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British Columbia Utilities Commission 6<sup>th</sup> 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
Vol	UME 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
Vol	UME 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

#### FORTISBC ENERGY UTILITIES





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

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 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:

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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.

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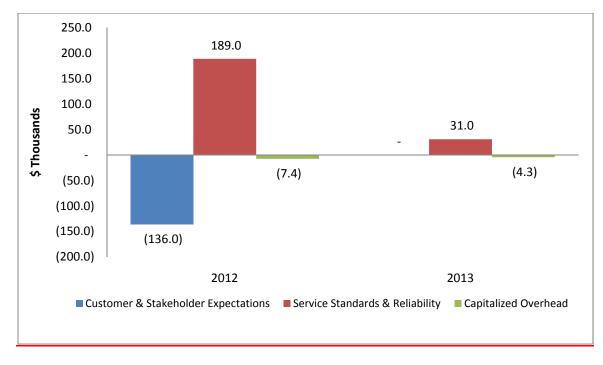


Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements<sup>46</sup>

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.

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

			2013	
				Cost of
\$ thousands)	Reference	Total	Cost of Gas	Service <sup>1</sup>
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 Servi	ce & Rate Base	(2,158)	-	(2,158
FEW Transportation	n Charge	(2,585)	-	(2,585
Squamish Transpor	tation Charge	 (416)	(416)	-
Total Amalgamation	Adjustments	(5,159)	(12,440)	7,281
Amalgamated FEU Co	ost of Service	\$ 1,508,865	\$ 728,927	\$ 779,938
<sup>1</sup> Cost of service exclu	uding 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 <u>FEW</u> but as a revenue <u>FEVI</u>; 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.

#### Deleted: and tax expense

**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	Regulations	Customer & Stakeholder Expectations	Demographics	Service Standards & Reliability	Total Incremental	Total Forecast
2012 2013	6,134 6,755	(41) -	62 63	(92) 45	-		693 201	621 308	6,755 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:

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(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	2010		2011		2011		2012		2013
	Ap	proved	Actual	Αp	proved	Pr	ojection	F	orecast	F	orecast
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

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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

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Section 7 TAB 7.5 Schedule 1

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No.	Particulars	FEI	FEVI	F	FEW	F	N	Total	Ad	justments	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	2,900	\$ 740,068	\$	(12,440) 1 \$	727,627	
2	GCVA Amortization	 -	(8,124)		-		-	(8,124)		<u> </u>	(8,124)	- Sect 7-TAB 7.5, Schedule 7
3 4	Net Cost of Gas	659,338	66,213		3,493	:	2,900	731,944		(12,440)	719,503	
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) <sup>2</sup>	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) <sup>3</sup>	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 <sup>5</sup>	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			•									

- 1 FEI LNG Mitigation to FEVI (\$12) MM, FEVI Squamish Wheeling from FEI (\$0.4) MM
- 2 FEVI Wheeling (\$3.5) MM to FEI, FEW Wheeling (\$2.5) MM to FEVI
- 3 FEVI amortization of Whistler Contribution \$0.25 MM offset by FEW amortization of Contribution deferral (\$0.29) MM
- 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
- 5 Change in Rate Base impact on Income Taxes
- 6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes

Section 7 TAB 7.5 Schedule 2

Line
No.

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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) <sup>1</sup> \$	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 <sup>4</sup>	(26,074)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	30,160	7,440	542	55	38,197	10 <sup>5</sup>	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									

- 1 FEI LNG Mitigation to FEVI (\$12) MM, FEVI Squamish Wheeling from FEI (\$0.4) MM
- 2 FEVI Wheeling (\$3.5) MM to FEI, FEW Wheeling (\$2.5) MM to FEVI
- 3 FEVI amortization of Whistler Contribution \$0.25 MM offset by FEW amortization of Contribution deferral (\$0.29) MM
- 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
- 5 Change in Rate Base impact on Income Taxes
- 6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes

Section 7 TAB 7.5 Schedule 3

Line

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Line	Particulara	FEI	FEVI	FEW	FN	Total	٨٨	iuatmonta	FEU	Cross Reference
No.	Particulars (1)					Total	Ad	justments		
	(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	\$ (432,176)	- Sect 7-TAB 7.5, Schedule 34
14	Adjustment - Opening Bal Adjt	-	2,484	-	-	2,484		(2,484)	-	
15	CIAC, Ending	(183,107)	(254,306)	(186)	(1,287)	(438,886)		14,550 <sup>1</sup>	(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) <sup>1</sup>	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 <sup>3</sup>	(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

