086.2	*$2.153*	**$41,088.12**	*$0.137*	**$2,602.41**	**6.76%**
18										
19	**INLAND SERVICE AREA**									
20	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
21										
22	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23										
24	Transportation - Firm Demand	212.6 GJ x	$15.943 =	**$40,673.76**	212.6 GJ x	$16.996 =	**$43,360.20**	$1.053	**$2,686.44**	**3.63%**
25										
26	Delivery Charge	40,670.5 GJ x	$0.645 =	$26,232.4725	40,670.5 GJ x	$0.696 =	$28,306.6680	$0.051	$2,074.1955	2.80%
27	Rider 2 2009 ROE Rate Rider	40,670.5 GJ x	$0.000 =	$0.0000	40,670.5 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5 GJ x	($0.021) =	($854.0805)	40,670.5 GJ x	$0.000 =	$0.0000	$0.021	$854.0805	1.15%
29	Transportation - Firm			**$25,378.39**			**$28,306.67**		**$2,928.28**	**3.96%**
30										
31	Non-Standard Charges (not forecast)									
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
33										
34	Total *(with effective $/GJ rate)*	40,670.5	*$1.820*	**$74,032.15**	40,670.5	*$1.958*	**$79,646.87**	*$0.138*	**$5,614.72**	**7.58%**
35										
36	**COLUMBIA SERVICE**									
37	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
38										
39	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
40										
41	Transportation - Firm Demand	182.2 GJ x	$15.943 =	**$34,857.72**	182.2 GJ x	$16.996 =	**$37,160.04**	$1.053	**$2,302.32**	**3.73%**
42										
43	Delivery Charge	30,357.8 GJ x	$0.645 =	$19,580.7810	30,357.8 GJ x	$0.696 =	$21,129.0288	$0.051	$1,548.2478	2.51%
44	Rider 2 2009 ROE Rate Rider	30,357.8 GJ x	$0.000 =	$0.0000	30,357.8 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8 GJ x	($0.021) =	($637.5138)	30,357.8 GJ x	$0.000 =	$0.0000	$0.021	$637.5138	1.03%
46	Transportation - Firm			**$18,943.27**			**$21,129.03**		**$2,185.76**	**3.54%**
47										
48	Non-Standard Charges (not forecast)									
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
50										
51	Total *(with effective $/GJ rate)*	30,357.8	*$2.035*	**$61,780.99**	30,357.8	*$2.183*	**$66,269.07**	*$0.148*	**$4,488.08**	**7.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00 =	**$936.00**	12	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	53,957.0	GJ x	$1.073 =	$57,895.8610	53,957.0	GJ x	$1.140 =	$61,510.9800	$0.067	$3,615.1190	5.26%
8	Rider 2 2009 ROE Rate Rider	53,957.0	GJ x	$0.000 =	$0.0000	53,957.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0	GJ x	($0.013) =	($701.4410)	53,957.0	GJ x	$0.000 =	$0.0000	$0.013	$701.4410	1.02%
10	Transportation - Interruptible				**$57,194.42**				**$61,510.98**		**$4,316.56**	**6.28%**
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Balancing gas, Backstopping Gas											
14												
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.273*	**$68,690.42**	53,957.0		*$1.353*	**$73,006.98**	*$0.080*	**$4,316.56**	**6.28%**
16												
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12.0	months x	$78.00 =	**$936.00**	12.0	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	48,903.9	GJ x	$1.073 =	$52,473.8847	48,903.9	GJ x	$1.140 =	$55,750.4460	$0.067	$3,276.5613	5.17%
24	Rider 2 2009 ROE Rate Rider	48,903.9	GJ x	$0.000 =	$0.0000	48,903.9	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9	GJ x	($0.013) =	($635.7507)	48,903.9	GJ x	$0.000 =	$0.0000	$0.013	$635.7507	1.00%
26	Transportation - Interruptible				**$51,838.13**				**$55,750.45**		**$3,912.32**	**6.18%**
27												
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas											
31		48,903.9		*$1.295*	**$63,334.13**	48,903.9		*$1.375*	**$67,246.45**	*$0.080*	**$3,912.32**	**6.18%**
32	Total *(with effective $/GJ rate)*											
33												
34												
35	**COLUMBIA SERVICE AREA**											
36	Basic Charge	12	months x	$880.00 =	**$10,560.00**	12	months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
37												
38	Administration Charge	12.0	months x	$78.00 =	**$936.00**	12.0	months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
39												
40	Delivery Charge	7,733.8	GJ x	$1.073 =	$8,298.3674	7,733.8	GJ x	$1.140 =	$8,816.5320	$0.067	$518.1646	0.82%
41	Rider 2 2009 ROE Rate Rider	7,733.8	GJ x	$0.000 =	$0.0000	7,733.8	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8	GJ x	($0.013) =	($100.5394)	7,733.8	GJ x	$0.000 =	$0.0000	$0.013	$100.5394	0.16%
43	Transportation - Interruptible				**$8,197.83**				**$8,816.53**		**$618.70**	**0.98%**
44												
45												
46	Non-Standard Charges (not forecast)											
47	UOR, Balancing gas, Backstopping Gas											
48		7,733.8		*$2.546*	**$19,693.83**	7,733.8		*$2.626*	**$20,312.53**	*$0.080*	**$618.70**	**0.98%**
49	Total *(with effective $/GJ rate)*											

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	EXISTING JANUARY 1, 2011 RATES					PROPOSED JANUARY 1, 2012 RATES					Annual Increase/Decrease		
1	**INLAND SERVICE AREA**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$3.275	=	$163.7500	50.0	GJ x	$3.531	=	$176.5500	$0.256	$12.8000	1.20%
8	Rider 2 2009 ROE Rate Rider	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	($0.048)	=	($2.4000)	50.0	GJ x	$0.000	=	$0.0000	$0.048	$2.4000	0.23%
10	Rider 5 RSAM	50.0	GJ x	($0.020)	=	($1.0000)	50.0	GJ x	($0.032)	=	($1.6000)	($0.012)	($0.6000)	-0.06%
11	Subtotal Delivery Margin Related Charges			$3.207		**$302.43**			$3.499		**$317.03**		**$14.60**	**1.37%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$1.315	=	$65.7500	50.0	GJ x	$1.315	=	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$4.568	=	$228.4000	50.0	GJ x	$4.568	=	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$9.331	=	$466.5500	50.0	GJ x	$9.331	=	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges			$15.214		**$760.70**			$15.214		**$760.70**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$21.263*		**$1,063.13**	50.0		*$21.555*		**$1,077.73**	*$0.292*	**$14.60**	**1.37%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.714	=	$678.5000	250.0	GJ x	$2.907	=	$726.7500	$0.193	$48.2500	1.07%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	($0.036)	=	($9.0000)	250.0	GJ x	$0.000	=	$0.0000	$0.036	$9.0000	0.20%
28	Rider 5 RSAM	250.0	GJ x	($0.020)	=	($5.0000)	250.0	GJ x	($0.032)	=	($8.0000)	($0.012)	($3.0000)	-0.07%
29	Subtotal Delivery Margin Related Charges			$2.658		**$962.58**			$2.875		**$1,016.83**		**$54.25**	**1.21%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$4.568	=	$1,142.0000	250.0	GJ x	$4.568	=	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$8.254	=	$2,063.5000	250.0	GJ x	$8.254	=	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges			$14.123		**$3,530.75**			$14.123		**$3,530.75**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$17.973*		**$4,493.33**	250.0		*$18.190*		**$4,547.58**	*$0.217*	**$54.25**	**1.21%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.318	=	$10,431.0000	4,500.0	GJ x	$2.467	=	$11,101.5000	$0.149	$670.5000	0.89%
44	Rider 2 2009 ROE Rate Rider	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0	GJ x	($0.028)	=	($126.0000)	4,500.0	GJ x	$0.000	=	$0.0000	$0.028	$126.0000	0.17%
46	Rider 5 RSAM	4,500.0	GJ x	($0.020)	=	($90.0000)	4,500.0	GJ x	($0.032)	=	($144.0000)	($0.012)	($54.0000)	-0.07%
47	Subtotal Delivery Margin Related Charges			$2.270		**$11,805.24**			$2.435		**$12,547.74**		**$742.50**	**0.99%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.999	=	$4,495.5000	4,500.0	GJ x	$0.999	=	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$4.568	=	$20,556.0000	4,500.0	GJ x	$4.568	=	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$8.556	=	$38,502.0000	4,500.0	GJ x	$8.556	=	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges			$14.123		**$63,553.50**			$14.123		**$63,553.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$16.746*		**$75,358.74**	4,500.0		*$16.911*		**$76,101.24**	*$0.165*	**$742.50**	**0.99%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent comparison purposes.

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.531	$3.531	$3.531	$0.325	$0.325	$0.325	$3.856	$3.856	$3.856
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.499**	**$3.499**	**$3.499**	**$0.325**	**$0.325**	**$0.325**	**$3.824**	**$3.824**	**$3.824**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009
14	Subtotal **Midstream Related Charges per GJ**	**$1.349**	**$1.324**	**$1.364**	**$0.000**	**$0.000**	**$0.000**	**$1.349**	**$1.324**	**$1.364**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.907	$2.907	$2.907	$0.245	$0.245	$0.245	$3.152	$3.152	$3.152
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.875**	**$2.875**	**$2.875**	**$0.245**	**$0.245**	**$0.245**	**$3.120**	**$3.120**	**$3.120**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	**RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE** Particulars	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland			**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland			**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland		
			Inland	**Columbia**		**Inland**	**Columbia**		**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.435**	**$2.435**	**$2.435**	**$0.188**	**$0.188**	**$0.188**	**$2.623**	**$2.623**	**$2.623**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.935	$0.935	$0.935	$0.103	$0.103	$0.103	$1.038	$1.038	$1.038
6	(b) Extension Period	$1.712	$1.712	$1.712	$0.103	$0.103	$0.103	$1.815	$1.815	$1.815
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.267	$6.252	$6.288	$0.103	$0.103	$0.103	$6.370	$6.355	$6.391
33	(b) Extension Period	$7.044	$7.029	$7.065	$0.103	$0.103	$0.103	$7.147	$7.132	$7.168

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
5										
6	**Delivery Charge per GJ**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$6.028	$6.013	$6.049	$0.065	$0.065	$0.065	$6.093	$6.078	$6.114

Line No.	RATE SCHEDULE 6: NGV - STATIONS Particulars	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.782	$8.775	$8.775	$0.266	$0.266	$0.266	$9.048	$9.041	$9.041

Revised May 16, 2011

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	PROPOSED JANUARY 1, 2012 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.821	$0.266	$4.087
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	$0.000	$0.000	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$14.022	$0.266	$14.288

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.472	$6.457	$6.493	$0.086	$0.086	$0.086	$6.558	$6.543	$6.579

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE	PROPOSED JANUARY 1, 2012			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7										
8										
9	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19										
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899

Line No.	**RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012**	**DELIVERY MARGIN RELATED CHARGES CHANGES**	**PROPOSED JANUARY 1, 2013 RATES**
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$13.407	$0.927	$14.334
7	(b) Firm MTQ	$0.093	$0.007	$0.100
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.061	$0.073	$1.134
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	$0.000	$0.000	$0.000
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.093	$0.007	$0.100
35	(b) Interruptible MTQ	$1.061	$0.073	$1.134

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Columbia Except Elkview	PROPOSED JANUARY 1, 2012 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	DELIVERY MARGIN RELATED CHARGES CHANGES Elkview Coal	PROPOSED JANUARY 1, 2013 RATES Columbia Except Elkview	PROPOSED JANUARY 1, 2013 RATES Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.578	$1.947	$0.667	$0.152	$9.245	$2.099
7	(b) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
11	(b) between and including Nov. 1 and Mar.31	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
31	(b) Interruptible MTQ - Summer	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
32	- Winter	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330

Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.435	$2.435	$2.435	$0.188	$0.188	$0.188	$2.623	$2.623	$2.623

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE	PROPOSED JANUARY 1, 2012			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761

Line No.	RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE	PROPOSED JANUARY 1, 2012			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	PROPOSED JANUARY 1, 2012			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	95.0	GJ x	$3.531 =	$335.4450	95.0	GJ x	$3.856 =	$366.3200	$0.325	$30.8750	2.98%
6	Rider 2 2009 ROE Rate Rider	95.0	GJ x	$0.000 =	$0.0000	95.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0	GJ x	$0.000 =	$0.0000	95.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	95.0	GJ x	($0.032) =	($3.0400)	95.0	GJ x	($0.032) =	($3.0400)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$474.49**				**$505.36**		**$30.87**	**2.98%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	95.0	GJ x	$1.340 =	$127.3000	95.0	GJ x	$1.340 =	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	$0.009 =	$0.8550	95.0	GJ x	$0.009 =	0.8550	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$128.16				$128.16		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	$4.568 =	$433.96	95.0	GJ x	$4.568 =	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$562.12**				**$562.12**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	95.0		*$10.912*	**$1,036.61**	95.0		*$11.237*	**$1,067.48**	*$0.325*	**$30.87**	**2.98%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days	$0.389 =	$142.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	75.0	GJ x	$3.531 =	$264.8250	75.0	GJ x	$3.856 =	$289.2000	$0.325	$24.3750	2.88%
26	Rider 2 2009 ROE Rate Rider	75.0	GJ x	$0.000 =	$0.0000	75.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0	GJ x	$0.000 =	$0.0000	75.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	75.0	GJ x	($0.032) =	($2.4000)	75.0	GJ x	($0.032) =	($2.4000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$404.51**				**$428.88**		**$24.37**	**2.88%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	75.0	GJ x	$1.315 =	$98.6250	75.0	GJ x	$1.315 =	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	$0.009 =	$0.6750	75.0	GJ x	$0.009 =	$0.6750	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$99.30				$99.30		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	$4.568 =	$342.60	75.0	GJ x	$4.568 =	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$441.90**				**$441.90**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	75.0		*$11.285*	**$846.41**	75.0		*$11.610*	**$870.78**	*$0.325*	**$24.37**	**2.88%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	80.0	GJ x	$3.531 =	$282.4800	80.0	GJ x	$3.856 =	$308.4800	$0.325	$26.0000	2.90%
46	Rider 2 2009 ROE Rate Rider	80.0	GJ x	$0.000 =	$0.0000	80.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0	GJ x	$0.000 =	$0.0000	80.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	80.0	GJ x	($0.032) =	($2.5600)	80.0	GJ x	($0.032) =	($2.5600)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges				**$422.00**				**$448.00**		**$26.00**	**2.90%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	80.0	GJ x	$1.355 =	$108.4000	80.0	GJ x	$1.355 =	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0	GJ x	$0.009 =	$0.7200	80.0	GJ x	$0.009 =	$0.7200	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$109.12				$109.12		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	$4.568	$365.44	80.0	GJ x	$4.568 =	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$474.56**	80.0			**$474.56**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	80.0		*$11.207*	**$896.56**	80.0		*$11.532*	**$922.56**	*$0.325*	**$26.00**	**2.90%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	300.0	GJ x	$2.907 =	$872.1000	300.0	GJ x	$3.152 =	$945.6000	$0.245	$73.5000	2.51%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	300.0	GJ x	($0.032) =	($9.6000)	300.0	GJ x	($0.032) =	($9.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$1,160.58**				**$1,234.08**		**$73.50**	**2.51%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327 =	$398.1000	300.0	GJ x	$1.327 =	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$398.10				$398.10		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568 =	$1,370.40	300.0	GJ x	$4.568 =	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$1,768.50**				**$1,768.50**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	300.0		*$9.764*	**$2,929.08**	300.0		*$10.009*	**$3,002.58**	*$0.245*	**$73.50**	**2.51%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	250.0	GJ x	$2.907 =	$726.7500	250.0	GJ x	$3.152 =	$788.0000	$0.245	$61.2500	2.47%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032) =	($8.0000)	250.0	GJ x	($0.032) =	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$1,016.83**				**$1,078.08**		**$61.25**	**2.47%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301 =	$325.2500	250.0	GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$325.25				$325.25		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568 =	$1,142.00	250.0	GJ x	$4.568 =	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$1,467.25**				**$1,467.25**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	250.0		*$9.936*	**$2,484.08**	250.0		*$10.181*	**$2,545.33**	*$0.245*	**$61.25**	**2.47%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	320.0	GJ x	$2.907 =	$930.2400	320.0	GJ x	$3.152 =	$1,008.6400	$0.245	$78.4000	2.52%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	320.0	GJ x	($0.032) =	($10.2400)	320.0	GJ x	($0.032) =	($10.2400)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges				**$1,218.08**				**$1,296.48**		**$78.40**	**2.52%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342 =	$429.4400	320.0	GJ x	$1.342 =	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$429.44				$429.44		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568 =	$1,461.76	320.0	GJ x	$4.568 =	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$1,891.20**				**$1,891.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	320.0		*$9.717*	**$3,109.28**	320.0		*$9.962*	**$3,187.68**	*$0.245*	**$78.40**	**2.52%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
4														
5	Delivery Charge	2,800.0	GJ x	$2.467	=	$6,907.6000	2,800.0	GJ x	$2.655	=	$7,434.0000	$0.188	$526.4000	2.19%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	2,800.0	GJ x	($0.032)	=	($89.6000)	2,800.0	GJ x	($0.032)	=	($89.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$8,408.24**					**$8,934.64**		**$526.40**	**2.19%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018	=	$2,850.4000	2,800.0	GJ x	$1.018	=	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal					$2,850.40					$2,850.40		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568	=	$12,790.40	2,800.0	GJ x	$4.568	=	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$15,640.80**					**$15,640.80**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.589*		**$24,049.04**	2,800.0		*$8.777*		**$24,575.44**	*$0.188*	**$526.40**	**2.19%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
24														
25	Delivery Charge	2,600.0	GJ x	$2.467	=	$6,414.2000	2,600.0	GJ x	$2.655	=	$6,903.0000	$0.188	$488.8000	2.18%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	2,600.0	GJ x	($0.032)	=	($83.2000)	2,600.0	GJ x	($0.032)	=	($83.2000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges					**$7,921.24**					**$8,410.04**		**$488.80**	**2.18%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999	=	$2,597.4000	2,600.0	GJ x	$0.999	=	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal					$2,597.40					$2,597.40		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568	=	$11,876.80	2,600.0	GJ x	$4.568	=	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$14,474.20**					**$14,474.20**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.614*		**$22,395.44**	2,600.0		*$8.802*		**$22,884.24**	*$0.188*	**$488.80**	**2.18%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
44														
45	Delivery Charge	3,300.0	GJ x	$2.467	=	$8,141.1000	3,300.0	GJ x	$2.655	=	$8,761.5000	$0.188	$620.4000	2.21%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	3,300.0	GJ x	($0.032)	=	($105.6000)	3,300.0	GJ x	($0.032)	=	($105.6000)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges					**$9,625.74**					**$10,246.14**		**$620.40**	**2.21%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036	=	$3,418.8000	3,300.0	GJ x	$1.036	=	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal					$3,418.80					$3,418.80		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568	=	$15,074.40	3,300.0	GJ x	$4.568	=	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$18,493.20**					**$18,493.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.521*		**$28,118.94**	3,300.0		*$8.709*		**$28,739.34**	*$0.188*	**$620.40**	**2.21%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
5												
6	Delivery Charge											
7	(a) Off-Peak Period	5,400.0	GJ x	$0.935 =	$5,049.0000	5,400.0	GJ x	$1.038 =	$5,605.2000	$0.103	$556.2000	1.51%
8	(b) Extension Period	0.0	GJ x	$1.712 =	$0.0000	0.0	GJ x	$1.815 =	$0.0000	$0.103	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0	GJ x	$0.000 =	$0.0000	5,400.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0	GJ x	$0.000 =	$0.0000	5,400.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges				**$8,135.52**				**$8,691.72**		**$556.20**	**1.51%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge											
15	(a) Off-Peak Period	5,400.0	GJ x	$0.764 =	$4,125.6000	5,400.0	GJ x	$0.764 =	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.764 =	$0.0000	0.0	GJ x	$0.764 =	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge											
18	(a) Off-Peak Period	5,400.0	GJ x	$4.568 =	24,667.2000	5,400.0	GJ x	$4.568 =	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
20												
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$28,792.80**				**$28,792.80**		**$0.00**	**0.00%**
22												
23	Unauthorized Gas Charge During Peak Period (not forecast)											
24												
25	Total during Off-Peak Period	5,400.0			**$36,928.32**	5,400.0			**$37,484.52**		**$556.20**	**1.51%**
26												
27												
28	**INLAND SERVICE AREA**											
29	Delivery Margin Related Charges											
30	Basic Charge	214	days x	$14.423 =	$3,086.5216	214	days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
31												
32	Delivery Charge											
33	(a) Off-Peak Period	9,300.0	GJ x	$0.935 =	$8,695.5000	9,300.0	GJ x	$1.038 =	$9,653.4000	$0.103	$957.9000	1.56%
34	(b) Extension Period	0.0	GJ x	$1.712 =	$0.0000	0.0	GJ x	$1.815 =	$0.0000	$0.103	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0	GJ x	$0.000 =	$0.0000	9,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0	GJ x	$0.000 =	$0.0000	9,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
37	Subtotal Delivery Margin Related Charges				**$11,782.02**				**$12,739.92**		**$957.90**	**1.56%**
38												
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge											
41	(a) Off-Peak Period	9,300.0	GJ x	$0.749 =	$6,965.7000	9,300.0	GJ x	$0.749 =	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.749 =	$0.0000	0.0	GJ x	$0.749 =	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge											
44	(a) Off-Peak Period	9,300.0	GJ x	$4.568 =	$42,482.4000	9,300.0	GJ x	$4.568 =	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$4.568 =	$0.0000	0.0	GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
46												
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				**$49,448.10**				**$49,448.10**		**$0.00**	**0.00%**
48												
49	Unauthorized Gas Charge During Peak Period (not forecast)											
50												
51	Total during Off-Peak Period	9,300.0			**$61,230.12**	9,300.0			**$62,188.02**		**$957.90**	**1.56%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5														
6	Demand Charge	58.5	GJ x	$16.996	=	**$11,931.19**	58.5	GJ x	$18.324	=	**$12,863.45**	$1.328	**$932.26**	**1.20%**
7														
8	Delivery Charge	9,700.0	GJ x	$0.696	=	$6,751.2000	9,700.0	GJ x	$0.761	=	$7,381.7000	$0.065	$630.5000	0.81%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000	=	$0.0000	9,700.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	$0.000	=	$0.0000	9,700.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges					**$6,751.20**					**$7,381.70**		**$630.50**	**0.81%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764	=	$7,410.8000	9,700.0	GJ x	$0.764	=	$7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568	=	$44,309.6000	9,700.0	GJ x	$4.568	=	$44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$51,720.40**					**$51,720.40**		**$0.00**	**0.00%**
17														
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.984*		**$77,446.79**	9,700.0		*$8.145*		**$79,009.55**	*$0.161*	**$1,562.76**	**2.02%**
19														
20	**INLAND SERVICE AREA**													
21	Delivery Margin Related Charges													
22	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23														
24	Demand Charge	82.0	GJ x	$16.996	=	**$16,724.06**	82.0	GJ x	$18.324	=	**$18,030.82**	$1.328	**$1,306.76**	**1.30%**
25														
26	Delivery Charge	12,800.0	GJ x	$0.696	=	$8,908.8000	12,800.0	GJ x	$0.761	=	$9,740.8000	$0.065	$832.0000	0.83%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000	=	$0.0000	12,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	$0.000	=	$0.0000	12,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges					**$8,908.80**					**$9,740.80**		**$832.00**	**0.83%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749	=	$9,587.2000	12,800.0	GJ x	$0.749	=	$9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568	=	$58,470.4000	12,800.0	GJ x	$4.568	=	$58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$68,057.60**					**$68,057.60**		**$0.00**	**0.00%**
35														
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.870*		**$100,734.46**	12,800.0		*$8.037*		**$102,873.22**	*$0.167*	**$2,138.76**	**2.12%**
37														
38	**COLUMBIA SERVICE AREA**													
39	Delivery Margin Related Charges													
40	Basic Charge	12	months x	$587.00	=	**$7,044.00**	12	months x	$587.00	=	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41														
42	Demand Charge	55.4	GJ x	$16.996	=	**$11,298.94**	55.4	GJ x	$18.324	=	**$12,181.80**	$1.328	**$882.86**	**1.20%**
43														
44	Delivery Charge	9,100.0	GJ x	$0.696	=	$6,333.6000	9,100.0	GJ x	$0.761	=	$6,925.1000	$0.065	$591.5000	PAGE 13
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000	=	$0.0000	9,100.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	$0.000	=	$0.0000	9,100.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges					**$6,333.60**					**$6,925.10**		**$591.50**	**0.81%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785	=	$7,143.5000	9,100.0	GJ x	$0.785	=	$7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568	=	$41,568.8000	9,100.0	GJ x	$4.568	=	$41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)					**$48,712.30**					**$48,712.30**		**$0.00**	**0.00%**
53														
54	Total *(with effective $/GJ rate)*	9,100.0		$8.065		**$73,388.84**	9,100.0		$8.227		**$74,863.20**	*$0.162*	**$1,474.36**	**2.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	365.25	days x	$2.004 =	$732.00	365.25	days x	$2.004 =	$732.00	$0.00	$0.00	0.00%
5												
6	Delivery Charge	2,900.0	GJ x	$3.861 =	$11,196.9000	2,900.0	GJ x	$4.127 =	$11,968.3000	$0.266	$771.4000	2.94%
7	Rider 2 2009 ROE Rate Rider	2,900.0	GJ x	$0.000 =	$0.0000	2,900.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0	GJ x	$0.000 =	$0.0000	2,900.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$11,928.90**				**$12,700.30**		**$771.40**	**2.94%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.353 =	$1,023.7000	2,900.0	GJ x	$0.353 =	$1,023.7000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$4.568 =	$13,247.2000	2,900.0	GJ x	$4.568 =	$13,247.2000	$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)				**$14,270.90**				**$14,270.90**		**$0.00**	**0.00%**
15												
16	Total *(with effective $/GJ rate)*	2,900.0		*$9.034*	**$26,199.80**	2,900.0		*$9.300*	**$26,971.20**	*$0.266*	**$771.40**	**2.94%**
17												
18												
19	**INLAND SERVICE AREA**											
20	Delivery Margin Related Charges											
21	Basic Charge	365.25	days x	$2.004 =	$732.00	365.25	days x	$2.004 =	$732.00	$0.00	$0.00	0.00%
22												
23	Delivery Charge	11,900.0	GJ x	$3.861 =	$45,945.9000	11,900.0	GJ x	$4.127 =	$49,111.3000	$0.266	$3,165.4000	3.01%
24	Rider 2 2009 ROE Rate Rider	11,900.0	GJ x	$0.000 =	$0.0000	11,900.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0	GJ x	$0.000 =	$0.0000	11,900.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
26	Subtotal Delivery Margin Related Charges				**$46,677.90**				**$49,843.30**		**$3,165.40**	**3.01%**
27												
28	Commodity Related Charges											
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.346 =	$4,117.4000	11,900.0	GJ x	$0.346 =	$4,117.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$4.568 =	$54,359.2000	11,900.0	GJ x	$4.568 =	$54,359.2000	$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)				**$58,476.60**				**$58,476.60**		**$0.00**	**0.00%**
32												
33	Total *(with effective $/GJ rate)*	11,900.0		*$8.837*	**$105,154.50**	11,900.0		*$9.103*	**$108,319.90**	*$0.266*	**$3,165.40**	**3.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5														
6	Delivery Charge	8,100.0	GJ x	$1.140	=	$9,234.0000	8,100.0	GJ x	$1.226	=	$9,930.6000	$0.086	$696.6000	1.11%
7	Rider 2 2009 ROE Rate Rider	8,100.0	GJ x	$0.000	=	$0.0000	8,100.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0	GJ x	$0.000	=	$0.0000	8,100.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 4 Reserve for Future Use	8,100.0	GJ x	$0.000	=	$0.0000	8,100.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges					**$9,234.00**					**$9,930.60**		**$696.60**	**1.11%**
11														
12	Commodity Related Charges													
13	Midstream Cost Recovery Charge	8,100.0	GJ x	$0.764	=	$6,188.4000	8,100.0	GJ x	$0.764	=	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0	GJ x	$4.568	=	$37,000.8000	8,100.0	GJ x	$4.568	=	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)					**$43,189.20**					**$43,189.20**		**$0.00**	**0.00%**
16														
17	Non-Standard Charges (not forecast)													
18	Index Pricing Option, UOR													
19														
20	Total *(with effective $/GJ rate)*	8,100.0		*$7.776*		**$62,983.20**	8,100.0		*$7.862*		**$63,679.80**	*$0.086*	**$696.60**	**1.11%**
21														
22														
23	**INLAND SERVICE AREA**													
24	Delivery Margin Related Charges													
25	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26														
27	Delivery Charge	4,000.0	GJ x	$1.140	=	$4,560.0000	4,000.0	GJ x	$1.226	=	$4,904.0000	$0.086	$344.0000	0.95%
28	Rider 2 2009 ROE Rate Rider	4,000.0	GJ x	$0.000	=	$0.0000	4,000.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0	GJ x	$0.000	=	$0.0000	4,000.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
30	Rider 4 Reserve for Future Use	4,000.0	GJ x	$0.000	=	$0.0000	4,000.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges					**$4,560.00**					**$4,904.00**		**$344.00**	**0.95%**
32														
33	Commodity Related Charges													
34	Midstream Cost Recovery Charge	4,000.0	GJ x	$0.749	=	$2,996.0000	4,000.0	GJ x	$0.749	=	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0	GJ x	$4.568	=	$18,272.0000	4,000.0	GJ x	$4.568	=	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)					**$21,268.00**					**$21,268.00**		**$0.00**	**0.00%**
37														
38	Non-Standard Charges (not forecast)													
39	Index Pricing Option, UOR													
40														
41	Total *(with effective $/GJ rate)*	4,000.0		*$9.097*		**$36,388.00**	4,000.0		*$9.183*		**$36,732.00**	*$0.086*	**$344.00**	**0.95%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1														
2	**LOWER MAINLAND SERVICE AREA**													
3	Basic Charge	12	months x	$3,664.00	=	**$43,968.00**	12	months x	$3,664.00	=	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ x	$0.838	=	$391,602.0928	467,305.6	GJ x	$0.899	=	$420,107.7344	$0.061	$28,505.6416	6.53%
7	Rider 2 2009 ROE Rate Rider	467,305.6	GJ x	$0.000	=	$0.0000	467,305.6	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6	GJ x	$0.000	=	$0.0000	467,305.6	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Transportation - Interruptible					**$391,602.09**					**$420,107.73**		**$28,505.64**	**6.53%**
10														
11														
12	Non-Standard Charges (not forecast)													
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
14														
15														
16	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
17														
18														
19	Total *(with effective $/GJ rate)*	467,305.6		*$0.934*		**$436,506.09**	467,305.6		*$0.995*		**$465,011.73**	*$0.061*	**$28,505.64**	**6.53%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**INLAND SERVICE AREA**													
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**	12	months x	$4,810.00	=	**$57,720.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$13.407	=	**$417,558.36**	2,595.4	GJ x	$14.334	=	**$446,429.52**	$0.927	**$28,871.16**	**5.15%**
7														
8														
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.093	=	$54,356.2494	584,475.8	GJ x	$0.100	=	$58,447.5800	$0.007	$4,091.3306	0.73%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$54,356.25**					**$58,447.58**		**$4,091.33**	**0.73%**
13														
14														
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.061	=	$30,352.9819	28,607.9	GJ x	$1.134	=	$32,441.3586	$0.073	$2,088.3767	0.37%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$30,352.98**					**$32,441.36**		**$2,088.38**	**0.37%**
19														
20														
21	Non-Standard Charges (not forecast)													
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
23														
24														
25	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
26														
27														
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.960*		**$560,923.59**	584,475.8		*$1.020*		**$595,974.46**	*$0.060*	**$35,050.87**	**6.25%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**											
3	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
4												
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.578	= **$227,673.84**	2,211.8	GJ x	$9.245	= **$245,377.08**	$0.667	**$17,703.24**	**5.35%**
6												
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.092	= $42,075.8136	457,345.8	GJ x	$0.099	= $45,277.2342	$0.007	$3,201.4206	0.97%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	= $0.0000	457,345.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	$0.000	= $0.0000	457,345.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Transportation - Firm (Delivery Charge Firm MTQ)				**$42,075.81**				**$45,277.23**		**$3,201.42**	**0.97%**
11												
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.855	= $5,756.2020	6,732.4	GJ x	$0.921	= $6,200.5404	$0.066	$444.3384	0.13%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.231	= $0.0000	0.0	GJ x	$1.327	= $0.0000	$0.096	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	= $0.0000	6,732.4	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	$0.000	= $0.0000	6,732.4	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$5,756.20**				**$6,200.54**		**$444.34**	**0.13%**
18												
19	Non-Standard Charges (not forecast)											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21												
22	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.713*	**$330,885.85**	464,078.2		*$0.759*	**$352,234.85**	*$0.046*	**$21,349.00**	**6.45%**
25												
26												
27	**COLUMBIA SERVICE - ELKVIEW COAL**											
28	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
29												
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.947	= **$62,381.88**	2,670.0	GJ x	$2.099	= **$67,251.96**	$0.152	**$4,870.08**	**2.70%**
31												
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.092	= $58,102.9220	631,553.5	GJ x	$0.099	= $62,523.7965	$0.007	$4,420.8745	2.45%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	= $0.0000	631,553.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	$0.000	= $0.0000	631,553.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
35	Transportation - Firm (Delivery Charge Firm MTQ)				**$58,102.92**				**$62,523.80**		**$4,420.88**	**2.45%**
36												
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.214	= $0.0000	0.0	GJ x	$0.231	= $0.0000	$0.017	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.306	= $4,437.9486	14,503.1	GJ x	$0.330	= $4,786.0230	$0.024	$348.0744	0.19%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$4,437.95**				**$4,786.02**		**$348.07**	**0.19%**
44												
45	Non-Standard Charges (not forecast)											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47												
48	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
49												
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.279*	**$180,302.75**	646,056.6		*$0.294*	**$189,941.78**	*$0.015*	**$9,639.03**	**5.35%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012						PROPOSED JANUARY 1, 2013 RATES						Annual Increase/Decrease		
1		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**															
3	Basic Charge	12	months x	$132.52	=	**$1,590.24**		12	months x	$132.52	=	**$1,590.24**		$0.00	**$0.00**	**0.00%**
4																
5	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
6																
7	Delivery Charge	4,100.0	GJ x	$2.467	=	$10,114.7000		4,100.0	GJ x	$2.655	=	$10,885.5000		$0.188	$770.8000	6.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0	GJ x	$0.000	=	$0.0000		4,100.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0	GJ x	$0.000	=	$0.0000		4,100.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
10	Rider 5 RSAM	4,100.0	GJ x	($0.032)	=	($131.2000)		4,100.0	GJ x	($0.032)	=	($131.2000)		$0.000	$0.0000	0.00%
11	Transportation - Firm					**$9,983.50**						**$10,754.30**			**$770.80**	**6.16%**
12																
13	Non-Standard Charges (not forecast)															
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas															
15																
16	Total *(with effective $/GJ rate)*	4,100.0		*$3.051*		**$12,509.74**		4,100.0		*$3.239*		**$13,280.54**		*$0.188*	**$770.80**	**6.16%**
17																
18	**INLAND SERVICE AREA**															
19	Basic Charge	12	months x	$132.52	=	**$1,590.24**		12	months x	$132.52	=	**$1,590.24**		$0.00	**$0.00**	**0.00%**
20																
21	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
22																
23	Delivery Charge	4,700.0	GJ x	$2.467	=	$11,594.9000		4,700.0	GJ x	$2.655	=	$12,478.5000		$0.188	$883.6000	6.32%
24	Rider 2 2009 ROE Rate Rider	4,700.0	GJ x	$0.000	=	$0.0000		4,700.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0	GJ x	$0.000	=	$0.0000		4,700.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
26	Rider 5 RSAM	4,700.0	GJ x	($0.032)	=	($150.4000)		4,700.0	GJ x	($0.032)	=	($150.4000)		$0.000	$0.0000	0.00%
27	Transportation - Firm					**$11,444.50**						**$12,328.10**			**$883.60**	**6.32%**
28																
29	Non-Standard Charges (not forecast)															
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas															
31																
32	Total *(with effective $/GJ rate)*	4,700.0		*$2.972*		**$13,970.74**		4,700.0		*$3.160*		**$14,854.34**		*$0.188*	**$883.60**	**6.32%**
33																
34	**COLUMBIA SERVICE AREA**															
35	Basic Charge	12	months x	$132.52	=	**$1,590.24**		12	months x	$132.52	=	**$1,590.24**		$0.00	**$0.00**	**0.00%**
36																
37	Administration Charge	12	months x	$78.00	=	**$936.00**		12	months x	$78.00	=	**$936.00**		$0.00	**$0.00**	**0.00%**
38																
39	Delivery Charge	4,200.0	GJ x	$2.467	=	$10,361.4000		4,200.0	GJ x	$2.655	=	$11,151.0000		$0.188	$789.6000	6.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0	GJ x	$0.000	=	$0.0000		4,200.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0	GJ x	$0.000	=	$0.0000		4,200.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
42	Rider 5 RSAM	4,200.0	GJ x	($0.032)	=	($134.4000)		4,200.0	GJ x	($0.032)	=	($134.4000)		$0.000	$0.0000	0.00%
43	Transportation - Firm					**$10,227.00**						**$11,016.60**			**$789.60**	**6.19%**
44																
45	Non-Standard Charges (not forecast)															
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas															
47																
48	Total *(with effective $/GJ rate)*	4,200.0		*$3.036*		**$12,753.24**		4,200.0		*$3.224*		**$13,542.84**		*$0.188*	**$789.60**	**6.19%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Transportation - Firm Demand	97.2 GJ x	$16.996	= **$19,824.12**	97.2 GJ x	$18.324	= **$21,373.08**	$1.328	**$1,548.96**	**3.77%**
8										
9	Delivery Charge	19,086.2 GJ x	$0.696	= $13,283.9952	19,086.2 GJ x	$0.761	= $14,524.5982	$0.065	$1,240.6030	3.02%
10	Rider 2 2009 ROE Rate Rider	19,086.2 GJ x	$0.000	= $0.0000	19,086.2 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2 GJ x	$0.000	= $0.0000	19,086.2 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
12	Transportation - Firm			**$13,284.00**			**$14,524.60**		**$1,240.60**	**3.02%**
13										
14	Non-Standard Charges (not forecast)	214								
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16										
17	Total *(with effective $/GJ rate)*	19,086.2	*$2.153*	**$41,088.12**	19,086.2	*$2.299*	**$43,877.68**	*$0.146*	**$2,789.56**	**6.79%**
18										
19	**INLAND SERVICE AREA**									
20	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
21										
22	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23										
24	Transportation - Firm Demand	212.6 GJ x	$16.996	= **$43,360.20**	212.6 GJ x	$18.324	= **$46,748.16**	$1.328	**$3,387.96**	**4.25%**
25										
26	Delivery Charge	40,670.5 GJ x	$0.696	= $28,306.6680	40,670.5 GJ x	$0.761	= $30,950.2505	$0.065	$2,643.5825	3.32%
27	Rider 2 2009 ROE Rate Rider	40,670.5 GJ x	$0.000	= $0.0000	40,670.5 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5 GJ x	$0.000	= $0.0000	40,670.5 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
29	Transportation - Firm			**$28,306.67**			**$30,950.25**		**$2,643.58**	**3.32%**
30										
31	Non-Standard Charges (not forecast)									
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
33										
34	Total *(with effective $/GJ rate)*	40,670.5	*$1.958*	**$79,646.87**	40,670.5	*$2.107*	**$85,678.41**	*$0.149*	**$6,031.54**	**7.57%**
35										
36	**COLUMBIA SERVICE**									
37	Basic Charge	12 months x	$587.00	= **$7,044.00**	12 months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
38										
39	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
40										
41	Transportation - Firm Demand	182.2 GJ x	$16.996	= **$37,160.04**	182.2 GJ x	$18.324	= **$40,063.56**	$1.328	**$2,903.52**	**4.38%**
42										
43	Delivery Charge	30,357.8 GJ x	$0.696	= $21,129.0288	30,357.8 GJ x	$0.761	= $23,102.2858	$0.065	$1,973.2570	2.98%
44	Rider 2 2009 ROE Rate Rider	30,357.8 GJ x	$0.000	= $0.0000	30,357.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8 GJ x	$0.000	= $0.0000	30,357.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
46	Transportation - Firm			**$21,129.03**			**$23,102.29**		**$1,973.26**	**2.98%**
47										
48	Non-Standard Charges (not forecast)									
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
50										
51	Total *(with effective $/GJ rate)*	30,357.8	*$2.183*	**$66,269.07**	30,357.8	*$2.344*	**$71,145.85**	*$0.161*	**$4,876.78**	**7.36%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
4														
5	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
6														
7	Delivery Charge	53,957.0	GJ x	$1.140	=	$61,510.9800	53,957.0	GJ x	$1.226	=	$66,151.2820	$0.086	$4,640.3020	6.36%
8	Rider 2 2009 ROE Rate Rider	53,957.0	GJ x	$0.000	=	$0.0000	53,957.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0	GJ x	$0.000	=	$0.0000	53,957.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Transportation - Interruptible					**$61,510.98**					**$66,151.28**		**$4,640.30**	**6.36%**
11														
12	Non-Standard Charges (not forecast)													
13	UOR, Balancing gas, Backstopping Gas													
14														
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.353*		**$73,006.98**	53,957.0		*$1.439*		**$77,647.28**	*$0.086*	**$4,640.30**	**6.36%**
16														
17														
18	**INLAND SERVICE AREA**													
19	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
20														
21	Administration Charge	12.0	months x	$78.00	=	**$936.00**	12.0	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
22														
23	Delivery Charge	48,903.9	GJ x	$1.140	=	$55,750.4460	48,903.9	GJ x	$1.226	=	$59,956.1814	$0.086	$4,205.7354	6.25%
24	Rider 2 2009 ROE Rate Rider	48,903.9	GJ x	$0.000	=	$0.0000	48,903.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9	GJ x	$0.000	=	$0.0000	48,903.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
26	Transportation - Interruptible					**$55,750.45**					**$59,956.18**		**$4,205.73**	**6.25%**
27														
28														
29	Non-Standard Charges (not forecast)													
30	UOR, Balancing gas, Backstopping Gas													
31		48,903.9		*$1.375*		**$67,246.45**	48,903.9		*$1.461*		**$71,452.18**	*$0.086*	**$4,205.73**	**6.25%**
32	Total *(with effective $/GJ rate)*													
33														
34														
35	**COLUMBIA SERVICE AREA**													
36	Basic Charge	12	months x	$880.00	=	**$10,560.00**	12	months x	$880.00	=	**$10,560.00**	$0.00	**$0.00**	**0.00%**
37														
38	Administration Charge	12.0	months x	$78.00	=	**$936.00**	12.0	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
39														
40	Delivery Charge	7,733.8	GJ x	$1.140	=	$8,816.5320	7,733.8	GJ x	$1.226	=	$9,481.6388	$0.086	$665.1068	0.99%
41	Rider 2 2009 ROE Rate Rider	7,733.8	GJ x	$0.000	=	$0.0000	7,733.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8	GJ x	$0.000	=	$0.0000	7,733.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible					**$8,816.53**					**$9,481.64**		**$665.11**	**0.99%**
44														
45														
46	Non-Standard Charges (not forecast)													
47	UOR, Balancing gas, Backstopping Gas													
48		7,733.8		*$2.626*		**$20,312.53**	7,733.8		*$2.712*		**$20,977.64**	*$0.086*	**$665.11**	**0.99%**
49	Total *(with effective $/GJ rate)*													

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1	**INLAND SERVICE AREA**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$3.531	=	$176.5500	50.0	GJ x	$3.856	=	$192.8000	$0.325	$16.2500	1.51%
8	Rider 2 2009 ROE Rate Rider	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 5 RSAM	50.0	GJ x	($0.032)	=	($1.6000)	50.0	GJ x	($0.032)	=	($1.6000)	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges			$3.499		**$317.03**			$3.824		**$333.28**		**$16.25**	**1.51%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$1.315	=	$65.7500	50.0	GJ x	$1.315	=	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$4.568	=	$228.4000	50.0	GJ x	$4.568	=	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$9.331	=	$466.5500	50.0	GJ x	$9.331	=	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges			$15.214		**$760.70**			$15.214		**$760.70**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$21.555*		**$1,077.73**	50.0		*$21.880*		**$1,093.98**	*$0.325*	**$16.25**	**1.51%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.907	=	$726.7500	250.0	GJ x	$3.152	=	$788.0000	$0.245	$61.2500	1.35%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032)	=	($8.0000)	250.0	GJ x	($0.032)	=	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges			$2.875		**$1,016.83**			$3.120		**$1,078.08**		**$61.25**	**1.35%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$4.568	=	$1,142.0000	250.0	GJ x	$4.568	=	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$8.254	=	$2,063.5000	250.0	GJ x	$8.254	=	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges			$14.123		**$3,530.75**			$14.123		**$3,530.75**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$18.190*		**$4,547.58**	250.0		*$18.435*		**$4,608.83**	*$0.245*	**$61.25**	**1.35%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.467	=	$11,101.5000	4,500.0	GJ x	$2.655	=	$11,947.5000	$0.188	$846.0000	1.11%
44	Rider 2 2009 ROE Rate Rider	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
46	Rider 5 RSAM	4,500.0	GJ x	($0.032)	=	($144.0000)	4,500.0	GJ x	($0.032)	=	($144.0000)	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges			$2.435		**$12,547.74**			$2.623		**$13,393.74**		**$846.00**	**1.11%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.999	=	$4,495.5000	4,500.0	GJ x	$0.999	=	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$4.568	=	$20,556.0000	4,500.0	GJ x	$4.568	=	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$8.556	=	$38,502.0000	4,500.0	GJ x	$8.556	=	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges			$14.123		**$63,553.50**			$14.123		**$63,553.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$16.911*		**$76,101.24**	4,500.0		*$17.099*		**$76,947.24**	*$0.188*	**$846.00**	**1.11%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Effective Rate January 1, 2011	Proposed Rate January 1, 2012	Increase / (Decrease)	% Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.440	$10.680	$0.2400	2.30%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.263**	**$16.503**	**$0.2400**	**1.48%**
8						
9	Rider A	*($/GJ)*	($0.948)	($0.948)	$0.000	0.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.000	$0.524	$0.524	n/a
12	Total Riders	*($/GJ)*	**($0.948)**	**($0.424)**	**$0.524**	**155.27%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 15.315**	**$ 16.079**	**$ 0.764**	**4.99%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,468.35	$1,537.11		
22						
23	Change in Annual Bill	*($)*			**$ 68.76**	
24	Change in Annual Bill	*(%)*			**4.68%**	

Note: Existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Proposed Rate January 1, 2012	Proposed Rate January 1, 2013	Increase / (Decrease)	Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.680	$11.963	$1.2830	12.01%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.503**	**$17.786**	**$1.2830**	**7.77%**
8						
9	Rider A	*($/GJ)*	($0.948)	($0.948)	$0.000	0.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.524	$0.524	$0.000	0.00%
12	Total Riders	*($/GJ)*	**($0.424)**	**($0.424)**	**$0.000**	**0.00%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 16.079**	**$ 17.362**	**$ 1.283**	**7.98%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,537.11	$1,652.58		
22						
23	Change in Annual Bill	*($)*			**$ 115.47**	
24	Change in Annual Bill	*(%)*			**7.51%**	

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11

RATE 25 - TRANSPORTATION SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Transportation Delivery Charges											
4												
5	Delivery Charge per Gigajoule											
6	i) First 20 Gigajoules	240	GJ x	$2.910	= $698.4000	240	GJ x	$2.910	= $698.4000	$0.000	$0.0000	0.00%
7	ii) Next 260 Gigajoules	3,120	GJ x	$2.926	= $9,129.1200	3,120	GJ x	$2.926	= $9,129.1200	0.000	$0.0000	0.00%
8	iii) Excess over 280 Gigajoules	3,530	GJ x	$2.333	= $8,235.4900	3,530	GJ x	$2.373	= $8,376.6900	0.040	$141.2000	0.69%
9	iv) Minimum Delivery Charge per month	12	months x	$1,945.00		12	months x	$1,975.00		$30.00	$0.0000	0.00%
10												
11	Administration Charge per month	12	months x	$202.00	= $2,424.0000	12	months x	$202.00	= $2,424.0000	$0.00	$0.0000	0.00%
12												
13	Rider 5: RSAM per GJ	6,890	GJ x	($0.011)	= ($75.7900)	6,890	GJ x	($0.011)	= ($75.7900)	$0.000	$0.0000	0.00%
14												
15	Total Transportation Delivery & Administration Charges	6,890	GJ x	*$2.962*	$20,411.22	6,890	GJ x	*$2.983*	$20,552.42	*$0.021*	$141.20	0.69%
16												
17												
18	Summary of Annual Delivery, Administration and Commodity Charges											
19	Delivery & Administration Charge (including RSAM)	6,890	GJ x	$2.962	= $20,411.2200	6,890	GJ x	$2.983	= $20,552.4200	$0.021	$141.2000	0.69%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ	$0.000	= $0.0000	0	GJ	$0.000	= $0.0000	0.000	$0.0000	0.00%
21	Total	6,890	GJ x	*$2.962*	= $20,411.22	6,890	GJ x	*$2.983*	= $20,552.42	*$0.021*	$141.20	0.69%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

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Agreement for FEI's 2010-2011 RRA, approved by BCUC Order No. G-141-09, acknowledged that FEI would be engaged in Thermal Energy Services (or AES). The Negotiated Settlement Agreement for FEVI's 2010-2011 RRA, approved by BCUC Order No. G-140-09, acknowledged the fact that FEVI withdrew its requests for relief in the RRA relating to AES and the Parties acknowledged that FEI will be pursuing AES projects within the FEVI service area and agreed that the costs incurred by FEI to provide AES will not be recovered in FEVI's natural gas service rates.