<sup>1</sup> FEVI CIAC - Pipeline Contribution from FEW

<sup>2</sup> FEW's contribution deferral to FEVI for pipeline

<sup>3</sup> Applying FEI Lead/Lag days to FEVI and FEW expense/revenue

Section 7 TAB 7.5

Schedule 4

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No.	Particulars		FEI		FEVI	F	EW	F	=N		Total	Ad	justments		FEU	Cross Refe	erence
	(1)		(2)		(3)		(4)	(	(5)		(6)		(7)		(8)	(9)	
1	Gas Plant in Service, Beginning	\$	3,770,188	\$	1,317,524	\$	17,203	\$ 12	2,525	\$	5,117,440			\$	5,117,445	- Sect 7-TAB 7.5, S	Schedule 25
2	Adjustment - CPCNs / Opening Bal Adjt		-		-		-		-		-				-		
3	Gas Plant in Service, Ending		3,904,928		1,344,362		17,637	1:	2,919		5,279,846				5,279,855	- Sect 7-TAB 7.5, S	Schedule 25
4																	
5	Accumulated Depreciation Beginning - Plant	\$	(1,014,039)	\$	(318,482)	\$	(2,933)	\$ (2	2,718)	\$	(1,338,172)			\$	(1,338,167)	- Sect 7-TAB 7.5, S	Schedule 31
6	Adjustment - CPCNs / Opening Bal Adjt		-		-		-		-		-				-		
7 8	Accumulated Depreciation Ending - Plant		(1,105,609)		(346,979)		(3,200)	(;	3,076)		(1,458,864)				(1,458,860)	- Sect 7-TAB 7.5, S	Schedule 31
9	Negative Salvage Depreciation Beginning - Plant	\$	(7,994)	\$	(12,476)	\$	(74)	\$	_	\$	(20,544)			\$	(20 543)	- Sect 7-TAB 7.5, S	Schedule 33
10	Adjustment - CPCNs / Opening Bal Adjt	Ψ	(,,00.)	Ψ	-	Ψ	-	Ψ	_	٣	(=0,0 : 1)			Ψ	(20,0.0)	000(7 17.2 7.0, 0	30000.00
11	Negative Salvage Depreciation Ending - Plant		(11,805)		(15,874)		(150)		_		(27,829)				(27,825)	- Sect 7-TAB 7.5, S	Schedule 33
12			, , ,		, , ,		, ,				, , ,				, ,		
13	CIAC, Beginning	\$	(183,107)	\$	(254,306)	\$	(186)	\$ (	1,287)	\$	(438,886)	\$	14,550 <sup>1</sup>	\$	(424,337)	- Sect 7-TAB 7.5, S	Schedule 35
14	Adjustment - Opening Bal Adjt		-		-		-		-		-				-		
15	CIAC, Ending		(189,803)		(250,614)		(186)	(	1,287)		(441,890)		14,550 <sup>1</sup>		(427,341)	- Sect 7-TAB 7.5, S	Schedule 35
16																	
17	Accumulated Amortization Beginning - CIAC	\$	49,913	\$	63,319	\$	22	\$	490	\$	113,744	\$	(755) <sup>1</sup>	\$	112,986	- Sect 7-TAB 7.5, S	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, 8	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	9,028	\$	3,454,398	\$	13,669	\$	3,468,077		
24																	
25	Adjustment to 13-Month Average		-		-		-		-		<del>-</del>				-		
26	Work in Progress, No AFUDC		17,110		2,285		23		-		19,418				19,418		
27	Unamortized Deferred Charges		38,574		3,891	2	26,703		82		69,250		(13,435) 2			- Sect 7-TAB 7.5, S	
28	Cash Working Capital		(1,963)		476		61		12		(1,414)		328 <sup>3</sup>		,	- Sect 7-TAB 7.5, S	
29	Other Working Capital		101,622		10,436		635		4		112,697				*	- Sect 7-TAB 7.5, S	
30	Future Income Taxes Regulatory Asset		282,359		76,663		2,319		-		361,341					- Sect 7-TAB 7.5, S	
31	Future Income Taxes Regulatory Liability		(282,359)		(76,663)		(2,319)		-		(361,341)				, , ,	- Sect 7-TAB 7.5, S	Schedule 43
32	LILO Benefit	_	(1,316)		-		-		-		(1,316)				(1,316)		
33	Utility Rate Base	\$	2,788,327	\$	814,078	\$ 4	41,502	\$ 9	9,126	\$	3,653,033	\$	562	\$	3,653,604	- Sect 7-TAB 7.5, S	Schedule 45
34																	

<sup>1</sup> FEVI CIAC - Pipeline Contribution from FEW

<sup>2</sup> FEW's contribution deferral to FEVI for pipeline

<sup>3</sup> 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

2 Impact of Rate Base Change \$0.04 MM, Impact of rounding Weighted Average ROE to 2 decimals \$0.05 MM

Section 7 TAB 7.5 Schedule 5

Line

25

(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, S	chedule 18
1 Rate Base \$ 2,736,507 \$ 787,864 \$ 42,139 \$ 8,889 \$ 3,575,399 \$ 897 \$ 3,576,297 - Sect 7-TAB 7.5, S	chedule 18
2	
3 Equity Thickness 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00%	chedule 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, S	chedule 44
5 ROE9.50% 10.00% 10.00% 9.50% 9.62% 19.62% - Sect 7-TAB 7.5, S	chedule 44
6 Equity Earned Return 103,987 31,515 1,686 338 137,525 91 2 137,616 - Sect 7-TAB 7.5, S	chedule 44
7	
8 Long Term Debt % of Capital Structure <u>57.82% 46.39% 47.46% 57.30% 55.18%</u> <u>55.22%</u> - Sect 7-TAB 7.5, S	
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, S	
10 Average Rate <u>6.73% 5.75% 5.11% 6.73% 6.53%</u> <u>6.53%</u> - <u>6.54%</u> - Sect 7-TAB 7.5, S	chedule 44
11 LTD Earned Return 106,548 21,003 1,022 343 128,916 233 129,149 - Sect 7-TAB 7.5, S	chedule 44
12	
13 Short Term Debt % of Capital Structure 2.18% 13.61% 12.54% 2.69% 4.82% 4.82% 4.78% - Sect 7-TAB 7.5, S	chedule 44
14 Short Term Debt 59,787 107,192 5,283 239 172,501 (1,395) 171,106 - Sect 7-TAB 7.5, S	chedule 44
15 Average Rate 2.75% 4.25% 3.75% 2.93% 3.71% 2.75% - Sect 7-TAB 7.5, S	chedule 44
16 STD Earned Return 1,644 4,556 198 7 6,405 (1,700) 4,705 - Sect 7-TAB 7.5, S	chedule 44
17	
18 Total Earned Return \$\frac{12,179}{57,074}\$ \frac{2,906}{57,074}\$ \frac{688}{272,846}\$ \frac{1,376}{572,846}\$ - Sect 7-TAB 7.5, S	chedule 44
19	
20 Notes	
21 1 Calculation of Weigted Average ROE	
22 Total Equity Return 137,525 (Line 6, Column 6)	
Eguity Portion of Rate Base 1,430,160 (Line 4, Column 6)	
24 Weighted Average ROE 9.62% (Line 22 / Line 23)	

2 Impact of Rate Base Change \$0.02 MM, Impact of rounding Weighted Average ROE to 2 decimals \$0.04 MM

Section 7 TAB 7.5 Schedule 6

Line

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No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1 2	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
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	140,591	- Sect 7-TAB 7.5, Schedule 45
7		-							
8	Long Term Debt % of Capital Structure	56.76%	42.99%		56.25%	53.59%			
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		N	otes						
21		_		Weigted Ave	rage ROE				
22				ity Return		140,526	(Line 6, Colum	n 6)	
23				rtion of Rate	Base	1,461,213	(Line 4, Colum	,	
24				l Average RC	-	9.62%	(Line 22 / Line	,	
			5.9			0.0270	(=:::: == / =:::0	,	

Section 7 TAB 7.5 Schedule 7

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

Line		2012	2013		
No.	Particulars	FORECAST	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)	<u> </u>	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	

Section 7 TAB 7.5 Schedule 8

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

Line			2012		2013					
No.	Particulars	FO	RECAST	FO	FORECAST		hange	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		

FortisBC Energy Utilities

May 16, 2011

Section 7 TAB 7.5 Schedule 9

## OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013

(\$000)

Lina	(4000)		2012	2013	
Line No.	Particulars	FΩ	RECAST	RECAST	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

Section 7 TAB 7.5

Schedule 10

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

Line **BCUC** 2012 2013 **FORECAST FORECAST** Cross Reference No. **Particulars** Reference (1) (2)(5)1 Distribution Supervision 100-11 \$ 13,305 \$ 13,825 2 3 Operation Centre - Distribution 100-21 12,743 13,443 4,587 Asset Management - Distribution 100-22 3,259 Preventative Maintenance - Distribution 100-23 3,202 3,483 5 Distribution Operations - General 100-24 7,003 7,355 6 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 Distribution Corrective - Leak Repair 100-33 1,374 1.415 Distribution Corrective - Stations 100-34 773 793 14 Distribution Corrective - General 100-35 638 987 15 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 Right of Way 200-22 730 808 23 24 Compression 200-23 2.171 2,239 25 Gas Control 200-24 2,848 3,000 Transmission Pipeline Integrity Project (TPIP) 26 200-25 2,611 2,797 27 Transmission Operations Total 200-20 11,983 12,610 28 Pipeline - Maintenance 200-31 2,830 2,684 30 Compression - Maintenance 200-32 1,624 1,764 TPIP - Maintenance 31 200-33 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 2,937 797 37 LNG Plant Maintenance 300-21 824 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 43 400 **Measurement Total** 7,491 7,861

## OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)

OF ENTITION A NUMBER OF THE PROPERTY OF THE PR
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
(\$000)

Line	(\$000)	BCUC	2012	2013	
No.	Particulars	Reference	FORECAST	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	240000 4 001.11000 1044.				
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	900-30	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		500			
41	Total Gross O&M Expenses		261,127	273,766	
42	. ota. Grood Odin Experiees		201,127	210,100	
43	Less: Capitalized Overhood		(26 EE0)	(20 227)	
43	Less: Capitalized Overhead		(36,558)	(38,327)	
44	Total O&M Expenses		\$ 224,569	\$ 235,438	- Sect 7-TAB 7.5, Schedule 7
46				,	

Section 7

Schedule 11

TAB 7.5

#### FortisBC Energy Utilities

May 16, 2011 Section 7 TAB 7.5 Schedule 12

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

Line No.	Particulars (1)	2012 RECAST (2)	2013 RECAST (3)	 Change (4)	Cross Reference (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			2012		2013			
No.	Particulars	FC	DRECAST	FC	DRECAST	C	Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
4	Depreciation & Removal Provision							
0	Depreciation & Removal Provision							
2	Degraciation Function	Φ	150,000	Φ	150 400	Φ	0.000	Cook 7 TAD 7 F. Cobodula 00 0 01
3	Depreciation Expense	\$	152,890	\$	159,498	\$	6,608	- Sect 7-TAB 7.5, Schedule 28 & 31
4			(,,,,,,,,)		( ===)			0
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			- 70 - 0		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,			
17	TOTAL	\$	171,197	\$	191,565	\$	20,368	- Sect 7-TAB 7.5, Schedule 7

Schedule 13

FortisBC Energy Utilities May 16, 2011

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

Section 7
TAB 7.5
Schedule 14

Line		2012	2013		
No.	Particulars	FORECAST	<b>FORECAST</b>	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

FortisBC Energy Utilities May 16, 2011

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

Line No.	Particulars (1)	2012 FORECAST (2)	2013 FORECAST (3)	Change (4)	Cross Reference (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 Removal Costs	(16,752)	(17,517)	(765)	
22 23		(13,247)	(13,586)	(339) 464	
23 24	Major Inspection Costs Biomethane Other Revenue	(1,806) 62	(1,342) 29	-	
2 <del>4</del> 25	Diomethalie Other nevenue	62	29	(33)	
26	TOTAL	\$ (51,320)	\$ (25,970)	\$ 25,350	- Sect 7-TAB 7.5, Schedule 14

Section 7 TAB 7.5

Schedule 15

May 16, 2011

Section 7 **TAB** 7.5 Schedule 16

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

Line	Class	CCA Data	12/31/2011	A divistments	2012 Net	2012	12/31/2012
No.	Class	CCA Rate	UCC Balance	Adjustments	Additions	CCA (C)	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

Section 7 TAB 7.5 Schedule 17

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

Line			12/31/2012		2013 Net	2013	12/31/2013	
No.	Class	CCA Rate	UCC Balance	Adjustments	Additions	CCA	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, S	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 3	Opening Balance Adjustment Gas Plant in Service, Ending	- E 117 //E	- 5,279,855	- 162,410	- Sect 7-TAB 7.5, Schedule 22 & 25				
3 4	Gas Flant in Service, Ending	5,117,445	5,279,655	102,410	- Sect 7-1AB 7.5, Scriedule 22 & 25				
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 8	Accumulated Depreciation Ending - Plant	(1,338,167)	(1,458,860)	(120,693)	- Sect 7-TAB 7.5, Schedule 28 & 31				
9	Negative Salvage Beginning	\$ -	\$ (20,543)	\$ (20,543)	- Sect 7-TAB 7.5, Schedule 32 & 33				
10	Opening Balance Adjustment	(13,597)	<del>-</del>	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	ψ (402,170)	ψ (+2+,557)	Ψ 7,009	- Sect 7-17D 7.5, Schedule 54 & 55				
15	CIAC, Ending	(424,337)	(427,341)	(3,004)	- Sect 7-TAB 7.5, Schedule 34 & 35				
16	, <b>3</b>	( , ,	( ,- ,	(-, ,	-,				
17	Accumulated Amortization Beginning - CIAC	\$ 107,884	\$ 112,986	\$ 5,102	- Sect 7-TAB 7.5, Schedule 34 & 35				
18	Opening Balance Adjustment	-	-	-					
19 20	Accumulated Amortization Ending - CIAC	112,986	122,940	9,954	- Sect 7-TAB 7.5, Schedule 34 & 35				
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				