The Commission's approval of the FEI NSA resulted in an approved Rate Schedule for Thermal Energy Services, and implemented the necessary terms and certain conditions to establish Thermal Energy Services as a distinct line of business within FEI. Some of the conditions included in the approved NSA were as follows:

> *"Natural Gas service taken in combination with AES will be charged under TGI's natural gas rates.*
>
> *The Parties agree that the costs incurred by TGI to provide AES should not be recovered as part of natural gas service rates, and visa versa. The Parties agree that TGI's proposed New Energy Solutions Deferral Account, attracting AFUDC, is an appropriate mechanism to address allocation issues as between TGI's gas customers and TGI's AES customers. Therefore, the Parties agree that the new Energy Solutions Deferral Account will remain in effect pending a future rate design application at an unspecified future date after 2011 and will capture and record the following (plus AFUDC) to be recovered from AES customers:*
>
>> *(a) Direct costs associated with AES projects as outlined on pages 267-268 of the Application, including cost of design, equipment, etc. constructing and financing; and*
>>
>> *(b) Sales and marketing O&M and other development costs will be directly charged to the deferral account by time sheets or other direct charge (estimated at $1.0 million in 2010 and $1.5 million in 2011, representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011); and*
>>
>> *(c) An appropriate overhead allocation, which the parties have agreed will be $500,000 in each of 2010 and 2011 (representing a portion of the agreed upon Gross O&M reduction from gas customers of $4.0 million in 2010 and $5.5 million in 2011).*
>
> *Revenues received from customers for all AES projects, which are based on contracts approved by Commission will be recorded in the AES deferral account.*
>
> *The risk of non-recovery of amounts in the New Energy Solutions Deferral Account will not be borne by natural gas ratepayers. The Parties agree that any debit balance in the New Energy Solutions Deferral Account will not be recovered through natural gas rates and any credit balance will not be applied to reduce natural gas rates…"*

FEI is making progress towards developing the Thermal Energy Services line of business. It is expected that FEI will be bring forth individual projects with signed contracts for Commission approval during the Spring and Summer of 2011 that will also meet the terms of the NSA. Consistent with the approved framework, forecast costs for 2012 and 2013 relating to Thermal

Energy Services have been segregated and allocated to the Thermal Energy Services line of business. FEI activities in the area of Thermal Energy Services will continue to be captured in the approved non-rate base deferral account attracting AFUDC, and do not form a part of the rate base or cost of service included in this Application. There is also a reduction in the O&M included in the natural gas cost of service (i.e. a benefit to natural gas customers) that is associated with the recovery of overheads from the Thermal Energy Services line of business. This is discussed further in Appendix G.

The growing prevalence of thermal solutions such as solar, DES and geo exchange, regardless of the provider of those services, will have an increasingly significant impact on the natural gas requirements over time. Thus, from the perspective of natural gas customers it is important to understand the growth of these energy alternatives over time and how they may impact the natural gas throughput and utilization. FEU sees this as an important issue to address in future filings such as the Long Term Resource Plan and future Rate Design applications. The need for additional resources to examine these impacts as part of the long term integrated resource planning process is discussed further in Section 5.3.8.

1.2.4 INCREASED FOCUS ON INVESTMENTS TO MAINTAIN THE SAFETY AND RELIABILITY OF OUR SYSTEM

In our 2010-2011 RRAs, we requested increases to O&M and capital budgets to ensure ongoing compliance to existing codes and anticipated new or changed codes and to allow us to continue to invest in the safety, integrity and reliability of the energy delivery system. To address these requirements, we received approval for additional O&M in the amount of $5.3 million in 2010 and a further $2.1 million in 2011. This funding allowed us to enhance safety messaging for customers, begin the long-range asset planning and address the specific code changes that were required. How each of these three areas has evolved since then is discussed below. The FEU believes that continued funding in these areas is necessary to ensure safe and reliable natural gas service.

1.2.4.1 Codes & Regulations

In addition to the codes and regulations that were addressed in 2010 and 2011, the FEU have identified new codes and regulations, and changes to existing codes and regulations that need to be addressed. A further discussion of these specific codes and regulations and incremental funding of $0.9 million in 2012 and a further $0.8 million in 2013 to address these requirements is included in O&M Section 5.3.

Two other areas where the Utilities need funding to address safety and system integrity are:

- The BCOneCall project - a multi-stream two and a half year project that will automate a portion of the BCOneCall process and allow for the realization of significant benefits immediately upon completion of the project; and

- The Gas Assets Project - a four year project to move historic gas system asset compliance records into one system, with three distinct phases which will improve access to records, the integrity of compliance record information, the completeness of existing compliance records, the protection of compliance records, and the retention and disposal of compliance records no longer needed for operational, or other requirements.

Each of these two significant projects is discussed further in the Rate Base Deferrals Section 6.2.

1.2.4.2 Safety Messaging

In 2010 and 2011, the FEU spent approximately $1.0 million on safety awareness, primarily to increase the public's awareness of how to identify and respond to a gas leak. This initiative requires additional funding in 2012 and 2013 to fully implement our gas odour and action safety messaging, and also to increase public safety education around excavation diligence. The details regarding our plans to spend an additional $900 thousand in 2012 and a further $100 thousand in 2013 are included in O&M Section 5.3.8.5 Energy Solutions and External Relations.

1.2.4.3 Long Term Asset Planning

FEU recognized the need to develop a long term life cycle view of gas assets when planning its sustainment capital and related asset management programs a number of years ago and first described these requirements in their 2010-2011 Revenue Requirements Application and 2010 Resource Plan. A long term view of gas assets is required primarily because of risks related to aging infrastructure. Complicating this planning requirement is the continual need to also address environmental responsibility, increased public expectations and increased regulations to maintain the safety, reliability and integrity of the distribution and transmission system used to provide gas delivery service. Critical in this regard is the concept of a "Long Term Sustainment Plan", which serves as a key component of FEU's approach for managing this challenge. This approach to long term planning is also important in order to ensure that any transmission and distribution system changes are cost effective so that their impact on customers' rates is kept to a minimum.

Today, FEU is responsible for managing gas transmission and distribution assets with a book value of approximately $3.0 billion and an approximate replacement value of $6.8 billion. Nearly 25 percent of distribution mains and 35 percent of intermediate and transmission pressure pipelines have been in service for 40 to 55 years. These aging assets face an increasing rate of deterioration as they approach the end of their service life. FEU anticipates that over the next 40 years approximately two-thirds of current assets will need to be replaced.

To successfully manage this coming wave of asset replacements, FEU must also be cognizant of other interrelated factors. A long term view of asset management is therefore required due to a number of reasons:

- customers expect natural gas to be there when they need it. Tolerance for service disruption due to inadequate planning on the part of the utility is understood to be limited;

- codes and regulations are becoming increasingly stringent with the natural gas delivery system operator being held to higher standards of reliability, safety and environmental stewardship;

- the increased focus on public safety has recently been seen in the response to a pipeline rupture and subsequent fire in San Bruno, California which has resulted in the introduction of a number of initiatives to increase the onus on the operators to ensure public safety. Asset failure that impacts public safety is not acceptable;

- significant rate increases due to costs of repairs and unanticipated asset replacements passed on to customers would not be in the best interest of the customers, especially if they come in large spikes as significant assets fail and require immediate replacement;

- the wave of asset replacement poses the challenge of mobilizing additional O&M and capital resources. Additional O&M resources are required to enhance the asset management practices needed to manage aging infrastructure. Capital resources are needed to procure material, equipment, services, labour and contractors for the execution of asset replacement; and

- municipalities and utilities across North America are starting to come to grips with aging infrastructure and how to maintain services to their customers. This need, combined with baby boomers retiring, is resulting in resource shortages across the continent. Adequate lead time and visibility of asset replacement programs is required in order to engage contractors so that resources can be successfully mobilized when they are needed.

FEU expects system sustainment costs to continue rising in the future given the extent of its aging infrastructure and because of the complexity of the interrelated factors described above. To help manage these increasing costs, ensure system integrity, address risk to public safety and property and continue to reliably deliver service, FEU is developing a Long Term Sustainment Plan (“LTSP”).

The LTSP includes enhancements to our asset management and system integrity processes. The cost to establish these enhancements are included as a key component of the incremental O&M funding requested in Section 5.3 of this Application. Instead of identifying asset replacement requirements on a reactive basis and with a limited view beyond a three to five year horizon, and potentially overlooking major projects that address high risks, a higher level of resources is needed to complete the comprehensive reviews and analyses that are required to support long-term capital expenditure commitments of the amounts anticipated after 2013.

As a result, under a US GAAP adoption scenario, the FEU would propose the creation of a non rate base deferral account to capture any differences that arise from the implementation of FIN 48.

3.2.2.3 Other US GAAP Items

A number of other adjustments are contemplated on transition to US GAAP that should not affect cost of service or rate base. These potential adjustments include the application of pushdown accounting, adjusting for how FEI accounts for Lease In/Lease Out transactions for external financial reporting, and others. None of these transactions are expected to affect regulatory accounting or reporting and would not affect the revenue requirement.

3.2.2.4 Costs Associated with the Adoption of US GAAP

In their US GAAP Application, the FEU outlined the expected costs of adopting both IFRS and US GAAP. The costs of adopting US GAAP were estimated to be incremental one-time costs of $1.8 million and incremental on-going costs of $0.9 million. These one-time costs are generally as a result of audit fees on the adoption of US GAAP. The higher on-going costs are as a result of higher audit fees including work required under Sarbanes-Oxley. These costs have not been included in this application. Under a US GAAP adoption scenario, the FEU would include the recovery of these costs through an evidentiary update to this RRA.

3.2.3 SUMMARY OF STATUS OF GAAP

In summary, upon receipt of a decision in the US GAAP Application, the FEU will provide an evidentiary update.

If the US GAAP Application is approved as proposed, the FEU will update their Application to include:

1. A total decrease in cost of service from pension and OPEBs (decrease of $782 thousand in 2012 and $2.24 million in 2013 as shown in Table 3.2-1 above) plus any associated income tax impacts;
2. The changes to rate base resulting from the pension and OPEB deferrals discussed in Section 3.2.2.1,
3. A total increase in O&M of $0.9 million in each of 2012 and 2013 for the ongoing costs of US GAAP compliance; and
4. A rate base deferral to capture the estimated $1.8 million in one-time US GAAP conversion costs.

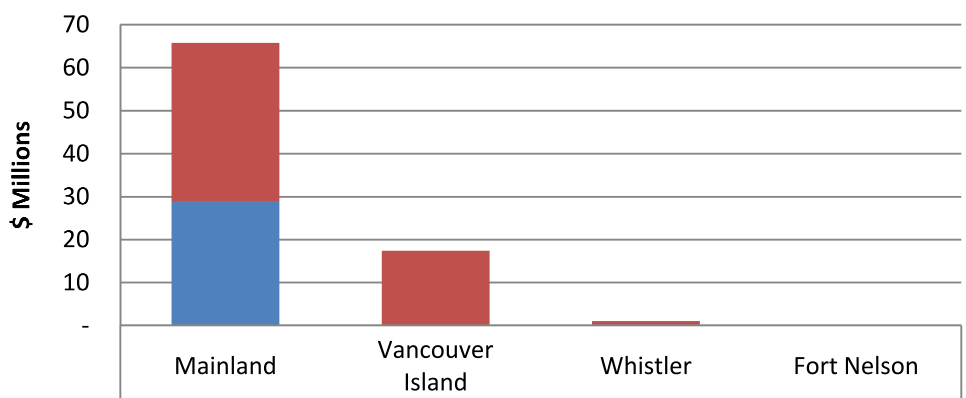
In the event that the FEU are ordered to implement accounting policies other than US GAAP, the FEU will update their Application to include the impacts of those changes.

3.3 Summary of Revenue Requirements for 2012 and 2013

The revenue requirements reflect all of the inputs in the financial schedules, and take into consideration all of the impacts described in this Application. The revenue requirement changes that the Companies are requesting are based on sound research and forecasting, using our knowledge and experience to determine what the Companies believe is the likely course of events over the upcoming forecast periods of 2012 and 2013.

The following figure provides the 2012 and 2013 revenue deficiencies for the FortisBC Energy Utilities. The revenue deficiency or surplus is determined by comparing the forecast cost of service to the forecast revenue at existing 2011 rates for each year.

Figure 3.3-1: Forecast 2012 and 2013 Revenue Deficiencies for the FortisBC Energy Utilities[20]

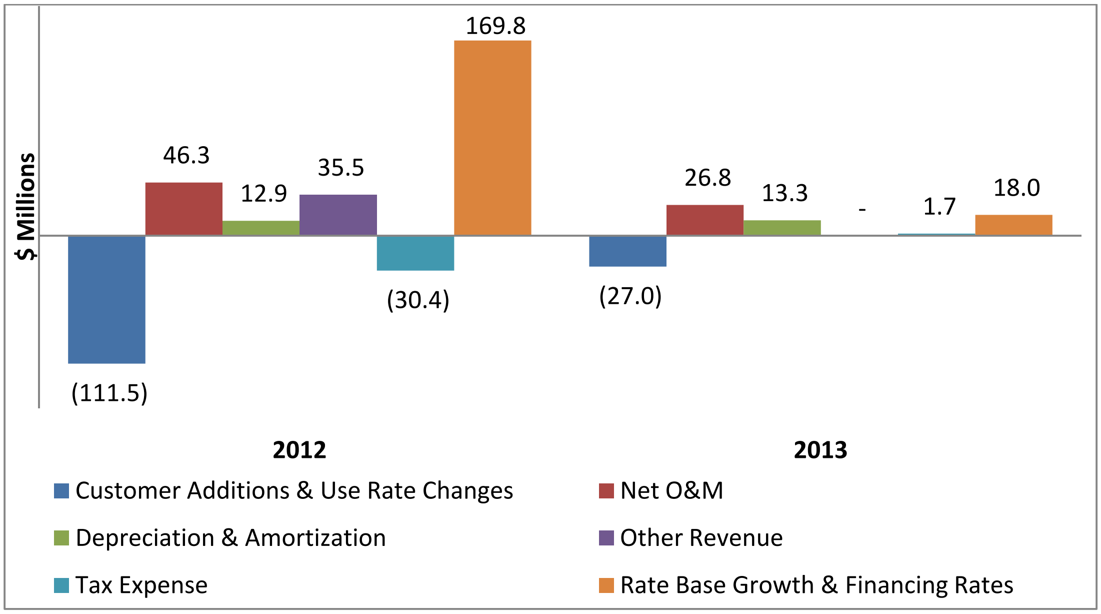


	Mainland	Vancouver Island	Whistler	Fort Nelson
2013	$36.79	$17.44	$0.91	$0.03
2012	$28.97	$0.00	$0.17	$0.12

The revenue deficiencies result in 2012 and 2013 delivery rate changes for Mainland, Whistler and Fort Nelson as demonstrated in Table 3.3-1. The forecast revenue deficiency for Vancouver Island in 2013 is being offset by part of the projected December 31, 2012 surplus balance of $71.6 million (before tax) in the RSDA. In this Application, Vancouver Island is seeking approval for a rate freeze for 2012 (which equals the forecast cost of service) and 2013 and the continuation of the RSDA mechanism for 2012 and 2013.

[20] Section 7.1 to 7.4, Schedule 2 and 3

Figure 3.3-12: Fort Nelson Revenue Deficiency Components[44]



3.3.4.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 4, is a key component of the determination of the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the year. The sales customer demand determined in Section 4 is 34 TJs greater than the demand forecast embedded in 2011 rates, with an increase of approximately 9 TJs in 2013. This increase in demand is attributable to customer growth and changes in use rates and results in a revenue surplus of approximately $112 thousand in 2012 and $27 thousand in 2013.[45]

The demand forecast is discussed more fully in Section 4, Demand Forecast and Revenue at Existing Rates and has been properly reflected in the calculation of the Company's revenue requirement.

3.3.4.2 Operations and Maintenance Expenses

The 2012 and 2013 O&M expense reflects the two key business drivers identified in Section 5.3. 2012 and 2013 revenue requirements are summarized in the figure below by these drivers. As shown in Figure 3.3-13, the impact of changes in the O&M is an increase to the revenue requirement of $46 thousand in 2012 and $27 thousand in 2013, net of capitalized overhead.

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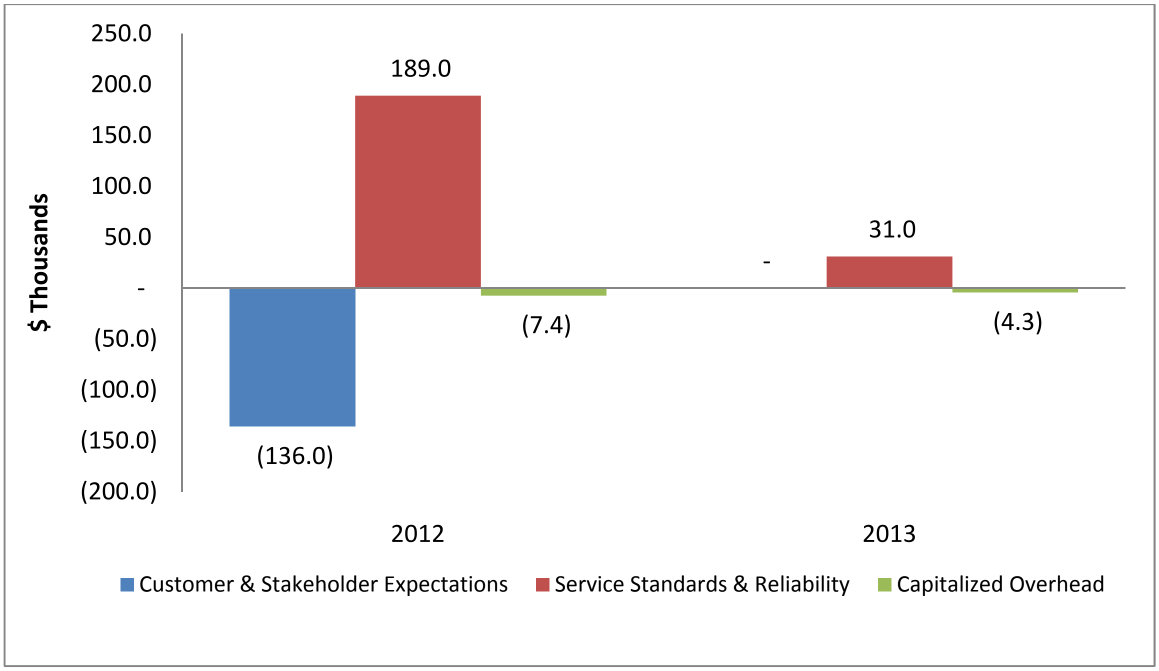
44 Section 7.4, Schedule 1
45 Section 7.4, Schedules 4 to 9

Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements[46]



The items in the chart above are discussed more fully in Section 5.3, and have been properly reflected in the calculation of the Company's revenue requirement.

Depreciation and Amortization Expense

A full year of depreciation associated with the Muskwa River Crossing Project, as well as additions in 2012 and 2013, have resulted in higher depreciation expense of $68 thousand in 2012 and a further $10 thousand in 2013. This increase is offset by the impacts of the changes in depreciation rates which reduce the expense by $30 thousand. Since the impacts on depreciation are not deductible for income tax purposes, the total impact on revenue requirements for these items needs to be grossed up. The revenue requirement impact of depreciation changes is an increase of $50 thousand in 2012 and a further $13 thousand in 2013.

In addition, amortization expense has decreased $37 thousand in 2012 with no further changes in 2013. This amount is after-tax, so the impact to revenue requirements is as stated.

46 Please refer to Section 5.3, Table 5.3-12 and Table 5.3-13

3.3.4.4 Other Revenues

As discussed in Section 5.5, a decrease in Other Revenue of $36 thousand in 2012 is forecast with no further change forecast in 2013. Decreases in other revenue increase the revenue requirement and the revenue deficiency. The decrease is attributable to a forecast reduction in Late Payment Charges; a downward trend consistent with the lower bad debt expense experienced by the Utilities.

3.3.4.5 Taxes

As discussed in Section 5.6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to CCA rates all have an impact on the revenue requirement calculation. The property tax increase of $7 thousand in 2012 and a further increase of $6 thousand in 2013 result in increases to the revenue requirement. Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2012 of $37 thousand and a reduction in 2013 of $4 thousand.

3.3.4.6 Earned Return

Fort Nelson earns a return on rate base, so changes in the amount of rate base affect the amount of return included in the revenue requirement by approximately 3.8 per cent of that change. The rate base proposals contained in Section 6 increase revenue requirement by $78 thousand in 2012 and have a further increase of $9 thousand to the 2013 revenue requirement.

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in 5.7, Financing Costs and ROE. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by higher rate base, and changes in interest rates result in a net increase associated with financing costs of $92 thousand in 2012 followed by an increase of $8 thousand in 2013.

The revenue requirement changes discussed above are translated into customer delivery rate impacts by comparing the resulting revenue deficiency with the existing gross margin. The percentage change is applied to all existing delivery rates.

3.3.5 SUMMARY OF AMALGAMATED COST OF SERVICE

As discussed in Section 1.2.5, in addition to seeking approval of rates for each of the FEU, we are also seeking approval of the amalgamated cost of service for 2013. This will form the first step of the Companies' plans to amalgamate, and will be followed by an application in Fall 2011 requesting approval to amalgamate with a rate design based on the amalgamated cost of service. As the FEU are seeking approval for the amalgamated cost of service prior to the merits of amalgamation being considered by the Commission, the FEU have phrased the approval requested in this application to be conditional upon the amalgamation being approved and going forward. The efficiency rationale for proceeding in this fashion is also discussed in Section 1.2.5.

In Section 3.3.5.1, the FEU provide a summary of the amalgamated cost of service. The amalgamated cost of service represents the summation of the Mainland, Vancouver Island, Whistler and Fort Nelson cost of service as described above, as well as adjustments to account for cost of service line items that will eliminate or change upon amalgamation.

3.3.5.1 FEU Amalgamated Cost of Service

The FEU amalgamated cost of service of $1.509 billion ($779.9 million delivery margin) is determined in Section 7.5, Schedule 2 as follows:

Table 3.3-10: Amalgamated 2013 Cost of Service

		2013		
($ thousands)	Reference	Total	Cost of Gas	Cost of Service[1]
Mainland	*Section 7, Tab 7.1, Schedule 6, Column 5*	$ 1,282,763	$ 658,568	$ 624,195
Vancouver Island	*Section 7, Tab 7.2, Schedule 6, Column 5*	214,087	76,399	137,688
Whistler	*Section 7, Tab 7.3, Schedule 6, Column 5*	12,173	3,455	8,718
Fort Nelson	*Section 7, Tab 7.4, Schedule 6, Column 5*	5,001	2,945	2,056
		1,514,024	741,367	772,657
Add (Deduct):				
FEI (LNG Mitigation fee to FEVI)		-	(12,024)	12,024
Other Cost of Service & Rate Base		(2,158)	-	(2,158)
FEW Transportation Charge		(2,585)	-	(2,585)
Squamish Transportation Charge		(416)	(416)	-
Total Amalgamation Adjustments		(5,159)	(12,440)	7,281
Amalgamated FEU Cost of Service		**$ 1,508,865**	**$ 728,927**	**$ 779,938**

[1] *Cost of service excluding cost of gas*

AMALGAMATION ADJUSTMENTS

The cost of service must be adjusted to reflect intercompany items that will be eliminated upon amalgamation and rate harmonization. In the case of shared services and wheeling or transportation charges between the Regions, the amalgamation of the entities results in the inter-company agreements ceasing to be in effect, and the need to retain them for regulatory purposes disappears upon amalgamation. In the case of the three items below, an adjustment must be made to the cost of service.

- The LNG mitigation revenues are included in the Vancouver Island delivery cost of service with the offset cost residing in the Mainland midstream costs. For purposes of this analysis, FEU has taken the approach of showing this $12 million adjustment to the delivery cost of service and cost of gas; however, the allocation of the LNG mitigation revenues as between midstream and delivery will be reviewed in the Fall 2011 Amalgamation and Rate Design Phase 'A' Application and may result in changes from what has been presented in this RRA.

- Other cost of service impacts from changes in interest expense and cash working capital occur. The short term interest expense for the amalgamated cost of service is determined using the FEI short term debt rate, which results in a reduction to the cost of service of approximately $2.2 million. The cash working capital for the amalgamated cost of service is determined using the FEI approved Lead and Lag days.
- The FEW Transport charges are accounted for as a cost in FEW but as a revenue FEVI; therefore the delivery cost of service has been adjusted to remove these costs.
- The Squamish Transport charges are accounted for as commodity costs in FEI but as revenue in FEVI; therefore the cost of gas has been adjusted to remove these costs.

The Companies do not expect that there will be material cost savings as a result of the amalgamation, since the operations and management of the utilities are already fully integrated and the savings have been captured for the benefit of customers over the 2004 through 2011 period; however, some small annual savings will be realized. These savings would be limited to reporting efficiencies such as financial, legal and regulatory reporting and debt issuance requirements. There will also be costs incurred to effect a future legal amalgamation of the Companies, if approved. For the one year of amalgamated cost of service (2013) relevant to this RRA, the costs and savings are expected to offset each other, and therefore the FEU have not forecast a change to the cost of service for this item. The FEU will capture any variances from the forecast of zero in a deferral account for future recovery from/return to customers. Although the costs related to the legal amalgamation are one-time in nature, any efficiency savings, although not large, will be ongoing, and will be included in future RRAs.

3.4 Rate Proposals

3.4.1 DELIVERY RATES

The proposed delivery rates reflect the revenue requirements for each Utility as discussed in Section 3.3. Preliminary bill impacts and tariff continuity schedules for all customers are provided in Appendix F-2, showing the annual bill impacts below. The following summary for each Utility provides the delivery rate change required and a summary of the annual bill impact of the rate proposals for an average residential customer in Mainland, Whistler, and Fort Nelson.

3.4.1.1 Mainland

The Mainland proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 5.0 per cent in 2012 and an additional effective base rate delivery increase of 6.4 per cent in 2013 (cumulative increase of 11.4 per cent).[47] These proposed increases result in changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.4 per cent or $24 in 2012 and an additional 3.0 per cent or $31 in 2013.[48]

3.4.1.2 Whistler

The Whistler proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 2.2 per cent in 2012 and an additional effective base rate delivery increase of 11.9 per cent in 2013 (cumulative increase of 14.1 per cent).[49] These proposed increases result in changes to the annual bill of an average Whistler residential customer with an approximate net increase of 1.5 per cent or $22 in 2012 and an additional 7.1 per cent or $115 in 2013.[50]

3.4.1.3 Fort Nelson

The Fort Nelson proposed delivery rates reflect the 2012 and 2013 revenue requirements and result in an effective delivery rate increase of 6.5 per cent in 2012 and an additional effective base rate delivery increase of 1.6 per cent in 2013 (cumulative increase of 8.1 per cent).[51] These proposed increases result in changes to the annual bill of an average Fort Nelson residential customer with an approximate net increase of 2.3 per cent or $26 in 2012 and an additional 0.6 per cent or $7 in 2013.[52]

3.4.2 VANCOUVER ISLAND EFFECTIVE RATES

FEVI has been operating under the Vancouver Island Natural Gas Pipeline Act Special Direction[53] (the "Special Direction") since 1995.[54] The Special Direction is appended to the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA"), an agreement among the predecessor companies to FEVI, the Province, and (by assignment from Westcoast Energy Inc.) Fortis BC Holdings Inc. ("FHI"). The VINGPA contemplates the payment by the Provincial

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[47] Section 7.1, Schedules 2 and 3
[48] Appendix F-2, Tab 1.1.1 and Tab 1.2.1, Page 1
[49] Section 7.3, Schedules 2 and 3
[50] Appendix F-2, Tab 3.1 and Tab 3.2, Page 1
[51] Section 7.4, Schedules 2 and 3
[52] Appendix F-2, Tab 4.1.1 and Tab 4.2.1, Page 1
[53] OIC No. 1510 (Dec. 13, 1995).
[54] The Special Direction states that it shall cease to have any application after the latest of three conditions occurring: (a) the time when the balance of the RDDA has been reduced to zero; (b) the expiration/termination of the Joint Venture Transportation Service Agreement ("JV TSA"), but no later than January 1, 2011; or (c) the date of the termination of the Squamish Gas TSA. Although the RDDA has been reduced to zero and January 1, 2011 has passed, the Squamish Gas TSA continues to remain in effect thus keeping the Special Direction in effect.

employees anticipated to retire by the end of 2012 is reflected in the decrease that is expected for 2013.

SERVICE STANDARDS AND RELIABILITY

Transmission requires an additional $1.005 million in O&M funding in 2012 and an additional $1.048 million is needed in 2013 to meet service standards and reliability. These amounts are comprised of standard inflation on materials for a total of $180 thousand in 2012 and an additional $185 thousand in 2013, and the need for additional system sustainment resources for a total of $1.1 million in 2012 and an additional $803 thousand in 2013. These increases are offset by a forecast savings in Own Use Fuel.

The system sustainment resources include the additional level of staffing described above in the discussion on employee changes in Section 5.3.5.11, as well as consulting resources needed to help with the further refinement of asset management processes and for the completion of project feasibility investigations. These additional O&M costs need to be incurred to plan for increased asset renewals as a large portion of the Company's gas system assets approach the end of their useful life. The incremental O&M funding is required to complete feasibility studies and early stage planning, and to prepare budget requests for a variety of potential projects required to provide a long term view of asset management and system sustainability. Please refer to the discussion about system sustainment and asset management in Section 2 of the Application and to the discussion of capital requirements in Section 6.2 for information about this critical requirement.

These cost increases are offset by a forecast reduction in Own Use Fuel required to operate the Company's compressors and the Tilbury LNG facility (savings of $275 thousand in 2012 followed an increase of $61 thousand in 2013). The changes in Own Use Fuel costs are based on current forward market prices, which are lower than those forecast for 2011, but increase in 2013 from the cost estimated for 2012.

5.3.5.15 Transmission 2012 and 2013 Forecast - Vancouver Island

Transmission requires $621 thousand in incremental O&M funding in 2012 and a further $308 thousand in 2013 for Vancouver Island Transmission system operating and maintenance activities. A discussion of these increases by cost driver follows.

Table 5.3-24: Incremental Transmission O&M Requirements to Meet Future Obligations

Year (in $'000's)	Prior Year	2011 HST Savings	Labour Inflation and Benefits	Code and Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012	6,134	(41)	62	(92)	-	-	693	621	6,755
2013	6,755	-	63	45	-	-	201	308	7,064

CODES AND REGULATIONS

A number of non-recurring activities in 2011 that resulted from CSA Z662 are no longer required. In particular, aerial recoating, inline inspection activities, and seismic inspection activities required by CSA Z662 are complete for the 2012 and 2013 period, which results in an O&M reduction of $187 thousand in 2012. This savings is offset in 2012 by primarily two items:

(1) a $20 thousand cost increase driven by the need to ensure that transmission pipeline signage meets CSA Z662 code to clearly identify the presence of pipelines in order to reduce the possibility of damage and interference and (2) an additional $75 thousand to manage the existing condition of vegetation growing on transmission rights of way on the Vancouver Island system.

In 2013, a cost increase of $45 thousand is forecast for the recertification of pressure safety valves used in Transmission's compressors. This recertification requirement reoccurs on a three year cycle.

SERVICE STANDARDS AND RELIABILITY

Transmission needs an additional $693 thousand in incremental O&M in 2012 and an additional $201 thousand in 2013 on Vancouver Island to meet its objectives related to Service Standards and Reliability. These amounts are comprised of standard inflation on materials for a total of $65 thousand in 2012 and an additional $66 thousand in 2013, and the need for additional Transmission pipeline employees for a total of $170 thousand in 2012 and an additional $95 thousand in 2013. An additional $166 thousand is required in 2012 for Mt. Hayes LNG plant operators who were able to capitalize a portion of their labour costs in 2011 while assisting with the construction of the LNG facility. The access road leading to the new Mt. Hayes LNG facility requires an additional $50 thousand in 2012 for ongoing annual maintenance. Additionally, Mt. Hayes will incur incremental electricity costs required for ongoing liquefaction and vaporization activities. In 2012 Mt. Hayes is forecast to incur additional electricity costs, net of a minor fuel gas savings, totalling $242 thousand. In 2013 electricity costs are expected to increase a further $40 thousand.

5.3.5.16 Operations Summary

Outside of inflationary pressures, the main contributors to the increase in 2012 and 2013 forecast O&M expenditures for the Operations department relate to demographics, service standards and reliability, and code and regulations compliance.

Having effective asset, distribution and transmission system management is necessary to help ensure reliable, secure, and cost effective supplies of natural gas and propane to customers. The Operations department believes the costs it has presented are prudent and necessary to meet the above objectives and customer priorities.

5.3.6 ENERGY SUPPLY AND RESOURCE DEVELOPMENT

5.3.6.1 Departmental Overview

The Energy Supply and Resource Development department is responsible for two broad functional areas of activity – Energy Supply, and Resource Development. The purpose of each of these two functional areas and the scope of their activities are described in the following section.

ENERGY SUPPLY AND RESOURCE DEVELOPMENT ORGANIZATIONAL STRUCTURE

The organizational chart for the Energy Supply and Resource Development department is presented below.

NGV

Capital invested in NGV fueling assets, subject to approval of the NGV Application presently before the Commission, is forecast to be $4 million in 2012 and $3.8 million in 2013. These projects will be accompanied by contracts that provide for their forecast incremental costs of service to be recovered through dedicated take-or-pay incremental revenues from the incremental NGV fueling customers. Further detail on this capital investment is provided in Appendix I.

6.2.3.6 Vancouver Island Growth Capital Overview

Anticipated Growth Capital expenditures for 2012-2013 together with 2010 and 2011 data for Vancouver Island are summarized in Table 6.2-16 below.

Table 6.2-16: Approved, Actual and Forecast Vancouver Island Growth Capital Expenditures

($ thousands)

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Growth Capital						
New Customer Mains	2,725	1,836	2,966	2,553	2,757	2,922
New Customer Services	5,940	5,309	6,459	4,517	4,926	5,270
New Customer Meters	540	430	582	440	480	513
	9,206	**7,575**	**10,006**	**7,510**	**8,163**	**8,705**

6.2.3.7 Mains – Vancouver Island

Forecast new mains activity, together with unit costs and capital expenditure levels are summarized in Table 6.2-17 below.

Table 6.2-17: Approved, Actual and Forecast Vancouver Island Mains Activities, Unit Costs & Expenditures

	2010 Approved	2010 Actual	2011 Approved	2011 Projection	2012 Forecast	2013 Forecast
Activities (meters)	30,116	18,282	31,610	24,927	26,393	27,415
Unit Costs ($/meter)	$ 90	$ 100	$ 94	$ 102	$ 104	$ 107
Expenditures ($000's)	$ 2,725	$ 1,836	$ 2,966	$ 2,553	$ 2,757	$ 2,922

Forecast mains activity levels, forecast mains unit costs and capital expenditure forecasts for mains are described in the following three sections.

MAINS ACTIVITY LEVELS

The forecast level of mains activity is derived indirectly from the customer additions forecast. Customer additions determine the forecast quantity of Service additions based on a three year

(2008-2010) historical ratio of 0.81 Services per Gross (new) customer addition. In turn, the forecast mains activity level is determined by using a three year (2008-2010) historical ratio of 12 metres of new main per new Service addition. A three year historical ratio is used to smooth out the annual fluctuations in the ratio as well as to recognize any trends materializing in the past three years of actual data.

Projected new mains activity levels for 2011 are 24,927 metres based on the 2011 forecast new customer additions and the forecasting methodology described above. Using the same methodology, in 2012 and 2013, new mains activity has been forecast at 26,393 and 27,415 metres, respectively.

MAINS UNIT COSTS

The forecast unit costs for 2012 and 2013 reflect the unit cost experience of 2010 inflated by 2 percent annually. The 2010 activity levels declined 26 percent from 2009 levels which contributed to economy of scale unit cost pressures when compared to 2010 approved activity levels and unit cost. Due to the declining service activity levels, on a percentage basis, the Vancouver Island mains work has seen a slight shift back to the company workforce from the install contractors although the total amount of new mains work installed by the company's own workforce has remained unchanged in 2010 from 2009. The percent of mains activity completed by contractors in 2010 was 80 percent versus 87 percent in 2009 and 97 percent in 2008. Vancouver Island maintains company workforce levels sufficient to respond to emergencies and consequently, Vancouver Island own workforce unit costs are historically higher than contractors due to having to periodically interrupt projects to respond to emergencies. 2010 unit costs ($100/metre) have dropped from 2009 actuals ($105/metre) due to changes in contract pricing, exclusion of training costs in company labour rates and strengthening of the main extension estimating process. Other variables impacting overall unit costs are geographical location of main extension and the corresponding municipal, pavement, and traffic control requirements.

Forecast unit costs reflect a significant component of new mains work activity being assigned to the install contractor as our crews typically have sufficient levels of emergencies, new and conversion service activity to limit assignments to the lengthier more complex main jobs. 2012 and 2013 forecast unit costs are based on 2010 actuals and 2011 projection and reflect inflationary increases for the contractor workforces. The inflationary increase used for both 2012 and 2013 is 2 percent.

MAINS EXPENDITURES

The 2010 actuals and 2011 projected expenditures are lower than the 2010-2011 approved amounts due primarily to lower activity levels. Higher actual unit costs in 2010 versus approved unit costs driven by the factors cited above partially offset the reduction in expenditures due to lower activities.

versions can be as short as 18 months. Larger application vendors (i.e. GE Smallworld and SAP) have scheduled version updates that incorporate new changes and additional functionality to the application, incorporate correction patches into the core system and take advantage of improvements in infrastructure. Many software and hardware vendors typically abandon older versions and withdraw support as their new version becomes available. Consequently, continuous sustainment investments must be made to replace these older applications and technologies. This sustainment cycle also requires the upgrading and replacement of desktop computer technologies in order to operate more advanced versions of the software applications. The establishment of an "Evergreening" program has enabled us to follow a consistent and predictable approach to ensuring core infrastructure and applications are reasonably current in today's ever changing version landscape, optimizing the usage the existing assets and then replacing them before they start to break down which would result in costly maintenance repairs and lost productivity.

The focus on IT security has increased steadily. A dramatic shift in security threats began early in 2001. This is primarily due to the increased use of Internet e-mail functionality and the escalating threat of external hackers. These security threats have grown to exploit weaknesses in all areas of network and software applications. The increased use of the Internet to support business processes requires additional investment in the protection of those processes and associated data. IT security must continue to be implemented with a depth model that uses many layers of differing protection but still offers the capability to support business requirements. With the disaster recovery site operational, IT is better equipped to support the breadth of the Disaster Recovery Plan required for business continuity; however continued investment must be made to ensure the relevancy of the information slated for disaster recovery considering the constant change in the Company's applications and systems.

The demand for IT capital investment pursuant to the categories above is significant. It is the IT department's experience that this demand continues to outpace the Company's capacity to execute. It is also the Company's experience that not all projects that are implemented by the end of any year are identified during the prior year's budgeting process. The capability of the business units to invest resources required to successfully implement new solutions must be balanced against operational demands.

IT PROJECT PORTFOLIO DEVELOPMENT

In order to mitigate the issues above, the Company implemented in 2010 a well established methodology known as IT Project Portfolio Management (PPM). This methodology is a recognized discipline for managing IT Project portfolios that facilitates the evaluation, prioritization and coordination of the requirements of the various operating business units and technology, thus enabling more effective capital investment decisions.

The Company's PPM provides a standard framework to evaluate projects allowing for the comparison and selection of competing IT investment options. Projects must be aligned to one or more of the Company's strategic goals, and each project is required to demonstrate how it supports the achievement of organizational goals and priorities. PPM compares and prioritizes potential IT project investments based on the project's value contribution to the organization's goals, irrespective of where the initiative originated. Those projects with the greatest contribution and alignment will receive highest priority. The priority of each project guides the financial and resource allocation for the portfolio. Prioritization ideally assures projects with the greatest value to the Company will be considered first when allocating finite resources. PPM ultimately drives the establishment of the IT Project Portfolio which must be reviewed and accepted by the Utility Operating Committee Capital Management group consisting of the key representatives from IT, Finance, Regulatory, Distribution, Transmission, Marketing, and Engineering Services. This activity takes place annually following the corporate budgeting process and in advance of initiation of the targeted fiscal year. Prior to execution, all approved IT Project Portfolio projects must still acquire formal authorization for capital investment through written justification (business casing) which reconfirms the business value of undertaking the project and validates the assumptions made in the initial establishment of the IT Project Portfolio.