Schedule 18

#### FortisBC Energy Utilities

May 16, 2011

Section 7

CAPITAL EXPENDITURES AND PLANT ADDITIONS FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013 (\$000) TAB 7.5 Schedule 19

Line No.	Particulars		2012 orecast		2013 Forecast	Cross Reference
110.	(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	Total Decider Conital Evenenditures	Φ	105.050	Φ	100.040	
8	Total Regular Capital Expenditures	\$	165,250	\$	160,648	
9	On said Decises OPONIs					
10	Special Projects - CPCN's Customer Care Enhancement		14.010			
11			14,916		-	
12	Kootenay River Xing		1,223		-	
13 14	Victoria Regional Office Total CPCN's	\$	4,782 20,921	Φ.	<del>-</del>	
	Total GPGINS	Φ	20,921	\$		
15						
16	TOTAL CARITAL EVENIDITURES	Φ	100 171	ф	100.040	
17	TOTAL CAPITAL EXPENDITURES	\$	186,171	\$	160,648	
18						
19	RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS					
20	RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS					
21 22	Degular Canital					
23	Regular Capital Regular Capital Expenditures	\$	165,250	Φ	160,648	
23 24	Add - Opening WIP	Ф	38,957	\$	38,957	
25	Less - Closing WIP		(38,957)		(38,957)	
26	Capital Vehicle Lease Addition		3,180		2,860	
20 27	Add - AFUDC		2,088		1,916	
28	Add - Overhead Capitalized		36,556		38,329	- Sect 7-TAB 7.5, Schedule 22 & 25
29	Add - Overnead Capitalized		30,330		30,329	- Sect 7-1AB 7.5, Schedule 22 & 25
30	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	\$	207,073	\$	203,753	
31	TO THE THE GOLD IN THE PRODUCTION OF GRAPH BY GETTINGE	Ψ	207,070	<u> </u>	200,700	
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			1,072			
40	TOTAL CPCN ADDITIONS	\$	104,589	\$	-	- Sect 7-TAB 7.5, Schedule 22 & 25
41		Ψ	10 1,000	Ψ		2001
42	TOTAL PLANT ADDITIONS	\$	311,662	\$	203,753	
<b>-7</b>	TOTAL LINE ADDITIONS	Ψ	311,002	Ψ	200,700	

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

Line No.	Particulars	Balance 12/31/2011	СР	'CN'S		112 itions		2012 .FUDC		2012 CapOH	Reti	rements		ansfers/ ecovery		lance 31/2012	,	rear GPIS epreciation
	(1)	(2)		(3)	(4	4)		(5)		(6)	(7)		(8)		(9)		(10)	
	INTANOIDI E DI ANT																	
1	INTANGIBLE PLANT	Φ.	•		Φ.		Φ.		•		Φ.		Φ.		•		•	
2	, , ,	\$ -	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
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	-	2,325		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
26 27				-		-		-		-		-		-				
	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309		-		-		-		-		-		-		309		309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-		-		-		-		-		-		-				7.004
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	C	PCN'S	012 ditions	2012 AFUDC		2012 CapOH	Retirements		ansfers/ ecovery	Balance 12/31/2012		year GPIS epreciation
	(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	9	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	22	3	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	3:	2	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	1,25	4	11,639		(2,093)	 -	 1,516,297		1,492,212
22				.,	,	-,,		,		(=,000)		 .,		<u>.,,</u>
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	10,134		_	_	_		_		_	_	10,134		10,134
28	473-00 Services	869,678		_	22,878	_		7,255		(3,109)	_	896,702		883,190
29	473-00 Services - LILO	43,024		_	-	_		7,200		(0,100)	_	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				_		-		(1,700)		16,070		16,070
32	477-00 Meters/Regulators Installations	10,070		_	11,944	_		3,857		_	_	15,801		7,901
33	475-00 Mains	1,190,478			31,791	17	7	10,028		(2,963)		1,229,511		1,209,995
34	475-00 Mains - LILO	39,717		-	31,791	17	,	10,020		(2,903)	-	39,717		39,717
35		1,026		-				-		-	-	,		,
36	476-00 Compressor Equipment	97,304		-	3,305	13	n	1,107		(571)	-	1,026 101,284		1,026 99,294
36 37	477-00 Measuring & Regulating Equipment	97,304 6,617		-	,		9 5	,		٠,	-	,		,
38	477-00 Telemetering	163		-	750	•	5	249		(120)	-	7,501		7,059 163
39	477-10 Measuring & Regulating Equipment - Byron Creek			-	10 100	-		-		- (4.270)	-	163		
	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			<del></del>		-		- 00 501		(10.010)	 <del></del>	 		
43	TOTAL DISTRIBUTION	2,698,625			83,154	32	1	22,581		(12,916)	 	 2,791,765		2,745,195
44	DIG 040													
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)

Section 7 TAB 7.5 Schedule 22

Line No.	Particulars	Balance 12/31/20	<u> 11                                   </u>	CPCN'S		2012 dditions	AF	2012 FUDC	(	2012 CapOH	Retir	rements		ansfers/ ecovery		alance 31/2012		year GPIS epreciation
	(1)	(2)		(3)		(4)		(5)		(6)		(7)		(8)		(9)		(10)
1	Natural Gas for Transportation																	
2	476-10 NG Transportation CNG Dispensing Equipment	\$ 2.0	40	\$ -	\$	1,540	\$	-	\$	536	\$	-	\$	-	\$	4,116	\$	3,078
3	476-20 NG Transportation LNG Dispensing Equipment	1,7	37	-		1,180		-		411		-		-		3,328		2,533
4	476-30 NG Transportation CNG Foundations	. 4	50	-		340		-		118		-		-		908		679
5	476-40 NG Transportation LNG Foundations	3	83	-		260		-		91		-		-		734		559
6	476-50 NG Transportation LNG Pumps	8	24	-		560		-		195		-		-		1,579		1,202
7	476-60 NG Transportation CNG Dehydrator	1	59	-		120		-		42		-		-		321		240
8	476-70 NG Transportation LNG Dehydrator			-		-		-		-		-		-		-		-
9	TOTAL NG FOR TRANSP	5,5	93	-		4,000		-		1,393		-		-		10,986		8,290
10																		
11	GENERAL PLANT & EQUIPMENT																	
12	480-00 Land in Fee Simple	21,5	40	6,355		2,000		_		-		-		_		29,895		25,718
13	481-00 Land Rights	,-		-		-		_		-		-		_		-		-
14	482-00 Structures & Improvements			_		_		_		-		-		_		-		-
15	- Frame Buildings	12,1	10	_		_		_		_		-		_		12,110		12,110
16	- Masonry Buildings	87,5		15,752		4,471		_		_		-		_		107,781		97,670
17	- Leasehold Improvement	,	66	3,429		200		_		_		(313)		_		4,082		5,854
18	Office Equipment & Furniture			-,				_		_		-		_		-		-
19	483-30 GP Office Equipment	4,2	46	443		513		_		_		-		_		5,202		4,901
20	483-40 GP Furniture	19,8		2.829		1.571		_		_		(567)		_		23,680		23,250
21	483-10 GP Computer Hardware	23,6		3,533		8,000		206		_		(1,517)		_		33,899		30,647
22	483-20 GP Computer Software	2,2		-		-		-		_		(475)		_		1,736		1,974
23	483-21 GP Computer Software	_,_		_		_		_		_		-		_				-
24	483-22 GP Computer Software		51	_		_		_		_		_		_		51		51
25	484-00 Vehicles	7,4		_		3,398		_		_		(262)		_		10,546		8.978
26	484-00 Vehicles - Leased	28,4		_		3,180		_		_		(1,908)		_		29,753		29,117
27	485-10 Heavy Work Equipment	,	89	_		-		_		_		(1,000)		_		678		684
28	485-20 Heavy Mobile Equipment	2,2		_		360		_		_		- ( ,		_		2,651		2,471
29	486-00 Small Tools & Equipment	47,5		_		3.022		_		_		(1,207)		_		49,368		48,461
30	487-00 Equipment on Customer's Premises	-17,0	9	_				_		_		(1,207)		_		9		9
31	- VRA Compressor Installation Costs			_		_		_		_		_		_		_		-
32	488-00 Communications Equipment			_		_		_		_		_		_		_		_
33	- Telephone	8,4	04	_		115		_		_		(10)		_		8,509		8,457
34	- Radio	4,5		_		45		_		_		(7)		_		4,584		4,565
35	489-00 Other General Equipment	4,0	(2)	_		-		_		_		- (,,		_		(2)		(2)
36	TOTAL GENERAL	271,3		32,341		26,875		206				(6,277)				324,532		304,912
37	TOTAL GENERAL			32,341		20,073		200				(0,211)				324,332		304,312
38	UNCLASSIFIED PLANT																	
39	499 Plant Suspense																	
39 40	TOTAL UNCLASSIFIED																	
41	TOTAL UNGLASSIFIED																	
	TOTAL CAPITAL	¢ 4000 4	40	¢ 104 E00	Φ	160 400	Φ	0.000	φ	20 550	Φ.	'07 CCE\	Φ		φ -	117 445	φ.	- 014 011
42	TOTAL CAPITAL	\$ 4,833,4	40	\$ 104,589	Φ	100,429	Φ	2,088	Φ	36,556	Φ (	27,665)	\$	-	фЭ	,117,445	ф	5,014,011
43	Crees Deference	0	ND 7 5	Calaadula 40	,										0 -	7 TAP =	r C - 1	
44	Cross Reference	- Sect 7-17		Schedule 18		0.1	40								- Se	ct 7-TAB 7	.5, Sch	eaule 18
45				- Sect 7-TAE	7.5,	ocneaule	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	CF	PCN'S		013 ditions	ļ	2013 AFUDC		2013 apOH	Reti	rements		ansfers/ ecovery		ance 1/2013	,	ear GPIS
	(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	1,907		_		=		=		-		=		=		1,307		1,307
11	461-00 Transmission Land Rights	51,348		-		328		-		-		-		-		51,676		51,512
		,		-		320		-		-		-		-				
12	461-10 Transmission Land Rights - Byron Creek	15 24		-		-		-		-		-		-		15 24		15
13	461-13 IP Land Rights Whistler			-		-		-		-		-		-				24
14	471-00 Distribution Land Rights	3,184		-		-		-		-		-		-		3,184		3,184
15	471-10 Distribution Land Rights - Byron Creek	-		-		-		-		-		(0.750)		-				-
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 Equipmen	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 Hay	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)	-		-		-		-		-		-		-		´-		, <u>-</u>
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
	- :::= :::: ::::::= : :::=::===					.,555						\				, , , , <del>,</del> ,		