2012 AND 2013 FORECASTS

The Company is forecasting an increase of $2.0 million for the Mainland and $500 thousand for Vancouver Island for 2012 from the 2011 total of $16.0 million and $1.5 million respectively, with 2013 held at that level. This increase is based on enabling several robust technology roadmaps created in 2010 and 2011 in addition to satisfying pent-up demand from restrictions on the execution of several IT projects other than the CCE CPCN. Effective execution of this increased forecast will be managed through the employment of PPM, management of inter-project dependencies and risk mitigation within the IT Project Portfolio and the optimal usage of IT and business resources freed up from the cessation of the CCE CPCN. For projects that require significant business involvement, the business must prioritize between IT project commitments and other business imperatives. Over the years, the Company has invested time and effort on technology that enables operational efficiencies and the integration of business processes spanning multiple business units. Consequently, the IT Project Portfolio management team must work to ensure that all affected groups are coordinated and have the same ability to commit resources to projects that impact them all.

The capital request for IT investment is forecast at an amount in 2012 and 2013 that FEU believes is the appropriate amount that can prudently be executed while meeting the top priorities of the business. The incremental $2.5 million from 2011 to a total of $20 million for the in each of 2012 and 2013 reflects the costs anticipated to ensure a balanced IT Project Portfolio that will address the requirements of technology sustainment, security and risk mitigation and meet the priority demands of the Company's further IT enablement.

UTILITY INCOME AND EARNED RETURN CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2012
($000s)

May 16, 2011

Section 7
TAB 7.5
Schedule 1

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Cost of Gas Sold (Including Gas Lost)	$ 659,338	$ 74,337	$ 3,493	$ 2,900	$ 740,068	$ (12,440) [1]	$ 727,627	
2	GCVA Amortization	-	(8,124)	-	-	(8,124)	-	(8,124)	- Sect 7-TAB 7.5, Schedule 7
3	Net Cost of Gas	659,338	66,213	3,493	2,900	731,944	(12,440)	719,503	
4									
5	Operation and Maintenance	192,742	30,303	779	744	224,568	-	224,568	- Sect 7-TAB 7.5, Schedule 11
6	Transportation Costs	-	4,483	2,585	-	7,068	(6,041) [2]	1,027	- Sect 7-TAB 7.5, Schedule 7
7	Property and Sundry Taxes	49,656	9,895	236	172	59,959	-	59,959	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	133,920	35,896	1,062	360	171,238	(41) [3]	171,197	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(27,203)	(12,651)	(16)	(24)	(39,894)	15,522 [4]	(24,373)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	24,478	3,878	336	56	28,748	17 [5]	28,765	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	212,179	57,074	2,906	688	272,847	(1,376) [6]	271,470	- Sect 7-TAB 7.5, Schedule 5
12	Delivery Cost of Service	585,772	128,878	7,888	1,996	724,534	8,081	732,613	
13									
14	Total Cost of Service	1,245,110	195,091	11,381	4,896	1,456,478	(4,358)	1,452,116	
15									
16		Notes							
17		1 FEI LNG Mitigation to FEVI ($12) MM, FEVI Squamish Wheeling from FEI ($0.4) MM							
18		2 FEVI Wheeling ($3.5) MM to FEI, FEW Wheeling ($2.5) MM to FEVI							
19		3 FEVI amortization of Whistler Contribution $0.25 MM offset by FEW amortization of Contribution deferral ($0.29) MM							
20		4 FEVI Wheeling $3.5 MM to FEI, FEVI LNG Mitigation $12 MM from FEI, Late Payment Ratio applied to FEU Revenues $0.02 MM							
21		5 Change in Rate Base impact on Income Taxes							
22		6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes							

UTILITY INCOME AND EARNED RETURN CONTINUITY
FOR THE YEARS ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Cost of Gas Sold (Including Gas Lost)	$ 658,568	$ 76,399	$ 3,455	$ 2,945	$ 741,367	$ (12,440) [1]	$ 728,927	
2	GCVA Amortization	-	-	-	-	-	-	-	
3	Net Cost of Gas	658,568	76,399	3,455	2,945	741,367	(12,440)	728,927	
4									
5	Operation and Maintenance	203,365	30,515	787	771	235,438	-	235,438	- Sect 7-TAB 7.5, Schedule 11
6	Transportation Costs	-	4,494	2,585	-	7,079	(6,049) [2]	1,029	- Sect 7-TAB 7.5, Schedule 7
7	Property and Sundry Taxes	51,239	10,263	244	178	61,924	-	61,924	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	152,235	37,334	1,661	370	191,600	(35) [3]	191,565	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(28,883)	(12,662)	(16)	(24)	(41,585)	15,513 [4]	(26,074)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	30,160	7,440	542	55	38,197	10 [5]	38,207	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	216,079	60,304	2,915	706	280,004	(2,155) [6]	277,849	- Sect 7-TAB 7.5, Schedule 6
12	Delivery Cost of Service	624,195	137,688	8,718	2,056	772,657	7,283	779,938	
13									
14	Total Cost of Service	1,282,763	214,087	12,173	5,001	1,514,024	(5,156)	1,508,865	
15									
16		Notes							
17		1 FEI LNG Mitigation to FEVI ($12) MM, FEVI Squamish Wheeling from FEI ($0.4) MM							
18		2 FEVI Wheeling ($3.5) MM to FEI, FEW Wheeling ($2.5) MM to FEVI							
19		3 FEVI amortization of Whistler Contribution $0.25 MM offset by FEW amortization of Contribution deferral ($0.29) MM							
20		4 FEVI Wheeling $3.5 MM to FEI, FEVI LNG Mitigation $12 MM from FEI, Late Payment Ratio applied to FEU Revenues $0.02 MM							
21		5 Change in Rate Base impact on Income Taxes							
22		6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes							

($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Gas Plant in Service, Beginning	$ 3,542,280	$ 1,263,155	$ 16,216	$ 11,799	$ 4,833,450		$ 4,833,448	- Sect 7-TAB 7.5, Schedule 22
2	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
3	Gas Plant in Service, Ending	3,770,188	1,317,524	17,203	12,525	5,117,440		5,117,445	- Sect 7-TAB 7.5, Schedule 22
4									
5	Accumulated Depreciation Beginning - Plant	$ (923,722)	$ (295,740)	$ (2,588)	$ (2,366)	$ (1,224,416)		$ (1,224,413)	- Sect 7-TAB 7.5, Schedule 28
6	Adjustment - CPCNs / Opening Bal Adjt	4,405	9,193	-	-	13,598		13,597	- Sect 7-TAB 7.5, Schedule 28
7	Accumulated Depreciation Ending - Plant	(1,014,039)	(318,482)	(2,933)	(2,718)	(1,338,172)		(1,338,167)	- Sect 7-TAB 7.5, Schedule 28
8									
9	Negative Salvage Depreciation Beginning - Plant	$ -	$ -	$ -	$ -	$ -		$ -	- Sect 7-TAB 7.5, Schedule 32
10	Adjustment - CPCNs / Opening Bal Adjt	(4,405)	(9,193)	-	-	(13,598)		(13,597)	- Sect 7-TAB 7.5, Schedule 32
11	Negative Salvage Depreciation Ending - Plant	(7,994)	(12,476)	(74)	-	(20,544)		(20,543)	- Sect 7-TAB 7.5, Schedule 32
12									
13	CIAC, Beginning	$ (171,372)	$ (276,364)	$ (186)	$ (1,287)	$ (449,209)	17,034 [1]	$ (432,176)	- Sect 7-TAB 7.5, Schedule 34
14	Adjustment - Opening Bal Adjt	-	2,484	-	-	2,484	(2,484) [1]	-	
15	CIAC, Ending	(183,107)	(254,306)	(186)	(1,287)	(438,886)	14,550 [1]	(424,337)	- Sect 7-TAB 7.5, Schedule 34
16									
17	Accumulated Amortization Beginning - CIAC	$ 48,742	$ 59,227	$ 17	$ 490	$ 108,476	(592) [1]	$ 107,884	- Sect 7-TAB 7.5, Schedule 34
18	Adjustment - Opening Bal Adjt	-	(86)	-	-	(86)	86 [1]	-	
19	Accumulated Amortization Ending - CIAC	49,913	63,319	22	490	113,744	(760) [1]	112,986	- Sect 7-TAB 7.5, Schedule 34
20									
21	Allocated Plant Adjustment, Mid-Year	-	-	-	-	-		-	
22									
23	Net Plant in Service, Mid-Year	$ 2,555,445	$ 774,128	$ 13,746	$ 8,823	$ 3,352,141	$ 13,917	$ 3,366,064	
24									
25	Adjustment to 13-Month Average	40,567	1,210	111	-	41,888		41,888	
26	Work in Progress, No AFUDC	17,110	2,285	23	-	19,418		19,418	
27	Unamortized Deferred Charges	27,407	(1,096)	27,584	54	53,949	(13,724) [2]	40,223	- Sect 7-TAB 7.5, Schedule 37
28	Cash Working Capital	(3,445)	295	42	8	(3,100)	704 [3]	(2,398)	- Sect 7-TAB 7.5, Schedule 40
29	Other Working Capital	100,905	11,042	633	4	112,584		112,584	- Sect 7-TAB 7.5, Schedule 40
30	Future Income Taxes Regulatory Asset	271,465	72,524	2,172	-	346,161		346,161	- Sect 7-TAB 7.5, Schedule 43
31	Future Income Taxes Regulatory Liability	(271,465)	(72,524)	(2,172)	-	(346,161)		(346,161)	- Sect 7-TAB 7.5, Schedule 43
32	LILO Benefit	(1,482)	-	-	-	(1,482)		(1,482)	
33	Utility Rate Base	$ 2,736,507	$ 787,864	$ 42,139	$ 8,889	$ 3,575,399	$ 897	$ 3,576,297	- Sect 7-TAB 7.5, Schedule 44
34									
35	Notes								
36	1 FEVI CIAC - Pipeline Contribution from FEW								
37	2 FEW's contribution deferral to FEVI for pipeline								
38	3 Applying FEI Lead/Lag days to FEVI and FEW expense/revenue								

($000s)

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Adjustments	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Gas Plant in Service, Beginning	$ 3,770,188	$ 1,317,524	$ 17,203	$ 12,525	$ 5,117,440		$ 5,117,445	- Sect 7-TAB 7.5, Schedule 25
2	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
3	Gas Plant in Service, Ending	3,904,928	1,344,362	17,637	12,919	5,279,846		5,279,855	- Sect 7-TAB 7.5, Schedule 25
4									
5	Accumulated Depreciation Beginning - Plant	$ (1,014,039)	$ (318,482)	$ (2,933)	$ (2,718)	$ (1,338,172)		$ (1,338,167)	- Sect 7-TAB 7.5, Schedule 31
6	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
7	Accumulated Depreciation Ending - Plant	(1,105,609)	(346,979)	(3,200)	(3,076)	(1,458,864)		(1,458,860)	- Sect 7-TAB 7.5, Schedule 31
8									
9	Negative Salvage Depreciation Beginning - Plant	$ (7,994)	$ (12,476)	$ (74)	$ -	$ (20,544)		$ (20,543)	- Sect 7-TAB 7.5, Schedule 33
10	Adjustment - CPCNs / Opening Bal Adjt	-	-	-	-	-		-	
11	Negative Salvage Depreciation Ending - Plant	(11,805)	(15,874)	(150)	-	(27,829)		(27,825)	- Sect 7-TAB 7.5, Schedule 33
12									
13	CIAC, Beginning	$ (183,107)	$ (254,306)	$ (186)	$ (1,287)	$ (438,886)	$ 14,550 [1]	$ (424,337)	- Sect 7-TAB 7.5, Schedule 35
14	Adjustment - Opening Bal Adjt	-	-	-	-	-		-	
15	CIAC, Ending	(189,803)	(250,614)	(186)	(1,287)	(441,890)	14,550 [1]	(427,341)	- Sect 7-TAB 7.5, Schedule 35
16									
17	Accumulated Amortization Beginning - CIAC	$ 49,913	$ 63,319	$ 22	$ 490	$ 113,744	$ (755) [1]	$ 112,986	- Sect 7-TAB 7.5, Schedule 35
18	Adjustment - Opening Bal Adjt	-	-	-	-	-		-	
19	Accumulated Amortization Ending - CIAC	55,928	67,506	27	490	123,951	(1,007) [1]	122,940	- Sect 7-TAB 7.5, Schedule 35
20									
21	Allocated Plant Adjustment, Mid-Year	-	-	-	-	-		-	
22									
23	Net Plant in Service, Mid-Year	$ 2,634,300	$ 796,990	$ 14,080	$ 9,028	$ 3,454,398	$ 13,669	$ 3,468,077	
24									
25	Adjustment to 13-Month Average	-	-	-	-	-		-	
26	Work in Progress, No AFUDC	17,110	2,285	23	-	19,418		19,418	
27	Unamortized Deferred Charges	38,574	3,891	26,703	82	69,250	(13,435) [2]	55,814	- Sect 7-TAB 7.5, Schedule 39
28	Cash Working Capital	(1,963)	476	61	12	(1,414)	328 [3]	(1,086)	- Sect 7-TAB 7.5, Schedule 40
29	Other Working Capital	101,622	10,436	635	4	112,697		112,697	- Sect 7-TAB 7.5, Schedule 40
30	Future Income Taxes Regulatory Asset	282,359	76,663	2,319	-	361,341		361,341	- Sect 7-TAB 7.5, Schedule 43
31	Future Income Taxes Regulatory Liability	(282,359)	(76,663)	(2,319)	-	(361,341)		(361,341)	- Sect 7-TAB 7.5, Schedule 43
32	LILO Benefit	(1,316)	-	-	-	(1,316)		(1,316)	
33	Utility Rate Base	$ 2,788,327	$ 814,078	$ 41,502	$ 9,126	$ 3,653,033	$ 562	$ 3,653,604	- Sect 7-TAB 7.5, Schedule 45
34									
35		Notes							
36		1 FEVI CIAC - Pipeline Contribution from FEW							
37		2 FEW's contribution deferral to FEVI for pipeline							
38		3 Applying FEI Lead/Lag days to FEVI and FEW expense/revenue							

FortisBC Energy Utilities
EARNED RETURN CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

May 16, 2011

Section 7
TAB 7.5
Schedule 5

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Rate Base	$ 2,736,507	$ 787,864	$ 42,139	$ 8,889	$ 3,575,399	$ 897	$ 3,576,297	- Sect 7-TAB 7.5, Schedule 18
2									
3	Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%		40.00%	- Sect 7-TAB 7.5, Schedule 44
4	Common Equity	1,094,603	315,146	16,856	3,556	1,430,160	359	1,430,519	- Sect 7-TAB 7.5, Schedule 44
5	ROE	9.50%	10.00%	10.00%	9.50%	9.62% [1]		9.62%	- Sect 7-TAB 7.5, Schedule 44
6	Equity Earned Return	103,987	31,515	1,686	338	137,525	91 [2]	137,616	- Sect 7-TAB 7.5, Schedule 44
7									
8	Long Term Debt % of Capital Structure	57.82%	46.39%	47.46%	57.30%	55.18%		55.22%	- Sect 7-TAB 7.5, Schedule 44
9	Long Term Debt	1,582,117	365,526	20,000	5,094	1,972,737	1,935	1,974,672	- Sect 7-TAB 7.5, Schedule 44
10	Average Rate	6.73%	5.75%	5.11%	6.73%	6.53%		6.54%	- Sect 7-TAB 7.5, Schedule 44
11	LTD Earned Return	106,548	21,003	1,022	343	128,916	233	129,149	- Sect 7-TAB 7.5, Schedule 44
12									
13	Short Term Debt % of Capital Structure	2.18%	13.61%	12.54%	2.69%	4.82%		4.78%	- Sect 7-TAB 7.5, Schedule 44
14	Short Term Debt	59,787	107,192	5,283	239	172,501	(1,395)	171,106	- Sect 7-TAB 7.5, Schedule 44
15	Average Rate	2.75%	4.25%	3.75%	2.93%	3.71%		2.75%	- Sect 7-TAB 7.5, Schedule 44
16	STD Earned Return	1,644	4,556	198	7	6,405	(1,700)	4,705	- Sect 7-TAB 7.5, Schedule 44
17									
18	Total Earned Return	$ 212,179	$ 57,074	$ 2,906	$ 688	$ 272,846	$ (1,376)	$ 271,470	- Sect 7-TAB 7.5, Schedule 44
19									
20		Notes							
21		1 Calculation of Weigted Average ROE							
22		Total Equity Return				137,525	(Line 6, Column 6)		
23		Equity Portion of Rate Base				1,430,160	(Line 4, Column 6)		
24		Weighted Average ROE				9.62%	(Line 22 / Line 23)		
25		2 Impact of Rate Base Change $0.04 MM, Impact of rounding Weighted Average ROE to 2 decimals $0.05 MM							

FortisBC Energy Utilities
EARNED RETURN CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

May 16, 2011

Section 7
TAB 7.5
Schedule 6

Line No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Rate Base	$ 2,788,327	$ 814,078	$ 41,502	$ 9,126	$ 3,653,033	$ 562	$ 3,653,604	- Sect 7-TAB 7.5, Schedule 18
2									
3	Equity Thickness	40.00%	40.00%	40.00%	40.00%	40.00%		40.00%	- Sect 7-TAB 7.5, Schedule 45
4	Common Equity	1,115,331	325,631	16,601	3,650	1,461,213	229	1,461,442	- Sect 7-TAB 7.5, Schedule 45
5	ROE	9.50%	10.00%	10.00%	9.50%	9.62% [1]		9.62%	- Sect 7-TAB 7.5, Schedule 45
6	Equity Earned Return	105,956	32,563	1,660	347	140,526	64 [2]	140,591	- Sect 7-TAB 7.5, Schedule 45
7									
8	Long Term Debt % of Capital Structure	56.76%	42.99%	48.19%	56.25%	53.59%		53.64%	- Sect 7-TAB 7.5, Schedule 45
9	Long Term Debt	1,582,515	350,000	20,000	5,134	1,957,649	2,210	1,959,859	- Sect 7-TAB 7.5, Schedule 45
10	Average Rate	6.74%	5.85%	5.11%	6.74%	6.57%		6.56%	- Sect 7-TAB 7.5, Schedule 45
11	LTD Earned Return	106,730	20,473	1,022	346	128,571	(24)	128,547	- Sect 7-TAB 7.5, Schedule 45
12									
13	Short Term Debt % of Capital Structure	3.24%	17.01%	11.81%	3.75%	6.41%		6.36%	- Sect 7-TAB 7.5, Schedule 45
14	Short Term Debt	90,481	138,447	4,901	342	234,171	(1,868)	232,303	- Sect 7-TAB 7.5, Schedule 45
15	Average Rate	3.75%	5.25%	4.75%	3.80%	4.66%		3.75%	- Sect 7-TAB 7.5, Schedule 45
16	STD Earned Return	3,393	7,268	233	13	10,907	(2,196)	8,711	- Sect 7-TAB 7.5, Schedule 45
17									
18	Total Earned Return	$ 216,079	$ 60,304	$ 2,915	$ 706	$ 280,004	$ (2,156)	$ 277,849	- Sect 7-TAB 7.5, Schedule 45
19									
20			Notes						
21			1 Calculation of Weigted Average ROE						
22			Total Equity Return			140,526	(Line 6, Column 6)		
23			Equity Portion of Rate Base			1,461,213	(Line 4, Column 6)		
24			Weighted Average ROE			9.62%	(Line 22 / Line 23)		
25			2 Impact of Rate Base Change $0.02 MM, Impact of rounding Weighted Average ROE to 2 decimals $0.04 MM						

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Cost of Gas Sold (Including Gas Lost)	727,627	728,927	1,300	
2	GCVA Amortization	(8,124)	-	8,124	
3	Net Cost of Gas	719,503	728,927	9,424	
4					
5	Operation and Maintenance	224,568	235,438	10,870	- Sect 7-TAB 7.5, Schedule 9
6	Transportation Costs	1,027	1,029	2	
7	Property and Sundry Taxes	59,959	61,924	1,965	- Sect 7-TAB 7.5, Schedule 12
8	Depreciation and Amortization	171,197	191,565	20,368	- Sect 7-TAB 7.5, Schedule 13
9	Other Operating Revenue	(24,373)	(26,074)	(1,701)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	28,765	38,207	9,442	- Sect 7-TAB 7.5, Schedule 14
11	Earned Return	271,470	277,849	6,379	- Sect 7-TAB 7.5, Schedule 44 & 45
12	Delivery Cost of Service	732,613	779,938	47,325	
13					
14	Total Cost of Service	1,452,116	1,508,865	56,749	

OTHER OPERATING REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,557	$ 2,560	$3	
4					
5	Connection Charge	3,075	3,108	33	
6					
7	NSF Returned Cheque Charges	83	83	-	
8					
9	Other Recoveries	124	127	3	
10					
11	Total Other Utility Revenue	5,839	5,878	39	
12					
13	**Miscellaneous Revenue**				
14					
15	SCP Third Party Revenue	14,852	14,827	(25)	
16					
17	Biomethane Other Revenue	(62)	(29)	33	
18					
19	CNG & LNG Service Revenues	3,744	5,398	1,654	
20					
21					
22	Total Miscellaneous	18,534	20,196	1,662	
23					
24	**Total Other Operating Revenue**	$ 24,373	$ 26,074	$ 1,701	- Sect 7-TAB 7.5, Schedule 7

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)
1	M&E Costs	$ 58,567	$ 60,697	
2	COPE Costs	36,133	38,131	
3	COPE Customer Services Costs	11,824	11,177	
4	IBEW Costs	33,159	34,931	
5				
6	**Labour Costs**	**139,683**	**144,935**	
7				
8	Vehicle Costs	4,484	4,544	
9	Employee Expenses	6,172	6,351	
10	Materials and Supplies	8,117	8,490	
11	Computer Costs	14,734	15,306	
12	Fees and Administration Costs	74,264	79,629	
13	Contractor Costs	23,920	26,386	
14	Facilities	18,511	16,344	
15	Recoveries & Revenue	(28,758)	(28,220)	
16				
17	**Non-Labour Costs**	**121,444**	**128,831**	
18				
19				
20	**Total Gross O&M Expenses**	**261,127**	**273,766**	
21				
22	Less: Capitalized Overhead	(36,558)	(38,327)	
23				
24	**Total O&M Expenses**	**$ 224,569**	**$ 235,438**	- Sect 7-TAB 7.5, Schedule 7

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Distribution Supervision	100-11	$ 13,305	$ 13,825	
2					
3	Operation Centre - Distribution	100-21	12,743	13,443	
4	Asset Management - Distribution	100-22	3,259	4,587	
5	Preventative Maintenance - Distribution	100-23	3,202	3,483	
6	Distribution Operations - General	100-24	7,003	7,355	
7	Meter Exchange	100-25	-	-	
8	Emergency Management	100-26	5,938	6,134	
9	Distribution Operations Total	100-20	32,145	35,002	
10					
11	Distribution Corrective - Meters	100-31	1,886	1,945	
12	Distribution Corrective - Propane	100-32	-	-	
13	Distribution Corrective - Leak Repair	100-33	1,374	1,415	
14	Distribution Corrective - Stations	100-34	773	793	
15	Distribution Corrective - General	100-35	638	987	
16	Distribution Maintenance Total	100-30	4,671	5,140	
17					
18	**Distribution Total**	**100**	**50,121**	**53,966**	
19					
20	Transmission Supervision	200-11	5,497	6,453	
21					
22	Pipeline Operation	200-21	3,622	3,766	
23	Right of Way	200-22	730	808	
24	Compression	200-23	2,171	2,239	
25	Gas Control	200-24	2,848	3,000	
26	Transmission Pipeline Integrity Project (TPIP)	200-25	2,611	2,797	
27	Transmission Operations Total	200-20	11,983	12,610	
28					
29	Pipeline - Maintenance	200-31	2,830	2,684	
30	Compression - Maintenance	200-32	1,624	1,764	
31	TPIP - Maintenance	200-33	1,567	1,587	
32	Transmission Maintenance Total	200-30	6,021	6,035	
33					
34	**Transmission Total**	**200**	**23,502**	**25,098**	
35					
36	LNG Plant Operations	300-11	2,780	2,937	
37	LNG Plant Maintenance	300-21	797	824	
38					
39	**LNG Plant Total**	**300**	**3,577**	**3,761**	
40					
41	Measurement Operations	400-11	4,951	5,261	
42	Measurement Maintenance	400-21	2,539	2,601	
43					
44	**Measurement Total**	**400**	**7,491**	**7,861**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	BCUC Reference	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Facilities Management	500-10	$ 10,433	$ 9,451	
2	Shops & Stores	500-20	4,677	4,783	
3	Operations Engineering	500-30	10,621	11,092	
4	Property Services	500-40	1,411	1,453	
5	System Integrity	500-50	2,567	2,608	
6	Environmental Health & Safety	500-60	2,893	3,057	
7	Operations Governance	500-70	1,649	1,705	
8	Energy Supply & Resource Development	500-80	-	-	
9	**General Operations Total**	**500**	**34,251**	**34,149**	
10					
11	Energy Efficiency	600-10	0	(0)	
12	Marketing - Supervision	600-20	(807)	(785)	
13	Corporate & Marketing Communications	600-30	3,887	4,103	
14	Marketing Planning & Development	600-40	955	981	
15	**Marketing Total**	**600**	**4,035**	**4,298**	
16					
17	Customer Care - Supervision	700-10	2,793	2,883	
18	Customer Contact	700-20	45,431	48,917	
19	Bad Debt Management and Administration	700-30	5,445	5,494	
20	Customer Management & Sales	700-40	8,189	8,545	
21	**Customer Care Total**	**700**	**61,859**	**65,839**	
22					
23	Business & IT Services - Supervision	800-10	0	-	
24	Application Management	800-20	16,540	17,297	
25	Infrastructure Management	800-30	8,760	9,154	
26	Procurement Services	800-40	1,265	1,412	
27	**Business & IT Services Total**	**800**	**26,564**	**27,863**	
28					
29	Administration & General	900-11	2,748	3,273	
30	Insurance	900-12	5,437	5,257	
31	Finance and Regulatory Affairs	900-13	11,564	11,892	
32	Shared Services Agreement	900-14	11,095	11,410	
33	Corporate Administration Total	900-10	30,844	31,833	
34	Forecasting	900-20	3,036	3,335	
35	Public Affairs	900-30	2,253	2,309	
36	Business Development	900-40	3,979	4,113	
37	Human Resources	900-50	8,152	8,457	
38	Other Post Employment Benefits (OPEB)	900-60	1,464	883	
39	**Administration & General Total**	**900**	**49,727**	**50,930**	
40					
41	**Total Gross O&M Expenses**		**261,127**	**273,766**	
42					
43	Less: Capitalized Overhead		(36,558)	(38,327)	
44					
45	**Total O&M Expenses**		**$ 224,569**	**$ 235,438**	- Sect 7-TAB 7.5, Schedule 7
46					

PROPERTY AND SUNDRY TAXES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Property Taxes				
2					
3	1% in Lieu of General Municipal Tax	$ 15,452	$ 15,452	$ -	
4					
5	General, School and Other	44,507	46,472	1,965	
6					
7		59,959	61,924	1,965	
8					
9	Add / Less: Deferred Property Taxes	-	-	-	
10					
11	Total	$ 59,959	$ 61,924	$ 1,965	- Sect 7-TAB 7.5, Schedule 7

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 152,890	$ 159,498	$ 6,608	- Sect 7-TAB 7.5, Schedule 28 & 31
4					
5	Less: Amortization of Contributions in Aid of Construction	(10,208)	(10,158)	50	- Sect 7-TAB 7.5, Schedule 34 & 35
6		142,682	149,340	6,658	
7					
8	Add: Removal Cost Provision	20,192	20,868	676	
9		162,874	170,208	7,334	- Sect 7-TAB 7.5, Schedule 15
10					
11	**Amortization Expense**				
12					
13	Amortization of Deferred Charges	$ 199	$ 21,357	$ 21,158	- Sect 7-TAB 7.5, Schedule 37 & 39
14	Less: GCVA Amortization	8,124	-	(8,124)	- Sect 7-TAB 7.5, Schedule 7
15		8,323	21,357	13,034	
16					
17	TOTAL	$ 171,197	$ 191,565	$ 20,368	- Sect 7-TAB 7.5, Schedule 7

INCOME TAXES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	CALCULATION OF INCOME TAXES				
2	EARNED RETURN after VINGPA Adjustment	$ 271,470	$ 277,849	$ 6,379	- Sect 7-TAB 7.5, Schedule 7
3	Deduct - Interest on Debt	(133,854)	(137,258)	(3,404)	- Sect 7-TAB 7.5, Schedule 44 & 45
4	Net Additions (Deductions)	(51,320)	(25,970)	25,350	- Sect 7-TAB 7.5, Schedule 15
5	Adjusted Taxable Income After Tax	86,296	114,621	28,325	
6					
7	Current Income Tax Rate	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	0.00%	
9					
10	Taxable Income	115,061	$ 152,828	$ 37,767	
11					
12					
13	Income Tax - Current	$ 28,765	$ 38,207	$ 9,442	
14	Previous Year Adjustment	-		-	
15					
16	**Total Income Tax**	$ 28,765	$ 38,207	$ 9,442	- Sect 7-TAB 7.5, Schedule 7

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 765	765	$ -	
3	Depreciation	162,874	170,208	7,334	- Sect 7-TAB 7.5, Schedule 13
4	Amortization of Debt Issue Expenses	1,019	797	(222)	
5	Vehicle Capital Lease: Interest & Capitialized Depreciation	2,056	2,190	134	
6	Pension Expense	9,479	9,066	(413)	
7	OPEB Expense	4,495	4,752	257	
8	Amortization of Decommissioning of Propane Assets	232	232	-	
9	Amortization of 75% Direct Appliance Conversion Costs	331	331	-	
10					
11	Deductions:				
12	Amortization of Deferred Charges	199	21,357	21,158	- Sect 7-TAB 7.5, Schedule 13
13	Less: Amortization of Decommissioning of Propane Assets (TGW)	(232)	(232)	-	
14	Less: Amortization of 75% Direct Appliance Conversion Costs (FEW)	(331)	(331)	-	
15	Capital Cost Allowance	(176,598)	(179,622)	(3,024)	- Sect 7-TAB 7.5, Schedule 16 & 17
16	Cumulative Eligible Capital Allowance	(2,174)	(2,046)	128	
17	Debt Issue Costs	(1,531)	(702)	829	
18	Vehicle Lease Payment	(3,776)	(4,006)	(230)	
19	Pension Contributions	(13,835)	(13,636)	199	
20	OPEB Contributions	(2,550)	(2,677)	(127)	
21	Overheads Capitalized Expensed for Tax Purposes	(16,752)	(17,517)	(765)	
22	Removal Costs	(13,247)	(13,586)	(339)	
23	Major Inspection Costs	(1,806)	(1,342)	464	
24	Biomethane Other Revenue	62	29	(33)	
25					
26	TOTAL	$ (51,320)	$ (25,970)	$ 25,350	- Sect 7-TAB 7.5, Schedule 14

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Class	CCA Rate	12/31/2011 UCC Balance	Adjustments	2012 Net Additions	2012 CCA	12/31/2012 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,374,427	$ -	$ 60	$ (54,978)	$ 1,319,509
2	1(b)	6%	27,103	-	22,657	(2,306)	47,454
3	2	6%	151,899	-	-	(9,113)	142,786
4	3	5%	2,695	-	-	(135)	2,560
5	6	10%	172	1	-	(18)	155
6	7	15%	21,070	(1)	8,911	(3,828)	26,152
7	8	20%	27,030	-	12,417	(6,648)	32,799
8	10	30%	3,742	2	3,398	(1,633)	5,509
9	12	100%	7,097	(1)	66,233	(40,213)	33,116
10	13	manual	345	-	3,504	(3,027)	822
11	14	manual	275	-	-	(25)	250
12	17	8%	190	-	-	(15)	175
13	38	30%	967	-	360	(344)	983
14	39	25%	-	-	-	-	-
15	45	45%	405	-	-	(183)	222
16	47	8%	158,860	1	3,439	(12,847)	149,453
17	49	8%	126,340	-	27,790	(11,220)	142,910
18	50	55%	5,394	-	11,548	(6,143)	10,799
19	51	6%	335,722	-	84,610	(22,681)	397,651
20	43.2	50%	1,450	1	2,063	(1,241)	2,273
21							
22		Total	$ 2,245,183	$ 3	$ 246,990	$ (176,598)	$ 2,315,578
23							
24	Cross Reference					- Sect 7-TAB 7.5, Schedule 15	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,319,509	$ -	$ -	$ (52,780)	$ 1,266,729
2	1(b)	6%	47,454	-	3,559	(2,955)	48,058
3	2	6%	142,786	(2)	-	(8,567)	134,217
4	3	5%	2,560	(1)	-	(128)	2,431
5	6	10%	155	1	-	(15)	141
6	7	15%	26,152	-	6,184	(4,387)	27,949
7	8	20%	32,799	-	7,613	(7,321)	33,091
8	10	30%	5,509	(1)	3,646	(2,199)	6,955
9	12	100%	33,116	1	12,000	(39,117)	6,000
10	13	manual	822	1	130	(446)	507
11	14	manual	250	-	-	(25)	225
12	17	8%	175	(1)	-	(14)	160
13	38	30%	983	-	360	(349)	994
14	39	25%	-	-	-	-	-
15	45	45%	222	2	-	(101)	123
16	47	8%	149,453	(1)	1,516	(12,017)	138,951
17	49	8%	142,910	-	20,234	(12,242)	150,902
18	50	55%	10,799	-	8,000	(8,139)	10,660
19	51	6%	397,651	(1)	106,120	(27,043)	476,727
20	43.2	50%	2,273	(1)	2,563	(1,777)	3,058
21							
22		Total	$ 2,315,578	$ (3)	$ 171,925	$ (179,622)	$ 2,307,878
23							
24	Cross Reference					- Sect 7-TAB 7.5, Schedule 15	

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Gas Plant in Service, Beginning	$ 4,833,448	$ 5,117,445	$ 283,997	- Sect 7-TAB 7.5, Schedule 22 & 25
2	Opening Balance Adjustment	-	-	-	
3	Gas Plant in Service, Ending	5,117,445	5,279,855	162,410	- Sect 7-TAB 7.5, Schedule 22 & 25
4					
5	Accumulated Depreciation Beginning - Plant	$ (1,224,413)	$ (1,338,167)	$ (113,754)	- Sect 7-TAB 7.5, Schedule 28 & 31
6	Opening Balance Adjustment	13,597	-	(13,597)	
7	Accumulated Depreciation Ending - Plant	(1,338,167)	(1,458,860)	(120,693)	- Sect 7-TAB 7.5, Schedule 28 & 31
8					
9	Negative Salvage Beginning	$ -	$ (20,543)	$ (20,543)	- Sect 7-TAB 7.5, Schedule 32 & 33
10	Opening Balance Adjustment	(13,597)	-	13,597	
11	Negative Salvage Ending	(20,543)	(27,825)	(7,282)	- Sect 7-TAB 7.5, Schedule 32 & 33
12					
13	CIAC, Beginning	$ (432,176)	$ (424,337)	$ 7,839	- Sect 7-TAB 7.5, Schedule 34 & 35
14	Opening Balance Adjustment	-	-	-	
15	CIAC, Ending	(424,337)	(427,341)	(3,004)	- Sect 7-TAB 7.5, Schedule 34 & 35
16					
17	Accumulated Amortization Beginning - CIAC	$ 107,884	$ 112,986	$ 5,102	- Sect 7-TAB 7.5, Schedule 34 & 35
18	Opening Balance Adjustment	-	-	-	
19	Accumulated Amortization Ending - CIAC	112,986	122,940	9,954	- Sect 7-TAB 7.5, Schedule 34 & 35
20					
21	Net Plant in Service, Mid-Year	$ 3,366,064	$ 3,468,077	$ 102,013	
22					
23	Adjustment to 13-Month Average	41,888	-	(41,888)	
24	Work in Progress, No AFUDC	19,418	19,418	-	
25	Unamortized Deferred Charges	40,223	55,814	15,591	- Sect 7-TAB 7.5, Schedule 37 & 39
26	Cash Working Capital	(2,398)	(1,086)	1,312	- Sect 7-TAB 7.5, Schedule 40
27	Other Working Capital	112,584	112,697	113	- Sect 7-TAB 7.5, Schedule 40
28	Future Income Taxes Regulatory Asset	346,161	361,341	15,180	- Sect 7-TAB 7.5, Schedule 43
29	Future Income Taxes Regulatory Liability	(346,161)	(361,341)	(15,180)	- Sect 7-TAB 7.5, Schedule 43
30	LILO Benefit	(1,482)	(1,316)	166	
31	**Utility Rate Base**	$ 3,576,297	$ 3,653,604	$ 77,307	- Sect 7-TAB 7.5, Schedule 44 & 45

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000)

Line No.	Particulars	2012 Forecast	2013 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 153,750	$ 158,898	
6	Gateway Project	11,500	1,750	
7				
8	Total Regular Capital Expenditures	$ 165,250	$ 160,648	
9				
10	Special Projects - CPCN's			
11	Customer Care Enhancement	14,916	-	
12	Kootenay River Xing	1,223	-	
13	Victoria Regional Office	4,782	-	
14	Total CPCN's	$ 20,921	$ -	
15				
16				
17	TOTAL CAPITAL EXPENDITURES	$ 186,171	$ 160,648	
18				
19				
20	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
21				
22	Regular Capital			
23	Regular Capital Expenditures	$ 165,250	$ 160,648	
24	Add - Opening WIP	38,957	38,957	
25	Less - Closing WIP	(38,957)	(38,957)	
26	Capital Vehicle Lease Addition	3,180	2,860	
27	Add - AFUDC	2,088	1,916	
28	Add - Overhead Capitalized	36,556	38,329	- Sect 7-TAB 7.5, Schedule 22 & 25
29				
30	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 207,073	$ 203,753	
31				
32	Special Projects - CPCN's			
33	CPCN Expenditures	20,921	-	
34	Add - Opening WIP	68,412	(26)	
35	Less - Closing WIP	26	26	
36	Add: Projects transferred from Deferral Accounts	14,700	-	
37	Less: Adjustments	(512)	-	
38	Add - AFUDC	1,042	-	
39				
40	TOTAL CPCN ADDITIONS	$ 104,589	$ -	- Sect 7-TAB 7.5, Schedule 22 & 25
41				
42	TOTAL PLANT ADDITIONS	$ 311,662	$ 203,753	

FortisBC Energy Utilities | May 16, 2011 | Section 7
TAB 7.5
Schedule 20

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	297	-	-	-	-	-	-	297	297
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	1,907	-	-	-	-	-	-	1,907	1,907
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	51,023	-	325	-	-	-	-	51,348	51,186
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
14	471-00 Distribution Land Rights	3,184	-	-	-	-	-	-	3,184	3,184
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	56,692	56,325	6,000	149	-	(3,653)	-	115,513	117,715
17	402-02 Application Software - 20%	19,942	-	6,000	95	-	(2,045)	-	23,992	21,967
18	TOTAL INTANGIBLE	134,760	56,325	12,325	244	-	(5,698)	-	197,956	197,970
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	146	-	50	-	17	-	-	213	180
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	928	14,112	-	-	-	-	-	15,040	7,984
30	442-00 Structures & Improvements (Tilbury)	4,959	588	-	-	-	-	-	5,547	5,253
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,658	-	2,050	63	714	(681)	-	28,804	27,731
36	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	1,012	-	-	-	-	-	-	1,012	1,012
37	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
38	443-00 Gas Holders - Storage (Mount Hayes)	60,757	-	750	-	-	-	-	61,507	61,132
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
43	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
44	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
45	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
46	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
47	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
48	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
49	TOTAL MANUFACTURED	251,039	14,700	2,850	63	731	(681)	-	268,702	259,871

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 10,244	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,244	$ 10,244
3	461-00 Transmission Land Rights	290	-	80	-	-	-	-	370	330
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	26,434	-	-	-	-	-	-	26,434	26,434
6	463-00 Measuring Structures	12,897	-	-	-	-	-	-	12,897	12,897
7	464-00 Other Structures & Improvements	6,144	-	-	-	-	-	-	6,144	6,144
8	465-00 Mains	1,116,780	1,223	25,597	999	8,507	(1,065)	-	1,152,041	1,134,411
9	465-00 Mains - INSPECTION	7,523	-	1,806	-	595	-	-	9,924	8,724
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	170,447	-	6,478	223	1,954	(547)	-	178,555	174,501
14	466-00 Compressor Equipment - OVERHAUL	8,145	-	1,450	-	326	-	-	9,921	9,033
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
16	467-10 Measuring & Regulating Equipment	42,903	-	-	-	-	-	-	42,903	42,903
17	467-20 Telemetering	6,619	-	736	32	257	(481)	-	7,163	6,891
18	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	4,126	-	-	-	-	-	-	4,126	4,126
21	TOTAL TRANSMISSION	1,468,127	1,223	36,147	1,254	11,639	(2,093)	-	1,516,297	1,492,212
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	4,213	-	-	-	-	-	-	4,213	4,213
25	471-00 Distribution Land Rights	2	-	50	-	-	-	-	52	27
26	472-00 Structures & Improvements	18,194	-	-	-	-	-	-	18,194	18,194
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	869,678	-	22,878	-	7,255	(3,109)	-	896,702	883,190
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	176,159	-	246	-	85	(1,783)	-	174,707	175,433
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	-	-	11,944	-	3,857	-	-	15,801	7,901
33	475-00 Mains	1,190,478	-	31,791	177	10,028	(2,963)	-	1,229,511	1,209,995
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	97,304	-	3,305	139	1,107	(571)	-	101,284	99,294
37	477-00 Telemetering	6,617	-	750	5	249	(120)	-	7,501	7,059
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	214,345	-	12,190	-	-	(4,370)	-	222,165	218,255
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,698,625	-	83,154	321	22,581	(12,916)	-	2,791,765	2,745,195
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	187	-	203	-	71	-	-	461	324
49	418-10 Bio Gas Purification Overhaul	402	-	413	-	-	-	-	815	609
50	418-20 Bio Gas Purification Upgrader	1,607	-	1,650	-	-	-	-	3,257	2,432
51	474-10 Bio Gas Reg & Meter Installations	1,681	-	406	-	141	-	-	2,228	1,955
52	478-30 Bio Gas Meters	40	-	406	-	-	-	-	446	243
53	TOTAL BIO-GAS	3,917	-	3,078	-	212	-	-	7,207	5,562

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	CPCN'S	2012 Additions	2012 AFUDC	2012 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2012	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,040	$ -	$ 1,540	$ -	$ 536	$ -	$ -	$ 4,116	$ 3,078
3	476-20 NG Transportation LNG Dispensing Equipment	1,737	-	1,180	-	411	-	-	3,328	2,533
4	476-30 NG Transportation CNG Foundations	450	-	340	-	118	-	-	908	679
5	476-40 NG Transportation LNG Foundations	383	-	260	-	91	-	-	734	559
6	476-50 NG Transportation LNG Pumps	824	-	560	-	195	-	-	1,579	1,202
7	476-60 NG Transportation CNG Dehydrator	159	-	120	-	42	-	-	321	240
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,593	-	4,000	-	1,393	-	-	10,986	8,290
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	21,540	6,355	2,000	-	-	-	-	29,895	25,718
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	12,110	-	-	-	-	-	-	12,110	12,110
16	- Masonry Buildings	87,558	15,752	4,471	-	-	-	-	107,781	97,670
17	- Leasehold Improvement	766	3,429	200	-	-	(313)	-	4,082	5,854
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	4,246	443	513	-	-	-	-	5,202	4,901
20	483-40 GP Furniture	19,847	2,829	1,571	-	-	(567)	-	23,680	23,250
21	483-10 GP Computer Hardware	23,677	3,533	8,000	206	-	(1,517)	-	33,899	30,647
22	483-20 GP Computer Software	2,211	-	-	-	-	(475)	-	1,736	1,974
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
25	484-00 Vehicles	7,410	-	3,398	-	-	(262)	-	10,546	8,978
26	484-00 Vehicles - Leased	28,481	-	3,180	-	-	(1,908)	-	29,753	29,117
27	485-10 Heavy Work Equipment	689	-	-	-	-	(11)	-	678	684
28	485-20 Heavy Mobile Equipment	2,291	-	360	-	-	-	-	2,651	2,471
29	486-00 Small Tools & Equipment	47,553	-	3,022	-	-	(1,207)	-	49,368	48,461
30	487-00 Equipment on Customer's Premises	9	-	-	-	-	-	-	9	9
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	8,404	-	115	-	-	(10)	-	8,509	8,457
34	- Radio	4,546	-	45	-	-	(7)	-	4,584	4,565
35	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
36	TOTAL GENERAL	271,387	32,341	26,875	206	-	(6,277)	-	324,532	304,912
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 4,833,448	$ 104,589	$ 168,429	$ 2,088	$ 36,556	$ (27,665)	$ -	$ 5,117,445	$ 5,014,011
43										
44	Cross Reference	- Sect 7-TAB 7.5, Schedule 18							- Sect 7-TAB 7.5, Schedule 18	
45			- Sect 7-TAB 7.5, Schedule 19							