### 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 Additio		2013 AFUDC	2013 CapOH	Retiren	nents	Transfe Recove		Balance 12/31/2013		l-year GPIS 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	1	(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	6 (1	,968)		-	1,555,826		1,536,062
22				,		•	•	,	<del></del>			,		
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	1 (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	l	(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	7	_		-	32,403		24,102
33	475-00 Mains	1,229,511	-		920	213	12,168		,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	ı	(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	1	-		_	738		600
49	418-10 Bio Gas Purification Overhaul	815	_		513	_	-	•	_		_	1,328		1,072
50	418-20 Bio Gas Purification Upgrader	3,257	_		050	_	_		_		_	5,307		4,282
51	474-10 Bio Gas Reg & Meter Installations	2,228	_	,	406	_	148	3	-		_	2,782		2,505
52	478-30 Bio Gas Meters	446	_		406	_	-	-	_		_	852		649
53	TOTAL BIO-GAS	7,207			578		222	2	_				. —	9,107
53	TOTAL BIO-GAS	7,207		3,	578	-	222	2			<u> </u>	11,007		_

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

Section 7 TAB 7.5 Schedule 25

Line No.	B.C.U.C. Account	Balance 12/31/2012	CPCN'S		2013 Iditions	2013 AFUDC	(	2013 CapOH	Retire	ements	ansfers/ ecovery		alance 31/2013		year GPIS epreciation
	(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	_		_		- (0)	_		110,776		109,279
17	- Leasehold Improvement	4,082	_		130	_		_		(146)	_		4,066		4,074
18	Office Equipment & Furniture	-,002	_		-	_				(140)			-,000		-,07-
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		-		(1, <del>334)</del> (6,581)	-		35,524		34,712
		1,736	-		0,000	200	)	-			-		,		,
22	483-20 GP Computer Software	1,736	-		-	-		-		(211)	-		1,525		1,631
23	483-21 GP Computer Software		-		-	-		-		-	-				
24 25	483-22 GP Computer Software	51	-		- 0.040	-		-		- (4 400)	-		51		51
	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	-		-		- (4 057)	-		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	5	-	( '	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	\$ (4	11,343)	\$ 	\$ 5	,279,855	\$ !	5,198,650
43			-												
44	Cross Reference	- Sect 7-TAB 7	.5, Schedule	18								- Se	ct 7-TAB 7	.5, Sch	nedule 18
45			- Sect 7-TA		Schedule	19								,	

Section 7 TAB 7.5 Schedule 26

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

			Pro	ovision					
Line		 2012	Α	djust-			Accu	mulate	ed
No.	Account	(Cr.)	n	nents	Retire	ments	12/31/2011	12	2/31/2012
	(1)	 (2)		(3)	(4	ł)	(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)	- 1,170				(001)	0,100		0,001
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)	1,021				_	-		1,010
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
43	TO TAL IVIANOPACTORED	 1,201				(001)	20,030		31,304