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	297	-	-	-	-	-	-	297	297
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	1,907	-	-	-	-	-	-	1,907	1,907
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	51,348	-	328	-	-	-	-	51,676	51,512
12	461-10 Transmission Land Rights - Byron Creek	15	-	-	-	-	-	-	15	15
13	461-13 IP Land Rights Whistler	24	-	-	-	-	-	-	24	24
14	471-00 Distribution Land Rights	3,184	-	-	-	-	-	-	3,184	3,184
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	-	-	-	-	-	-
16	402-01 Application Software - 12.5%	115,513	-	6,000	149	-	(8,758)	-	112,904	114,209
17	402-02 Application Software - 20%	23,992	-	6,000	95	-	(4,268)	-	25,819	24,906
18	TOTAL INTANGIBLE	197,956	-	12,328	244	-	(13,026)	-	197,502	197,729
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	464	-	-	-	-	-	-	464	464
24	433-00 Manufact'd Gas - Equipment	213	-	-	-	-	-	-	213	213
25	434-00 Manufact'd Gas - Gas Holders	358	-	-	-	-	-	-	358	358
26	436-00 Manufact'd Gas - Compressor Equipment	53	-	-	-	-	-	-	53	53
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309	-	-	-	-	-	-	309	309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,040	-	-	-	-	-	-	15,040	15,040
30	442-00 Structures & Improvements (Tilbury)	5,547	-	-	-	-	-	-	5,547	5,547
31	443-00 Gas Holders - Storage (Tilbury)	16,494	-	-	-	-	-	-	16,494	16,494
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	28,804	-	450	14	164	(149)	-	29,283	29,044
36	440/441-00 Land in Fee Simple and Land Rights (Mount Ha	1,012	-	-	-	-	-	-	1,012	1,012
37	442-00 Structures & Improvements (Mount Hayes)	17,442	-	-	-	-	-	-	17,442	17,442
38	443-00 Gas Holders - Storage (Mount Hayes)	61,507	-	603	-	-	-	-	62,110	61,809
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	11,605	-	-	-	-	-	-	11,605	11,605
43	448-20 Pre-treatment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
44	448-30 Liquefaction Equipment (Mount Hayes)	29,012	-	-	-	-	-	-	29,012	29,012
45	448-40 Send out Equipment (Mount Hayes)	23,237	-	-	-	-	-	-	23,237	23,237
46	448-50 Sub-station and Electric (Mount Hayes)	22,466	-	-	-	-	-	-	22,466	22,466
47	448-60 Control Room (Mount Hayes)	5,923	-	-	-	-	-	-	5,923	5,923
48	449-00 Local Storage Equipment (Mount Hayes)	173	-	-	-	-	-	-	173	173
49	TOTAL MANUFACTURED	268,702	-	1,053	14	164	(149)	-	269,784	269,243

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 10,244	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,244	$ 10,244
3	461-00 Transmission Land Rights	370	-	82	-	-	-	-	452	411
4	461-02 Land Rights - Mt. Hayes	801	-	-	-	-	-	-	801	801
5	462-00 Compressor Structures	26,434	-	-	-	-	-	-	26,434	26,434
6	463-00 Measuring Structures	12,897	-	-	-	-	-	-	12,897	12,897
7	464-00 Other Structures & Improvements	6,144	-	-	-	-	-	-	6,144	6,144
8	465-00 Mains	1,152,041	-	22,422	867	7,734	(899)	-	1,182,165	1,167,103
9	465-00 Mains - INSPECTION	9,924	-	1,342	-	490	-	-	11,756	10,840
10	465-11 IP Transmission Pipeline - Whistler	41,927	-	-	-	-	-	-	41,927	41,927
11	465-30 Mt Hayes - Mains	6,015	-	-	-	-	-	-	6,015	6,015
12	465-10 Mains - Byron Creek	971	-	-	-	-	-	-	971	971
13	466-00 Compressor Equipment	178,555	-	5,347	186	1,711	(458)	-	185,341	181,948
14	466-00 Compressor Equipment - OVERHAUL	9,921	-	-	-	-	-	-	9,921	9,921
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	5,509	-	-	-	-	-	-	5,509	5,509
16	467-10 Measuring & Regulating Equipment	42,903	-	-	-	-	-	-	42,903	42,903
17	467-20 Telemetering	7,163	-	935	40	341	(611)	-	7,868	7,516
18	467-31 IP Intermediate Pressure Whistler	313	-	-	-	-	-	-	313	313
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	4,126	-	-	-	-	-	-	4,126	4,126
21	TOTAL TRANSMISSION	1,516,297	-	30,128	1,093	10,276	(1,968)	-	1,555,826	1,536,062
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	4,213	-	-	-	-	-	-	4,213	4,213
25	471-00 Distribution Land Rights	52	-	50	-	-	-	-	102	77
26	472-00 Structures & Improvements	18,194	-	-	-	-	-	-	18,194	18,194
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	896,702	-	25,321	-	8,464	(2,965)	-	927,522	912,112
29	473-00 Services - LILO	43,024	-	-	-	-	-	-	43,024	43,024
30	474-00 House Regulators & Meter Installations	174,707	-	193	-	71	(852)	-	174,119	174,413
31	474-00 House Regulators & Meter Installations - LILO	16,070	-	-	-	-	-	-	16,070	16,070
32	477-00 Meters/Regulators Installations	15,801	-	12,405	-	4,197	-	-	32,403	24,102
33	475-00 Mains	1,229,511	-	35,920	213	12,168	(3,526)	-	1,274,286	1,251,899
34	475-00 Mains - LILO	39,717	-	-	-	-	-	-	39,717	39,717
35	476-00 Compressor Equipment	1,026	-	-	-	-	-	-	1,026	1,026
36	477-00 Measuring & Regulating Equipment	101,284	-	3,380	142	1,191	(585)	-	105,412	103,348
37	477-00 Telemetering	7,501	-	550	4	189	(83)	-	8,161	7,831
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	222,165	-	12,598	-	-	(4,370)	-	230,393	226,279
40	478-11 Meters - LILO	10,027	-	-	-	-	-	-	10,027	10,027
41	478-20 Instruments	11,501	-	-	-	-	-	-	11,501	11,501
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,791,765	-	90,417	359	26,280	(12,381)	-	2,896,440	2,844,103
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	461	-	203	-	74	-	-	738	600
49	418-10 Bio Gas Purification Overhaul	815	-	513	-	-	-	-	1,328	1,072
50	418-20 Bio Gas Purification Upgrader	3,257	-	2,050	-	-	-	-	5,307	4,282
51	474-10 Bio Gas Reg & Meter Installations	2,228	-	406	-	148	-	-	2,782	2,505
52	478-30 Bio Gas Meters	446	-	406	-	-	-	-	852	649
53	TOTAL BIO-GAS	7,207	-	3,578	-	222	-	-	11,007	9,107

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 4,116	$ -	$ 1,386	$ -	$ 506	$ -	$ -	$ 6,008	$ 5,062
3	476-20 NG Transportation LNG Dispensing Equipment	3,328	-	1,180	-	431	-	-	4,939	4,134
4	476-30 NG Transportation CNG Foundations	908	-	306	-	112	-	-	1,326	1,117
5	476-40 NG Transportation LNG Foundations	734	-	260	-	95	-	-	1,089	912
6	476-50 NG Transportation LNG Pumps	1,579	-	560	-	204	-	-	2,343	1,961
7	476-60 NG Transportation CNG Dehydrator	321	-	108	-	39	-	-	468	395
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	10,986	-	3,800	-	1,387	-	-	16,173	13,580
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	29,895	-	400	-	-	-	-	30,295	30,095
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	12,110	-	-	-	-	(3)	-	12,107	12,109
16	- Masonry Buildings	107,781	-	2,995	-	-	-	-	110,776	109,279
17	- Leasehold Improvement	4,082	-	130	-	-	(146)	-	4,066	4,074
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	5,202	-	113	-	-	-	-	5,315	5,259
20	483-40 GP Furniture	23,680	-	465	-	-	(1,954)	-	22,191	22,936
21	483-10 GP Computer Hardware	33,899	-	8,000	206	-	(6,581)	-	35,524	34,712
22	483-20 GP Computer Software	1,736	-	-	-	-	(211)	-	1,525	1,631
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	51	-	-	-	-	-	-	51	51
25	484-00 Vehicles	10,546	-	3,646	-	-	(1,409)	-	12,783	11,665
26	484-00 Vehicles - Leased	29,753	-	2,860	-	-	(1,716)	-	30,897	30,325
27	485-10 Heavy Work Equipment	678	-	-	-	-	-	-	678	678
28	485-20 Heavy Mobile Equipment	2,651	-	360	-	-	-	-	3,011	2,831
29	486-00 Small Tools & Equipment	49,368	-	3,160	-	-	(1,357)	-	51,171	50,270
30	487-00 Equipment on Customer's Premises	9	-	-	-	-	-	-	9	9
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	8,509	-	30	-	-	(408)	-	8,131	8,320
34	- Radio	4,584	-	45	-	-	(34)	-	4,595	4,590
35	489-00 Other General Equipment	(2)	-	-	-	-	-	-	(2)	(2)
36	TOTAL GENERAL	324,532	-	22,204	206	-	(13,819)	-	333,123	328,828
37										
38	**UNCLASSIFIED PLANT**									
39	499 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 5,117,445	$ -	$ 163,508	$ 1,916	$ 38,329	$ (41,343)	$ -	$ 5,279,855	$ 5,198,650
43										
44	Cross Reference	- Sect 7-TAB 7.5, Schedule 18							- Sect 7-TAB 7.5, Schedule 18	
45			- Sect 7-TAB 7.5, Schedule 19							

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**INTANGIBLE PLANT**					
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	1	-	-	531	532
4	175-00 Unamortized Conversion Expense - Squamish	78	-	-	78	156
5	178-00 Organization Expense	7	-	-	383	390
6	179-01 Other Deferred Charges	-	-	-	-	-
7	401-00 Franchise and Consents	55	-	-	164	219
8	402-00 Utility Plant Acquisition Adjustment	36	-	-	57	93
9	402-00 Other Intangible Plant	39	-	-	821	860
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-
11	461-00 Transmission Land Rights	-	-	-	1,751	1,751
12	461-10 Transmission Land Rights - Byron Creek	-	-	-	19	$ 19
13	461-13 IP Land Rights Whistler	-	-	-	-	-
14	471-00 Distribution Land Rights	-	-	-	249	249
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	1	1
16	402-01 Application Software - 12.5%	14,283	-	(3,653)	25,431	36,061
17	402-02 Application Software - 20%	4,393	-	(2,045)	7,989	10,337
18	TOTAL INTANGIBLE	18,892	-	(5,698)	37,474	50,668
19						
20	**MANUFACTURED GAS / LOCAL STORAGE**					
21	430-00 Manufact'd Gas - Land	-	-	-	(899)	(899)
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	16	-	-	120	136
24	433-00 Manufact'd Gas - Equipment	12	-	-	70	82
25	434-00 Manufact'd Gas - Gas Holders	8	-	-	201	209
26	436-00 Manufact'd Gas - Compressor Equipment	3	-	-	29	32
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	49	-	-	272	321
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	188	-	-	2,612	2,800
31	443-00 Gas Holders - Storage (Tilbury)	318	-	-	10,403	10,721
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	1,176	-	(681)	9,189	9,684
36	440/441-00 Land in Fee Simple and Land Rights (Mount Hayes)	-	-	-	-	-
37	442-00 Structures & Improvements (Mount Hayes)	698	-	-	407	1,105
38	443-00 Gas Holders - Storage (Mount Hayes)	1,021	-	-	592	1,613
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	290	-	-	169	459
43	448-20 Pre-treatment (Mount Hayes)	1,160	-	-	677	1,837
44	448-30 Liquefaction Equipment (Mount Hayes)	725	-	-	423	1,148
45	448-40 Send out Equipment (Mount Hayes)	581	-	-	290	871
46	448-50 Sub-station and Electric (Mount Hayes)	562	-	-	281	843
47	448-60 Control Room (Mount Hayes)	395	-	-	198	593
48	449-00 Local Storage Equipment (Mount Hayes)	5	-	-	3	8
49	TOTAL MANUFACTURED	7,207	-	(681)	25,038	31,564

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**TRANSMISSION PLANT**					
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-
5	462-00 Compressor Structures	968	(219)	-	10,655	11,404
6	463-00 Measuring Structures	431	(95)	-	4,609	4,945
7	464-00 Other Structures & Improvements	174	-	-	1,742	1,916
8	465-00 Mains	16,691	(2,672)	(1,065)	303,997	316,951
9	465-00 Mains - INSPECTION	1,276	-	-	1,939	3,215
10	465-11 IP Transmission Pipeline - Whistler	600	-	-	1,511	2,111
11	465-30 Mt Hayes - Mains	93	-	-	54	147
12	465-10 Mains - Byron Creek	49	-	-	889	938
13	466-00 Compressor Equipment	5,027	(404)	(547)	60,620	64,696
14	466-00 Compressor Equipment - OVERHAUL	1,908	-	-	3,154	5,062
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	204	-	-	119	323
16	467-10 Measuring & Regulating Equipment	1,836	(72)	-	13,993	15,757
17	467-20 Telemetering	23	-	(481)	6,280	5,822
18	467-31 IP Intermediate Pressure Whistler	13	-	-	32	45
19	467-20 Measuring & Regulating Equipment - Byron Creek	-	-	-	4	4
20	468-00 Communication Structures & Equipment	468	-	-	2,786	3,254
21	TOTAL TRANSMISSION	29,761	(3,462)	(2,093)	412,785	436,991
22						
23	**DISTRIBUTION PLANT**					
24	470-00 Land in Fee Simple	-	-	-	26	26
25	471-00 Distribution Land Rights	-	-	-	-	-
26	472-00 Structures & Improvements	600	(22)	-	5,362	5,940
27	472-10 Structures & Improvements - Byron Creek	5	-	-	27	32
28	473-00 Services	19,684	(3,009)	(3,109)	167,256	180,822
29	473-00 Services - LILO	2,543	-	-	1,820	4,363
30	474-00 House Regulators & Meter Installations	12,619	(5,354)	(1,783)	19,116	24,598
31	474-00 House Regulators & Meter Installations - LILO	598	-	-	704	1,302
32	477-00 Meters/Regulators Installations	359	-	-	-	359
33	475-00 Mains	17,940	(2,845)	(2,963)	362,762	374,894
34	475-00 Mains - LILO	1,803	-	-	1,560	3,363
35	476-00 Compressor Equipment	272	-	-	706	978
36	477-00 Measuring & Regulating Equipment	4,675	(75)	(571)	26,356	30,385
37	477-00 Telemetering	17	-	(120)	6,362	6,259
38	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	204	204
39	478-10 Meters	16,994	1,169	(4,370)	66,199	79,992
40	478-11 Meters - LILO	524	-	-	660	1,184
41	478-20 Instruments	362	-	-	926	1,288
42	479-00 Other Distribution Equipment	-	-	-	-	-
43	TOTAL DISTRIBUTION	78,995	(10,136)	(12,916)	660,046	715,989
44						
45	**BIO GAS**					
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	5	-	-	2	7
49	418-10 Bio Gas Purification Overhaul	81	-	-	-	81
50	418-20 Bio Gas Purification Upgrader	162	-	-	-	162
51	474-10 Bio Gas Reg & Meter Installations	145	-	-	44	189
52	478-30 Bio Gas Meters	19	-	-	1	20
53	TOTAL BIO-GAS	412	-	-	47	459

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision 2012 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2011	Accumulated 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Natural Gas for Transportation**					
2	476-10 NG Transportation CNG Dispensing Equipment	$ 154	$ -	$ -	$ 51	$ 205
3	476-20 NG Transportation LNG Dispensing Equipment	127	-	-	43	170
4	476-30 NG Transportation CNG Foundations	34	-	-	11	45
5	476-40 NG Transportation LNG Foundations	28	-	-	10	38
6	476-50 NG Transportation LNG Pumps	120	-	-	41	161
7	476-60 NG Transportation CNG Dehydrator	12	-	-	4	16
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-
9	TOTAL NG FOR TRANSP	475	-	-	160	635
10						
11	**GENERAL PLANT & EQUIPMENT**					
12	480-00 Land in Fee Simple	-	-	-	30	30
13	481-00 Land Rights	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-
15	- Frame Buildings	648	-	-	3,331	3,979
16	- Masonry Buildings	2,180	-	-	13,825	16,005
17	- Leasehold Improvement	374	-	(313)	501	562
18	Office Equipment & Furniture	-	-	-	-	-
19	483-30 GP Office Equipment	326	-	-	433	759
20	483-40 GP Furniture	1,159	-	(567)	14,395	14,987
21	483-10 GP Computer Hardware	6,111	-	(1,517)	9,766	14,360
22	483-20 GP Computer Software	247	-	(475)	956	728
23	483-21 GP Computer Software	-	-	-	-	-
24	483-22 GP Computer Software	10	-	-	39	49
25	484-00 Vehicles	1,393	-	(262)	3,050	4,181
26	484-00 Vehicles - Leased	3,086	-	(1,908)	14,746	15,924
27	485-10 Heavy Work Equipment	46	-	(11)	(13)	22
28	485-20 Heavy Mobile Equipment	402	-	-	780	1,182
29	486-00 Small Tools & Equipment	2,423	-	(1,207)	20,120	21,336
30	487-00 Equipment on Customer's Premises	1	-	-	(6)	(5)
31	- VRA Compressor Installation Costs	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-
33	- Telephone	564	-	(10)	4,515	5,069
34	- Radio	305	-	(7)	2,397	2,695
35	489-00 Other General Equipment	-	-	-	(2)	(2)
36	TOTAL GENERAL	19,275	-	(6,277)	88,863	101,861
37						
38	**UNCLASSIFIED PLANT**					
39	499 Plant Suspense	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-
41						
42	TOTALS	$ 155,017	$ (13,598)	$ (27,665)	$ 1,224,413	$ 1,338,167
43						
44	Less: Vehicle Depreciation Allocated To Capital Projects	(1,884)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA	(243)				
46	**Net Depreciation Expense**	$ 152,890				
47						
48	Cross Reference	- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision 2013 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	**INTANGIBLE PLANT**					
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	1	-	-	532	533
4	175-00 Unamortized Conversion Expense - Squamish	78	-	-	156	234
5	178-00 Organization Expense	7	-	-	390	397
6	179-01 Other Deferred Charges	-	-	-	-	-
7	401-00 Franchise and Consents	55	-	-	219	274
8	402-00 Utility Plant Acquisition Adjustment	36	-	-	93	129
9	402-00 Other Intangible Plant	39	-	-	860	899
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-
11	461-00 Transmission Land Rights	-	-	-	1,751	1,751
12	461-10 Transmission Land Rights - Byron Creek	-	-	-	$ 19	19
13	461-13 IP Land Rights Whistler	-	-	-	-	-
14	471-00 Distribution Land Rights	-	-	-	249	249
15	471-10 Distribution Land Rights - Byron Creek	-	-	-	1	1
16	402-01 Application Software - 12.5%	14,276	-	(8,758)	36,061	41,579
17	402-02 Application Software - 20%	4,981	-	(4,268)	10,337	11,050
18	TOTAL INTANGIBLE	19,473	-	(13,026)	50,668	57,115
19						
20	**MANUFACTURED GAS / LOCAL STORAGE**					
21	430-00 Manufact'd Gas - Land	-	-	-	(899)	(899)
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	16	-	-	136	152
24	433-00 Manufact'd Gas - Equipment	14	-	-	82	96
25	434-00 Manufact'd Gas - Gas Holders	8	-	-	209	217
26	436-00 Manufact'd Gas - Compressor Equipment	3	-	-	32	35
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	49	-	-	321	370
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	198	-	-	2,800	2,998
31	443-00 Gas Holders - Storage (Tilbury)	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	1,231	-	(149)	9,684	10,766
36	440/441-00 Land in Fee Simple and Land Rights (Mount Hayes)	-	-	-	-	-
37	442-00 Structures & Improvements (Mount Hayes)	698	-	-	1,105	1,803
38	443-00 Gas Holders - Storage (Mount Hayes)	1,032	-	-	1,613	2,645
39	446-00 Compressor Equipment (Mount Hayes)	-	-	-	-	-
40	447-00 Measuring & Regulating Equipment (Mount Hayes)	-	-	-	-	-
41	448-00 Purification Equipment (Mount Hayes)	-	-	-	-	-
42	448-10 Piping (Mount Hayes)	290	-	-	459	749
43	448-20 Pre-treatment (Mount Hayes)	1,160	-	-	1,837	2,997
44	448-30 Liquefaction Equipment (Mount Hayes)	725	-	-	1,148	1,873
45	448-40 Send out Equipment (Mount Hayes)	581	-	-	871	1,452
46	448-50 Sub-station and Electric (Mount Hayes)	562	-	-	843	1,405
47	448-60 Control Room (Mount Hayes)	395	-	-	593	988
48	449-00 Local Storage Equipment (Mount Hayes)	5	-	-	8	13
49	TOTAL MANUFACTURED	7,285	-	(149)	31,564	38,700

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision 2013 (Cr.)	Provision Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	**TRANSMISSION PLANT**					
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-
5	462-00 Compressor Structures	968	-	-	11,404	12,372
6	463-00 Measuring Structures	431	-	-	4,945	5,376
7	464-00 Other Structures & Improvements	174	-	-	1,916	2,090
8	465-00 Mains	17,174	-	(899)	316,951	333,226
9	465-00 Mains - INSPECTION	1,590	-	-	3,215	4,805
10	465-11 IP Transmission Pipeline - Whistler	600	-	-	2,111	2,711
11	465-30 Mt Hayes - Mains	93	-	-	147	240
12	465-10 Mains - Byron Creek	49	-	-	938	987
13	466-00 Compressor Equipment	5,241	-	(458)	64,696	69,479
14	466-00 Compressor Equipment - OVERHAUL	2,146	-	-	5,062	7,208
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	204	-	-	323	527
16	467-10 Measuring & Regulating Equipment	1,836	-	-	15,757	17,593
17	467-20 Telemetering	25	-	(611)	5,822	5,236
18	467-31 IP Intermediate Pressure Whistler	13	-	-	45	58
19	467-20 Measuring & Regulating Equipment - Byron Creek	-	-	-	4	4
20	468-00 Communication Structures & Equipment	468	-	-	3,254	3,722
21	TOTAL TRANSMISSION	31,012	-	(1,968)	436,991	466,035
22						
23	**DISTRIBUTION PLANT**					
24	470-00 Land in Fee Simple	-	-	-	26	26
25	471-00 Distribution Land Rights	-	-	-	-	-
26	472-00 Structures & Improvements	600	-	-	5,940	6,540
27	472-10 Structures & Improvements - Byron Creek	5	-	-	32	37
28	473-00 Services	20,325	-	(2,965)	180,822	198,182
29	473-00 Services - LILO	2,543	-	-	4,363	6,906
30	474-00 House Regulators & Meter Installations	12,549	-	(852)	24,598	36,295
31	474-00 House Regulators & Meter Installations - LILO	598	-	-	1,302	1,900
32	477-00 Meters/Regulators Installations	1,097	-	-	359	1,456
33	475-00 Mains	18,561	-	(3,526)	374,894	389,929
34	475-00 Mains - LILO	1,803	-	-	3,363	5,166
35	476-00 Compressor Equipment	272	-	-	978	1,250
36	477-00 Measuring & Regulating Equipment	4,866	-	(585)	30,385	34,666
37	477-00 Telemetering	19	-	(83)	6,259	6,195
38	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	204	204
39	478-10 Meters	17,621	-	(4,370)	79,992	93,243
40	478-11 Meters - LILO	524	-	-	1,184	1,708
41	478-20 Instruments	362	-	-	1,288	1,650
42	479-00 Other Distribution Equipment	-	-	-	-	-
43	TOTAL DISTRIBUTION	81,745	-	(12,381)	715,989	785,353
44						
45	**BIO GAS**					
46	472-00 Bio Gas Struct. & Improvements	-	-	-	-	-
47	475-10 Bio Gas Mains – Municipal Land	-	-	-	-	-
48	475-20 Bio Gas Mains – Private Land	9	-	-	7	16
49	418-10 Bio Gas Purification Overhaul	143	-	-	81	224
50	418-20 Bio Gas Purification Upgrader	286	-	-	162	448
51	474-10 Bio Gas Reg & Meter Installations	186	-	-	189	375
52	478-30 Bio Gas Meters	51	-	-	20	71
53	TOTAL BIO-GAS	675	-	-	459	1,134

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision 2013 (Cr.)	Provision Adjust-ments	Provision Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Natural Gas for Transportation**					
2	476-10 NG Transportation CNG Dispensing Equipment	$ 253	$ -	$ -	$ 205	$ 458
3	476-20 NG Transportation LNG Dispensing Equipment	207	-	-	170	377
4	476-30 NG Transportation CNG Foundations	56	-	-	45	101
5	476-40 NG Transportation LNG Foundations	46	-	-	38	84
6	476-50 NG Transportation LNG Pumps	196	-	-	161	357
7	476-60 NG Transportation CNG Dehydrator	20	-	-	16	36
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-
9	TOTAL NG FOR TRANSP	778	-	-	635	1,413
10						
11	**GENERAL PLANT & EQUIPMENT**					
12	480-00 Land in Fee Simple	-	-	-	30	30
13	481-00 Land Rights	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-
15	- Frame Buildings	648	-	(3)	3,979	4,624
16	- Masonry Buildings	2,440	-	-	16,005	18,445
17	- Leasehold Improvement	373	-	(146)	562	789
18	Office Equipment & Furniture	-	-	-	-	-
19	483-30 GP Office Equipment	351	-	-	759	1,110
20	483-40 GP Furniture	1,147	-	(1,954)	14,987	14,180
21	483-10 GP Computer Hardware	6,942	-	(6,581)	14,360	14,721
22	483-20 GP Computer Software	204	-	(211)	728	721
23	483-21 GP Computer Software	-	-	-	-	-
24	483-22 GP Computer Software	10	-	-	49	59
25	484-00 Vehicles	1,832	-	(1,409)	4,181	4,604
26	484-00 Vehicles - Leased	3,239	-	(1,716)	15,924	17,447
27	485-10 Heavy Work Equipment	46	-	-	22	68
28	485-20 Heavy Mobile Equipment	461	-	-	1,182	1,643
29	486-00 Small Tools & Equipment	2,513	-	(1,357)	21,336	22,492
30	487-00 Equipment on Customer's Premises	1	-	-	(5)	(4)
31	- VRA Compressor Installation Costs	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-
33	- Telephone	555	-	(408)	5,069	5,216
34	- Radio	306	-	(34)	2,695	2,967
35	489-00 Other General Equipment	-	-	-	(2)	(2)
36	TOTAL GENERAL	21,068	-	(13,819)	101,861	109,110
37						
38	**UNCLASSIFIED PLANT**					
39	499 Plant Suspense	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-
41						
42	TOTALS	$ 162,036	$ -	$ (41,343)	$ 1,338,167	$ 1,458,860
43						
44	Less: Vehicle Depreciation Allocated To Capital Projects	(2,109)				
45	Less: Depreciation & Amortization transferred to Biomethane BVA	(429)				
46	**Net Depreciation Expense**	$ 159,498				
47						
48	Cross Reference	- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Account	Provision (Cr.)	Provision Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2011	Ending 12/31/2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**MANUFACTURED GAS / LOCAL STORAGE**						
2	442-00 Structures & Improvements (Tilbury)	$ 19	$ -	$ -	$ -	$ -	$ 19
3	443-00 Gas Holders - Storage (Tilbury)	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	103	-	-	-	-	103
5	TOTAL MANUFACTURED	188	-	-	-	-	188
6							
7	**TRANSMISSION PLANT**						
8	462-00 Compressor Structures	48	219	-	-	-	267
9	463-00 Measuring Structures	10	95	-	-	-	105
10	464-00 Other Structures & Improvements	9	-	-	-	-	9
11	465-00 Mains	1,691	2,672	-	-	-	4,363
12	466-00 Compressor Equipment	501	404	-	-	-	905
13	467-10 Measuring & Regulating Equipment	80	72	-	-	-	152
14	468-00 Communication Structures & Equipment	87	-	-	-	-	87
15	TOTAL TRANSMISSION	2,426	3,462	-	-	-	5,888
16							
17	**DISTRIBUTION PLANT**						
18	472-00 Structures & Improvements	29	22	-	-	-	51
19	473-00 Services	9,330	3,009	(9,464)	-	-	2,875
20	473-00 Services - LILO	1,230	-	-	-	-	1,230
21	474-00 House Regulators & Meter Installations	1,315	5,354	(2,700)	-	-	3,969
22	477-00 Meters/Regulators Installations	59	-	-	-	-	59
23	475-00 Mains	3,562	2,845	(908)	-	-	5,499
24	475-00 Mains - LILO	389	-	-	-	-	389
25	476-00 Compressor Equipment	117	-	-	-	-	117
26	477-00 Measuring & Regulating Equipment	461	75	(175)	-	-	361
27	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	-	-	-
28	478-10 Meters	1,084	(1,169)	-	-	-	(85)
29	TOTAL DISTRIBUTION	17,576	10,136	(13,247)	-	-	14,465
30							
31	**BIO GAS**						
32	475-20 Bio Gas Mains – Private Land	1	-	-	-	-	1
33	478-30 Bio Gas Meters	1	-	-	-	-	1
34	TOTAL BIO-GAS	2	-	-	-	-	2
35							
36	TOTALS	$ 20,192	$ 13,598	$ (13,247)	$ -	$ -	$ 20,543
37							
38	Cross Reference	- Sect 7-TAB 7.5, Schedule 13					- Sect 7-TAB 7.5, Schedule 18
39							

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Provision (Cr.)	Provision Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**MANUFACTURED GAS / LOCAL STORAGE**						
2	442-00 Structures & Improvements (Tilbury)	$ 20	$ -	$ -	$ -	$ 19	$ 39
3	443-00 Gas Holders - Storage (Tilbury)	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	107	-	-	-	103	210
5	TOTAL MANUFACTURED	193	-	-	-	188	381
6							
7	**TRANSMISSION PLANT**						
8	462-00 Compressor Structures	48	-	-	-	267	315
9	463-00 Measuring Structures	10	-	-	-	105	115
10	464-00 Other Structures & Improvements	9	-	-	-	9	18
11	465-00 Mains	1,738	-	-	-	4,363	6,101
12	466-00 Compressor Equipment	522	-	-	-	905	1,427
13	467-10 Measuring & Regulating Equipment	80	-	-	-	152	232
14	468-00 Communication Structures & Equipment	87	-	-	-	87	174
15	TOTAL TRANSMISSION	2,494	-	-	-	5,888	8,382
16							
17	**DISTRIBUTION PLANT**						
18	472-00 Structures & Improvements	29	-	-	-	51	80
19	473-00 Services	9,635	-	(9,487)	-	2,875	3,023
20	473-00 Services - LILO	1,230	-	-	-	1,230	2,460
21	474-00 House Regulators & Meter Installations	1,307	-	(2,700)	-	3,969	2,576
22	477-00 Meters/Regulators Installations	181	-	-	-	59	240
23	475-00 Mains	3,685	-	(1,224)	-	5,499	7,960
24	475-00 Mains - LILO	389	-	-	-	389	778
25	476-00 Compressor Equipment	117	-	-	-	117	234
26	477-00 Measuring & Regulating Equipment	480	-	(175)	-	361	666
27	477-10 Measuring & Regulating Equipment - Byron Creek	-	-	-	-	-	-
28	478-10 Meters	1,123	-	-	-	(85)	1,038
29	TOTAL DISTRIBUTION	18,176	-	(13,586)	-	14,465	19,055
30							
31	**BIO GAS**						
32	475-20 Bio Gas Mains – Private Land	2	-	-	-	1	3
33	478-30 Bio Gas Meters	3	-	-	-	1	4
34	TOTAL BIO-GAS	5	-	-	-	2	7
35							
36	TOTALS	$ 20,868	$ -	$ (13,586)	$ -	$ 20,543	$ 27,825
37							
38	Cross Reference	- Sect 7-TAB 7.5, Schedule 13					- Sect 7-TAB 7.5, Schedule 18
39							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Balance 12/31/2011	Adjustment	2012 FORECAST Additions	Retirements	Balance 12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 250,340	$ -	$ 6,517	$ -	$ 256,857	
4							
5	Transmission Contributions	116,849	-	10,750	-	127,599	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	15,864	-	-	(5,106)	10,758	
11							
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13	Government Loans Contribution	49,123	-	-	(20,000)	29,123	
14							
15	Biomethane	-	-	-	-	-	
16							
17	TOTAL Contributions	432,176	-	17,267	(25,106)	424,337	- Sect 7-TAB 7.5, Schedule 18
18							
19							
20							
21	**Amortization**						
22							
23	Distribution Contributions	(65,154)	-	(6,351)	-	(71,505)	
24							
25	Transmission Contributions	(33,438)	-	(2,203)	-	(35,641)	
26							
27	Others	10	-	10	-	20	
28							
29	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
30	- Infrastructure/Custom	(9,302)	-	(1,664)	5,106	(5,860)	
31							
32	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
33	Government Loans Contribution	-	-	-	-	-	
34							
35	Biomethane	-	-	-	-	-	
36							
37	TOTAL CIAC Amortization	(107,884)	-	(10,208)	5,106	(112,986)	- Sect 7-TAB 7.5, Schedule 18
38							
39	**NET CONTRIBUTIONS**	$ 324,292	$ -	$ 7,059	$ (20,000)	$ 311,351	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 FORECAST Additions	Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 256,857	$ -	$ 6,581	$ -	$ 263,438	
4							
5	Transmission Contributions	127,599	-	750	-	128,349	
6							
7	Others	-	-	-	-	-	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,758	-	-	(204)	10,554	
11							
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13	Government Loans Contribution	29,123	-	-	(4,123)	25,000	
14							
15	Biomethane	-	-	-	-	-	
16							
17	TOTAL Contributions	424,337	-	7,331	(4,327)	427,341	- Sect 7-TAB 7.5, Schedule 18
18							
19							
20							
21	**Amortization**						
22							
23	Distribution Contributions	(71,505)	-	(6,537)	-	(78,042)	
24							
25	Transmission Contributions	(35,641)	-	(2,299)	-	(37,940)	
26							
27	Others	20	-	10	-	30	
28							
29	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
30	- Infrastructure/Custom	(5,860)	-	(1,332)	204	(6,988)	
31							
32	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
33	Government Loans Contribution	-	-	-	-	-	
34							
35	Biomethane	-	-	-	-	-	
36							
37	TOTAL CIAC Amortization	(112,986)	-	(10,158)	204	(122,940)	- Sect 7-TAB 7.5, Schedule 18
38							
39	**NET CONTRIBUTIONS**	$ 311,351	$ -	$ (2,827)	$ (4,123)	$ 304,401	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (23,385)	$ -	$ 31,179	$ (7,795)	$ 23,385	$ -	$ -	$ -	$ (0)	$ (11,692)
3	Midstream Cost Reconciliation Account (MCRA)	18,725	-	-	-	-	-	(8,322)	2,081	12,484	15,604
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(7,964)	464	-	-	-	-	3,333	(833)	(5,000)	(6,250)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(3,006)	-	3,953	(988)	2,965	2	15	(4)	(28)	(1,517)
6	Revelstoke Propane Cost Deferral Account	189	-	(252)	63	(189)	-	-	-	0	94
7	SCP Mitigation Revenues Variance Account	(6,180)	-	-	-	-	2,515	-	-	(3,665)	(4,922)
8	Gas Cost Variance Account (GCVA)	(8,124)	-	-	-	-	8,124	-	-	(0)	(4,062)
9	Gas Cost Reconciliation Account (GCRA)	11,435	(11,492)	76	(19)	57	-	-	-	(0)	(28)
10	Cost of Gas - Rate Rider A	(11,492)	11,492	-	-	-	-	-	-	(0)	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	23,714	-	20,000	(5,000)	15,000	(2,842)	-	-	35,871	29,793
14	NGV Conversion Grants	101	-	82	(20)	61	(27)	-	-	135	118
15	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
16	2010-2011 Biomethane Program Costs	-	897	-	-	-	(299)	-	-	598	748
17	2011 CNG and LNG Service Costs and Recoveries	-	-	(95)	24	(71)	24	-	-	(48)	(24)
18	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
19											
20	Non-Controllable Items										
21	Property Tax Deferral	(1,799)	-	-	-	-	1,074	-	-	(724)	(1,262)
22	Insurance Variance	(1,197)	-	-	-	-	1,197	-	-	-	(598)
23	Pension & OPEB Variance	9,574	-	-	-	-	(3,191)	-	-	6,383	7,978
24	BCUC Levies Variance	235	-	-	-	-	(234)	-	-	0	118
25	Interest Variance	(6,227)	-	-	-	-	2,820	-	-	(3,408)	(4,817)
26	Interest Variance - Funding benefits via Customer Deposits	917	-	-	-	-	(387)	-	-	530	723
27	Tax Variance Account	(7,029)	-	-	-	-	7,029	-	-	0	(3,514)
28	Olympics Security Costs Deferral	475	-	-	-	-	(244)	-	-	232	353
29	IFRS Conversion Costs	572	-	-	-	-	(286)	-	-	285	428
30	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
31	Vancouver Island Joint Venture Litigation Costs	-	137	-	-	-	(137)	-	-	-	68
32	Vancouver Island HST Implementation	(133)	-	-	-	-	133	-	-	-	(66)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Forecast Balance 12/31/2011	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2012	Mid-Year Average 2012
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 713	$ -	$ -	$ -	$ -	$ (184)	$ -	$ -	$ 529	$ 621
3	2010-2011 Revenue Requirement Application	100	-	-	-	-	(100)	-	-	0	50
4	2012-2013 Revenue Requirement Application	979	-	-	-	-	(489)	-	-	489	734
5	CCE CPCN Application	228	-	-	-	-	(63)	-	-	165	197
6	NGV for Transportation Application	-	147	-	-	-	(49)	-	-	98	123
7	Long Term Resource Plan Application	136	-	70	(18)	53	-	-	-	188	162
8	Victoria Regional Centre CPCN Application	69	-	-	-	-	(69)	-	-	-	35
9											
10	Whistler Pipeline										
11	Whistler Pipeline Conversion	13,288	-	-	-	-	(740)	-	-	12,548	12,918
12	Capital Contribution to FEVI	-	-	-	-	-	-	-	-	-	-
13	Pipeline Contribution Costs Variance Account	-	(434)	-	-	-	434	-	-	-	(217)
14											
15	Other										
16	Pension & OPEB Funding	(30,602)	-	(76,859)	-	(76,859)	-	-	-	(107,461)	(69,032)
17	Deferred Removal Costs	3,363	-	-	-	-	(1,682)	-	-	1,682	2,522
18	Gains and Losses on Asset Disposition	18,739	(6,176)	-	-	-	(628)	-	-	11,935	12,249
19	PCEC Start Up Costs	1,052	-	-	-	-	(44)	-	-	1,008	1,030
20	2010-2011 Customer Service O&M and COS	-	26,025	4,973	(1,243)	3,730	(3,253)	-	-	26,502	26,264
21	2011 Kootney River Crossing COS	-	120	-	-	-	(40)	-	-	80	100
22	Gas Asset Records Project	-	-	2,000	(500)	1,500	(300)	-	-	1,200	600
23	BC OneCall Project	-	-	1,250	(313)	938	(188)	-	-	750	375
24	IFRS Transitional Costs	(6,176)	6,176	75,131	-	75,131	(8,066)	-	-	67,065	33,533
25											
26	Residual Deferred Charges										
27	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
28	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
29	Carbon Tax Cost of Service	(66)	-	-	-	-	66	-	-	-	(33)
30	OSC Certification Compliance	(59)	-	-	-	-	59	-	-	-	(30)
31	Deferred ROE Variance	(47)	-	-	-	-	47	-	-	0	(24)
32	Sales Margin Differential	464	(464)	-	-	-	-	-	-	-	-
33	FEW 2009 Revenue Requirement Application	1	-	-	-	-	(1)	-	-	-	1
34	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
35	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
36	Residual Rider Disposition	-	179	-	-	-	(179)	-	-	-	89
37											
38	Total Deferred Charges for Rate Base	$ (7,733)	$ 27,071	$ 61,507	$ (15,809)	$ 45,699	$ (199)	$ (4,974)	$ 1,243	$ 61,107	$ 40,223
39											
40	Cross Reference						- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	$ (0)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (0)	$ -
3	Midstream Cost Reconciliation Account (MCRA)	12,484	-	-	-	-	-	(8,322)	2,081	6,242	9,363
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(5,000)	-	-	-	-	-	3,333	(833)	(2,500)	(3,750)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(28)	-	(0)	-	(0)	2	10	(3)	(18)	(23)
6	Revelstoke Propane Cost Deferral Account	0	-	-	-	-	-	-	-	0	0
7	SCP Mitigation Revenues Variance Account	(3,665)	-	-	-	-	2,150	-	-	(1,514)	(2,590)
8	Gas Cost Variance Account (GCVA)	(0)	-	-	-	-	-	-	-	(0)	-
9	Gas Cost Reconciliation Account (GCRA)	(0)	-	-	-	-	-	-	-	(0)	-
10	Cost of Gas - Rate Rider A	(0)	-	-	-	-	-	-	-	(0)	-
11											
12	Energy Policy Related										
13	Energy Efficiency & Conservation (EEC)	35,871	-	20,000	(5,000)	15,000	(4,396)	-	-	46,475	41,173
14	NGV Conversion Grants	135	-	82	(20)	61	(42)	-	-	154	145
15	Emmissions Regulations	-	-	-	-	-	-	-	-	-	-
16	2010-2011 Biomethane Program Costs	598	-	-	-	-	(299)	-	-	299	449
17	2011 CNG and LNG Service Costs and Recoveries	(48)	-	-	-	-	24	-	-	(24)	(36)
18	CNG and LNG Costs and Service Recoveries	-	-	-	-	-	-	-	-	-	-
19											
20	Non-Controllable Items										
21	Property Tax Deferral	(724)	-	-	-	-	362	-	-	(362)	(543)
22	Insurance Variance	-	-	-	-	-	-	-	-	-	-
23	Pension & OPEB Variance	6,383	-	-	-	-	(3,191)	-	-	3,191	4,787
24	BCUC Levies Variance	0	-	-	-	-	-	-	-	0	0
25	Interest Variance	(3,408)	-	-	-	-	1,704	-	-	(1,704)	(2,556)
26	Interest Variance - Funding benefits via Customer Deposits	530	-	-	-	-	(265)	-	-	265	397
27	Tax Variance Account	0	-	-	-	-	-	-	-	0	-
28	Olympics Security Costs Deferral	232	-	-	-	-	(236)	-	-	(4)	114
29	IFRS Conversion Costs	285	-	-	-	-	(285)	-	-	0	143
30	Customer Service Variance Account	-	-	-	-	-	-	-	-	-	-
31	Vancouver Island Joint Venture Litigation Costs	-	-	-	-	-	-	-	-	-	-
32	Vancouver Island HST Implementation	-	-	-	-	-	-	-	-	-	-

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Forecast Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Cost of Current Applications										
2	2009 ROE & Cost of Capital Application	$ 529	$ -	$ -	$ -	$ -	$ (184)	$ -	$ -	$ 345	$ 437
3	2010-2011 Revenue Requirement Application	0	-	-	-	-	-	-	-	0	-
4	2012-2013 Revenue Requirement Application	489	-	-	-	-	(489)	-	-	(0)	245
5	CCE CPCN Application	165	-	-	-	-	(63)	-	-	102	134
6	NGV for Transportation Application	98	-	-	-	-	(49)	-	-	49	74
7	Long Term Resource Plan Application	188	-	200	(50)	150	(168)	-	-	171	180
8	Victoria Regional Centre CPCN Application	-	-	-	-	-	-	-	-	-	-
9											
10	Whistler Pipeline										
11	Whistler Pipeline Conversion	12,548	-	-	-	-	(740)	-	-	11,808	12,178
12	Capital Contribution to FEVI	-	-	-	-	-	-	-	-	-	-
13	Pipeline Contribution Costs Variance Account	-	-	-	-	-	-	-	-	-	-
14											
15	Other										
16	Pension & OPEB Funding	(107,461)	-	(3,332)	-	(3,332)	-	-	-	(110,793)	(109,127)
17	Deferred Removal Costs	1,682	-	-	-	-	(1,682)	-	-	0	841
18	Gains and Losses on Asset Disposition	11,935	-	-	-	-	(628)	-	-	11,307	11,621
19	PCEC Start Up Costs	1,008	-	-	-	-	(44)	-	-	964	986
20	2010-2011 Customer Service O&M and COS	26,502	-	-	-	-	(3,719)	-	-	22,783	24,642
21	2011 Kootney River Crossing COS	80	-	-	-	-	(40)	-	-	40	60
22	Gas Asset Records Project	1,200	-	2,250	(563)	1,688	(638)	-	-	2,250	1,725
23	BC OneCall Project	750	-	1,250	(313)	938	(375)	-	-	1,313	1,031
24	IFRS Transitional Costs	67,065	-	-	-	-	(8,066)	-	-	58,999	63,032
25											
26	Residual Deferred Charges										
27	SCP Tax Reassessment	684	-	-	-	-	-	-	-	684	684
28	Earnings Sharing Mechanism	-	-	-	-	-	-	-	-	-	-
29	Carbon Tax Cost of Service	-	-	-	-	-	-	-	-	-	-
30	OSC Certification Compliance	-	-	-	-	-	-	-	-	-	-
31	Deferred ROE Variance	0	-	-	-	-	-	-	-	0	-
32	Sales Margin Differential	-	-	-	-	-	-	-	-	-	-
33	FEW 2009 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
34	FEI 2010 Revenue Surplus	-	-	-	-	-	-	-	-	-	-
35	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
36	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-
37											
38	Total Deferred Charges for Rate Base	$ 61,107	$ -	$ 20,449	$ (5,945)	$ 14,504	$ (21,357)	$ (4,979)	$ 1,244	$ 50,520	$ 55,814
39											
40	Cross Reference						- Sect 7-TAB 7.5, Schedule 13			- Sect 7-TAB 7.5, Schedule 18	

WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Required for				
3	Operating Expenses	$ 8,850	$ 10,191	$ 1,341	- Sect 7-TAB 7.5, Schedule 41
4					
5					
6	Less - Funds Available:				
7					
8	Reserve for Bad Debts	(5,871)	(5,815)	56	
9					
10	Withholdings From Employees	(5,377)	(5,462)	(85)	
11					
12	Subtotal	(2,398)	(1,086)	1,312	- Sect 7-TAB 7.5, Schedule 18
13					
14	**Other Working Capital Items**				
15	Construction Advances	(633)	(633)	-	
16	Transmission Line Pack Gas	3,571	4,381	810	
17	Gas in Storage	108,527	107,802	(725)	
18	Inventory - Materials & Supplies	1,410	1,438	28	
19					
20	Subtotal	112,584	112,697	113	- Sect 7-TAB 7.5, Schedule 18
21					
22	Total	$ 110,186	$ 111,611	$ 1,425	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 Days	2012 Expenses	2012 Cash Working Capital	2013 Days	2013 Expenses	2013 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASHWORKING CAPITAL, REVISED RATES**							
2								
3	Revenue Lag Days	39.0			39.0			
4	Expense Lead Days	36.4			36.1			- Sect 7-TAB 7.5, Schedule 42
5								
6	Net Lead/(Lag) Days	2.6	$ 1,242,412	$ 8,850	2.9	$ 1,282,647	$ 10,191	- Sect 7-TAB 7.5, Schedule 40
7								
8								
9								
10								
11	Cash working capital = Col. 2 x Col. 3 / 365 days							

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 Amount	2012 Lead Days Expense to Payment	2012 Dollar Days	2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**							
2								
3	Operating And Maintenance							
4	Expenses	$ 224,568	25.5	$ 5,726,484	$ 235,438	25.5	$ 6,003,669	- Sect 7-TAB 7.5, Schedule 7
5	Transportation Costs	1,027	40.2	41,285	1,029	40.2	41,366	- Sect 7-TAB 7.5, Schedule 7
6	Gas Purchases (excl Royalty Credits)	727,627	40.2	29,250,605	728,927	40.2	29,302,866	- Sect 7-TAB 7.5, Schedule 7
7								
8	Taxes Other Than Income							
9	Property Taxes	59,959	2.0	119,918	61,924	2.0	123,848	- Sect 7-TAB 7.5, Schedule 12
10	Franchise Fees	9,156	420.3	3,848,267	9,498	420.3	3,992,009	
11	Carbon Tax	171,423	29.1	4,988,404	186,944	29.1	5,440,061	
12	HST - Net	30,240	38.9	1,176,379	31,439	38.9	1,222,993	
13	PST Component of HST (REC)	(10,353)	33.9	(350,652)	(10,758)	33.9	(364,390)	
14	Income Tax	28,765	15.2	437,228	38,207	15.2	580,746	- Sect 7-TAB 7.5, Schedule 14
15								
16	Total	$ 1,242,412	36.4	$ 45,237,918	$ 1,282,647	36.1	$ 46,343,168	

FUTURE INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
($000s)

Line No.	Particulars	2012 FORECAST	2013 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)
1	Property Plant & Equipment			
2	Net Book Value *	$ (3,511,931)	$ (3,556,636)	
3	Less: Undepreciated Capital Cost	(2,473,819)	(2,461,553)	
4		(1,038,112)	(1,095,083)	
5	Weighted Average Future Tax Rate	25.00%	25.00%	
6		(259,528)	(273,771)	
7				
8	Total FIT Liability- After Tax (PP&E)	(259,528)	(273,771)	
9	Total FIT Liability- After Tax (Non-PP&E)	(6,294)	(2,420)	
10	Total FIT Liability- After Tax	(265,822)	(276,191)	
11				
12	Tax Gross Up	(88,607)	(92,064)	
13				
14	FIT Liability/Asset - End of Year	(354,429)	(368,254)	
15				
16	FIT Liability/Asset - Opening Balance	(337,894)	(354,428)	
17				
18	FIT Liability/Asset - Mid Year	(346,162)	(361,341)	- Sect 7-TAB 7.5, Schedule 18
19				
20				
21	Note: * Excludes Land, Software CIAC, and WIP.			

($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1							
2	2012 FORECAST						
3	Long-Term Debt	$ 1,974,672	55.22%	6.54%	3.61%	$ 129,149	- Sect 7-TAB 7.5, Schedule 46
4	Unfunded Debt						
5	Adjustment, Revised Rates	171,106	4.78%	2.75%	0.13%	4,705	
6	Common Equity	1,430,519	40.00%	9.62%	3.85%	137,616	- Sect 7-TAB 7.5, Schedule 5
7							
8		$ 3,576,297	100.00%		7.59%	$ 271,470	- Sect 7-TAB 7.5, Schedule 18

WEIGHTED AVERAGE RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Capitalization Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1							
2	2013 FORECAST						
3	Long-Term Debt	$ 1,959,859	53.64%	6.56%	3.52%	$ 128,547	- Sect 7-TAB 7.5, Schedule 47
4	Unfunded Debt						
5	Adjustment, Revised Rates	232,303	6.36%	3.75%	0.24%	8,711	
6	Common Equity	1,461,442	40.00%	9.62%	3.85%	140,591	- Sect 7-TAB 7.5, Schedule 6
7							
8		$ 3,653,604	100.00%		7.60%	$ 277,849	- Sect 7-TAB 7.5, Schedule 18

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2012
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 73,843	*	12.054%	$ 74,698	$ 9,004
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,046	**	10.461%	157,274	16,452
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000		4.878%	100,000	2,860
13											
14	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999		6.109%	250,000	15,273
15	FEVI L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000		5.200%	100,000	5,200
16	FEVI PCEPA - 2012	1-Jan-2008	1-Jan-2013	3.416%	15,526	-	15,526		3.416%	15,526	530
17											
18	FEW Intercompany Loan 2009	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000		5.110%	20,000	1,022
19											
20											
21											
22	LILO Obligations - Kelowna								6.398%	24,678	1,579
23	LILO Obligations - Nelson								7.606%	3,931	299
24	LILO Obligations - Vernon								8.833%	11,752	1,038
25	LILO Obligations - Prince George								7.769%	30,171	2,344
26	LILO Obligations - Creston								6.958%	2,860	199
27											
28	Vehicle Lease Obligation								5.007%	13,782	690
29											
30	Total									$ 1,974,672	$ 129,149
31											
32	*Includes adjustment of $15,755 for BC Hydro Premium (Series A), using weighted average capital structure.									Average Embedded Cost	6.54%
33	**Includes adjustment of $0 for BC Hydro Premium (Series B), using weighted average capital structure.										
34	Cross Reference									- Sect 7-TAB 7.5, Schedule 44	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100 *	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	158,262 **	10.230%	160,490	16,418
3										
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588	5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000	6.627%	100,000	6,627
11										
12	2011 Medium Term Debt Issue - Series 25	1-Jun-2011	1-Jun-2021	4.750%	100,000	1,000	99,000	4.878%	100,000	2,860
13										
14	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
15	FEVI L/T Debt Issue - 2010	1-Oct-2010	1-Oct-2040	5.200%	100,000	-	100,000	5.200%	100,000	5,200
16	FEVI PCEPA - 2013	1-Jan-2008	1-Jan-2013	4.413%	15,526	-	15,526	4.413%	-	-
17										
18	FEW Intercompany Loan 2009	1-Jun-2009	1-Jun-2014	5.110%	20,000	-	20,000	5.110%	20,000	1,022
19										
20										
21										
22	LILO Obligations - Kelowna							6.413%	23,749	1,523
23	LILO Obligations - Nelson							7.696%	3,794	292
24	LILO Obligations - Vernon							8.929%	11,323	1,011
25	LILO Obligations - Prince George							7.862%	29,142	2,291
26	LILO Obligations - Creston							7.050%	2,766	195
27										
28	Vehicle Lease Obligation							5.630%	13,640	768
29										
30	Total								$ 1,959,859	$ 128,547
31										
32	*Includes adjustment of $16,012 for BC Hydro Premium (Series A), using weighted average capital structure.								Average Embedded Cost	6.56%
33	**Includes adjustment of $3,216 for BC Hydro Premium (Series B), using weighted average capital structure.									
34	Cross Reference								- Sect 7-TAB 7.5, Schedule 45	

8 APPROVALS SOUGHT AND PROPOSED REGULATORY PROCESS

8.1 Approvals Sought

ORDER SOUGHT

The Order Sought has, in general, been broken out by company, but also by year (2012 and 2013). The reason for separating the orders for 2012 and 2013 is because some of the orders will be different in 2013 depending on whether amalgamation proceeds. The 2013 rate orders for each utility are thus conditional, as is the request for a consolidated cost of service.

In this Application, the FortisBC Energy Utilities are respectfully seeking an Order or Orders of the Commission granting the following approvals:

INTERIM 2012 RATES FOR FEI, FEVI, FEW AND FORT NELSON

1. Interim approval, pursuant to section 89 of the Act and section 15 of the *Administrative Tribunals Act,* effective January 1, 2012 of the 2012 rates for FEI, FEVI, FEW and Fort Nelson sought in this Application, as a decision on the permanent rates requested is unlikely to be received in time for implementation effective January 1, 2012, with any variance between interim rates and permanent rates to be refunded to or collected from customers by way of a rate rider following the approval of permanent rates.

2012 RATE APPROVALS FOR FEI

2. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEI for all non-bypass customers effective January 1, 2012, to recover the revenue requirements as described in Section 3.3.1 of the Application, resulting in an increase of 5.0 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

3. Approval of the Rate Stabilization Adjustment Mechanism (“RSAM”) rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2U, 2X, 3, 3U, 3X and 23 effective January 1, 2012 of ($0.032)/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the FEI Fourth Quarter 2011 Gas Cost filing.)

4. Approval pursuant to sections 59 to 61 of the Act of the 2012 cost allocation to Thermal Energy Services (formerly Alternative Energy Services) as set out in Section 5.3.18 and Appendix G of the Application.

5. Approval of the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2012 forecast period as set out in Section 5.5 of the Application.

6. Approval of the change in the allocation between the delivery margin and midstream of the SCP costs and revenues, and of the Spectra Energy Kingsvale South charges related to the NWN capacity as set out in Section 5.5 of the Application.

2012 RATE APPROVALS FOR FEVI

7. Approval pursuant to sections 59 to 61 of the Act and section 2.1 of the Vancouver Island Natural Gas Pipeline Agreement Special Direction ("Special Direction") of permanent rates for FEVI effective January 1, 2012 for Core Market sales and transportation customers, other than customers who have specified rates in their transportation service agreements, at the same level as 2011 rates.

8. Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast Cost of Service for 2012 as set out in Section 3.3.2 of the Application.

9. Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast capital expenditures for 2012, as set out in Section 6.2 of the Application.

10. Approval pursuant to section 2.10(a)(ii) of the Special Direction of FEVI's forecast revenue for 2012, based on its proposed rates, as set out in Section 4.5.6 of the Application.

11. Approval of the forecast gross O&M expenditures for 2012 of $35.236 million.

12. Approval of the 2012 cost of gas and discontinuation of the quarterly reporting of gas costs for FEVI as set out in Sections 5.2 and 6.3 of the Application.

13. Approval for the difference between the net revenues received and the actual cost of service, excluding O&M variances from forecast, to be allocated to the RSDA, as set out in Section 3.4.2 of the Application.

2012 RATE APPROVALS FOR FEW

14. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEW for all customers effective January 1, 2012, to recover the requested revenue requirements as described in Section 3.3.3 of the Application, resulting in an increase of 2.2 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

15. Approval of the RSAM rider for customers served under FEW Rate Schedules SGS 1/2, LGS 1, LGS 2 and LGS 3 effective January 1, 2012 of $0.524/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the FEW Fourth Quarter 2011 Gas Cost filing.)

2012 RATE APPROVALS FOR FORT NELSON

16. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for Fort Nelson customers effective January 1, 2012, to recover the requested revenue requirements as described in Section 3.3.4 of the Application, resulting in an increase of 6.5 per cent compared to 2011 delivery rates, with the increase to be applied to the delivery charge and the minimum monthly service charge.

17. Approval of the RSAM rider for customers served under Fort Nelson Rate Schedules 1, 2.1, 2.2 and 25 effective January 1, 2012 of ($0.011)/GJ as set out in Section 3.4.3 of the Application. (2013 RSAM rider will be adjusted with the Fort Nelson Fourth Quarter 2011 Gas Cost filing.)

2013 RATE APPROVALS BY COMPANY, IN EFFECT UNLESS AMALGAMATION AND HARMONIZED RATES ARE PUT IN PLACE

18. The FortisBC Energy Utilities seek the following orders for the implementation of 2013 rates by utility, which will be in effect unless the following occurs: (i) the amalgamation of the FortisBC Energy Utilities proceeds, having obtained the necessary approvals, and (ii) the Commission, in a future proceeding, fixes harmonized rates for the amalgamated entity:

2013 FEI Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(a) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEI for all non-bypass customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.1 of the Application, resulting in an increase of 6.4 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

(b) Approval pursuant to sections 59 to 61 of the Act of the 2013 cost allocation to the Thermal Energy Services (previously referred to as Alternative Energy Services) customer class as set out in Section 5.3.18 and Appendix G of the Application.

(c) Approval to continue debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for the 2013 forecast period as set out in Section 5.5 of the Application.

FEVI 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(d) Approval pursuant to sections 59 to 61 of the Act and section 2.1 of the Special Direction of permanent rates for FEVI effective January 1, 2013 for Core Market sales and transportation customers, other than customers who have specified rates in their transportation service agreements, at the same level as 2011 rates.

(e) Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast Cost of Service for 2013 as set out in Section 3.3.2 of the Application.

(f) Approval pursuant to section 2.10(a)(i) of the Special Direction of FEVI's forecast capital expenditures for 2013, as set out in Section 6.2 of the Application.

(g) Approval pursuant to section 2.10(a)(ii) of the Special Direction of FEVI's forecast revenue for 2013, based on its proposed rates, as set out in Section 4.5.6 of the Application.

(h) Approval of the forecast gross O&M expenditures for 2013 of $35.482 million.

(i) Approval of the 2013 cost of gas as set out in Section 5.2 of the Application;

(j) Approval for the difference between the net revenues received and the actual cost of service, excluding O&M variances from forecast, to be allocated to the RSDA, as set out in Section 3.4.2 of the Application.

FEW 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(k) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for FEW for all customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.3 of the Application, resulting in an increase of 11.9 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2011 levels.

Fort Nelson 2013 Rates (Stand Alone Basis - No Amalgamation or Rate Harmonization)

(l) Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for Fort Nelson customers effective January 1, 2013, to recover the requested revenue requirements as described in Section 3.3.4 of the Application, resulting in an increase of 1.6 per cent compared to 2012 delivery rates, with the increase to be applied to the delivery charge and the minimum monthly service charge.

COMBINED COST OF SERVICE AND OTHER ORDERS IN ANTICIPATION OF APPLICATION FOR AMALGAMATION AND HARMONIZED RATES

19. Determination of an amalgamated cost of service for 2013 for FEI, FEVI, FEW and Fort Nelson combined as set out in Section 3.3.5 of the Application, in anticipation of an Amalgamation and Rate Design Phase 'A' Application to be filed in Fall 2011. The determination of the amalgamated cost of service does not in any way pre-determine the merits of any future application by the FEU to address amalgamation and harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

20. Approval of a deferral account to capture the costs and savings related to the amalgamation that vary from the forecast of zero for 2013. The approval of this deferral account does not in any way pre-determine the merits of any future application by the FEU to address amalgamation and harmonized rates, or the allocation of costs among rate classes or as between delivery rates and the midstream.

21. Approval to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09, to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011 as described in Section 5.7 of the Application.

ANCILLARY RATE APPROVALS FOR FEI, FEVI, FEW AND FORT NELSON

22. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and each of FEI, FEVI and FEW, as reflected in the Corporate Services Agreements between FortisBC Energy Holdings Inc. and FEI, FEVI and FEW as described in Section 5.3.18 of the Application.

23. Approval of the allocation of costs for shared services between FEI and FEVI, as described in Section 5.3.18 of the Application.

24. Approval of the allocation of costs for shared services between FEI and FEW, as described in Section 5.3.18 of the Application.

25. Approval to allow for charges between regulated entities to be based on a fully loaded benefits and concessions charge and to not include overheads, including a facilities fee as described in Section 5.3.18 of the Application.

26. Approval of the consolidated Core Market Administration Expense (for FEI, FEVI and FEW), and allocation percentages, as set out in Section 5.2 of the Application.

27. Approval of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI, FEVI, FEW and

Fort Nelson all as set out in Section 6.2 and Appendix G of the Application and summarized in the following table.

Type of Change	Account	Company	Reference
New Account	Compliance to Emission Regulations	FEU	Section 6.3.2.3; Additions and Amortization period TBD
	Customer Service Variance Account	FEU	Section 6.3.3.10; Additions and Amortization period TBD
	Vancouver Island Joint Venture Litigation Costs	FEVI	Section 6.3.3.11; amortization period of 1 year commencing January 1, 2012
	2012-2013 Revenue Requirement Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2012, allocated to FEU based on average customers
	Long Term Resource Plan Application Costs	FEU	Section 6.3.4.1; amortization period of 2 years commencing January 1, 2013, allocated to FEU based on average customers
	Gas Assets Records Management Project	FEU	Section 6.3.5.11; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	BCOneCall Project	FEU	Section 6.3.5.12; amortization period of 5 years commencing January 1, 2012, allocated to FEU based on average customers
	Residual Delivery Rate Riders	FEI	Section 6.3.6.3; amortization period of 1 year commencing January 1, 2012
Amortization Period Change-New or Modified	Revenue Stabilization Account Mechanism	FEW	Section 6.3.1.3; recovery through Rate Rider 5, 3 year recovery period consistent with FEI and FN, commencing January 1, 2012
	Gas in Storage Interest	FEI	Section 6.3.1.4; 3 year amortization period, commencing January 1, 2012
	Property Tax Variance Account	FEW, FN	Section 6.3.3.1; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
	Tax Variance Account	FEW	Section 6.3.3.6; 1 year amortization period, commencing January 1, 2012
	Vancouver Island HST Implementation	FEVI	Section 6.3.3.7; 1 year amortization period, commencing January 1, 2012
	Victoria Regional Centre CPCN	FEVI	Section 6.3.4.3; 1 year amortization period, commencing January 1, 2012
	Pipeline Contributions Variance Account	FEW	Section 6.3.5.3; 1 year amortization period, commencing January 1, 2012

Type of Change	Account	Company	Reference
	Deferred Removal Costs	FEU	Section 6.3.5.5; 2 year amortization period, commencing January 1, 2012
	IFRS Transitional Account	FEI, FEVI	Section 6.3.5.7; amortization by plan over EARSL
	2010-2011 Customer Service O&M and Cost of Service	FEU	Section 6.3.5.9; 8 year amortization period, commencing January 1, 2012
Other	Energy Efficiency and Conservation	FEU	Section 6.3.2.1; 1. Combined EEC rate base deferral account additions of $20.0 million in 2012 and $20.0 million in 2013, included on a net-of-tax basis and amortized in rates over a ten year period; 2. The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis; 3. The creation of the EEC Incentive non-rate base deferral account, attracting AFUDC, to capture the remaining portion of the EEC costs as incurred on an actual spend basis in 2012 and 2013, and to recover the balance over a ten year period beginning in 2014.
	CNG and LNG Service Costs and Recoveries	FEI	Section 6.3.2.6; inclusion of variations from the revenue forecast pertaining to Rate Schedule 16
	Property Tax Variance Account	FEW	Section 6.3.3.1; include the forecast balance of the existing Propane Plant Property Tax Deferral account in the Property Tax Variance account
	Tax Variance Account	FEI	Section 6.3.3.6; inclusion of LILO reassessment costs
	Gains and Losses on Asset Disposition	FEU	Section 6.3.5.6; transfer the general plant gains and losses as at January 1, 2010 from the IFRS Transitional account into the Gains and Losses on Asset Disposition account; 20 year amortization period, commencing January 1, 2012
Discontinuance	Residential Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012
	Commercial Commodity Unbundling Account	FEI	Appendix G, 2.2; discontinuation of this account effective January 1, 2012

28. Approvals pursuant to sections 59-61 of the Act of changes to the following accounting policies to be used in the determination of rates for FEI, FEVI, FEW and Fort Nelson effective January 1, 2012:

    (a) The depreciation and amortization rates and the creation of a separate sub account (474.02) to record future additions to Distribution Systems Meters/Regulator Installations with depreciation expense for this sub account calculated using a whole life rate, set out in Sections 5.4.2 and 5.4.5 of the Application.

    (b) The negative salvage rates and the treatment of negative salvage as set out in Section 5.4.3 of the Application.

    (c) Modification to the approved Lead Lag days with the removal of the GST and PST lead days and the insertion of the proposed HST and REC lead days as set out in Section 6.1 of the Application.

ENERGY EFFICIENCY AND CONSERVATION ORDERS FOR 2012 AND 2013

29. Acceptance pursuant to section 44.2 of the Act of the EEC expenditures of up to $74.5 million for FEU in 2012 and 2013, with expansion of all EEC program eligibility to customers of FEW and to offer the interruptible industrial program area to customers of FEVI, all as set out in Appendix K-1 of the Application. For clarity, the overall funding level of $74.5 million may not be exceeded and, while the Companies may only spend those funds on approved Program Areas (e.g.: Residential, Commercial, and Innovative Technologies), the Companies may transfer funds between approved program areas and will report on funding transfers in their EEC Annual Report. Treatment of EEC costs will be in accordance with the EEC deferral accounts set out above.

30. With respect to the assessment of EEC expenditures, as described in Appendix K-1 of the Application:

    (a) Approval to continue evaluating EEC expenditures as an overall portfolio, and with Innovative Technologies having an additional criterion that as an individual program area it must have a benefit-cost ratio of 1.0 or greater, as previously approved in the 2010-2011 RRA;

    (b) Approval to continue evaluating EEC expenditures on the basis previously approved by the Commission, except with respect to the following changes.

        (i) The overall portfolio including all EEC-funded activity, and the Innovative Technology program area individually, should have a benefit-cost result of 1.0 or greater, using a Societal Cost Test consisting of the following three modifications to the current benefit-cost analysis:

(A) Use of a social discount rate of 3 percent, rather than the Companies' weighted average cost of capital;

(B) Use of the ceiling price for biomethane, which is based on an efficiency-adjusted cost of electricity, as the avoided cost of gas;

(C) Use of a "deemed adder" of 30 percent for non-energy benefits of EEC activity.

(ii) The inclusion of spillover in the calculation of the Net-to-Gross Ratio when estimating program effects.

(c) The evaluation of EEC programs will continue to take place in the context of the EEC Annual Report to be filed by the FEU.

8.2 Proposed Regulatory Process

The FEU propose that this Application can be addressed efficiently and effectively through a Negotiated Settlement Process ("NSP"), or in the alternative, by a written hearing process. ,

The FEU propose the following draft regulatory timetable which acknowledges the workload required by the Commission and all parties and which will promote an efficient regulatory process.

ACTION	DATE (2011)
Workshop (commencing at 1:00 pm)	Wednesday, May 18
Procedural Conference (Timetable and Process - commencing at 9:00 am)	Tuesday, May 24
Procedural Order	Thursday, May 26
Commission Information Request No. 1 to FEU	Thursday, June 2
Intervener Information Request No. 1 to FEU	Thursday, June 9
FEU Response to Information Requests No. 1	Thursday, June 30
Commission Information Request No. 2 to FEU	Thursday, July 21
Intervener Information Request No. 2 to FEU	Thursday, July 21
FEU Response to Information Requests No. 2	Friday, August 19
Negotiated Settlement Process or Hearing if Required (proposed date range)	Tuesday, September 6 to Friday, September 30
FEU Final Argument Submissions	Friday, October 7

ACTION	DATE (2011)
Intervener Final Argument Submissions	Friday, October 21
FEU Reply Argument Submissions	Friday, November 4
Workshop (commencing at 1:00 pm)	Wednesday, May 18

At the procedural conference contemplated in the above timetable, the Companies will address matters including the following:

1. The rationale for requesting an NSP, or alternatively a written hearing process.
2. The request for interim rates effective January 1, 2012, pursuant to section 89 of the UCA and section 15 of the *Administrative Tribunals Act*. The rationale for the request for interim rates is that, based on the proposed schedule, the timing of a Commission Decision on this Application would be well into 2012. The contemplated process would not be possible without having interim rates in place because not having interim rates in effect January 1, 2012 precludes recovery of the cost of service between January 1, 2012 and the implementation date of the permanent rates. Interim rates thus allow the Commission and interveners to consider this Application within a reasonable time frame, without having to unduly hasten the process to facilitate a Commission determination prior to January 1, 2012.

   In terms of whether the interim rates should reflect the current rates or the proposed rates, the FEU are seeking interim approval of the proposed 2012 rates for FEI, FEVI, FEW and Fort Nelson. This request is fair to the Company and customers and is warranted on the basis of the evidence filed. Any variance between interim rates and permanent rates would be refunded to or collected from customers by way of a rate rider following the approval of permanent rates, as contemplated in the Orders Sought.

3. The Companies' request for approval to defer the filing of evidence with respect to FEVI and FEW's equity component required by Directive No. 7 of Commission Order G-158-09 to the Amalgamation and Rate Design Phase 'A' Application in Fall 2011 as described in Section 5.7 of the Application.

The FEU are optimistic that the Commission will be in a position to make its determination regarding the type of hearing process and the other matters following the procedural conference proposed for May 24, 2011.

The FEU look forward to working with the Commission and Interveners towards an efficient review of this Application.

Appendix F-2

BILL IMPACT AND TARIFF CONTINUITIES

DRAFT BILL IMPACT SCHEDULES AND TARIFF CONTINUITIES

This appendix includes draft bill impact schedules and tariff continuities that result from the financial schedules contained in Section 7 of this Application and the corresponding rate proposals contained in Section 3 of this Application.

This appendix includes fourteen tabs as follows:

Utility/Region		Appendix F-2 Tabs	Application Reference
Mainland	January 1, 2012 January 1, 2013	1.1.1 / 1.1.2 1.2.1 / 1.2.2	Section 7, Tab 7.1
Vancouver Island	January 1, 2012 January 1, 2013	2.1.1 / 2.1.2 2.2.1 / 2.2.2	Section 7, Tab 7.2
Whistler	January 1, 2012 January 1, 2013	3.1 3.2	Section 7, Tab 7.3
Fort Nelson	January 1, 2012 January 1, 2013	4.1.1 / 4.1.2 4.2.1 / 4.2.2	Section 7, Tab 7.4

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.275	$3.275	$3.275	$0.256	$0.256	$0.256	$3.531	$3.531	$3.531
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.048)	($0.048)	($0.048)	$0.048	$0.048	$0.048	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.207**	**$3.207**	**$3.207**	**$0.292**	**$0.292**	**$0.292**	**$3.499**	**$3.499**	**$3.499**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009
14	Subtotal **Midstream Related Charges per GJ**	**$1.349**	**$1.324**	**$1.364**	**$0.000**	**$0.000**	**$0.000**	**$1.349**	**$1.324**	**$1.364**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	**RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE** Particulars	**EXISTING JANUARY 1, 2011 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.714	$2.714	$2.714	$0.193	$0.193	$0.193	$2.907	$2.907	$2.907
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.036)	($0.036)	($0.036)	$0.036	$0.036	$0.036	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.658**	**$2.658**	**$2.658**	**$0.217**	**$0.217**	**$0.217**	**$2.875**	**$2.875**	**$2.875**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.270**	**$2.270**	**$2.270**	**$0.165**	**$0.165**	**$0.165**	**$2.435**	**$2.435**	**$2.435**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.854	$0.854	$0.854	$0.081	$0.081	$0.081	$0.935	$0.935	$0.935
6	(b) Extension Period	$1.631	$1.631	$1.631	$0.081	$0.081	$0.081	$1.712	$1.712	$1.712
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.014)	($0.014)	($0.014)	$0.014	$0.014	$0.014	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.172	$6.157	$6.193	$0.095	$0.095	$0.095	$6.267	$6.252	$6.288
33	(b) Extension Period	$6.949	$6.934	$6.970	$0.095	$0.095	$0.095	$7.044	$7.029	$7.065

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE	EXISTING JANUARY 1, 2011 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
5										
6	**Delivery Charge per GJ**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$5.956	$5.941	$5.977	$0.072	$0.072	$0.072	$6.028	$6.013	$6.049

Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**EXISTING JANUARY 1, 2011 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.530	$8.523	$8.523	$0.252	$0.252	$0.252	$8.782	$8.775	$8.775

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily basis for comparison purposes.

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	EXISTING JANUARY 1, 2011 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.608	$0.213	$3.821
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	($0.039)	$0.039	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$13.770	$0.252	$14.022

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES Particulars	EXISTING JANUARY 1, 2011 RATES Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.392	$6.377	$6.413	$0.080	$0.080	$0.080	$6.472	$6.457	$6.493

Line No.	RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland			DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland			PROPOSED JANUARY 1, 2012 RATES Lower Mainland		
		Lower Mainland	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.790	$0.790	$0.790	$0.048	$0.048	$0.048	$0.838	$0.838	$0.838
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	($0.009)	($0.009)	($0.009)	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.781	$0.781	$0.781	$0.057	$0.057	$0.057	$0.838	$0.838	$0.838

Line No.	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$12.673	$0.734	$13.407
7	(b) Firm MTQ	$0.088	$0.005	$0.093
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.003	$0.058	$1.061
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	($0.009)	$0.009	$0.000
13				
14				
15	**Charges per gigajoule for UOR Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.079	$0.014	$0.093
35	(b) Interruptible MTQ	$0.994	$0.067	$1.061

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Columbia Except Elkview	 Elkview Coal	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview	 Elkview Coal	PROPOSED JANUARY 1, 2012 RATES Columbia Except Elkview	 Elkview Coal
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.048	$1.827	$0.530	$0.120	$8.578	$1.947
7	(b) Firm MTQ	$0.086	$0.086	$0.006	$0.006	$0.092	$0.092
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.802	$0.201	$0.053	$0.013	$0.855	$0.214
11	(b) between and including Nov. 1 and Mar.31	$1.155	$0.287	$0.076	$0.019	$1.231	$0.306
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	($0.006)	($0.002)	$0.006	$0.002	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.080	$0.084	$0.012	$0.008	$0.092	$0.092
31	(b) Interruptible MTQ - Summer	$0.796	$0.199	$0.059	$0.015	$0.855	$0.214
32	- Winter	$1.149	$0.285	$0.082	$0.021	$1.231	$0.306

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	RATE SCHEDULE 23:				**DELIVERY MARGIN**					
	LARGE COMMERCIAL T-SERVICE	**EFFECTIVE JANUARY 1, 2011**			**RELATED CHARGES CHANGES**			**PROPOSED JANUARY 1, 2012 RATES**		
Line No.	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.318	$2.318	$2.318	$0.149	$0.149	$0.149	$2.467	$2.467	$2.467
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.028)	($0.028)	($0.028)	$0.028	$0.028	$0.028	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.020)	($0.020)	($0.020)	($0.012)	($0.012)	($0.012)	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.270	$2.270	$2.270	$0.165	$0.165	$0.165	$2.435	$2.435	$2.435

Line No.	RATE SCHEDULE 25 GENERAL FIRM T-SERVICE Particulars	EFFECTIVE JANUARY 1, 2011 Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$15.943	$15.943	$15.943	$1.053	$1.053	$1.053	$16.996	$16.996	$16.996
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.645	$0.645	$0.645	$0.051	$0.051	$0.051	$0.696	$0.696	$0.696
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	($0.021)	($0.021)	($0.021)	$0.021	$0.021	$0.021	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.624	$0.624	$0.624	$0.072	$0.072	$0.072	$0.696	$0.696	$0.696

Line No.	RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE	EFFECTIVE JANUARY 1, 2011			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.648	$3.648	$3.648	$0.213	$0.213	$0.213	$3.861	$3.861	$3.861
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.039)	($0.039)	($0.039)	$0.039	$0.039	$0.039	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.609	$3.609	$3.609	$0.252	$0.252	$0.252	$3.861	$3.861	$3.861

Line No.	**RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE** Particulars	**EFFECTIVE JANUARY 1, 2011** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.073	$1.073	$1.073	$0.067	$0.067	$0.067	$1.140	$1.140	$1.140
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	($0.013)	($0.013)	($0.013)	$0.013	$0.013	$0.013	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.060	$1.060	$1.060	$0.080	$0.080	$0.080	$1.140	$1.140	$1.140

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	95.0	GJ x	$3.275 =	$311.1250	95.0	GJ x	$3.531 =	$335.4450	$0.256	$24.3200	2.41%
6	Rider 2 2009 ROE Rate Rider	95.0	GJ x	$0.000 =	$0.0000	95.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0	GJ x	($0.048) =	($4.5600)	95.0	GJ x	$0.000 =	$0.0000	$0.048	$4.5600	0.45%
8	Rider 5 RSAM	95.0	GJ x	($0.020) =	($1.9000)	95.0	GJ x	($0.032) =	($3.0400)	($0.012)	($1.1400)	-0.11%
9	Subtotal Delivery Margin Related Charges				**$446.75**				**$474.49**		**$27.74**	**2.75%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	95.0	GJ x	$1.340 =	$127.3000	95.0	GJ x	$1.340 =	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	$0.009 =	$0.8550	95.0	GJ x	$0.009 =	0.8550	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$128.16				$128.16		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	$4.568 =	$433.96	95.0	GJ x	$4.568 =	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$562.12**				**$562.12**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	95.0		*$10.620*	**$1,008.87**	95.0		*$10.912*	**$1,036.61**	*$0.292*	**$27.74**	**2.75%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days	$0.389 =	$142.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	75.0	GJ x	$3.275 =	$245.6250	75.0	GJ x	$3.531 =	$264.8250	$0.256	$19.2000	2.33%
26	Rider 2 2009 ROE Rate Rider	75.0	GJ x	$0.000 =	$0.0000	75.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0	GJ x	($0.048) =	($3.6000)	75.0	GJ x	$0.000 =	$0.0000	$0.048	$3.6000	0.44%
28	Rider 5 RSAM	75.0	GJ x	($0.020) =	($1.5000)	75.0	GJ x	($0.032) =	($2.4000)	($0.012)	($0.9000)	-0.11%
29	Subtotal Delivery Margin Related Charges				**$382.61**				**$404.51**		**$21.90**	**2.66%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	75.0	GJ x	$1.315 =	$98.6250	75.0	GJ x	$1.315 =	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	$0.009 =	$0.6750	75.0	GJ x	$0.009 =	$0.6750	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$99.30				$99.30		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	$4.568 =	$342.60	75.0	GJ x	$4.568 =	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$441.90**				**$441.90**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	75.0		*$10.993*	**$824.51**	75.0		*$11.285*	**$846.41**	*$0.292*	**$21.90**	**2.66%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.389 =	$142.08	365.25	days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	80.0	GJ x	$3.275 =	$262.0000	80.0	GJ x	$3.531 =	$282.4800	$0.256	$20.4800	2.35%
46	Rider 2 2009 ROE Rate Rider	80.0	GJ x	$0.000 =	$0.0000	80.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0	GJ x	($0.048) =	($3.8400)	80.0	GJ x	$0.000 =	$0.0000	$0.048	$3.8400	0.44%
48	Rider 5 RSAM	80.0	GJ x	($0.020) =	($1.6000)	80.0	GJ x	($0.032) =	($2.5600)	($0.012)	($0.9600)	-0.11%
49	Subtotal Delivery Margin Related Charges				**$398.64**				**$422.00**		**$23.36**	**2.68%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	80.0	GJ x	$1.355 =	$108.4000	80.0	GJ x	$1.355 =	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0	GJ x	$0.009 =	$0.7200	80.0	GJ x	$0.009 =	$0.7200	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$109.12				$109.12		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	$4.568	$365.44	80.0	GJ x	$4.568 =	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$474.56**	80.0			**$474.56**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	80.0		*$10.915*	**$873.20**	80.0		*$11.207*	**$896.56**	*$0.292*	**$23.36**	**2.68%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	300.0	GJ x	$2.714 =	$814.2000	300.0	GJ x	$2.907 =	$872.1000	$0.193	$57.9000	2.02%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	($0.036) =	($10.8000)	300.0	GJ x	$0.000 =	$0.0000	$0.036	$10.8000	0.38%
8	Rider 5 RSAM	300.0	GJ x	($0.020) =	($6.0000)	300.0	GJ x	($0.032) =	($9.6000)	($0.012)	($3.6000)	-0.13%
9	Subtotal Delivery Margin Related Charges				**$1,095.48**				**$1,160.58**		**$65.10**	**2.27%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327 =	$398.1000	300.0	GJ x	$1.327 =	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000 =	$0.0000	300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$398.10				$398.10		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568 =	$1,370.40	300.0	GJ x	$4.568 =	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$1,768.50**				**$1,768.50**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	300.0		*$9.547*	**$2,863.98**	300.0		*$9.764*	**$2,929.08**	*$0.217*	**$65.10**	**2.27%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	250.0	GJ x	$2.714 =	$678.5000	250.0	GJ x	$2.907 =	$726.7500	$0.193	$48.2500	1.99%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	($0.036) =	($9.0000)	250.0	GJ x	$0.000 =	$0.0000	$0.036	$9.0000	0.37%
28	Rider 5 RSAM	250.0	GJ x	($0.020) =	($5.0000)	250.0	GJ x	($0.032) =	($8.0000)	($0.012)	($3.0000)	-0.12%
29	Subtotal Delivery Margin Related Charges				**$962.58**				**$1,016.83**		**$54.25**	**2.23%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301 =	$325.2500	250.0	GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000 =	$0.0000	250.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$325.25				$325.25		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568 =	$1,142.00	250.0	GJ x	$4.568 =	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$1,467.25**				**$1,467.25**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	250.0		*$9.719*	**$2,429.83**	250.0		*$9.936*	**$2,484.08**	*$0.217*	**$54.25**	**2.23%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.816 =	$298.08	365.25	days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	320.0	GJ x	$2.714 =	$868.4800	320.0	GJ x	$2.907 =	$930.2400	$0.193	$61.7600	2.03%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	($0.036) =	($11.5200)	320.0	GJ x	$0.000 =	$0.0000	$0.036	$11.5200	0.38%
48	Rider 5 RSAM	320.0	GJ x	($0.020) =	($6.4000)	320.0	GJ x	($0.032) =	($10.2400)	($0.012)	($3.8400)	-0.13%
49	Subtotal Delivery Margin Related Charges				**$1,148.64**				**$1,218.08**		**$69.44**	**2.28%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342 =	$429.4400	320.0	GJ x	$1.342 =	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000 =	$0.0000	320.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$429.44				$429.44		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568 =	$1,461.76	320.0	GJ x	$4.568 =	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$1,891.20**				**$1,891.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	320.0		*$9.500*	**$3,039.84**	320.0		*$9.717*	**$3,109.28**	*$0.217*	**$69.44**	**2.28%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
4												
5	Delivery Charge	2,800.0	GJ x	$2.318 =	$6,490.4000	2,800.0	GJ x	$2.467 =	$6,907.6000	$0.149	$417.2000	1.77%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	($0.028) =	($78.4000)	2,800.0	GJ x	$0.000 =	$0.0000	$0.028	$78.4000	0.33%
8	Rider 5 RSAM	2,800.0	GJ x	($0.020) =	($56.0000)	2,800.0	GJ x	($0.032) =	($89.6000)	($0.012)	($33.6000)	-0.14%
9	Subtotal Delivery Margin Related Charges				**$7,946.24**				**$8,408.24**		**$462.00**	**1.96%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018 =	$2,850.4000	2,800.0	GJ x	$1.018 =	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000 =	$0.0000	2,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$2,850.40				$2,850.40		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568 =	$12,790.40	2,800.0	GJ x	$4.568 =	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$15,640.80**				**$15,640.80**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.424*	**$23,587.04**	2,800.0		*$8.589*	**$24,049.04**	*$0.165*	**$462.00**	**1.96%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
24												
25	Delivery Charge	2,600.0	GJ x	$2.318 =	$6,026.8000	2,600.0	GJ x	$2.467 =	$6,414.2000	$0.149	$387.4000	1.76%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	($0.028) =	($72.8000)	2,600.0	GJ x	$0.000 =	$0.0000	$0.028	$72.8000	0.33%
28	Rider 5 RSAM	2,600.0	GJ x	($0.020) =	($52.0000)	2,600.0	GJ x	($0.032) =	($83.2000)	($0.012)	($31.2000)	-0.14%
29	Subtotal Delivery Margin Related Charges				**$7,492.24**				**$7,921.24**		**$429.00**	**1.95%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999 =	$2,597.4000	2,600.0	GJ x	$0.999 =	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000 =	$0.0000	2,600.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$2,597.40				$2,597.40		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568 =	$11,876.80	2,600.0	GJ x	$4.568 =	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$14,474.20**				**$14,474.20**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.449*	**$21,966.44**	2,600.0		*$8.614*	**$22,395.44**	*$0.165*	**$429.00**	**1.95%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$4.354 =	$1,590.24	365.25	days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
44												
45	Delivery Charge	3,300.0	GJ x	$2.318 =	$7,649.4000	3,300.0	GJ x	$2.467 =	$8,141.1000	$0.149	$491.7000	1.78%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	($0.028) =	($92.4000)	3,300.0	GJ x	$0.000 =	$0.0000	$0.028	$92.4000	0.34%
48	Rider 5 RSAM	3,300.0	GJ x	($0.020) =	($66.0000)	3,300.0	GJ x	($0.032) =	($105.6000)	($0.012)	($39.6000)	-0.14%
49	Subtotal Delivery Margin Related Charges				**$9,081.24**				**$9,625.74**		**$544.50**	**1.97%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036 =	$3,418.8000	3,300.0	GJ x	$1.036 =	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000 =	$0.0000	3,300.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$3,418.80				$3,418.80		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568 =	$15,074.40	3,300.0	GJ x	$4.568 =	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$18,493.20**				**$18,493.20**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.356*	**$27,574.44**	3,300.0		*$8.521*	**$28,118.94**	*$0.165*	**$544.50**	**1.97%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	214 days x	$14.423 =	$3,086.5216	214 days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
5										
6	Delivery Charge									
7	(a) Off-Peak Period	5,400.0 GJ x	$0.854 =	$4,611.6000	5,400.0 GJ x	$0.935 =	$5,049.0000	$0.081	$437.4000	1.20%
8	(b) Extension Period	0.0 GJ x	$1.631 =	$0.0000	0.0 GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0 GJ x	$0.000 =	$0.0000	5,400.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0 GJ x	($0.014) =	($75.6000)	5,400.0 GJ x	$0.000 =	$0.0000	$0.014	$75.6000	0.21%
11	Subtotal Delivery Margin Related Charges			**$7,622.52**			**$8,135.52**		**$513.00**	**1.41%**
12										
13	Commodity Related Charges									
14	Midstream Cost Recovery Charge									
15	(a) Off-Peak Period	5,400.0 GJ x	$0.764 =	$4,125.6000	5,400.0 GJ x	$0.764 =	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0 GJ x	$0.764 =	$0.0000	0.0 GJ x	$0.764 =	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge									
18	(a) Off-Peak Period	5,400.0 GJ x	$4.568 =	24,667.2000	5,400.0 GJ x	$4.568 =	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0 GJ x	$4.568 =	$0.0000	0.0 GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
20										
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak			**$28,792.80**			**$28,792.80**		**$0.00**	**0.00%**
22										
23	Unauthorized Gas Charge During Peak Period (not forecast)									
24										
25	Total during Off-Peak Period	5,400.0		**$36,415.32**	5,400.0		**$36,928.32**		**$513.00**	**1.41%**
26										
27										
28	**INLAND SERVICE AREA**									
29	Delivery Margin Related Charges									
30	Basic Charge	214 days x	$14.423 =	$3,086.5216	214 days x	$14.423 =	$3,086.5216	$0.00	$0.00	0.00%
31										
32	Delivery Charge									
33	(a) Off-Peak Period	9,300.0 GJ x	$0.854 =	$7,942.2000	9,300.0 GJ x	$0.935 =	$8,695.5000	$0.081	$753.3000	1.25%
34	(b) Extension Period	0.0 GJ x	$1.631 =	$0.0000	0.0 GJ x	$1.712 =	$0.0000	$0.081	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0 GJ x	$0.000 =	$0.0000	9,300.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0 GJ x	($0.014) =	($130.2000)	9,300.0 GJ x	$0.000 =	$0.0000	$0.014	$130.2000	0.22%
37	Subtotal Delivery Margin Related Charges			**$10,898.52**			**$11,782.02**		**$883.50**	**1.46%**
38										
39	Commodity Related Charges									
40	Midstream Cost Recovery Charge									
41	(a) Off-Peak Period	9,300.0 GJ x	$0.749 =	$6,965.7000	9,300.0 GJ x	$0.749 =	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0 GJ x	$0.749 =	$0.0000	0.0 GJ x	$0.749 =	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge									
44	(a) Off-Peak Period	9,300.0 GJ x	$4.568 =	$42,482.4000	9,300.0 GJ x	$4.568 =	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0 GJ x	$4.568 =	$0.0000	0.0 GJ x	$4.568 =	$0.0000	$0.000	$0.0000	0.00%
46										
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak			**$49,448.10**			**$49,448.10**		**$0.00**	**0.00%**
48										
49	Unauthorized Gas Charge During Peak Period (not forecast)									
50										
51	Total during Off-Peak Period	9,300.0		**$60,346.62**	9,300.0		**$61,230.12**		**$883.50**	**1.46%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1												
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$15.943 =	**$11,191.99**	58.5	GJ x	$16.996 =	**$11,931.19**	$1.053	**$739.20**	**0.97%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.645 =	$6,256.5000	9,700.0	GJ x	$0.696 =	$6,751.2000	$0.051	$494.7000	0.65%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000 =	$0.0000	9,700.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	($0.021) =	($203.7000)	9,700.0	GJ x	$0.000 =	$0.0000	$0.021	$203.7000	0.27%
11	Subtotal Delivery Margin Related Charges				**$6,052.80**				**$6,751.20**		**$698.40**	**0.92%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764 =	$7,410.8000	9,700.0	GJ x	$0.764 =	$7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568 =	$44,309.6000	9,700.0	GJ x	$4.568 =	$44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$51,720.40**				**$51,720.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.836*	**$76,009.19**	9,700.0		*$7.984*	**$77,446.79**	*$0.148*	**$1,437.60**	**1.89%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$15.943 =	**$15,687.91**	82.0	GJ x	$16.996 =	**$16,724.06**	$1.053	**$1,036.15**	**1.05%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.645 =	$8,256.0000	12,800.0	GJ x	$0.696 =	$8,908.8000	$0.051	$652.8000	0.66%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000 =	$0.0000	12,800.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	($0.021) =	($268.8000)	12,800.0	GJ x	$0.000 =	$0.0000	$0.021	$268.8000	0.27%
29	Subtotal Delivery Margin Related Charges				**$7,987.20**				**$8,908.80**		**$921.60**	**0.93%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749 =	$9,587.2000	12,800.0	GJ x	$0.749 =	$9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568 =	$58,470.4000	12,800.0	GJ x	$4.568 =	$58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$68,057.60**				**$68,057.60**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.717*	**$98,776.71**	12,800.0		*$7.870*	**$100,734.46**	*$0.153*	**$1,957.75**	**1.98%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00 =	**$7,044.00**	12	months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$15.943 =	**$10,598.91**	55.4	GJ x	$16.996 =	**$11,298.94**	$1.053	**$700.03**	**0.97%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.645 =	$5,869.5000	9,100.0	GJ x	$0.696 =	$6,333.6000	$0.051	$464.1000	0.64%
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000 =	$0.0000	9,100.0	GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	($0.021) =	($191.1000)	9,100.0	GJ x	$0.000 =	$0.0000	$0.021	$191.1000	0.27%
47	Subtotal Delivery Margin Related Charges				**$5,678.40**				**$6,333.60**		**$655.20**	**0.91%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785 =	$7,143.5000	9,100.0	GJ x	$0.785 =	$7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568 =	$41,568.8000	9,100.0	GJ x	$4.568 =	$41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,712.30**				**$48,712.30**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$7.916	**$72,033.61**	9,100.0		$8.065	**$73,388.84**	*$0.149*	**$1,355.23**	**1.88%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	365.25 days x	$2.004 =	$732.00	365.25 days x	$2.004 =	$732.00	$0.00	$0.00	0.00%
5										
6	Delivery Charge	2,900.0 GJ x	$3.648 =	$10,579.2000	2,900.0 GJ x	$3.861 =	$11,196.9000	$0.213	$617.7000	2.43%
7	Rider 2 2009 ROE Rate Rider	2,900.0 GJ x	$0.000 =	$0.0000	2,900.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0 GJ x	($0.039) =	($113.1000)	2,900.0 GJ x	$0.000 =	$0.0000	$0.039	$113.1000	0.44%
9	Subtotal Delivery Margin Related Charges			**$11,198.10**			**$11,928.90**		**$730.80**	**2.87%**
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge	2,900.0 GJ x	$0.353 =	$1,023.7000	2,900.0 GJ x	$0.353 =	$1,023.7000	$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0 GJ x	$4.568 =	$13,247.2000	2,900.0 GJ x	$4.568 =	$13,247.2000	$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)			**$14,270.90**			**$14,270.90**		**$0.00**	**0.00%**
15										
16	Total *(with effective $/GJ rate)*	2,900.0	*$8.782*	**$25,469.00**	2,900.0	*$9.034*	**$26,199.80**	*$0.252*	**$730.80**	**2.87%**
17										
18										
19	**INLAND SERVICE AREA**									
20	Delivery Margin Related Charges									
21	Basic Charge	365.25 days x	$2.004 =	$732.00	365.25 days x	$2.004 =	$732.00	$0.00	$0.00	0.00%
22										
23	Delivery Charge	11,900.0 GJ x	$3.648 =	$43,411.2000	11,900.0 GJ x	$3.861 =	$45,945.9000	$0.213	$2,534.7000	2.48%
24	Rider 2 2009 ROE Rate Rider	11,900.0 GJ x	$0.000 =	$0.0000	11,900.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0 GJ x	($0.039) =	($464.1000)	11,900.0 GJ x	$0.000 =	$0.0000	$0.039	$464.1000	0.45%
26	Subtotal Delivery Margin Related Charges			**$43,679.10**			**$46,677.90**		**$2,998.80**	**2.94%**
27										
28	Commodity Related Charges									
29	Midstream Cost Recovery Charge	11,900.0 GJ x	$0.346 =	$4,117.4000	11,900.0 GJ x	$0.346 =	$4,117.4000	$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0 GJ x	$4.568 =	$54,359.2000	11,900.0 GJ x	$4.568 =	$54,359.2000	$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)			**$58,476.60**			**$58,476.60**		**$0.00**	**0.00%**
32										
33	Total *(with effective $/GJ rate)*	11,900.0	*$8.585*	**$102,155.70**	11,900.0	*$8.837*	**$105,154.50**	*$0.252*	**$2,998.80**	**2.94%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$1.073 =	$8,691.3000	8,100.0 GJ x	$1.140 =	$9,234.0000	$0.067	$542.7000	0.87%
7	Rider 2 2009 ROE Rate Rider	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0 GJ x	($0.013) =	($105.3000)	8,100.0 GJ x	$0.000 =	$0.0000	$0.013	$105.3000	0.17%
9	Rider 4 Reserve for Future Use	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges			**$8,586.00**			**$9,234.00**		**$648.00**	**1.04%**
11										
12	Commodity Related Charges									
13	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.764 =	$6,188.4000	8,100.0 GJ x	$0.764 =	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0 GJ x	$4.568 =	$37,000.8000	8,100.0 GJ x	$4.568 =	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$43,189.20**			**$43,189.20**		**$0.00**	**0.00%**
16										
17	Non-Standard Charges (not forecast)									
18	Index Pricing Option, UOR									
19										
20	Total *(with effective $/GJ rate)*	8,100.0	*$7.696*	**$62,335.20**	8,100.0	*$7.776*	**$62,983.20**	*$0.080*	**$648.00**	**1.04%**
21										
22										
23	**INLAND SERVICE AREA**									
24	Delivery Margin Related Charges									
25	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26										
27	Delivery Charge	4,000.0 GJ x	$1.073 =	$4,292.0000	4,000.0 GJ x	$1.140 =	$4,560.0000	$0.067	$268.0000	0.74%
28	Rider 2 2009 ROE Rate Rider	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0 GJ x	($0.013) =	($52.0000)	4,000.0 GJ x	$0.000 =	$0.0000	$0.013	$52.0000	0.14%
30	Rider 4 Reserve for Future Use	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges			**$4,240.00**			**$4,560.00**		**$320.00**	**0.89%**
32										
33	Commodity Related Charges									
34	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.749 =	$2,996.0000	4,000.0 GJ x	$0.749 =	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0 GJ x	$4.568 =	$18,272.0000	4,000.0 GJ x	$4.568 =	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$21,268.00**			**$21,268.00**		**$0.00**	**0.00%**
37										
38	Non-Standard Charges (not forecast)									
39	Index Pricing Option, UOR									
40										
41	Total *(with effective $/GJ rate)*	4,000.0	*$9.017*	**$36,068.00**	4,000.0	*$9.097*	**$36,388.00**	*$0.080*	**$320.00**	**0.89%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011						PROPOSED JANUARY 1, 2012 RATES						Annual Increase/Decrease		
1		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**															
3	Basic Charge	12	months	x	$3,664.00	=	**$43,968.00**	12	months	x	$3,664.00	=	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4																
5																
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ	x	$0.790	=	$369,171.4240	467,305.6	GJ	x	$0.838	=	$391,602.0928	$0.048	$22,430.6688	5.47%
7	Rider 2 2009 ROE Rate Rider	467,305.6	GJ	x	$0.000	=	$0.0000	467,305.6	GJ	x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6	GJ	x	($0.009)	=	($4,205.7504)	467,305.6	GJ	x	$0.000	=	$0.0000	$0.009	$4,205.7504	1.03%
9	Transportation - Interruptible						**$364,965.67**						**$391,602.09**		**$26,636.42**	**6.50%**
10																
11																
12	Non-Standard Charges (not forecast)															
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas															
14																
15																
16	Administration Charge	12	months	x	$78.00	=	**$936.00**	12	months	x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
17																
18																
19	Total *(with effective $/GJ rate)*	467,305.6			*$0.877*		**$409,869.67**	467,305.6			*$0.934*		**$436,506.09**	*$0.057*	**$26,636.42**	**6.50%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**INLAND SERVICE AREA**											
3	Basic Charge	12	months x	$4,810.00	= **$57,720.00**	12	months x	$4,810.00	= **$57,720.00**	$0.00	**$0.00**	**0.00%**
4												
5												
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$12.673	= **$394,698.00**	2,595.4	GJ x	$13.407	= **$417,558.36**	$0.734	**$22,860.36**	**4.33%**
7												
8												
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.088	= $51,433.8704	584,475.8	GJ x	$0.093	= $54,356.2494	$0.005	$2,922.3790	0.55%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	= $0.0000	584,475.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	($0.009)	= ($5,260.2822)	584,475.8	GJ x	$0.000	= $0.0000	$0.009	$5,260.2822	1.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)				**$46,173.59**				**$54,356.25**		**$8,182.66**	**1.55%**
13												
14												
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.003	= $28,693.7237	28,607.9	GJ x	$1.061	= $30,352.9819	$0.058	$1,659.2582	0.31%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	= $0.0000	28,607.9	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	($0.009)	= ($257.4711)	28,607.9	GJ x	$0.000	= $0.0000	$0.009	$257.4711	0.05%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$28,436.25**				**$30,352.98**		**$1,916.73**	**0.36%**
19												
20												
21	Non-Standard Charges (not forecast)											
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
23												
24												
25	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
26												
27												
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.903*	**$527,963.84**	584,475.8		*$0.960*	**$560,923.59**	*$0.057*	**$32,959.75**	**6.24%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**											
3	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
4												
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.048	= **$213,606.84**	2,211.8	GJ x	$8.578	= **$227,673.84**	$0.530	**$14,067.00**	**4.52%**
6												
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.086	= $39,331.7388	457,345.8	GJ x	$0.092	= $42,075.8136	$0.006	$2,744.0748	0.88%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	= $0.0000	457,345.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	($0.006)	= ($2,744.0748)	457,345.8	GJ x	$0.000	= $0.0000	$0.006	$2,744.0748	0.88%
10	Transportation - Firm (Delivery Charge Firm MTQ)				**$36,587.66**				**$42,075.81**		**$5,488.15**	**1.77%**
11												
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.802	= $5,399.3848	6,732.4	GJ x	$0.855	= $5,756.2020	$0.053	$356.8172	0.11%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.155	= $0.0000	0.0	GJ x	$1.231	= $0.0000	$0.076	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	= $0.0000	6,732.4	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	($0.006)	= ($40.3944)	6,732.4	GJ x	$0.000	= $0.0000	$0.006	$40.3944	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$5,358.99**				**$5,756.20**		**$397.21**	**0.13%**
18												
19	Non-Standard Charges (not forecast)											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21												
22	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.670*	**$310,933.49**	464,078.2		*$0.713*	**$330,885.85**	*$0.043*	**$19,952.36**	**6.42%**
25												
26												
27	**COLUMBIA SERVICE - ELKVIEW COAL**											
28	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
29												
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.827	= **$58,537.08**	2,670.0	GJ x	$1.947	= **$62,381.88**	$0.120	**$3,844.80**	**2.25%**
31												
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.086	= $54,313.6010	631,553.5	GJ x	$0.092	= $58,102.9220	$0.006	$3,789.3210	2.21%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	= $0.0000	631,553.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	($0.002)	= ($1,263.1070)	631,553.5	GJ x	$0.000	= $0.0000	$0.002	$1,263.1070	0.74%
35	Transportation - Firm (Delivery Charge Firm MTQ)				**$53,050.49**				**$58,102.92**		**$5,052.43**	**2.95%**
36												
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.201	= $0.0000	0.0	GJ x	$0.214	= $0.0000	$0.013	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.287	= $4,162.3897	14,503.1	GJ x	$0.306	= $4,437.9486	$0.019	$275.5589	0.16%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	($0.002)	= ($29.0062)	14,503.1	GJ x	$0.000	= $0.0000	$0.002	$29.0062	0.02%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$4,133.38**				**$4,437.95**		**$304.57**	**0.18%**
44												
45	Non-Standard Charges (not forecast)											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47												
48	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
49												
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.265*	**$171,100.95**	646,056.6		*$0.279*	**$180,302.75**	*$0.014*	**$9,201.80**	**5.38%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	4,100.0 GJ x	$2.318 =	$9,503.8000	4,100.0 GJ x	$2.467 =	$10,114.7000	$0.149	$610.9000	5.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0 GJ x	$0.000 =	$0.0000	4,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0 GJ x	($0.028) =	($114.8000)	4,100.0 GJ x	$0.000 =	$0.0000	$0.028	$114.8000	0.97%
10	Rider 5 RSAM	4,100.0 GJ x	($0.020) =	($82.0000)	4,100.0 GJ x	($0.032) =	($131.2000)	($0.012)	($49.2000)	-0.42%
11	Transportation - Firm			**$9,307.00**			**$9,983.50**		**$676.50**	**5.72%**
12										
13	Non-Standard Charges (not forecast)									
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
15										
16	Total *(with effective $/GJ rate)*	4,100.0	*$2.886*	**$11,833.24**	4,100.0	*$3.051*	**$12,509.74**	*$0.165*	**$676.50**	**5.72%**
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	4,700.0 GJ x	$2.318 =	$10,894.6000	4,700.0 GJ x	$2.467 =	$11,594.9000	$0.149	$700.3000	5.31%
24	Rider 2 2009 ROE Rate Rider	4,700.0 GJ x	$0.000 =	$0.0000	4,700.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0 GJ x	($0.028) =	($131.6000)	4,700.0 GJ x	$0.000 =	$0.0000	$0.028	$131.6000	1.00%
26	Rider 5 RSAM	4,700.0 GJ x	($0.020) =	($94.0000)	4,700.0 GJ x	($0.032) =	($150.4000)	($0.012)	($56.4000)	-0.43%
27	Transportation - Firm			**$10,669.00**			**$11,444.50**		**$775.50**	**5.88%**
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
31										
32	Total *(with effective $/GJ rate)*	4,700.0	*$2.807*	**$13,195.24**	4,700.0	*$2.972*	**$13,970.74**	*$0.165*	**$775.50**	**5.88%**
33										
34	**COLUMBIA SERVICE AREA**									
35	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36										
37	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
38										
39	Delivery Charge	4,200.0 GJ x	$2.318 =	$9,735.6000	4,200.0 GJ x	$2.467 =	$10,361.4000	$0.149	$625.8000	5.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0 GJ x	$0.000 =	$0.0000	4,200.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0 GJ x	($0.028) =	($117.6000)	4,200.0 GJ x	$0.000 =	$0.0000	$0.028	$117.6000	0.98%
42	Rider 5 RSAM	4,200.0 GJ x	($0.020) =	($84.0000)	4,200.0 GJ x	($0.032) =	($134.4000)	($0.012)	($50.4000)	-0.42%
43	Transportation - Firm			**$9,534.00**			**$10,227.00**		**$693.00**	**5.75%**
44										
45	Non-Standard Charges (not forecast)									
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
47										
48	Total *(with effective $/GJ rate)*	4,200.0	*$2.871*	**$12,060.24**	4,200.0	*$3.036*	**$12,753.24**	*$0.165*	**$693.00**	**5.75%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Transportation - Firm Demand	97.2	GJ x	$15.943	= **$18,595.92**	97.2	GJ x	$16.996	= **$19,824.12**	$1.053	**$1,228.20**	**3.19%**
8												
9	Delivery Charge	19,086.2	GJ x	$0.645	= $12,310.5990	19,086.2	GJ x	$0.696	= $13,283.9952	$0.051	$973.3962	2.53%
10	Rider 2 2009 ROE Rate Rider	19,086.2	GJ x	$0.000	= $0.0000	19,086.2	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2	GJ x	($0.021)	= ($400.8102)	19,086.2	GJ x	$0.000	= $0.0000	$0.021	$400.8102	1.04%
12	Transportation - Firm				**$11,909.79**				**$13,284.00**		**$1,374.21**	**3.57%**
13												
14	Non-Standard Charges (not forecast)											
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
16												
17	Total *(with effective $/GJ rate)*	19,086.2		*$2.016*	**$38,485.71**	19,086.2		*$2.153*	**$41,088.12**	*$0.137*	**$2,602.41**	**6.76%**
18												
19	**INLAND SERVICE AREA**											
20	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
21												
22	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Transportation - Firm Demand	212.6	GJ x	$15.943	= **$40,673.76**	212.6	GJ x	$16.996	= **$43,360.20**	$1.053	**$2,686.44**	**3.63%**
25												
26	Delivery Charge	40,670.5	GJ x	$0.645	= $26,232.4725	40,670.5	GJ x	$0.696	= $28,306.6680	$0.051	$2,074.1955	2.80%
27	Rider 2 2009 ROE Rate Rider	40,670.5	GJ x	$0.000	= $0.0000	40,670.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5	GJ x	($0.021)	= ($854.0805)	40,670.5	GJ x	$0.000	= $0.0000	$0.021	$854.0805	1.15%
29	Transportation - Firm				**$25,378.39**				**$28,306.67**		**$2,928.28**	**3.96%**
30												
31	Non-Standard Charges (not forecast)											
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
33												
34	Total *(with effective $/GJ rate)*	40,670.5		*$1.820*	**$74,032.15**	40,670.5		*$1.958*	**$79,646.87**	*$0.138*	**$5,614.72**	**7.58%**
35												
36	**COLUMBIA SERVICE**											
37	Basic Charge	12	months x	$587.00	= **$7,044.00**	12	months x	$587.00	= **$7,044.00**	$0.00	**$0.00**	**0.00%**
38												
39	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
40												
41	Transportation - Firm Demand	182.2	GJ x	$15.943	= **$34,857.72**	182.2	GJ x	$16.996	= **$37,160.04**	$1.053	**$2,302.32**	**3.73%**
42												
43	Delivery Charge	30,357.8	GJ x	$0.645	= $19,580.7810	30,357.8	GJ x	$0.696	= $21,129.0288	$0.051	$1,548.2478	2.51%
44	Rider 2 2009 ROE Rate Rider	30,357.8	GJ x	$0.000	= $0.0000	30,357.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8	GJ x	($0.021)	= ($637.5138)	30,357.8	GJ x	$0.000	= $0.0000	$0.021	$637.5138	1.03%
46	Transportation - Firm				**$18,943.27**				**$21,129.03**		**$2,185.76**	**3.54%**
47												
48	Non-Standard Charges (not forecast)											
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
50												
51	Total *(with effective $/GJ rate)*	30,357.8		*$2.035*	**$61,780.99**	30,357.8		*$2.183*	**$66,269.07**	*$0.148*	**$4,488.08**	**7.26%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	EFFECTIVE JANUARY 1, 2011				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
4												
5	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6												
7	Delivery Charge	53,957.0	GJ x	$1.073	= $57,895.8610	53,957.0	GJ x	$1.140	= $61,510.9800	$0.067	$3,615.1190	5.26%
8	Rider 2 2009 ROE Rate Rider	53,957.0	GJ x	$0.000	= $0.0000	53,957.0	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0	GJ x	($0.013)	= ($701.4410)	53,957.0	GJ x	$0.000	= $0.0000	$0.013	$701.4410	1.02%
10	Transportation - Interruptible				**$57,194.42**				**$61,510.98**		**$4,316.56**	**6.28%**
11												
12	Non-Standard Charges (not forecast)											
13	UOR, Balancing gas, Backstopping Gas											
14												
15	Total *(with effective $/GJ rate)*	53,957.0		*$1.273*	**$68,690.42**	53,957.0		*$1.353*	**$73,006.98**	*$0.080*	**$4,316.56**	**6.28%**
16												
17												
18	**INLAND SERVICE AREA**											
19	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
20												
21	Administration Charge	12.0	months x	$78.00	= **$936.00**	12.0	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
22												
23	Delivery Charge	48,903.9	GJ x	$1.073	= $52,473.8847	48,903.9	GJ x	$1.140	= $55,750.4460	$0.067	$3,276.5613	5.17%
24	Rider 2 2009 ROE Rate Rider	48,903.9	GJ x	$0.000	= $0.0000	48,903.9	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9	GJ x	($0.013)	= ($635.7507)	48,903.9	GJ x	$0.000	= $0.0000	$0.013	$635.7507	1.00%
26	Transportation - Interruptible				**$51,838.13**				**$55,750.45**		**$3,912.32**	**6.18%**
27												
28												
29	Non-Standard Charges (not forecast)											
30	UOR, Balancing gas, Backstopping Gas											
31		48,903.9		*$1.295*	**$63,334.13**	48,903.9		*$1.375*	**$67,246.45**	*$0.080*	**$3,912.32**	**6.18%**
32	Total *(with effective $/GJ rate)*											
33												
34												
35	**COLUMBIA SERVICE AREA**											
36	Basic Charge	12	months x	$880.00	= **$10,560.00**	12	months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
37												
38	Administration Charge	12.0	months x	$78.00	= **$936.00**	12.0	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
39												
40	Delivery Charge	7,733.8	GJ x	$1.073	= $8,298.3674	7,733.8	GJ x	$1.140	= $8,816.5320	$0.067	$518.1646	0.82%
41	Rider 2 2009 ROE Rate Rider	7,733.8	GJ x	$0.000	= $0.0000	7,733.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8	GJ x	($0.013)	= ($100.5394)	7,733.8	GJ x	$0.000	= $0.0000	$0.013	$100.5394	0.16%
43	Transportation - Interruptible				**$8,197.83**				**$8,816.53**		**$618.70**	**0.98%**
44												
45												
46	Non-Standard Charges (not forecast)											
47	UOR, Balancing gas, Backstopping Gas											
48		7,733.8		*$2.546*	**$19,693.83**	7,733.8		*$2.626*	**$20,312.53**	*$0.080*	**$618.70**	**0.98%**
49	Total *(with effective $/GJ rate)*											

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/Decrease		
		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
1	**INLAND SERVICE AREA**									
2										
3	**Rate 1 - Residential**									
4	Delivery Margin Related Charges									
5	Basic Charge	365.25 days x	$0.389 =	$142.08	365.25 days x	$0.389 =	$142.08	$0.00	$0.00	0.00%
6										
7	Delivery Charge	50.0 GJ x	$3.275 =	$163.7500	50.0 GJ x	$3.531 =	$176.5500	$0.256	$12.8000	1.20%
8	Rider 2 2009 ROE Rate Rider	50.0 GJ x	$0.000 =	$0.0000	50.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0 GJ x	($0.048) =	($2.4000)	50.0 GJ x	$0.000 =	$0.0000	$0.048	$2.4000	0.23%
10	Rider 5 RSAM	50.0 GJ x	($0.020) =	($1.0000)	50.0 GJ x	($0.032) =	($1.6000)	($0.012)	($0.6000)	-0.06%
11	Subtotal Delivery Margin Related Charges		$3.207	**$302.43**		$3.499	**$317.03**		**$14.60**	**1.37%**
12										
13	Commodity Related Charges									
14	Midstream Cost Recovery Charge	50.0 GJ x	$1.315 =	$65.7500	50.0 GJ x	$1.315 =	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0 GJ x	$4.568 =	$228.4000	50.0 GJ x	$4.568 =	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0 GJ x	$9.331 =	$466.5500	50.0 GJ x	$9.331 =	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges		$15.214	**$760.70**		$15.214	**$760.70**		**$0.00**	**0.00%**
18										
19	*Total (with effective $/GJ rate)*	50.0	*$21.263*	**$1,063.13**	50.0	*$21.555*	**$1,077.73**	*$0.292*	**$14.60**	**1.37%**
20										
21	**Rate 2 - Small Commercial**									
22	Delivery Margin Related Charges									
23	Basic Charge	365.25 days x	$0.816 =	$298.08	365.25 days x	$0.816 =	$298.08	$0.00	$0.00	0.00%
24										
25	Delivery Charge	250.0 GJ x	$2.714 =	$678.5000	250.0 GJ x	$2.907 =	$726.7500	$0.193	$48.2500	1.07%
26	Rider 2 2009 ROE Rate Rider	250.0 GJ x	$0.000 =	$0.0000	250.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0 GJ x	($0.036) =	($9.0000)	250.0 GJ x	$0.000 =	$0.0000	$0.036	$9.0000	0.20%
28	Rider 5 RSAM	250.0 GJ x	($0.020) =	($5.0000)	250.0 GJ x	($0.032) =	($8.0000)	($0.012)	($3.0000)	-0.07%
29	Subtotal Delivery Margin Related Charges		$2.658	**$962.58**		$2.875	**$1,016.83**		**$54.25**	**1.21%**
30										
31	Commodity Related Charges									
32	Midstream Cost Recovery Charge	250.0 GJ x	$1.301 =	$325.2500	250.0 GJ x	$1.301 =	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0 GJ x	$4.568 =	$1,142.0000	250.0 GJ x	$4.568 =	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0 GJ x	$8.254 =	$2,063.5000	250.0 GJ x	$8.254 =	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges		$14.123	**$3,530.75**		$14.123	**$3,530.75**		**$0.00**	**0.00%**
36										
37	*Total (with effective $/GJ rate)*	250.0	*$17.973*	**$4,493.33**	250.0	*$18.190*	**$4,547.58**	*$0.217*	**$54.25**	**1.21%**
38										
39	**Rate 3 - Large Commercial**									
40	Delivery Margin Related Charges									
41	Basic Charge	365.25 days x	$4.354 =	$1,590.24	365.25 days x	$4.354 =	$1,590.24	$0.00	$0.00	0.00%
42										
43	Delivery Charge	4,500.0 GJ x	$2.318 =	$10,431.0000	4,500.0 GJ x	$2.467 =	$11,101.5000	$0.149	$670.5000	0.89%
44	Rider 2 2009 ROE Rate Rider	4,500.0 GJ x	$0.000 =	$0.0000	4,500.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0 GJ x	($0.028) =	($126.0000)	4,500.0 GJ x	$0.000 =	$0.0000	$0.028	$126.0000	0.17%
46	Rider 5 RSAM	4,500.0 GJ x	($0.020) =	($90.0000)	4,500.0 GJ x	($0.032) =	($144.0000)	($0.012)	($54.0000)	-0.07%
47	Subtotal Delivery Margin Related Charges		$2.270	**$11,805.24**		$2.435	**$12,547.74**		**$742.50**	**0.99%**
48										
49	Commodity Related Charges									
50	Midstream Cost Recovery Charge	4,500.0 GJ x	$0.999 =	$4,495.5000	4,500.0 GJ x	$0.999 =	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0 GJ x	$4.568 =	$20,556.0000	4,500.0 GJ x	$4.568 =	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0 GJ x	$8.556 =	$38,502.0000	4,500.0 GJ x	$8.556 =	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges		$14.123	**$63,553.50**		$14.123	**$63,553.50**		**$0.00**	**0.00%**
54										
55	*Total (with effective $/GJ rate)*	4,500.0	*$16.746*	**$75,358.74**	4,500.0	*$16.911*	**$76,101.24**	*$0.165*	**$742.50**	**0.99%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent comparison purposes.

Line No.	RATE SCHEDULE 1: RESIDENTIAL SERVICE	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.3890**	**$0.3890**	**$0.3890**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.3890**	**$0.3890**	**$0.3890**
3										
4	Delivery Charge per GJ	$3.531	$3.531	$3.531	$0.325	$0.325	$0.325	$3.856	$3.856	$3.856
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$3.499**	**$3.499**	**$3.499**	**$0.325**	**$0.325**	**$0.325**	**$3.824**	**$3.824**	**$3.824**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.340	$1.315	$1.355	$0.000	$0.000	$0.000	$1.340	$1.315	$1.355
13	Rider 8 Unbundling Recovery	$0.009	$0.009	$0.009	$0.000	$0.000	$0.000	$0.009	$0.009	$0.009
14	Subtotal **Midstream Related Charges per GJ**	**$1.349**	**$1.324**	**$1.364**	**$0.000**	**$0.000**	**$0.000**	**$1.349**	**$1.324**	**$1.364**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$9.331			$0.000			$9.331	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$15.214**			**$0.000**			**$15.214**	
23	per GJ (Includes Rider 1, excludes Riders 8)									

Line No.	RATE SCHEDULE 2: SMALL COMMERCIAL SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$0.8161**	**$0.8161**	**$0.8161**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.8161**	**$0.8161**	**$0.8161**
3										
4	Delivery Charge per GJ	$2.907	$2.907	$2.907	$0.245	$0.245	$0.245	$3.152	$3.152	$3.152
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.875**	**$2.875**	**$2.875**	**$0.245**	**$0.245**	**$0.245**	**$3.120**	**$3.120**	**$3.120**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.327	$1.301	$1.342	$0.000	$0.000	$0.000	$1.327	$1.301	$1.342
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.327**	**$1.301**	**$1.342**	**$0.000**	**$0.000**	**$0.000**	**$1.327**	**$1.301**	**$1.342**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.254			$0.000			$8.254	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 3: LARGE COMMERCIAL SERVICE — Particulars	PROPOSED JANUARY 1, 2012 RATES — Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES — Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES — Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	**$4.3538**	**$4.3538**	**$4.3538**	**$0.0000**	**$0.0000**	**$0.0000**	**$4.3538**	**$4.3538**	**$4.3538**
3										
4	Delivery Charge per GJ	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
5	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	Rider 3 ESM	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	Rider 5 RSAM	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
8	Subtotal **Delivery Margin Related Charges per GJ**	**$2.435**	**$2.435**	**$2.435**	**$0.188**	**$0.188**	**$0.188**	**$2.623**	**$2.623**	**$2.623**
9										
10										
11	Commodity Related Charges									
12	Midstream Cost Recovery Charge per GJ	$1.018	$0.999	$1.036	$0.000	$0.000	$0.000	$1.018	$0.999	$1.036
13	Rider 8 Unbundling Recovery	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	Subtotal **Midstream Related Charges per GJ**	**$1.018**	**$0.999**	**$1.036**	**$0.000**	**$0.000**	**$0.000**	**$1.018**	**$0.999**	**$1.036**
15										
16	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	**$4.568**	**$4.568**	**$4.568**	**$0.000**	**$0.000**	**$0.000**	**$4.568**	**$4.568**	**$4.568**
17										
18										
19	Rider 1 Propane Surcharge (Revelstoke only)		$8.556			$0.000			$8.556	
20										
21										
22	**Cost of Gas Recovery Related Charges for Revelstoke**		**$14.123**			**$0.000**			**$14.123**	
23	per GJ (Includes Rider 1, excludes Rider 8)									

Line No.	RATE SCHEDULE 4: SEASONAL SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$14.4230	$14.4230	$14.4230	$0.0000	$0.0000	$0.0000	$14.4230	$14.4230	$14.4230
3										
4	**Delivery Charge per GJ**									
5	(a) Off-Peak Period	$0.935	$0.935	$0.935	$0.103	$0.103	$0.103	$1.038	$1.038	$1.038
6	(b) Extension Period	$1.712	$1.712	$1.712	$0.103	$0.103	$0.103	$1.815	$1.815	$1.815
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11	Commodity Related Charges									
12	**Commodity Cost Recovery Charge**									
13	(a) Off-Peak Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	(b) Extension Period	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
15										
16	**Midstream Cost Recovery Charge per GJ**									
17	(a) Off-Peak Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
18	(b) Extension Period	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
19										
20										
21	Subtotal Off -Peak Commodity Related Charges per GJ									
22	(a) Off-Peak Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
23	(b) Extension Period	$5.332	$5.317	$5.353	$0.000	$0.000	$0.000	$5.332	$5.317	$5.353
24										
25										
26										
27	Unauthorized Gas Charge per gigajoule	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
28	during peak period									
29										
30										
31	Total Variable Cost per gigajoule between									
32	(a) Off-Peak Period	$6.267	$6.252	$6.288	$0.103	$0.103	$0.103	$6.370	$6.355	$6.391
33	(b) Extension Period	$7.044	$7.029	$7.065	$0.103	$0.103	$0.103	$7.147	$7.132	$7.168

Line No.	RATE SCHEDULE 5 GENERAL FIRM SERVICE Particulars	PROPOSED JANUARY 1, 2012 RATES Lower Mainland	Inland	Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	Inland	Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
3										
4	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
5										
6	**Delivery Charge per GJ**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
7										
8	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
9	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
10										
11										
12	Commodity Related Charges									
13	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
14	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
15	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
16										
17										
18										
19	Total Variable Cost per gigajoule	$6.028	$6.013	$6.049	$0.065	$0.065	$0.065	$6.093	$6.078	$6.114

Line No.	**RATE SCHEDULE 6: NGV - STATIONS** Particulars	**PROPOSED JANUARY 1, 2012 RATES** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per day**	$2.0041	$2.0041	$2.0041	$0.0000	$0.0000	$0.0000	$2.0041	$2.0041	$2.0041
3										
4	**Delivery Charge per GJ**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9										
10	Commodity Related Charges									
11	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
12	**Midstream Cost Recovery Charge per GJ**	$0.353	$0.346	$0.346	$0.000	$0.000	$0.000	$0.353	$0.346	$0.346
13	Subtotal Commodity Related Charges per GJ	**$4.921**	**$4.914**	**$4.914**	**$0.000**	**$0.000**	**$0.000**	**$4.921**	**$4.914**	**$4.914**
14										
15										
16	Total Variable Cost per gigajoule	$8.782	$8.775	$8.775	$0.266	$0.266	$0.266	$9.048	$9.041	$9.041

RATE SCHEDULE 6A:
NGV - VRA's

Line No.	Particulars	PROPOSED JANUARY 1, 2012 RATES	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**LOWER MAINLAND SERVICE AREA**			
2				
3	**Delivery Margin Related Charges**			
4	Basic Charge per month	$86.00	$0.00	$86.00
5				
6	Delivery Charge per GJ	$3.821	$0.266	$4.087
7	Rider 2 2009 ROE Rate Rider	$0.000	$0.000	$0.000
8	Rider 3 ESM	$0.000	$0.000	$0.000
9				
10				
11	**Commodity Related Charges**			
12	Cost of Gas (Commodity Cost Recovery Charge) per GJ	$4.568	$0.000	$4.568
13	Midstream Cost Recovery Charge per GJ	$0.353	$0.000	$0.353
14	Subtotal Commodity Related Charges per GJ	$4.921	$0.000	$4.921
15				
16	Compression Charge per gigajoule	$5.28	$0.00	$5.28
17				
18				
19	**Minimum Charges**	$125.00	$0.00	$125.00
20				
21				
22				
23	Total Variable Cost per gigajoule	$14.022	$0.266	$14.288

Line No.	RATE SCHEDULE 7: INTERRUPTIBLE SALES	PROPOSED JANUARY 1, 2012 RATES			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**	**Lower Mainland**	**Inland**	**Columbia**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Delivery Margin Related Charges									
2	**Basic Charge per month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
3										
4	**Delivery Charge per GJ**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
8										
9	Commodity Related Charges									
10	**Cost of Gas (Commodity Cost Recovery Charge) per GJ**	$4.568	$4.568	$4.568	$0.000	$0.000	$0.000	$4.568	$4.568	$4.568
11	**Midstream Cost Recovery Charge per GJ**	$0.764	$0.749	$0.785	$0.000	$0.000	$0.000	$0.764	$0.749	$0.785
12	Subtotal Commodity Related Charges per GJ	**$5.332**	**$5.317**	**$5.353**	**$0.000**	**$0.000**	**$0.000**	**$5.332**	**$5.317**	**$5.353**
13										
14										
15										
16	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
17										
18										
19										
20										
21										
22	Total Variable Cost per gigajoule	$6.472	$6.457	$6.493	$0.086	$0.086	$0.086	$6.558	$6.543	$6.579

Line No.	**RATE SCHEDULE 22: LARGE INDUSTRIAL T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$3,664.00	$3,664.00	$3,664.00	$0.00	$0.00	$0.00	$3,664.00	$3,664.00	$3,664.00
2										
3	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899
4										
5	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
6	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
7										
8		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
9	**Charges per gigajoule for UOR Gas**									
10										
11										
12	**Demand Surcharge per gigajoule**	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00	$17.00	$17.00	$17.00
13										
14										
15	**Balancing Service per gigajoule**									
16	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.30	n/a	$0.00	$0.00	n/a	$0.30	$0.30	n/a
17	(b) between and including Nov. 1 and Mar. 31	$1.10	$1.10	n/a	$0.00	$0.00	n/a	$1.10	$1.10	n/a
18										
19								Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
20	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.								
21										
22										
23										
24	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
25										
26										
27										
28										
29	Total Variable Cost per gigajoule	$0.838	$0.838	$0.838	$0.061	$0.061	$0.061	$0.899	$0.899	$0.899

RATE SCHEDULE 22A:
LARGE INDUSTRIAL T-SERVICE

Line No.	Particulars	PROPOSED JANUARY 1, 2012	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1	**INLAND SERVICE AREA**			
2				
3	**Basic Charge per Month**	$4,810.00	$0.00	$4,810.00
4				
5	**Delivery Charge per gigajoule - Firm**			
6	(a) Firm DTQ	$13.407	$0.927	$14.334
7	(b) Firm MTQ	$0.093	$0.007	$0.100
8				
9	**Delivery Charge per gigajoule - Interr MTQ**	$1.061	$0.073	$1.134
10				
11	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000
12	**Rider 3 ESM**	$0.000	$0.000	$0.000
13				
14		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
15	**Charges per gigajoule for UOR Gas**			
16				
17				
18	**Demand Surchage per gigajoule**	$17.00	$0.00	$17.00
19				
20	**Balancing Service per gigajoule**			
21	(a) between and including Apr. 1 and Oct. 31	$0.30	$0.00	$0.30
22	(b) between and including Nov. 1 and Mar. 31	$1.10	$0.00	$1.10
23				
24				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.
25	**Charges per gigajoule for Backstopping Gas**	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
26				
27				
28	**Replacement Gas**	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30				
31	**Administration Charge per Month**	$78.00	$0.00	$78.00
32				
33	Total Variable Cost per gigajoule			
34	(a) Firm MTQ	$0.093	$0.007	$0.100
35	(b) Interruptible MTQ	$1.061	$0.073	$1.134

Line No.	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE Particulars (1)	PROPOSED JANUARY 1, 2012 Columbia Except Elkview (2)	Elkview Coal (3)	DELIVERY MARGIN RELATED CHARGES CHANGES Columbia Except Elkview (4)	Elkview Coal (5)	PROPOSED JANUARY 1, 2013 RATES Columbia Except Elkview (6)	Elkview Coal (7)
1	**COLUMBIA SERVICE AREA**						
2							
3	**Basic Charge per Month**	$4,537.00	$4,537.00	$0.00	$0.00	$4,537.00	$4,537.00
4							
5	**Delivery Charge per gigajoule - Firm**						
6	(a) Firm DTQ	$8.578	$1.947	$0.667	$0.152	$9.245	$2.099
7	(b) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
8							
9	**Delivery Charge per gigajoule - Interr MTQ**						
10	(a) between and including Apr. 1 and Oct. 31	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
11	(b) between and including Nov. 1 and Mar.31	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330
12							
13	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
14	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15							
16		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
17	**Charges per gigajoule for UOR Gas**						
18							
19							
20	**Demand Surchage per gigajoule**	$17.00	$17.00	$0.00	$0.00	$17.00	$17.00
21							
22		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.				Balancing, Backstopping and UOR per BCUC Order No. G-110-00.	
23	**Charges per gigajoule for Backstopping Gas**						
24							
25							
26	**Administration Charge per Month**	$78.00	$78.00	$0.00	$0.00	$78.00	$78.00
27							
28							
29	Total Variable Cost per gigajoule						
30	(a) Firm MTQ	$0.092	$0.092	$0.007	$0.007	$0.099	$0.099
31	(b) Interruptible MTQ - Summer	$0.855	$0.214	$0.066	$0.017	$0.921	$0.231
32	- Winter	$1.231	$0.306	$0.096	$0.024	$1.327	$0.330

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Line No.	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE Particulars	PROPOSED JANUARY 1, 2012 Lower Mainland	 Inland	 Columbia	DELIVERY MARGIN RELATED CHARGES CHANGES Lower Mainland	 Inland	 Columbia	PROPOSED JANUARY 1, 2013 RATES Lower Mainland	 Inland	 Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$132.52	$132.52	$132.52	$0.00	$0.00	$0.00	$132.52	$132.52	$132.52
2										
3	**Delivery Charge per gigajoule**	$2.467	$2.467	$2.467	$0.188	$0.188	$0.188	$2.655	$2.655	$2.655
4										
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8	**Sales**									
9	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
10	(b) Charge per gigajoule for Backstopping Gas									
11	(c) Replacement Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16	**Rider 5 RSAM**	($0.032)	($0.032)	($0.032)	$0.000	$0.000	$0.000	($0.032)	($0.032)	($0.032)
17										
18										
19										
20	Total Variable Cost per gigajoule	$2.435	$2.435	$2.435	$0.188	$0.188	$0.188	$2.623	$2.623	$2.623

Line No.	**RATE SCHEDULE 25** **GENERAL FIRM T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$587.00	$587.00	$587.00	$0.00	$0.00	$0.00	$587.00	$587.00	$587.00
2										
3	**Demand Charge per gigajoule**	$16.996	$16.996	$16.996	$1.328	$1.328	$1.328	$18.324	$18.324	$18.324
4										
5	**Delivery Charge per gigajoule (Interr. MTQ)**	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761
6										
7	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
8										
9										
10	**Sales**									
11	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.		
12	(b) Charge per gigajoule for Backstopping Gas									
13	(c) Replacement Gas									
14	(d) Charge per gigajoule for UOR Gas									
15										
16										
17	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
18	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
19										
20										
21										
22	Total Variable Cost per gigajoule	$0.696	$0.696	$0.696	$0.065	$0.065	$0.065	$0.761	$0.761	$0.761

Line No.	**RATE SCHEDULE 26: NATURAL GAS VEHICLE T-SERVICE** Particulars	**PROPOSED JANUARY 1, 2012** Lower Mainland	Inland	Columbia	**DELIVERY MARGIN RELATED CHARGES CHANGES** Lower Mainland	Inland	Columbia	**PROPOSED JANUARY 1, 2013 RATES** Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$61.00	$61.00	$61.00	$0.00	$0.00	$0.00	$61.00	$61.00	$61.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$3.861	$3.861	$3.861	$0.266	$0.266	$0.266	$4.127	$4.127	$4.127

Line No.	RATE SCHEDULE 27: INTERRUPTIBLE T-SERVICE	PROPOSED JANUARY 1, 2012			DELIVERY MARGIN RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
	Particulars	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia	Lower Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Basic Charge per Month**	$880.00	$880.00	$880.00	$0.00	$0.00	$0.00	$880.00	$880.00	$880.00
2										
3										
4	**Delivery Charge per gigajoule (Interr. MTQ)**	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226
5										
6	**Administration Charge per Month**	$78.00	$78.00	$78.00	$0.00	$0.00	$0.00	$78.00	$78.00	$78.00
7										
8										
9	**Sales**									
10	(a) Charge per gigajoule for Balancing Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
11	(b) Charge per gigajoule for Backstopping Gas									
12	(d) Charge per gigajoule for UOR Gas									
13										
14	**Rider 2 2009 ROE Rate Rider**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
15	**Rider 3 ESM**	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
16										
17										
18										
19	Total Variable Cost per gigajoule	$1.140	$1.140	$1.140	$0.086	$0.086	$0.086	$1.226	$1.226	$1.226

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 1 - RESIDENTIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES Volume		Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**											
2	Delivery Margin Related Charges											
3	Basic Charge	365.25	days x	$0.389	$142.08	365.25	days x	$0.389	$142.08	$0.00	$0.00	0.00%
4												
5	Delivery Charge	95.0	GJ x	$3.531	$335.4450	95.0	GJ x	$3.856	$366.3200	$0.325	$30.8750	2.98%
6	Rider 2 2009 ROE Rate Rider	95.0	GJ x	$0.000	$0.0000	95.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	95.0	GJ x	$0.000	$0.0000	95.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	95.0	GJ x	($0.032)	($3.0400)	95.0	GJ x	($0.032)	($3.0400)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges				**$474.49**				**$505.36**		**$30.87**	**2.98%**
10												
11	Commodity Related Charges											
12	Midstream Cost Recovery Charge	95.0	GJ x	$1.340	$127.3000	95.0	GJ x	$1.340	$127.3000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	95.0	GJ x	$0.009	$0.8550	95.0	GJ x	$0.009	0.8550	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal				$128.16				$128.16		$0.00	0.00%
15												
16	Cost of Gas (Commodity Cost Recovery Charge)	95.0	GJ x	$4.568	$433.96	95.0	GJ x	$4.568	$433.96	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges				**$562.12**				**$562.12**		**$0.00**	**0.00%**
18												
19	Total *(with effective $/GJ rate)*	95.0		*$10.912*	**$1,036.61**	95.0		*$11.237*	**$1,067.48**	*$0.325*	**$30.87**	**2.98%**
20												
21	**INLAND SERVICE AREA**											
22	Delivery Margin Related Charges											
23	Basic Charge	365.25	days x	$0.389	$142.08	365.25	days	$0.389	$142.08	$0.00	$0.00	0.00%
24												
25	Delivery Charge	75.0	GJ x	$3.531	$264.8250	75.0	GJ x	$3.856	$289.2000	$0.325	$24.3750	2.88%
26	Rider 2 2009 ROE Rate Rider	75.0	GJ x	$0.000	$0.0000	75.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	75.0	GJ x	$0.000	$0.0000	75.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	75.0	GJ x	($0.032)	($2.4000)	75.0	GJ x	($0.032)	($2.4000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$404.51**				**$428.88**		**$24.37**	**2.88%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	75.0	GJ x	$1.315	$98.6250	75.0	GJ x	$1.315	$98.6250	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	75.0	GJ x	$0.009	$0.6750	75.0	GJ x	$0.009	$0.6750	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal				$99.30				$99.30		$0.00	0.00%
35												
36	Cost of Gas (Commodity Cost Recovery Charge)	75.0	GJ x	$4.568	$342.60	75.0	GJ x	$4.568	$342.60	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges				**$441.90**				**$441.90**		**$0.00**	**0.00%**
38												
39	Total *(with effective $/GJ rate)*	75.0		*$11.285*	**$846.41**	75.0		*$11.610*	**$870.78**	*$0.325*	**$24.37**	**2.88%**
40												
41	**COLUMBIA SERVICE AREA**											
42	Delivery Margin Related Charges											
43	Basic Charge	365.25	days x	$0.389	$142.08	365.25	days x	$0.389	$142.08	$0.00	$0.00	0.00%
44												
45	Delivery Charge	80.0	GJ x	$3.531	$282.4800	80.0	GJ x	$3.856	$308.4800	$0.325	$26.0000	2.90%
46	Rider 2 2009 ROE Rate Rider	80.0	GJ x	$0.000	$0.0000	80.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	80.0	GJ x	$0.000	$0.0000	80.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	80.0	GJ x	($0.032)	($2.5600)	80.0	GJ x	($0.032)	($2.5600)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges				**$422.00**				**$448.00**		**$26.00**	**2.90%**
50												
51	Commodity Related Charges											
52	Midstream Cost Recovery Charge	80.0	GJ x	$1.355	$108.4000	80.0	GJ x	$1.355	$108.4000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	80.0	GJ x	$0.009	$0.7200	80.0	GJ x	$0.009	$0.7200	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal				$109.12				$109.12		$0.00	0.00%
55												
56	Cost of Gas (Commodity Cost Recovery Charge)	80.0	GJ x	$4.568	$365.44	80.0	GJ x	$4.568	$365.44	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges				**$474.56**	80.0			**$474.56**		**$0.00**	**0.00%**
58												
59	Total *(with effective $/GJ rate)*	80.0		*$11.207*	**$896.56**	80.0		*$11.532*	**$922.56**	*$0.325*	**$26.00**	**2.90%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

Revised May 16, 2011

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 2 -SMALL COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
4														
5	Delivery Charge	300.0	GJ x	$2.907	=	$872.1000	300.0	GJ x	$3.152	=	$945.6000	$0.245	$73.5000	2.51%
6	Rider 2 2009 ROE Rate Rider	300.0	GJ x	$0.000	=	$0.0000	300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	300.0	GJ x	$0.000	=	$0.0000	300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	300.0	GJ x	($0.032)	=	($9.6000)	300.0	GJ x	($0.032)	=	($9.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$1,160.58**					**$1,234.08**		**$73.50**	**2.51%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	300.0	GJ x	$1.327	=	$398.1000	300.0	GJ x	$1.327	=	$398.1000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	300.0	GJ x	$0.000	=	$0.0000	300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal					$398.10					$398.10		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	300.0	GJ x	$4.568	=	$1,370.40	300.0	GJ x	$4.568	=	$1,370.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$1,768.50**					**$1,768.50**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	300.0		*$9.764*		**$2,929.08**	300.0		*$10.009*		**$3,002.58**	*$0.245*	**$73.50**	**2.51%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.907	=	$726.7500	250.0	GJ x	$3.152	=	$788.0000	$0.245	$61.2500	2.47%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032)	=	($8.0000)	250.0	GJ x	($0.032)	=	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges					**$1,016.83**					**$1,078.08**		**$61.25**	**2.47%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal					$325.25					$325.25		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	250.0	GJ x	$4.568	=	$1,142.00	250.0	GJ x	$4.568	=	$1,142.00	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$1,467.25**					**$1,467.25**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	250.0		*$9.936*		**$2,484.08**	250.0		*$10.181*		**$2,545.33**	*$0.245*	**$61.25**	**2.47%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
44														
45	Delivery Charge	320.0	GJ x	$2.907	=	$930.2400	320.0	GJ x	$3.152	=	$1,008.6400	$0.245	$78.4000	2.52%
46	Rider 2 2009 ROE Rate Rider	320.0	GJ x	$0.000	=	$0.0000	320.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	320.0	GJ x	$0.000	=	$0.0000	320.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	320.0	GJ x	($0.032)	=	($10.2400)	320.0	GJ x	($0.032)	=	($10.2400)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges					**$1,218.08**					**$1,296.48**		**$78.40**	**2.52%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	320.0	GJ x	$1.342	=	$429.4400	320.0	GJ x	$1.342	=	$429.4400	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	320.0	GJ x	$0.000	=	$0.0000	320.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal					$429.44					$429.44		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	320.0	GJ x	$4.568	=	$1,461.76	320.0	GJ x	$4.568	=	$1,461.76	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$1,891.20**					**$1,891.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	320.0		*$9.717*		**$3,109.28**	320.0		*$9.962*		**$3,187.68**	*$0.245*	**$78.40**	**2.52%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11
RATE SCHEDULE 3 - LARGE COMMERCIAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**LOWER MAINLAND SERVICE AREA**													
2	Delivery Margin Related Charges													
3	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
4														
5	Delivery Charge	2,800.0	GJ x	$2.467	=	$6,907.6000	2,800.0	GJ x	$2.655	=	$7,434.0000	$0.188	$526.4000	2.19%
6	Rider 2 2009 ROE Rate Rider	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
7	Rider 3 ESM	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
8	Rider 5 RSAM	2,800.0	GJ x	($0.032)	=	($89.6000)	2,800.0	GJ x	($0.032)	=	($89.6000)	$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$8,408.24**					**$8,934.64**		**$526.40**	**2.19%**
10														
11	Commodity Related Charges													
12	Midstream Cost Recovery Charge	2,800.0	GJ x	$1.018	=	$2,850.4000	2,800.0	GJ x	$1.018	=	$2,850.4000	$0.000	$0.0000	0.00%
13	Rider 8 Unbundling Recovery	2,800.0	GJ x	$0.000	=	$0.0000	2,800.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
14	Midstream Related Charges Subtotal					$2,850.40					$2,850.40		$0.00	0.00%
15														
16	Cost of Gas (Commodity Cost Recovery Charge)	2,800.0	GJ x	$4.568	=	$12,790.40	2,800.0	GJ x	$4.568	=	$12,790.40	$0.000	$0.00	0.00%
17	Subtotal Commodity Related Charges					**$15,640.80**					**$15,640.80**		**$0.00**	**0.00%**
18														
19	Total *(with effective $/GJ rate)*	2,800.0		*$8.589*		**$24,049.04**	2,800.0		*$8.777*		**$24,575.44**	*$0.188*	**$526.40**	**2.19%**
20														
21	**INLAND SERVICE AREA**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
24														
25	Delivery Charge	2,600.0	GJ x	$2.467	=	$6,414.2000	2,600.0	GJ x	$2.655	=	$6,903.0000	$0.188	$488.8000	2.18%
26	Rider 2 2009 ROE Rate Rider	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	2,600.0	GJ x	($0.032)	=	($83.2000)	2,600.0	GJ x	($0.032)	=	($83.2000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges					**$7,921.24**					**$8,410.04**		**$488.80**	**2.18%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	2,600.0	GJ x	$0.999	=	$2,597.4000	2,600.0	GJ x	$0.999	=	$2,597.4000	$0.000	$0.0000	0.00%
33	Rider 8 Unbundling Recovery	2,600.0	GJ x	$0.000	=	$0.0000	2,600.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
34	Midstream Related Charges Subtotal					$2,597.40					$2,597.40		$0.00	0.00%
35														
36	Cost of Gas (Commodity Cost Recovery Charge)	2,600.0	GJ x	$4.568	=	$11,876.80	2,600.0	GJ x	$4.568	=	$11,876.80	$0.000	$0.00	0.00%
37	Subtotal Commodity Related Charges					**$14,474.20**					**$14,474.20**		**$0.00**	**0.00%**
38														
39	Total *(with effective $/GJ rate)*	2,600.0		*$8.614*		**$22,395.44**	2,600.0		*$8.802*		**$22,884.24**	*$0.188*	**$488.80**	**2.18%**
40														
41	**COLUMBIA SERVICE AREA**													
42	Delivery Margin Related Charges													
43	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
44														
45	Delivery Charge	3,300.0	GJ x	$2.467	=	$8,141.1000	3,300.0	GJ x	$2.655	=	$8,761.5000	$0.188	$620.4000	2.21%
46	Rider 2 2009 ROE Rate Rider	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
47	Rider 3 ESM	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
48	Rider 5 RSAM	3,300.0	GJ x	($0.032)	=	($105.6000)	3,300.0	GJ x	($0.032)	=	($105.6000)	$0.000	$0.0000	0.00%
49	Subtotal Delivery Margin Related Charges					**$9,625.74**					**$10,246.14**		**$620.40**	**2.21%**
50														
51	Commodity Related Charges													
52	Midstream Cost Recovery Charge	3,300.0	GJ x	$1.036	=	$3,418.8000	3,300.0	GJ x	$1.036	=	$3,418.8000	$0.000	$0.0000	0.00%
53	Rider 8 Unbundling Recovery	3,300.0	GJ x	$0.000	=	$0.0000	3,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
54	Midstream Related Charges Subtotal					$3,418.80					$3,418.80		$0.00	0.00%
55														
56	Cost of Gas (Commodity Cost Recovery Charge)	3,300.0	GJ x	$4.568	=	$15,074.40	3,300.0	GJ x	$4.568	=	$15,074.40	$0.000	$0.00	0.00%
57	Subtotal Commodity Related Charges					**$18,493.20**					**$18,493.20**		**$0.00**	**0.00%**
58														
59	Total *(with effective $/GJ rate)*	3,300.0		*$8.521*		**$28,118.94**	3,300.0		*$8.709*		**$28,739.34**	*$0.188*	**$620.40**	**2.21%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 4 - SEASONAL SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
1		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**													
3	Delivery Margin Related Charges													
4	Basic Charge	214	days x	$14.423	=	$3,086.5216	214	days x	$14.423	=	$3,086.5216	$0.00	$0.00	0.00%
5														
6	Delivery Charge													
7	(a) Off-Peak Period	5,400.0	GJ x	$0.935	=	$5,049.0000	5,400.0	GJ x	$1.038	=	$5,605.2000	$0.103	$556.2000	1.51%
8	(b) Extension Period	0.0	GJ x	$1.712	=	$0.0000	0.0	GJ x	$1.815	=	$0.0000	$0.103	$0.0000	0.00%
9	Rider 2 2009 ROE Rate Rider	5,400.0	GJ x	$0.000	=	$0.0000	5,400.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	5,400.0	GJ x	$0.000	=	$0.0000	5,400.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges					**$8,135.52**					**$8,691.72**		**$556.20**	**1.51%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge													
15	(a) Off-Peak Period	5,400.0	GJ x	$0.764	=	$4,125.6000	5,400.0	GJ x	$0.764	=	$4,125.6000	$0.000	$0.0000	0.00%
16	(b) Extension Period	0.0	GJ x	$0.764	=	$0.0000	0.0	GJ x	$0.764	=	$0.0000	$0.000	$0.0000	0.00%
17	Commodity Cost Recovery Charge													
18	(a) Off-Peak Period	5,400.0	GJ x	$4.568	=	24,667.2000	5,400.0	GJ x	$4.568	=	$24,667.2000	$0.000	$0.0000	0.00%
19	(b) Extension Period	0.0	GJ x	$4.568	=	$0.0000	0.0	GJ x	$4.568	=	$0.0000	$0.000	$0.0000	0.00%
20														
21	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak					**$28,792.80**					**$28,792.80**		**$0.00**	**0.00%**
22														
23	Unauthorized Gas Charge During Peak Period (not forecast)													
24														
25	Total during Off-Peak Period	5,400.0				**$36,928.32**	5,400.0				**$37,484.52**		**$556.20**	**1.51%**
26														
27														
28	**INLAND SERVICE AREA**													
29	Delivery Margin Related Charges													
30	Basic Charge	214	days x	$14.423	=	$3,086.5216	214	days x	$14.423	=	$3,086.5216	$0.00	$0.00	0.00%
31														
32	Delivery Charge													
33	(a) Off-Peak Period	9,300.0	GJ x	$0.935	=	$8,695.5000	9,300.0	GJ x	$1.038	=	$9,653.4000	$0.103	$957.9000	1.56%
34	(b) Extension Period	0.0	GJ x	$1.712	=	$0.0000	0.0	GJ x	$1.815	=	$0.0000	$0.103	$0.0000	0.00%
35	Rider 2 2009 ROE Rate Rider	9,300.0	GJ x	$0.000	=	$0.0000	9,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
36	Rider 3 ESM	9,300.0	GJ x	$0.000	=	$0.0000	9,300.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
37	Subtotal Delivery Margin Related Charges					**$11,782.02**					**$12,739.92**		**$957.90**	**1.56%**
38														
39	Commodity Related Charges													
40	Midstream Cost Recovery Charge													
41	(a) Off-Peak Period	9,300.0	GJ x	$0.749	=	$6,965.7000	9,300.0	GJ x	$0.749	=	$6,965.7000	$0.000	$0.0000	0.00%
42	(b) Extension Period	0.0	GJ x	$0.749	=	$0.0000	0.0	GJ x	$0.749	=	$0.0000	$0.000	$0.0000	0.00%
43	Commodity Cost Recovery Charge													
44	(a) Off-Peak Period	9,300.0	GJ x	$4.568	=	$42,482.4000	9,300.0	GJ x	$4.568	=	$42,482.4000	$0.000	$0.0000	0.00%
45	(b) Extension Period	0.0	GJ x	$4.568	=	$0.0000	0.0	GJ x	$4.568	=	$0.0000	$0.000	$0.0000	0.00%
46														
47	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak					**$49,448.10**					**$49,448.10**		**$0.00**	**0.00%**
48														
49	Unauthorized Gas Charge During Peak Period (not forecast)													
50														
51	Total during Off-Peak Period	9,300.0				**$61,230.12**	9,300.0				**$62,188.02**		**$957.90**	**1.56%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 5 -GENERAL FIRM SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Total Annual Bill
2	**LOWER MAINLAND SERVICE AREA**											
3	Delivery Margin Related Charges											
4	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
5												
6	Demand Charge	58.5	GJ x	$16.996	**$11,931.19**	58.5	GJ x	$18.324	**$12,863.45**	$1.328	**$932.26**	**1.20%**
7												
8	Delivery Charge	9,700.0	GJ x	$0.696	$6,751.2000	9,700.0	GJ x	$0.761	$7,381.7000	$0.065	$630.5000	0.81%
9	Rider 2 2009 ROE Rate Rider	9,700.0	GJ x	$0.000	$0.0000	9,700.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
10	Rider 3 ESM	9,700.0	GJ x	$0.000	$0.0000	9,700.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges				**$6,751.20**				**$7,381.70**		**$630.50**	**0.81%**
12												
13	Commodity Related Charges											
14	Midstream Cost Recovery Charge	9,700.0	GJ x	$0.764	$7,410.8000	9,700.0	GJ x	$0.764	$7,410.8000	$0.000	$0.0000	0.00%
15	Commodity Cost Recovery Charge	9,700.0	GJ x	$4.568	$44,309.6000	9,700.0	GJ x	$4.568	$44,309.6000	$0.000	$0.0000	0.00%
16	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$51,720.40**				**$51,720.40**		**$0.00**	**0.00%**
17												
18	Total *(with effective $/GJ rate)*	9,700.0		*$7.984*	**$77,446.79**	9,700.0		*$8.145*	**$79,009.55**	*$0.161*	**$1,562.76**	**2.02%**
19												
20	**INLAND SERVICE AREA**											
21	Delivery Margin Related Charges											
22	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
23												
24	Demand Charge	82.0	GJ x	$16.996	**$16,724.06**	82.0	GJ x	$18.324	**$18,030.82**	$1.328	**$1,306.76**	**1.30%**
25												
26	Delivery Charge	12,800.0	GJ x	$0.696	$8,908.8000	12,800.0	GJ x	$0.761	$9,740.8000	$0.065	$832.0000	0.83%
27	Rider 2 2009 ROE Rate Rider	12,800.0	GJ x	$0.000	$0.0000	12,800.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	12,800.0	GJ x	$0.000	$0.0000	12,800.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges				**$8,908.80**				**$9,740.80**		**$832.00**	**0.83%**
30												
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	12,800.0	GJ x	$0.749	$9,587.2000	12,800.0	GJ x	$0.749	$9,587.2000	$0.000	$0.0000	0.00%
33	Commodity Cost Recovery Charge	12,800.0	GJ x	$4.568	$58,470.4000	12,800.0	GJ x	$4.568	$58,470.4000	$0.000	$0.0000	0.00%
34	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$68,057.60**				**$68,057.60**		**$0.00**	**0.00%**
35												
36	Total *(with effective $/GJ rate)*	12,800.0		*$7.870*	**$100,734.46**	12,800.0		*$8.037*	**$102,873.22**	*$0.167*	**$2,138.76**	**2.12%**
37												
38	**COLUMBIA SERVICE AREA**											
39	Delivery Margin Related Charges											
40	Basic Charge	12	months x	$587.00	**$7,044.00**	12	months x	$587.00	**$7,044.00**	$0.00	**$0.00**	**0.00%**
41												
42	Demand Charge	55.4	GJ x	$16.996	**$11,298.94**	55.4	GJ x	$18.324	**$12,181.80**	$1.328	**$882.86**	**1.20%**
43												
44	Delivery Charge	9,100.0	GJ x	$0.696	$6,333.6000	9,100.0	GJ x	$0.761	$6,925.1000	$0.065	$591.5000	PAGE 13
45	Rider 2 2009 ROE Rate Rider	9,100.0	GJ x	$0.000	$0.0000	9,100.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
46	Rider 3 ESM	9,100.0	GJ x	$0.000	$0.0000	9,100.0	GJ x	$0.000	$0.0000	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges				**$6,333.60**				**$6,925.10**		**$591.50**	**0.81%**
48												
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	9,100.0	GJ x	$0.785	$7,143.5000	9,100.0	GJ x	$0.785	$7,143.5000	$0.000	$0.0000	0.00%
51	Commodity Cost Recovery Charge	9,100.0	GJ x	$4.568	$41,568.8000	9,100.0	GJ x	$4.568	$41,568.8000	$0.000	$0.0000	0.00%
52	Subtotal Gas Commodity Cost (Commodity Related Charge)				**$48,712.30**				**$48,712.30**		**$0.00**	**0.00%**
53												
54	Total *(with effective $/GJ rate)*	9,100.0		$8.065	**$73,388.84**	9,100.0		$8.227	**$74,863.20**	*$0.162*	**$1,474.36**	**2.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 6 - NGV - STATIONS

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES						PROPOSED JANUARY 1, 2013 RATES						Annual Increase/Decrease		
1		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**															
3	Delivery Margin Related Charges															
4	Basic Charge	365.25	days x	$2.004	=	$732.00		365.25	days x	$2.004	=	$732.00		$0.00	$0.00	0.00%
5																
6	Delivery Charge	2,900.0	GJ x	$3.861	=	$11,196.9000		2,900.0	GJ x	$4.127	=	$11,968.3000		$0.266	$771.4000	2.94%
7	Rider 2 2009 ROE Rate Rider	2,900.0	GJ x	$0.000	=	$0.0000		2,900.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
8	Rider 3 ESM	2,900.0	GJ x	$0.000	=	$0.0000		2,900.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
9	Subtotal Delivery Margin Related Charges					**$11,928.90**						**$12,700.30**			**$771.40**	**2.94%**
10																
11	Commodity Related Charges															
12	Midstream Cost Recovery Charge	2,900.0	GJ x	$0.353	=	$1,023.7000		2,900.0	GJ x	$0.353	=	$1,023.7000		$0.000	$0.0000	0.00%
13	Commodity Cost Recovery Charge	2,900.0	GJ x	$4.568	=	$13,247.2000		2,900.0	GJ x	$4.568	=	$13,247.2000		$0.000	$0.0000	0.00%
14	Subtotal Cost of Gas (Commodity Related Charge)					**$14,270.90**						**$14,270.90**			**$0.00**	**0.00%**
15																
16	Total *(with effective $/GJ rate)*	2,900.0		*$9.034*		**$26,199.80**		2,900.0		*$9.300*		**$26,971.20**		*$0.266*	**$771.40**	**2.94%**
17																
18																
19	**INLAND SERVICE AREA**															
20	Delivery Margin Related Charges															
21	Basic Charge	365.25	days x	$2.004	=	$732.00		365.25	days x	$2.004	=	$732.00		$0.00	$0.00	0.00%
22																
23	Delivery Charge	11,900.0	GJ x	$3.861	=	$45,945.9000		11,900.0	GJ x	$4.127	=	$49,111.3000		$0.266	$3,165.4000	3.01%
24	Rider 2 2009 ROE Rate Rider	11,900.0	GJ x	$0.000	=	$0.0000		11,900.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
25	Rider 3 ESM	11,900.0	GJ x	$0.000	=	$0.0000		11,900.0	GJ x	$0.000	=	$0.0000		$0.000	$0.0000	0.00%
26	Subtotal Delivery Margin Related Charges					**$46,677.90**						**$49,843.30**			**$3,165.40**	**3.01%**
27																
28	Commodity Related Charges															
29	Midstream Cost Recovery Charge	11,900.0	GJ x	$0.346	=	$4,117.4000		11,900.0	GJ x	$0.346	=	$4,117.4000		$0.000	$0.0000	0.00%
30	Commodity Cost Recovery Charge	11,900.0	GJ x	$4.568	=	$54,359.2000		11,900.0	GJ x	$4.568	=	$54,359.2000		$0.000	$0.0000	0.00%
31	Subtotal Cost of Gas (Commodity Related Charge)					**$58,476.60**						**$58,476.60**			**$0.00**	**0.00%**
32																
33	Total *(with effective $/GJ rate)*	11,900.0		*$8.837*		**$105,154.50**		11,900.0		*$9.103*		**$108,319.90**		*$0.266*	**$3,165.40**	**3.01%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RATE SCHEDULE 7 - INTERRUPTIBLE SALES

Line No.	Particular	PROPOSED JANUARY 1, 2012 RATES			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Delivery Margin Related Charges									
4	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
5										
6	Delivery Charge	8,100.0 GJ x	$1.140 =	$9,234.0000	8,100.0 GJ x	$1.226 =	$9,930.6000	$0.086	$696.6000	1.11%
7	Rider 2 2009 ROE Rate Rider	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 4 Reserve for Future Use	8,100.0 GJ x	$0.000 =	$0.0000	8,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges			**$9,234.00**			**$9,930.60**		**$696.60**	**1.11%**
11										
12	Commodity Related Charges									
13	Midstream Cost Recovery Charge	8,100.0 GJ x	$0.764 =	$6,188.4000	8,100.0 GJ x	$0.764 =	$6,188.4000	$0.000	$0.0000	0.00%
14	Commodity Cost Recovery Charge	8,100.0 GJ x	$4.568 =	$37,000.8000	8,100.0 GJ x	$4.568 =	$37,000.8000	$0.000	$0.0000	0.00%
15	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$43,189.20**			**$43,189.20**		**$0.00**	**0.00%**
16										
17	Non-Standard Charges (not forecast)									
18	Index Pricing Option, UOR									
19										
20	Total *(with effective $/GJ rate)*	8,100.0	*$7.776*	**$62,983.20**	8,100.0	*$7.862*	**$63,679.80**	*$0.086*	**$696.60**	**1.11%**
21										
22										
23	**INLAND SERVICE AREA**									
24	Delivery Margin Related Charges									
25	Basic Charge	12 months x	$880.00 =	**$10,560.00**	12 months x	$880.00 =	**$10,560.00**	$0.00	**$0.00**	**0.00%**
26										
27	Delivery Charge	4,000.0 GJ x	$1.140 =	$4,560.0000	4,000.0 GJ x	$1.226 =	$4,904.0000	$0.086	$344.0000	0.95%
28	Rider 2 2009 ROE Rate Rider	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Rider 3 ESM	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
30	Rider 4 Reserve for Future Use	4,000.0 GJ x	$0.000 =	$0.0000	4,000.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges			**$4,560.00**			**$4,904.00**		**$344.00**	**0.95%**
32										
33	Commodity Related Charges									
34	Midstream Cost Recovery Charge	4,000.0 GJ x	$0.749 =	$2,996.0000	4,000.0 GJ x	$0.749 =	$2,996.0000	$0.000	$0.0000	0.00%
35	Commodity Cost Recovery Charge	4,000.0 GJ x	$4.568 =	$18,272.0000	4,000.0 GJ x	$4.568 =	$18,272.0000	$0.000	$0.0000	0.00%
36	Subtotal Gas Sales - Fixed (Commodity Related Charge)			**$21,268.00**			**$21,268.00**		**$0.00**	**0.00%**
37										
38	Non-Standard Charges (not forecast)									
39	Index Pricing Option, UOR									
40										
41	Total *(with effective $/GJ rate)*	4,000.0	*$9.097*	**$36,388.00**	4,000.0	*$9.183*	**$36,732.00**	*$0.086*	**$344.00**	**0.95%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$3,664.00 =	**$43,968.00**	12 months x	$3,664.00 =	**$43,968.00**	$0.00	**$0.00**	**0.00%**
4										
5										
6	Delivery Charge - Interruptible MTQ	467,305.6 GJ x	$0.838 =	$391,602.0928	467,305.6 GJ x	$0.899 =	$420,107.7344	$0.061	$28,505.6416	6.53%
7	Rider 2 2009 ROE Rate Rider	467,305.6 GJ x	$0.000 =	$0.0000	467,305.6 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
8	Rider 3 ESM	467,305.6 GJ x	$0.000 =	$0.0000	467,305.6 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Transportation - Interruptible			**$391,602.09**			**$420,107.73**		**$28,505.64**	**6.53%**
10										
11										
12	Non-Standard Charges (not forecast)									
13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas									
14										
15										
16	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
17										
18										
19	Total *(with effective $/GJ rate)*	467,305.6	*$0.934*	**$436,506.09**	467,305.6	*$0.995*	**$465,011.73**	*$0.061*	**$28,505.64**	**6.53%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 Volume		Rate		Annual $	PROPOSED JANUARY 1, 2013 RATES Volume		Rate		Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1														
2	**INLAND SERVICE AREA**													
3	Basic Charge	12	months x	$4,810.00	=	**$57,720.00**	12	months x	$4,810.00	=	**$57,720.00**	$0.00	**$0.00**	**0.00%**
4														
5														
6	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,595.4	GJ x	$13.407	=	**$417,558.36**	2,595.4	GJ x	$14.334	=	**$446,429.52**	$0.927	**$28,871.16**	**5.15%**
7														
8														
9	Delivery Charge - Firm MTQ	584,475.8	GJ x	$0.093	=	$54,356.2494	584,475.8	GJ x	$0.100	=	$58,447.5800	$0.007	$4,091.3306	0.73%
10	Rider 2 2009 ROE Rate Rider	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	$0.000	=	$0.0000	584,475.8	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
12	Transportation - Firm (Delivery Charge Firm MTQ)					**$54,356.25**					**$58,447.58**		**$4,091.33**	**0.73%**
13														
14														
15	Delivery Charge - Interruptible MTQ	28,607.9	GJ x	$1.061	=	$30,352.9819	28,607.9	GJ x	$1.134	=	$32,441.3586	$0.073	$2,088.3767	0.37%
16	Rider 2 2009 ROE Rate Rider	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	$0.000	=	$0.0000	28,607.9	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
18	Transportation - Interruptible (Delivery Charge Interruptible MTQ)					**$30,352.98**					**$32,441.36**		**$2,088.38**	**0.37%**
19														
20														
21	Non-Standard Charges (not forecast)													
22	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
23														
24														
25	Administration Charge	12	months x	$78.00	=	**$936.00**	12	months x	$78.00	=	**$936.00**	$0.00	**$0.00**	**0.00%**
26														
27														
28	Total *(with effective $/GJ rate)*	584,475.8		*$0.960*		**$560,923.59**	584,475.8		*$1.020*		**$595,974.46**	*$0.060*	**$35,050.87**	**6.25%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/Decrease		
1		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**COLUMBIA SERVICE - EXCEPT ELKVIEW COAL**											
3	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
4												
5	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,211.8	GJ x	$8.578	= **$227,673.84**	2,211.8	GJ x	$9.245	= **$245,377.08**	$0.667	**$17,703.24**	**5.35%**
6												
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	$0.092	= $42,075.8136	457,345.8	GJ x	$0.099	= $45,277.2342	$0.007	$3,201.4206	0.97%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	$0.000	= $0.0000	457,345.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	$0.000	= $0.0000	457,345.8	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Transportation - Firm (Delivery Charge Firm MTQ)				**$42,075.81**				**$45,277.23**		**$3,201.42**	**0.97%**
11												
12	Delivery Charge - Interruptible MTQ											
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	$0.855	= $5,756.2020	6,732.4	GJ x	$0.921	= $6,200.5404	$0.066	$444.3384	0.13%
14	- Nov. 1 to Apr. 1	0.0	GJ x	$1.231	= $0.0000	0.0	GJ x	$1.327	= $0.0000	$0.096	$0.0000	0.00%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ x	$0.000	= $0.0000	6,732.4	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	$0.000	= $0.0000	6,732.4	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$5,756.20**				**$6,200.54**		**$444.34**	**0.13%**
18												
19	Non-Standard Charges (not forecast)											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21												
22	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
23												
24	Total *(with effective $/GJ rate)*	464,078.2		*$0.713*	**$330,885.85**	464,078.2		*$0.759*	**$352,234.85**	*$0.046*	**$21,349.00**	**6.45%**
25												
26												
27	**COLUMBIA SERVICE - ELKVIEW COAL**											
28	Basic Charge	12	months x	$4,537.00	= **$54,444.00**	12	months x	$4,537.00	= **$54,444.00**	$0.00	**$0.00**	**0.00%**
29												
30	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,670.0	GJ x	$1.947	= **$62,381.88**	2,670.0	GJ x	$2.099	= **$67,251.96**	$0.152	**$4,870.08**	**2.70%**
31												
32	Delivery Charge - Firm MTQ	631,553.5	GJ x	$0.092	= $58,102.9220	631,553.5	GJ x	$0.099	= $62,523.7965	$0.007	$4,420.8745	2.45%
33	Rider 2 2009 ROE Rate Rider	631,553.5	GJ x	$0.000	= $0.0000	631,553.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ x	$0.000	= $0.0000	631,553.5	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
35	Transportation - Firm (Delivery Charge Firm MTQ)				**$58,102.92**				**$62,523.80**		**$4,420.88**	**2.45%**
36												
37	Delivery Charge - Interruptible MTQ											
38	- Apr. 1 to Nov. 1	0.0	GJ x	$0.214	= $0.0000	0.0	GJ x	$0.231	= $0.0000	$0.017	$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	$0.306	= $4,437.9486	14,503.1	GJ x	$0.330	= $4,786.0230	$0.024	$348.0744	0.19%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	$0.000	= $0.0000	14,503.1	GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				**$4,437.95**				**$4,786.02**		**$348.07**	**0.19%**
44												
45	Non-Standard Charges (not forecast)											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47												
48	Administration Charge	12	months x	$78.00	= **$936.00**	12	months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
49												
50	Total *(with effective $/GJ rate)*	646,056.6		*$0.279*	**$180,302.75**	646,056.6		*$0.294*	**$189,941.78**	*$0.015*	**$9,639.03**	**5.35%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012 Volume	Rate	Annual $	PROPOSED JANUARY 1, 2013 RATES Volume	Rate	Annual $	Annual Increase/Decrease Rate	Annual $	% of Previous Annual Bill
1										
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	4,100.0 GJ x	$2.467 =	$10,114.7000	4,100.0 GJ x	$2.655 =	$10,885.5000	$0.188	$770.8000	6.16%
8	Rider 2 2009 ROE Rate Rider	4,100.0 GJ x	$0.000 =	$0.0000	4,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	4,100.0 GJ x	$0.000 =	$0.0000	4,100.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
10	Rider 5 RSAM	4,100.0 GJ x	($0.032) =	($131.2000)	4,100.0 GJ x	($0.032) =	($131.2000)	$0.000	$0.0000	0.00%
11	Transportation - Firm			**$9,983.50**			**$10,754.30**		**$770.80**	**6.16%**
12										
13	Non-Standard Charges (not forecast)									
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
15										
16	Total *(with effective $/GJ rate)*	4,100.0	*$3.051*	**$12,509.74**	4,100.0	*$3.239*	**$13,280.54**	*$0.188*	**$770.80**	**6.16%**
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	4,700.0 GJ x	$2.467 =	$11,594.9000	4,700.0 GJ x	$2.655 =	$12,478.5000	$0.188	$883.6000	6.32%
24	Rider 2 2009 ROE Rate Rider	4,700.0 GJ x	$0.000 =	$0.0000	4,700.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	4,700.0 GJ x	$0.000 =	$0.0000	4,700.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
26	Rider 5 RSAM	4,700.0 GJ x	($0.032) =	($150.4000)	4,700.0 GJ x	($0.032) =	($150.4000)	$0.000	$0.0000	0.00%
27	Transportation - Firm			**$11,444.50**			**$12,328.10**		**$883.60**	**6.32%**
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
31										
32	Total *(with effective $/GJ rate)*	4,700.0	*$2.972*	**$13,970.74**	4,700.0	*$3.160*	**$14,854.34**	*$0.188*	**$883.60**	**6.32%**
33										
34	**COLUMBIA SERVICE AREA**									
35	Basic Charge	12 months x	$132.52 =	**$1,590.24**	12 months x	$132.52 =	**$1,590.24**	$0.00	**$0.00**	**0.00%**
36										
37	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
38										
39	Delivery Charge	4,200.0 GJ x	$2.467 =	$10,361.4000	4,200.0 GJ x	$2.655 =	$11,151.0000	$0.188	$789.6000	6.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0 GJ x	$0.000 =	$0.0000	4,200.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
41	Rider 3 ESM	4,200.0 GJ x	$0.000 =	$0.0000	4,200.0 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
42	Rider 5 RSAM	4,200.0 GJ x	($0.032) =	($134.4000)	4,200.0 GJ x	($0.032) =	($134.4000)	$0.000	$0.0000	0.00%
43	Transportation - Firm			**$10,227.00**			**$11,016.60**		**$789.60**	**6.19%**
44										
45	Non-Standard Charges (not forecast)									
46	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
47										
48	Total *(with effective $/GJ rate)*	4,200.0	*$3.036*	**$12,753.24**	4,200.0	*$3.224*	**$13,542.84**	*$0.188*	**$789.60**	**6.19%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 25 - GENERAL FIRM T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Transportation - Firm Demand	97.2 GJ x	$16.996 =	**$19,824.12**	97.2 GJ x	$18.324 =	**$21,373.08**	$1.328	**$1,548.96**	**3.77%**
8										
9	Delivery Charge	19,086.2 GJ x	$0.696 =	$13,283.9952	19,086.2 GJ x	$0.761 =	$14,524.5982	$0.065	$1,240.6030	3.02%
10	Rider 2 2009 ROE Rate Rider	19,086.2 GJ x	$0.000 =	$0.0000	19,086.2 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
11	Rider 3 ESM	19,086.2 GJ x	$0.000 =	$0.0000	19,086.2 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
12	Transportation - Firm			**$13,284.00**			**$14,524.60**		**$1,240.60**	**3.02%**
13										
14	Non-Standard Charges (not forecast)	214								
15	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16										
17	Total *(with effective $/GJ rate)*	19,086.2	*$2.153*	**$41,088.12**	19,086.2	*$2.299*	**$43,877.68**	*$0.146*	**$2,789.56**	**6.79%**
18										
19	**INLAND SERVICE AREA**									
20	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
21										
22	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
23										
24	Transportation - Firm Demand	212.6 GJ x	$16.996 =	**$43,360.20**	212.6 GJ x	$18.324 =	**$46,748.16**	$1.328	**$3,387.96**	**4.25%**
25										
26	Delivery Charge	40,670.5 GJ x	$0.696 =	$28,306.6680	40,670.5 GJ x	$0.761 =	$30,950.2505	$0.065	$2,643.5825	3.32%
27	Rider 2 2009 ROE Rate Rider	40,670.5 GJ x	$0.000 =	$0.0000	40,670.5 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
28	Rider 3 ESM	40,670.5 GJ x	$0.000 =	$0.0000	40,670.5 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
29	Transportation - Firm			**$28,306.67**			**$30,950.25**		**$2,643.58**	**3.32%**
30										
31	Non-Standard Charges (not forecast)									
32	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
33										
34	Total *(with effective $/GJ rate)*	40,670.5	*$1.958*	**$79,646.87**	40,670.5	*$2.107*	**$85,678.41**	*$0.149*	**$6,031.54**	**7.57%**
35										
36	**COLUMBIA SERVICE**									
37	Basic Charge	12 months x	$587.00 =	**$7,044.00**	12 months x	$587.00 =	**$7,044.00**	$0.00	**$0.00**	**0.00%**
38										
39	Administration Charge	12 months x	$78.00 =	**$936.00**	12 months x	$78.00 =	**$936.00**	$0.00	**$0.00**	**0.00%**
40										
41	Transportation - Firm Demand	182.2 GJ x	$16.996 =	**$37,160.04**	182.2 GJ x	$18.324 =	**$40,063.56**	$1.328	**$2,903.52**	**4.38%**
42										
43	Delivery Charge	30,357.8 GJ x	$0.696 =	$21,129.0288	30,357.8 GJ x	$0.761 =	$23,102.2858	$0.065	$1,973.2570	2.98%
44	Rider 2 2009 ROE Rate Rider	30,357.8 GJ x	$0.000 =	$0.0000	30,357.8 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	30,357.8 GJ x	$0.000 =	$0.0000	30,357.8 GJ x	$0.000 =	$0.0000	$0.000	$0.0000	0.00%
46	Transportation - Firm			**$21,129.03**			**$23,102.29**		**$1,973.26**	**2.98%**
47										
48	Non-Standard Charges (not forecast)									
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas									
50										
51	Total *(with effective $/GJ rate)*	30,357.8	*$2.183*	**$66,269.07**	30,357.8	*$2.344*	**$71,145.85**	*$0.161*	**$4,876.78**	**7.36%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC.
DELIVERY MARGIN RELATED CHARGES CHANGES
BCUC ORDER NO.G-XXX-11
RATE SCHEDULE 27 - INTERRUPTIBLE T-SERVICE

Line No.	Particular	PROPOSED JANUARY 1, 2012			PROPOSED JANUARY 1, 2013 RATES			Annual Increase/Decrease		
1		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2	**LOWER MAINLAND SERVICE AREA**									
3	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
4										
5	Administration Charge	12 months x	$78.00	= **$936.00**	12 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
6										
7	Delivery Charge	53,957.0 GJ x	$1.140	= $61,510.9800	53,957.0 GJ x	$1.226	= $66,151.2820	$0.086	$4,640.3020	6.36%
8	Rider 2 2009 ROE Rate Rider	53,957.0 GJ x	$0.000	= $0.0000	53,957.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	53,957.0 GJ x	$0.000	= $0.0000	53,957.0 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
10	Transportation - Interruptible			**$61,510.98**			**$66,151.28**		**$4,640.30**	**6.36%**
11										
12	Non-Standard Charges (not forecast)									
13	UOR, Balancing gas, Backstopping Gas									
14										
15	Total *(with effective $/GJ rate)*	53,957.0	*$1.353*	**$73,006.98**	53,957.0	*$1.439*	**$77,647.28**	*$0.086*	**$4,640.30**	**6.36%**
16										
17										
18	**INLAND SERVICE AREA**									
19	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
20										
21	Administration Charge	12.0 months x	$78.00	= **$936.00**	12.0 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
22										
23	Delivery Charge	48,903.9 GJ x	$1.140	= $55,750.4460	48,903.9 GJ x	$1.226	= $59,956.1814	$0.086	$4,205.7354	6.25%
24	Rider 2 2009 ROE Rate Rider	48,903.9 GJ x	$0.000	= $0.0000	48,903.9 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
25	Rider 3 ESM	48,903.9 GJ x	$0.000	= $0.0000	48,903.9 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
26	Transportation - Interruptible			**$55,750.45**			**$59,956.18**		**$4,205.73**	**6.25%**
27										
28										
29	Non-Standard Charges (not forecast)									
30	UOR, Balancing gas, Backstopping Gas									
31		48,903.9	*$1.375*	**$67,246.45**	48,903.9	*$1.461*	**$71,452.18**	*$0.086*	**$4,205.73**	**6.25%**
32	Total *(with effective $/GJ rate)*									
33										
34										
35	**COLUMBIA SERVICE AREA**									
36	Basic Charge	12 months x	$880.00	= **$10,560.00**	12 months x	$880.00	= **$10,560.00**	$0.00	**$0.00**	**0.00%**
37										
38	Administration Charge	12.0 months x	$78.00	= **$936.00**	12.0 months x	$78.00	= **$936.00**	$0.00	**$0.00**	**0.00%**
39										
40	Delivery Charge	7,733.8 GJ x	$1.140	= $8,816.5320	7,733.8 GJ x	$1.226	= $9,481.6388	$0.086	$665.1068	0.99%
41	Rider 2 2009 ROE Rate Rider	7,733.8 GJ x	$0.000	= $0.0000	7,733.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
42	Rider 3 ESM	7,733.8 GJ x	$0.000	= $0.0000	7,733.8 GJ x	$0.000	= $0.0000	$0.000	$0.0000	0.00%
43	Transportation - Interruptible			**$8,816.53**			**$9,481.64**		**$665.11**	**0.99%**
44										
45										
46	Non-Standard Charges (not forecast)									
47	UOR, Balancing gas, Backstopping Gas									
48		7,733.8	*$2.626*	**$20,312.53**	7,733.8	*$2.712*	**$20,977.64**	*$0.086*	**$665.11**	**0.99%**
49	Total *(with effective $/GJ rate)*									

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY INC. - INLAND SERVICE AREA (APPLICABLE TO REVELSTOKE CUSTOMERS)
EFFECT ON REVELSTOKE RATE SCHEDULE 1, 2, AND 3 CUSTOMERS' WITH RATE CHANGES
BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

Line No.	PARTICULARS	PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
1	**INLAND SERVICE AREA**													
2														
3	**Rate 1 - Residential**													
4	Delivery Margin Related Charges													
5	Basic Charge	365.25	days x	$0.389	=	$142.08	365.25	days x	$0.389	=	$142.08	$0.00	$0.00	0.00%
6														
7	Delivery Charge	50.0	GJ x	$3.531	=	$176.5500	50.0	GJ x	$3.856	=	$192.8000	$0.325	$16.2500	1.51%
8	Rider 2 2009 ROE Rate Rider	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	$0.000	=	$0.0000	50.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
10	Rider 5 RSAM	50.0	GJ x	($0.032)	=	($1.6000)	50.0	GJ x	($0.032)	=	($1.6000)	$0.000	$0.0000	0.00%
11	Subtotal Delivery Margin Related Charges			$3.499		**$317.03**			$3.824		**$333.28**		**$16.25**	**1.51%**
12														
13	Commodity Related Charges													
14	Midstream Cost Recovery Charge	50.0	GJ x	$1.315	=	$65.7500	50.0	GJ x	$1.315	=	$65.7500	$0.000	$0.0000	0.00%
15	Cost of Gas	50.0	GJ x	$4.568	=	$228.4000	50.0	GJ x	$4.568	=	$228.4000	$0.000	$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x	$9.331	=	$466.5500	50.0	GJ x	$9.331	=	$466.5500	$0.000	$0.0000	0.00%
17	Subtotal Commodity Related Charges			$15.214		**$760.70**			$15.214		**$760.70**		**$0.00**	**0.00%**
18														
19	*Total (with effective $/GJ rate)*	50.0		*$21.555*		**$1,077.73**	50.0		*$21.880*		**$1,093.98**	*$0.325*	**$16.25**	**1.51%**
20														
21	**Rate 2 - Small Commercial**													
22	Delivery Margin Related Charges													
23	Basic Charge	365.25	days x	$0.816	=	$298.08	365.25	days x	$0.816	=	$298.08	$0.00	$0.00	0.00%
24														
25	Delivery Charge	250.0	GJ x	$2.907	=	$726.7500	250.0	GJ x	$3.152	=	$788.0000	$0.245	$61.2500	1.35%
26	Rider 2 2009 ROE Rate Rider	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
27	Rider 3 ESM	250.0	GJ x	$0.000	=	$0.0000	250.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
28	Rider 5 RSAM	250.0	GJ x	($0.032)	=	($8.0000)	250.0	GJ x	($0.032)	=	($8.0000)	$0.000	$0.0000	0.00%
29	Subtotal Delivery Margin Related Charges			$2.875		**$1,016.83**			$3.120		**$1,078.08**		**$61.25**	**1.35%**
30														
31	Commodity Related Charges													
32	Midstream Cost Recovery Charge	250.0	GJ x	$1.301	=	$325.2500	250.0	GJ x	$1.301	=	$325.2500	$0.000	$0.0000	0.00%
33	Cost of Gas	250.0	GJ x	$4.568	=	$1,142.0000	250.0	GJ x	$4.568	=	$1,142.0000	$0.000	$0.0000	0.00%
34	Rider 1 Propane Surcharge	250.0	GJ x	$8.254	=	$2,063.5000	250.0	GJ x	$8.254	=	$2,063.5000	$0.000	$0.0000	0.00%
35	Subtotal Commodity Related Charges			$14.123		**$3,530.75**			$14.123		**$3,530.75**		**$0.00**	**0.00%**
36														
37	*Total (with effective $/GJ rate)*	250.0		*$18.190*		**$4,547.58**	250.0		*$18.435*		**$4,608.83**	*$0.245*	**$61.25**	**1.35%**
38														
39	**Rate 3 - Large Commercial**													
40	Delivery Margin Related Charges													
41	Basic Charge	365.25	days x	$4.354	=	$1,590.24	365.25	days x	$4.354	=	$1,590.24	$0.00	$0.00	0.00%
42														
43	Delivery Charge	4,500.0	GJ x	$2.467	=	$11,101.5000	4,500.0	GJ x	$2.655	=	$11,947.5000	$0.188	$846.0000	1.11%
44	Rider 2 2009 ROE Rate Rider	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
45	Rider 3 ESM	4,500.0	GJ x	$0.000	=	$0.0000	4,500.0	GJ x	$0.000	=	$0.0000	$0.000	$0.0000	0.00%
46	Rider 5 RSAM	4,500.0	GJ x	($0.032)	=	($144.0000)	4,500.0	GJ x	($0.032)	=	($144.0000)	$0.000	$0.0000	0.00%
47	Subtotal Delivery Margin Related Charges			$2.435		**$12,547.74**			$2.623		**$13,393.74**		**$846.00**	**1.11%**
48														
49	Commodity Related Charges													
50	Midstream Cost Recovery Charge	4,500.0	GJ x	$0.999	=	$4,495.5000	4,500.0	GJ x	$0.999	=	$4,495.5000	$0.000	$0.0000	0.00%
51	Cost of Gas	4,500.0	GJ x	$4.568	=	$20,556.0000	4,500.0	GJ x	$4.568	=	$20,556.0000	$0.000	$0.0000	0.00%
52	Rider 1 Propane Surcharge	4,500.0	GJ x	$8.556	=	$38,502.0000	4,500.0	GJ x	$8.556	=	$38,502.0000	$0.000	$0.0000	0.00%
53	Subtotal Commodity Related Charges			$14.123		**$63,553.50**			$14.123		**$63,553.50**		**$0.00**	**0.00%**
54														
55	*Total (with effective $/GJ rate)*	4,500.0		*$16.911*		**$76,101.24**	4,500.0		*$17.099*		**$76,947.24**	*$0.188*	**$846.00**	**1.11%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2012 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Effective Rate January 1, 2010	Rate Changes	Proposed Rate January 1, 2012
	(1)	(2)	(3)	(4)
1	**APARTMENT GENERAL SERVICE (AGS)**			
2				
3	Basic Daily Charge	$1.3142	$0.0000	$1.3142
4	Energy Charge per GJ	$12.373	$0.000	$12.373
5				
6	Minimum Monthly Charge	$40.00	$0.00	$40.00
7				
8	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
9				
10	**RESIDENTIAL GENERAL SERVICE (RGS-1)**			
11				
12	Basic Daily Charge	$0.3450	$0.0000	$0.3450
13	Energy Charge per GJ	$14.325	$0.000	$14.325
14				
15	Minimum Monthly Charge	$10.50	$0.00	$10.50
16				
17	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
18				
19	**SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)**			
20				
21	Basic Daily Charge	$0.3105	$0.0000	$0.3105
22	Energy Charge per GJ	$16.940	$0.000	$16.940
23				
24	Minimum Monthly Charge	$9.45	$0.00	$9.45
25				
26	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
27				
28	**SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)**			
29				
30	Basic Daily Charge	$1.1016	$0.0000	$1.1016
31	Energy Charge per GJ	$16.455	$0.000	$16.455
32				
33	Minimum Monthly Charge	$33.53	$0.00	$33.53
34				
35	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
36				
37	**LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)**			
38				
39	Basic Daily Charge	$2.0041	$0.0000	$2.0041
40	Energy Charge per GJ	$13.353	$0.000	$13.353
41				
42	Minimum Monthly Charge	$61.00	$0.00	$61.00
43				
44	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
45				
46	**LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)**			
47				
48	Basic Daily Charge	$3.2138	$0.0000	$3.2138
49	Energy Charge per GJ	$12.311	$0.000	$12.311
50				
51	Minimum Monthly Charge	$97.82	$0.00	$97.82
52				
53	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
54				
55	**LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)**			
56				
57	Basic Daily Charge	$6.6205	$0.0000	$6.6205
58	Energy Charge per GJ	$12.015	$0.000	$12.015
59				
60	Minimum Monthly Charge	$201.51	$0.00	$201.51
61				
62	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			

Line No.	Particulars	Effective Rate January 1, 2010	Rate Changes	Proposed Rate January 1, 2012
	(1)	(2)	(3)	(4)
1	**LARGE COMMERCIAL SERVICE RATE NO. 13 (LCS-13)**			
2				
3	Basic Monthly Charge	$201.51	$0.00	$201.51
4	Energy Charge per GJ	$6.608	($0.907)	$5.701
5				
6	Minimum Monthly Charge	$201.51	$0.00	$201.51
7				
8	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
9				
10	**LARGE COMMERCIAL SERVICE RATE HIGH LOAD FACTOR (HLF)**			
11				
12	Basic Daily Charge	$8.2136	$0.0000	$8.2136
13	Demand Charge	$47.180	$0.000	$47.180
14	Energy Charge per GJ	$8.697	$0.000	$8.697
15				
16	Minimum Monthly Charge	$250.00	$0.00	$250.00
17				
18	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			
19				
20	**LARGE COMMERCIAL SERVICE RATE INVERSE LOAD FACTOR 150% (ILF)**			
21				
22	Basic Daily Charge	$8.2136	$0.0000	$8.2136
23	Energy Charge per GJ	$10.097	$0.000	$10.097
24				
25	Minimum Monthly Charge	$250.00	$0.00	$250.00
26				
27	*Note: Where applicable, existing monthly January 1, 2010 basic chage rates are prorated to a daily equivalent for comparison purposes.*			

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
APARTMENT GENERAL SERVICE (AGS)

Line No.	Particular	Existing January 1, 2010 Rates					Proposed Rate January 1, 2012 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$1.3142	=	$480.00	365.25	days x	$1.3142	=	$480.00	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	1,364.1	GJ x	$12.373	=	$16,878.01	1,364.1	GJ x	$12.373	=	$16,878.01	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	1,364.1		*$12.725*		**$17,358.01**	1,364.1		*$12.725*		**$17,358.01**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RESIDENTIAL GENERAL SERVICE (RGS-1)

Line No.	Particular	Existing January 1, 2010 Rates					Proposed Rate January 1, 2012 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$0.345	=	$126.00	365.25	days x	$0.345	=	$126.00	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	58.6	GJ x	$14.325	=	$839.45	58.6	GJ x	$14.325	=	$839.45	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	58.6		*$16.475*		**$965.45**	58.6		*$16.475*		**$965.45**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)

Line No.	Particular	Existing January 1, 2010 Rates					Proposed Rate January 1, 2012 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$0.3105	=	$113.40	365.25	days x	$0.3105	=	$113.40	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	80.3	GJ x	$16.940	=	$1,360.28	80.3	GJ x	$16.940	=	$1,360.28	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	80.3		*$18.352*		**$1,473.68**	80.3		*$18.352*		**$1,473.68**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$1.1016	=	$402.36		365.25	days x	$1.1016	=	$402.36		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	312.6	GJ x	$16.455	=	$5,143.83		312.6	GJ x	$16.455	=	$5,143.83		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	312.6		*$17.742*		**$5,546.19**		312.6		*$17.742*		**$5,546.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$2.0041	=	$732.00		365.25	days x	$2.0041	=	$732.00		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	929.8	GJ x	$13.353	=	$12,415.62		929.8	GJ x	$13.353	=	$12,415.62		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	929.8		*$14.140*		**$13,147.62**		929.8		*$14.140*		**$13,147.62**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$3.2138	=	$1,173.84		365.25	days x	$3.2138	=	$1,173.84		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	2,361.9	GJ x	$12.311	=	$29,077.35		2,361.9	GJ x	$12.311	=	$29,077.35		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	2,361.9		*$12.808*		**$30,251.19**		2,361.9		*$12.808*		**$30,251.19**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)

Line No.	Particular	Existing January 1, 2010 Rates						Proposed Rate January 1, 2012 Rates						Annual Increase/Decrease		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days x	$6.6205	=	$2,418.12		365.25	days x	$6.6205	=	$2,418.12		$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	17,694.0	GJ x	$12.015	=	$212,593.41		17,694.0	GJ x	$12.015	=	$212,593.41		$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	17,694.0		*$12.152*		**$215,011.53**		17,694.0		*$12.152*		**$215,011.53**		*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2010 basic charge rates are prorated to a daily basis for comparison purposes.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Proposed Rate January 1, 2012	Rate Changes	Proposed Rate January 1, 2013
	(1)	(2)	(3)	(4)
1	**APARTMENT GENERAL SERVICE (AGS)**			
3	Basic Daily Charge	$1.3142	$0.0000	$1.3142
4	Energy Charge per GJ	$12.373	$0.000	$12.373
6	Minimum Monthly Charge	$40.00	$0.00	$40.00
10	**RESIDENTIAL GENERAL SERVICE (RGS-1)**			
12	Basic Daily Charge	$0.3450	$0.0000	$0.3450
13	Energy Charge per GJ	$14.325	$0.000	$14.325
15	Minimum Monthly Charge	$10.50	$0.00	$10.50
19	**SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)**			
21	Basic Daily Charge	$0.3105	$0.0000	$0.3105
22	Energy Charge per GJ	$16.940	$0.000	$16.940
24	Minimum Monthly Charge	$9.45	$0.00	$9.45
28	**SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)**			
30	Basic Daily Charge	$1.1016	$0.0000	$1.1016
31	Energy Charge per GJ	$16.455	$0.000	$16.455
33	Minimum Monthly Charge	$33.53	$0.00	$33.53
37	**LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)**			
39	Basic Daily Charge	$2.0041	$0.0000	$2.0041
40	Energy Charge per GJ	$13.353	$0.000	$13.353
42	Minimum Monthly Charge	$61.00	$0.00	$61.00
46	**LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)**			
48	Basic Daily Charge	$3.2138	$0.0000	$3.2138
49	Energy Charge per GJ	$12.311	$0.000	$12.311
51	Minimum Monthly Charge	$97.82	$0.00	$97.82
55	**LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)**			
57	Basic Daily Charge	$6.6205	$0.0000	$6.6205
58	Energy Charge per GJ	$12.015	$0.000	$12.015
60	Minimum Monthly Charge	$201.51	$0.00	$201.51

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY
PROPOSED JANUARY 1, 2013 RATES
BCUC ORDER NO.G-XXX-11 G-XXX-11

Line No.	Particulars	Proposed Rate January 1, 2012	Rate Changes	Proposed Rate January 1, 2013
	(1)	(2)	(3)	(4)
1	**LARGE COMMERCIAL SERVICE RATE NO. 13 (LCS-13)**			
2				
3	Basic Monthly Charge	$201.51	$0.00	$201.51
4	Energy Charge per GJ	$5.701	($0.128)	$5.573
5				
6	Minimum Monthly Charge	$201.51	$0.00	$201.51
7				
8				
9				
10	**LARGE COMMERCIAL SERVICE RATE HIGH LOAD FACTOR (HLF)**			
11				
12	Basic Daily Charge	$8.2136	$0.0000	$8.2136
13	Demand Charge	$47.180	$0.000	$47.180
14	Energy Charge per GJ	$8.697	$0.000	$8.697
15				
16	Minimum Monthly Charge	$250.00	$0.00	$250.00
17				
18				
19				
20	**LARGE COMMERCIAL SERVICE RATE INVERSE LOAD FACTOR 150% (ILF)**			
21				
22	Basic Daily Charge	$8.2136	$0.0000	$8.2136
23	Energy Charge per GJ	$10.097	$0.000	$10.097
24				
25	Minimum Monthly Charge	$250.00	$0.00	$250.00
26				
27				

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
APARTMENT GENERAL SERVICE (AGS)

Line No.	Particular	Proposed January 1, 2012 Rates					Proposed Rate January 1, 2013 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$1.3142	=	$480.00	365.25	days x	$1.3142	=	$480.00	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	1,364.1	GJ x	$12.373	=	$16,878.01	1,364.1	GJ x	$12.373	=	$16,878.01	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	1,364.1		*$12.725*		**$17,358.01**	1,364.1		*$12.725*		**$17,358.01**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
RESIDENTIAL GENERAL SERVICE (RGS-1)

Line No.	Particular	Proposed January 1, 2012 Rates					Proposed Rate January 1, 2013 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$0.345	=	$126.00	365.25	days x	$0.345	=	$126.00	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	58.6	GJ x	$14.325	=	$839.45	58.6	GJ x	$14.325	=	$839.45	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	58.6		*$16.475*		**$965.45**	58.6		*$16.475*		**$965.45**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)

Line No.	Particular	Proposed January 1, 2012 Rates					Proposed Rate January 1, 2013 Rates					Annual Increase/Decrease		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**													
2														
3	Basic Daily Charge	365.25	days x	$0.3105	=	$113.40	365.25	days x	$0.3105	=	$113.40	$0.0000	$0.00	0.00%
4														
5	Energy Charge per GJ	80.3	GJ x	$16.940	=	$1,360.28	80.3	GJ x	$16.940	=	$1,360.28	$0.000	$0.00	0.00%
6														
7	**Total *(with effective $/GJ rate)***	80.3		*$18.352*		**$1,473.68**	80.3		*$18.352*		**$1,473.68**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days	x	$1.1016	=	$402.36	365.25	days	x	$1.1016	=	$402.36	$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	312.6	GJ	x	$16.455	=	$5,143.83	312.6	GJ	x	$16.455	=	$5,143.83	$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	312.6			*$17.742*		**$5,546.19**	312.6			*$17.742*		**$5,546.19**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 1 (LCS-1)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days	x	$2.0041	=	$732.00	365.25	days	x	$2.0041	=	$732.00	$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	929.8	GJ	x	$13.353	=	$12,415.62	929.8	GJ	x	$13.353	=	$12,415.62	$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	929.8			*$14.140*		**$13,147.62**	929.8			*$14.140*		**$13,147.62**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days	x	$3.2138	=	$1,173.84	365.25	days	x	$3.2138	=	$1,173.84	$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	2,361.9	GJ	x	$12.311	=	$29,077.35	2,361.9	GJ	x	$12.311	=	$29,077.35	$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	2,361.9			*$12.808*		**$30,251.19**	2,361.9			*$12.808*		**$30,251.19**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
DELIVERY MARGIN AND COMMODITY RELATED CHARGES
BCUC ORDER NO.G-XXX-11 G-XXX-11
LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)

Line No.	Particular	Proposed January 1, 2012 Rates						Proposed Rate January 1, 2013 Rates						Annual Increase/Decrease		
		Volume			Rate		Annual $	Volume			Rate		Annual $	Rate	Annual $	% of Previous Total Annual Bill
1	**FortisBC Energy Vancouver Island**															
2																
3	Basic Daily Charge	365.25	days	x	$6.6205	=	$2,418.12	365.25	days	x	$6.6205	=	$2,418.12	$0.0000	$0.00	0.00%
4																
5	Energy Charge per GJ	17,694.0	GJ	x	$12.015	=	$212,593.41	17,694.0	GJ	x	$12.015	=	$212,593.41	$0.000	$0.00	0.00%
6																
7	**Total *(with effective $/GJ rate)***	17,694.0			*$12.152*		**$215,011.53**	17,694.0			*$12.152*		**$215,011.53**	*$0.000*	**$0.00**	**0.00%**

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Effective Rate January 1, 2011	Proposed Rate January 1, 2012	Increase / (Decrease)	% Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.440	$10.680	$0.2400	2.30%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.263**	**$16.503**	**$0.2400**	**1.48%**
8						
9	Rider A	*($/GJ)*	($0.948)	($0.948)	$0.000	0.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.000	$0.524	$0.524	n/a
12	Total Riders	*($/GJ)*	**($0.948)**	**($0.424)**	**$0.524**	**155.27%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 15.315**	**$ 16.079**	**$ 0.764**	**4.99%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,468.35	$1,537.11		
22						
23	Change in Annual Bill	*($)*			**$ 68.76**	
24	Change in Annual Bill	*(%)*			**4.68%**	

Note: Existing monthly January 1, 2011 basic chage rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY (WHISTLER) INC.
Tariff Continuity and Bill Impact Schedule
BCUC Order No. G-XXX-11 G-XXX-11

Line No	Particulars		Proposed Rate January 1, 2012	Proposed Rate January 1, 2013	Increase / (Decrease)	Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1	**Tariff Rates**					
2						
3	Basic Charge	*($/Day)*	$0.2464	$0.2464	$0.0000	0.00%
4						
5	Delivery Charge	*($/GJ)*	$10.680	$11.963	$1.2830	12.01%
6	Gas Cost Recovery Charge	*($/GJ)*	$5.823	$5.823	$0.0000	0.00%
7	Total Cost Recovery Charges	*($/GJ)*	**$16.503**	**$17.786**	**$1.2830**	**7.77%**
8						
9	Rider A	*($/GJ)*	($0.948)	($0.948)	$0.000	0.00%
10	Rider B	*($/GJ)*	$0.000	$0.000	$0.000	0.00%
11	Rider 5 (RSAM)	*($/GJ)*	$0.524	$0.524	$0.000	0.00%
12	Total Riders	*($/GJ)*	**($0.424)**	**($0.424)**	**$0.000**	**0.00%**
13						
14	Total Variable Charges	*($/GJ)*	**$ 16.079**	**$ 17.362**	**$ 1.283**	**7.98%**
15						
16						
17	**Bill Impact Estimates**					
18						
19	Annual Residential Usage	*(GJ)*	90	90		
20						
21	Annual Bill	*($)*	$1,537.11	$1,652.58		
22						
23	Change in Annual Bill	*($)*			**$ 115.47**	
24	Change in Annual Bill	*(%)*			**7.51%**	

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	EXISTING RATE JANUARY 1, 2011	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2012
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3141	$0.0199	$0.3340
10			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
12			**Minimum Daily Charge** (includes first 2 gigajoules/month)	**$0.646**	$0.017	**$0.663**
13						
14			Delivery Charge per GJ	$2.410	$0.160	$2.570
15			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
16			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
17			**Next 28 Gigajoules in any month**	**$7.458**	$0.116	**$7.574**
18						
19			Delivery Charge per GJ	$2.340	$0.162	$2.502
20			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
21			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
22			**Excess of 30 Gigajoules in any month**	**$7.388**	$0.118	**$7.506**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3141	$0.0199	$0.3340
28			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
30			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$0.646**	$0.017	**$0.663**
31						
32			Delivery Charge per GJ	$2.410	$0.160	$2.570
33			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
34			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
35			**Next 28 Gigajoules in any month**	**$7.458**	$0.116	**$7.574**
36						
37			Delivery Charge per GJ	$2.340	$0.162	$2.502
38			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
39			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
40			**Excess of 30 Gigajoules in any month**	**$7.388**	$0.118	**$7.506**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATE	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATE
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9193	$0.0654	$0.9847
2			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.0029)	($0.0007)
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
4			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.251**	$0.063	**$1.314**
5						
6			Delivery Charge per GJ	$2.710	$0.181	$2.891
7			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
8			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
9			**Next 28 Gigajoules in any month**	**$7.758**	$0.137	**$7.895**
10						
11			Delivery Charge per GJ	$2.624	$0.176	$2.800
12			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
13			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
14			**Excess of 30 Gigajoules in any month**	**$7.672**	$0.132	**$7.804**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9193	$0.0654	$0.9847
17			Revenue Stabilization Adjustment Amount per Day	$0.0022	($0.00)	($0.0007)
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
19			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.251**	$0.063	**$1.314**
20						
21			Delivery Charge per GJ	$2.710	$0.181	$2.891
22			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
23			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
24			**Next 28 Gigajoules in any month**	**$7.758**	$0.137	**$7.895**
25						
26			Delivery Charge per GJ	$2.624	$0.176	$2.800
27			Revenue Stabilization Adjustment Amount per GJ	$0.033	($0.044)	($0.011)
28			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
29			**Excess of 30 Gigajoules in any month**	**$7.672**	$0.132	**$7.804**
30						
31	Rate 2.3	No. 2.1	Delivery Charge per Month	$28.08	$1.83	$29.91
32			Gas Cost Recovery Charge per Month	$10.030	$0.00	$10.030
33			**Minimum Monthly Charge** (includes first 2 gigajoules)	**$38.110**	$1.827	**$39.937**
34						
35			Delivery Charge per GJ	$3.450	$0.225	$3.675
36			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
37			**Next 28 Gigajoules in any month**	**$8.465**	$0.225	**$8.690**
38						
39			Delivery Charge per GJ	$3.362	$0.219	$3.581
40			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
41			**Excess of 30 Gigajoules in any month**	**$8.377**	$0.219	**$8.596**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATE	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATE
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
5			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
8			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
9						
10			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
16			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
17			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
20			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
21						
22			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
28			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
29			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.033	($0.044)	($0.011)
32			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
33						
34			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
EFFECTIVEJANUARY 1, 2012 RATES
BCUC ORDER NO. G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2011 EXISTING RATES	Delivery Related Changes	JANUARY 1, 2012 EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.690	$0.236	$2.926
5			Excess over 280 Gigajoules in any month	$2.174	$0.159	$2.333
6						
7			Minimum Monthly Delivery Charge	$1,826.00	$119.00	$1,945.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	$0.033	($0.044)	($0.011)

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/(Decrease)		
1	**Rate 1 Domestic Service Option B**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per day	365.25	days x	$0.3141	$114.7200	365.25	days x	$0.3340	$121.9800	$0.0199	$7.2600	0.66%
5	Rider 5 - RSAM per day	365.25	days x	$0.0022	$0.8036	365.25	days x	($0.0007)	-$0.2557	($0.0029)	($1.0592)	-0.10%
6	Gas Cost Recovery Charge per Day	365.25	days x	$0.3295	$120.3499	365.25	days x	$0.3295	$120.3499	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$0.6458	$235.8700			$0.6628	$242.0700	$0.0170	$6.2000	0.56%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$2.410	$279.5600	116	GJ x	$2.570	$298.1200	$0.160	$18.5600	1.69%
11	Rider 5 - RSAM per GJ	116	GJ x	$0.033	$3.8280	116	GJ x	($0.011)	($1.2760)	($0.044)	($5.1040)	-0.46%
12	Gas Cost Recovery Charge per GJ	116	GJ x	$5.015	$581.7400	116	GJ x	$5.015	$581.7400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.458	$865.1300			$7.574	$878.5800	$0.116	$13.4500	1.22%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.340	$0.0000	0	GJ x	$2.502	$0.0000	$0.162	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	$0.033	$0.0000	0	GJ x	($0.011)	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.388	$0.0000			$7.506	$0.0000	$0.118	$0.0000	0.00%
20												
21	Total	140	GJ		$1,101.00	140	GJ		$1,120.65		$19.65	1.78%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$398.91				$418.57		$19.66	1.79%
25	Commodity Charge				$702.09				$702.09		$0.00	0.00%
26	Total				$1,101.00				$1,120.66		$19.66	1.79%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES				PROPOSED JANUARY 1, 2012 RATES				Annual Increase/(Decrease)		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.1 General Service**											
2												
3	Daily Charge											
4	Delivery Charge per month	365.25	days x	$0.9193	$335.7600	365.25	months x	$0.9847	$359.6520	$0.0654	$23.8920	0.62%
5	Rider 5 - RSAM per month	365.25	days x	$0.0022	$0.8036	365.25	months x	($0.0007)	($0.2557)	($0.0029)	($1.0592)	-0.03%
6	Gas Cost Recovery Charge per month	365.25	days x	$0.3300	$120.5325	365.25	months x	$0.3300	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.2515	$457.1000			$1.3140	$479.9300	$0.0625	$22.8300	0.59%
8												
9	Next 298 Gigajoules in any month											
10	Delivery Charge per GJ	436	GJ x	$2.710	$1,181.5600	436	GJ x	$2.891	$1,260.4760	$0.181	$78.9160	2.06%
11	Rider 5 - RSAM per GJ	436	GJ x	$0.033	$14.3880	436	GJ x	($0.011)	($4.7960)	($0.044)	($19.1840)	-0.50%
12	Gas Cost Recovery Charge per GJ	436	GJ x	$5.015	$2,186.5400	436	GJ x	$5.015	$2,186.5400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.758	$3,382.4900			$7.895	$3,442.2200	$0.137	$59.7300	1.56%
14												
15	Excess of 300 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.624	$0.0000	0	GJ x	$2.800	$0.0000	$0.176	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	$0.033	$0.0000	0	GJ x	($0.011)	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.672	$0.0000			$7.804	$0.0000	$0.132	$0.0000	0.00%
20												
21	Total	460	GJ		$3,839.59	460	GJ		$3,922.15		$82.56	2.15%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$1,532.51				$1,615.08		$82.56	2.15%
25	Commodity Charge				$2,307.07				$2,307.07		$0.00	0.00%
26	Total				$3,839.58				$3,922.15		$82.57	2.15%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES			PROPOSED JANUARY 1, 2012 RATES			Annual Increase/(Decrease)		
1	**Rate 2.2 General Service**	Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2										
3	Daily Charge									
4	Delivery Charge per day	365.25 days x	$0.9193 =	$335.7600	365.25 days x	$0.9847 =	$359.6520	$0.0654	$23.8920	0.10%
5	Rider 5 - RSAM per day	365.25 days x	$0.0022 =	$0.8036	365.25 days x	($0.0007) =	-$0.2557	($0.0029)	-$1.0592	0.00%
6	Gas Cost Recovery Charge per day	365.25 days x	$0.3300 =	$120.5325	365.25 days x	$0.3300 =	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)		$1.2515	$457.1000		$1.3140	$479.9300	$0.0625	$22.8300	0.09%
8										
9	Next 298 Gigajoules in any month									
10	Delivery Charge per GJ	3,076 GJ x	$2.710 =	$8,335.9600	3,076 GJ x	$2.891 =	$8,892.7160	$0.181	$556.7560	2.29%
11	Rider 5 - RSAM per GJ	3,076 GJ x	$0.033 =	$101.5080	3,076 GJ x	($0.011) =	($33.8360)	($0.044)	($135.3440)	-0.56%
12	Gas Cost Recovery Charge per GJ	3,076 GJ x	$5.015 =	$15,426.1400	3,076 GJ x	$5.015 =	$15,426.1400	$0.000	$0.0000	0.00%
13	Total Charges per GJ		$7.758	$23,863.6100		$7.895	$24,285.0200	$0.137	$421.4100	1.73%
14										
15	Excess of 300 Gigajoules in any month									
16	Delivery Charge per GJ	0 GJ x	$2.624 =	$0.0000	0 GJ x	$2.800 =	$0.0000	$0.176	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0 GJ x	$0.033 =	$0.0000	0 GJ x	($0.011) =	$0.0000	($0.044)	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0 GJ x	$5.015 =	$0.0000	0 GJ x	$5.015 =	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ		$7.672	$0.0000		$7.804	$0.0000	$0.132	$0.0000	0.00%
20										
21	Total	3,100 GJ		$24,320.71	3,100 GJ		$24,764.95		$444.24	1.83%
22										
23	Summary of Annual Delivery and Commodity Charges									
24	Delivery Charge (including RSAM)			$8,774.03			$9,218.28		$444.24	1.83%
25	Commodity Charge			$15,546.67			$15,546.67		$0.00	0.00%
26	Total			$24,320.70			$24,764.95		$444.25	1.83%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11

RATE 25 - TRANSPORTATION SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES						PROPOSED JANUARY 1, 2012 RATES						Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2																
3	Transportation Delivery Charges															
4																
5	Delivery Charge per Gigajoule															
6	i) First 20 Gigajoules	240	GJ x	$2.910	=	$698.4000		240	GJ x	$2.910	=	$698.4000		$0.000	$0.0000	0.00%
7	ii) Next 260 Gigajoules	3,120	GJ x	$2.690	=	$8,392.8000		3,120	GJ x	$2.926	=	$9,129.1200		0.236	$736.3200	3.79%
8	iii) Excess over 280 Gigajoules	3,530	GJ x	$2.174	=	$7,674.2200		3,530	GJ x	$2.333	=	$8,235.4900		0.159	$561.2700	2.89%
9	iv) Minimum Delivery Charge per month	12	months x	$1,826.00				12	months x	$1,945.00				$119.00	$0.0000	0.00%
10																
11	Administration Charge per month	12	months x	$202.00	=	$2,424.0000		12	months x	$202.00	=	$2,424.0000		$0.00	$0.0000	0.00%
12																
13	Rider 5: RSAM per GJ	6,890	GJ x	$0.033	=	$227.3700		6,890	GJ x	($0.011)	=	($75.7900)		($0.044)	($303.1600)	-1.56%
14																
15	Total Transportation Delivery & Administration Charges	6,890	GJ x	*$2.818*		$19,416.79		6,890	GJ x	*$2.962*		$20,411.22		*$0.144*	$994.43	5.12%
16																
17																
18	Summary of Annual Delivery, Administration and Commodity Charges															
19	Delivery & Administration Charge (including RSAM)	6,890	GJ x	$2.818	=	$19,416.7900		6,890	GJ x	$2.962	=	$20,411.2200		$0.144	$994.4300	5.12%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ	$0.000	=	$0.0000		0	GJ	$0.000	=	$0.0000		0.000	$0.0000	0.00%
21	Total	6,890	GJ x	*$2.818*	=	$19,416.79		6,890	GJ x	*$2.962*	=	$20,411.22		*$0.144*	$994.43	5.12%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	PROPOSED RATE JANUARY 1, 2012	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3340	$0.0055	$0.3394
10			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
12			**Minimum Daily Charge** (includes first 2 gigajoules/month)	**$0.663**	$0.005	**$0.668**
13						
14			Delivery Charge per GJ	$2.570	$0.042	$2.612
15			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
16			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
17			**Next 28 Gigajoules in any month**	**$7.574**	$0.042	**$7.616**
18						
19			Delivery Charge per GJ	$2.502	($0.001)	$2.501
20			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
21			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
22			**Excess of 30 Gigajoules in any month**	**$7.506**	($0.001)	**$7.505**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3340	$0.0055	$0.3394
28			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
30			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$0.663**	$0.005	**$0.668**
31						
32			Delivery Charge per GJ	$2.570	$0.042	$2.612
33			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
34			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
35			**Next 28 Gigajoules in any month**	**$7.574**	$0.042	**$7.616**
36						
37			Delivery Charge per GJ	$2.502	($0.001)	$2.501
38			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
39			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
40			**Excess of 30 Gigajoules in any month**	**$7.506**	($0.001)	**$7.505**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	PROPOSED RATE JANUARY 1, 2012	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9847	$0.0159	$1.0005
2			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.0000	($0.0007)
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
4			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.314**	$0.016	**$1.330**
5						
6			Delivery Charge per GJ	$2.891	$0.043	$2.934
7			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
8			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
9			**Next 28 Gigajoules in any month**	**$7.895**	$0.043	**$7.938**
10						
11			Delivery Charge per GJ	$2.800	$0.029	$2.829
12			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
13			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
14			**Excess of 30 Gigajoules in any month**	**$7.804**	$0.029	**$7.833**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9847	$0.0159	$1.0005
17			Revenue Stabilization Adjustment Amount per Day	($0.0007)	$0.00	($0.0007)
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.330	$0.000	$0.330
19			**Minimum Daily Charge (includes first 2 gigajoules/month)**	**$1.314**	$0.016	**$1.330**
20						
21			Delivery Charge per GJ	$2.891	$0.043	$2.934
22			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
23			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
24			**Next 28 Gigajoules in any month**	**$7.895**	$0.043	**$7.938**
25						
26			Delivery Charge per GJ	$2.800	$0.029	$2.829
27			Revenue Stabilization Adjustment Amount per GJ	($0.011)	$0.000	($0.011)
28			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
29			**Excess of 30 Gigajoules in any month**	**$7.804**	$0.029	**$7.833**
30						
31	Rate 2.3	No. 2.1	Delivery Charge per Month	$29.91	$2.44	$32.35
32			Gas Cost Recovery Charge per Month	$10.030	$0.00	$10.030
33			**Minimum Monthly Charge** (includes first 2 gigajoules)	**$39.937**	$2.443	**$42.380**
34						
35			Delivery Charge per GJ	$3.675	$0.300	$3.975
36			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
37			**Next 28 Gigajoules in any month**	**$8.690**	$0.300	**$8.990**
38						
39			Delivery Charge per GJ	$3.581	$0.293	$3.874
40			Gas Cost Recovery Charge per GJ	$5.015	$0.000	$5.015
41			**Excess of 30 Gigajoules in any month**	**$8.596**	$0.293	**$8.889**

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	PROPOSED RATE JANUARY 1, 2012	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2013
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
4			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
5			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
8			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
9						
10			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
16			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
17			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
20			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
21						
22			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$2.910	($0.111)	$2.799
28			Next 260 Gigajoules in any month	$2.926	($0.111)	$2.815
29			Excess over 280 Gigajoules in any month	$2.333	($0.071)	$2.262
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	($0.011)	$0.000	($0.011)
32			Gas Cost Recovery Charge per Gigajoule	$5.015	$0.000	$5.015
33						
34			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00

Note: Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to a daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
EFFECTIVEJANUARY 1, 2013 RATES
BCUC ORDER NO. G-XXX-11

Line No.	Schedule	Tariff Page	Particulars	JANUARY 1, 2012 PROPOSED RATES	Delivery Related Changes	JANUARY 1, 2013 EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.910	$0.000	$2.910
4			Next 260 Gigajoules in any month	$2.926	$0.000	$2.926
5			Excess over 280 Gigajoules in any month	$2.333	$0.040	$2.373
6						
7			Minimum Monthly Delivery Charge	$1,945.00	$30.00	$1,975.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	($0.011)	$0.000	($0.011)

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/(Decrease)		
1	**Rate 1 Domestic Service Option B**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Daily Charge											
4	Delivery Charge per day	365.25	days x	$0.3340	$121.9800	365.25	days x	$0.3394	$123.9840	$0.0055	$2.0040	0.18%
5	Rider 5 - RSAM per day	365.25	days x	($0.0007)	-$0.2557	365.25	days x	($0.0007)	-$0.2557	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per Day	365.25	days x	$0.3295	$120.3499	365.25	days x	$0.3295	$120.3499	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$0.6628	$242.0700			$0.6682	$244.0800	$0.0055	$2.0100	0.18%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$2.570	$298.1200	116	GJ x	$2.612	$302.9920	$0.042	$4.8720	0.43%
11	Rider 5 - RSAM per GJ	116	GJ x	($0.011)	($1.2760)	116	GJ x	($0.011)	($1.2760)	$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	116	GJ x	$5.015	$581.7400	116	GJ x	$5.015	$581.7400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.574	$878.5800			$7.616	$883.4600	$0.042	$4.8800	0.44%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.502	$0.0000	0	GJ x	$2.501	$0.0000	($0.001)	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	$0.0000	0	GJ x	($0.011)	$0.0000	$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.506	$0.0000			$7.505	$0.0000	($0.001)	$0.0000	0.00%
20												
21	Total	140	GJ		$1,120.65	140	GJ		$1,127.54		$6.89	0.61%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$418.57				$425.44		$6.88	0.61%
25	Commodity Charge				$702.09				$702.09		$0.00	0.00%
26	Total				$1,120.66				$1,127.53		$6.87	0.61%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES				PROPOSED JANUARY 1, 2013 RATES				Annual Increase/(Decrease)		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.1 General Service**											
2												
3	Daily Charge											
4	Delivery Charge per month	365.25	days x	$0.9847	$359.6520	365.25	months x	$1.0005	$365.4480	$0.0159	$5.7960	0.15%
5	Rider 5 - RSAM per month	365.25	days x	($0.0007)	($0.2557)	365.25	months x	($0.0007)	($0.2557)	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per month	365.25	days x	$0.3300	$120.5325	365.25	months x	$0.3300	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.3140	$479.9300			$1.3298	$485.7200	$0.0159	$5.7900	0.15%
8												
9	Next 298 Gigajoules in any month											
10	Delivery Charge per GJ	436	GJ x	$2.891	$1,260.4760	436	GJ x	$2.934	$1,279.2240	$0.043	$18.7480	0.48%
11	Rider 5 - RSAM per GJ	436	GJ x	($0.011)	-$4.7960	436	GJ x	($0.011)	($4.7960)	$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	436	GJ x	$5.015	$2,186.5400	436	GJ x	$5.015	$2,186.5400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.895	$3,442.2200			$7.938	$3,460.9700	$0.043	$18.7500	0.48%
14												
15	Excess of 300 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.800	$0.0000	0	GJ x	$2.829	$0.0000	$0.029	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	$0.0000	0	GJ x	($0.011)	$0.0000	$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	$0.0000	0	GJ x	$5.015	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.804	$0.0000			$7.833	$0.0000	$0.029	$0.0000	0.00%
20												
21	Total	460	GJ		$3,922.15	460	GJ		$3,946.69		$24.54	0.63%
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$1,615.08				$1,639.62		$24.54	0.63%
25	Commodity Charge				$2,307.07				$2,307.07		$0.00	0.00%
26	Total				$3,922.15				$3,946.69		$24.54	0.63%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11 AND G-XXX-11

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES					PROPOSED JANUARY 1, 2013 RATES					Annual Increase/(Decrease)		
1	**Rate 2.2 General Service**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2														
3	Daily Charge													
4	Delivery Charge per day	365.25	days x	$0.9847	=	$359.6520	365.25	days x	$1.0005	=	$365.4480	$0.0159	$5.7960	0.02%
5	Rider 5 - RSAM per day	365.25	days x	($0.0007)	=	($0.2557)	365.25	days x	($0.0007)	=	-$0.2557	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge per day	365.25	days x	$0.3300	=	$120.5325	365.25	days x	$0.3300	=	$120.5325	$0.0000	$0.0000	0.00%
7	Minimum Daily Charge (includes the first 2 GJs/month)			$1.3140		$479.9300			$1.3298		$485.7200	$0.0159	$5.7900	0.02%
8														
9	Next 298 Gigajoules in any month													
10	Delivery Charge per GJ	3,076	GJ x	$2.891	=	$8,892.7160	3,076	GJ x	$2.934	=	$9,024.9840	$0.043	$132.2680	0.53%
11	Rider 5 - RSAM per GJ	3,076	GJ x	($0.011)	=	($33.8360)	3,076	GJ x	($0.011)	=	($33.8360)	$0.000	$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	3,076	GJ x	$5.015	=	$15,426.1400	3,076	GJ x	$5.015	=	$15,426.1400	$0.000	$0.0000	0.00%
13	Total Charges per GJ			$7.895		$24,285.0200			$7.938		$24,417.2900	$0.043	$132.2700	0.53%
14														
15	Excess of 300 Gigajoules in any month													
16	Delivery Charge per GJ	0	GJ x	$2.800	=	$0.0000	0	GJ x	$2.829	=	$0.0000	$0.029	$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	($0.011)	=	$0.0000	0	GJ x	($0.011)	=	$0.0000	$0.000	$0.0000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	$5.015	=	$0.0000	0	GJ x	$5.015	=	$0.0000	$0.000	$0.0000	0.00%
19	Total Charges per GJ			$7.804		$0.0000			$7.833		$0.0000	$0.029	$0.0000	0.00%
20														
21	Total	3,100	GJ			$24,764.95	3,100	GJ			$24,903.01		$138.06	0.56%
22														
23	Summary of Annual Delivery and Commodity Charges													
24	Delivery Charge (including RSAM)					$9,218.28					$9,356.34		$138.06	0.56%
25	Commodity Charge					$15,546.67					$15,546.67		$0.00	0.00%
26	Total					$24,764.95					$24,903.01		$138.06	0.56%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XXX-11

RATE 25 - TRANSPORTATION SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES							PROPOSED JANUARY 1, 2013 RATES							Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume			Rate		Annual $		Volume			Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
2																		
3	Transportation Delivery Charges																	
4																		
5	Delivery Charge per Gigajoule																	
6	i) First 20 Gigajoules	240	GJ	x	$2.910	=	$698.4000		240	GJ	x	$2.910	=	$698.4000		$0.000	$0.0000	0.00%
7	ii) Next 260 Gigajoules	3,120	GJ	x	$2.926	=	$9,129.1200		3,120	GJ	x	$2.926	=	$9,129.1200		0.000	$0.0000	0.00%
8	iii) Excess over 280 Gigajoules	3,530	GJ	x	$2.333	=	$8,235.4900		3,530	GJ	x	$2.373	=	$8,376.6900		0.040	$141.2000	0.69%
9	iv) Minimum Delivery Charge per month	12	months	x	$1,945.00				12	months	x	$1,975.00				$30.00	$0.0000	0.00%
10																		
11	Administration Charge per month	12	months	x	$202.00	=	$2,424.0000		12	months	x	$202.00	=	$2,424.0000		$0.00	$0.0000	0.00%
12																		
13	Rider 5: RSAM per GJ	6,890	GJ	x	($0.011)	=	($75.7900)		6,890	GJ	x	($0.011)	=	($75.7900)		$0.000	$0.0000	0.00%
14																		
15	Total Transportation Delivery & Administration Charges	6,890	GJ	x	*$2.962*		$20,411.22		6,890	GJ	x	*$2.983*		$20,552.42		*$0.021*	$141.20	0.69%
16																		
17																		
18	Summary of Annual Delivery, Administration and Commodity Charges																	
19	Delivery & Administration Charge (including RSAM)	6,890	GJ	x	$2.962	=	$20,411.2200		6,890	GJ	x	$2.983	=	$20,552.4200		$0.021	$141.2000	0.69%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ		$0.000	=	$0.0000		0	GJ		$0.000	=	$0.0000		0.000	$0.0000	0.00%
21	Total	6,890	GJ	x	*$2.962*	=	$20,411.22		6,890	GJ	x	*$2.983*	=	$20,552.42		*$0.021*	$141.20	0.69%

Notes: Tariff rate schedule per GJ charges are set at 3 decimals. Individual tariff components are calculated and shown to 4 decimals; subtotal amounts, equivalent to the line items on customer bills, are rounded and shown to 2 decimals, consistent with actual invoice calculations. Slight differences in totals due to rounding. Where applicable, existing monthly January 1, 2011 basic charge rates are prorated to daily equivalent for comparison purposes.