Section 7 TAB 7.5 Schedule 27

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

				Р	rovision					
Line		-	2012	-	Adjust-			Accum	nulate	d
No.	Account		(Cr.)		ments	Reti	rements	12/31/2011	12	2/31/2012
	(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		- (0.070)		- (4.005)	1,742		1,916
8	465-00 Mains		16,691		(2,672)		(1,065)	303,997		316,951
9 10	465-00 Mains - INSPECTION		1,276 600		-		-	1,939 1,511		3,215
11	465-11 IP Transmission Pipeline - Whistler 465-30 Mt Hayes - Mains		93		-		-	1,511 54		2,111 147
12	•		93 49		-		-	889		938
13	465-10 Mains - Byron Creek 466-00 Compressor Equipment		5,027		(404)		(547)	60,620		64,696
14	466-00 Compressor Equipment - OVERHAUL		1,908		(404)		(347)	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		-		-		- (4.070)	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 42	478-20 Instruments		362		-		-	926		1,288
42	479-00 Other Distribution Equipment TOTAL DISTRIBUTION		78,995		(10,136)		(12,916)	660,046		715,989
43 44	TOTAL DISTRIBUTION		76,995		(10,136)		(12,910)	000,040		715,969
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         Account         (Cr.)           No.         Account         (Cr.)           (1)         (2)           1         Natural Gas for Transportation         (1)           2         476-10 NG Transportation CNG Dispensing Equipment         \$154           3         476-20 NG Transportation LNG Dispensing Equipment         127           4         476-30 NG Transportation CNG Foundations         34           5         476-40 NG Transportation LNG Pumps         120           7         476-60 NG Transportation LNG Dehydrator         12           8         476-70 NG Transportation LNG Dehydrator         -           9         TOTAL NG FOR TRANSP         475           10         480-00 Land in Fee Simple         -           11         GENERAL PLANT & EQUIPMENT         -           12         480-00 Land Rights         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         - <th>Adjust-ments (3) </th> <th>\$</th> <th>\$ 51 43 11 10 41 4 4 - 160 30 30</th> <th>\$ 205 170 45 38 161 16 - 635</th>	Adjust-ments (3)	\$	\$ 51 43 11 10 41 4 4 - 160 30 30	\$ 205 170 45 38 161 16 - 635
Natural Gas for Transportation   2	(3)	(4) \$ - - - - - -	\$ 51 43 11 10 41 4 -	\$ 205 170 45 38 161 16 -
1         Natural Gas for Transportation           2         476-10 NG Transportation CNG Dispensing Equipment         154           3         476-20 NG Transportation LNG Dispensing Equipment         127           4         476-30 NG Transportation CNG Foundations         34           5         476-40 NG Transportation LNG Foundations         28           6         476-50 NG Transportation LNG Pumps         120           7         476-60 NG Transportation LNG Dehydrator         12           8         476-70 NG Transportation LNG Dehydrator         -           9         TOTAL NG FOR TRANSP         475           10         475           11         GENERAL PLANT & EQUIPMENT         -           12         480-00 Land in Fee Simple         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         -           20         483-40 GP Furniture         1,159           21         483-10 GP Computer Software	'	\$ - - - - - -	\$ 51 43 11 10 41 4 -	\$ 205 170 45 38 161 16 -
2       476-10 NG Transportation CNG Dispensing Equipment       \$ 154         3       476-20 NG Transportation LNG Dispensing Equipment       127         4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation LNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       481-00 Land Rights       -         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Software       247         23       483-21 GP Computer Software       247         24 </th <th>- - - -</th> <th>- - - - -</th> <th>43 11 10 41 4 - 160</th> <th>170 45 38 161 16 -</th>	- - - -	- - - - -	43 11 10 41 4 - 160	170 45 38 161 16 -
3       476-20 NG Transportation LNG Dispensing Equipment       127         4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25 <td< td=""><td>- - - -</td><td>- - - - -</td><td>43 11 10 41 4 - 160</td><td>170 45 38 161 16 -</td></td<>	- - - -	- - - - -	43 11 10 41 4 - 160	170 45 38 161 16 -
4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       -         24       483-22 GP Computer Software       -         24       483-20 GP Computer Software       10         25       484-00 Vehicles	- - - - - - - - - - - - - - - - - - -	-	11 10 41 4 - 160	45 38 161 16 - - 635
5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       480-00 Land NG FOR TRANSP       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment <td< td=""><td></td><td>- - - - - -</td><td>10 41 4 - 160</td><td>38 161 16 - 635</td></td<>		- - - - - -	10 41 4 - 160	38 161 16 - 635
6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-40 GP Furniture       1,159         20       483-40 GP Furniture       6,111         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       1         24       483-22 GP Computer Software       1         24       483-20 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased <td></td> <td>-</td> <td>41 4 - 160</td> <td>161 16 - 635</td>		-	41 4 - 160	161 16 - 635
7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Mobile Equipment       402		-	160	635
8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - - - - - -	- - - -	160	635
9         TOTAL NG FOR TRANSP         475           10         GENERAL PLANT & EQUIPMENT           12         480-00 Land in Fee Simple         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         -           19         483-30 GP Office Equipment         326           20         483-40 GP Furniture         1,159           21         483-10 GP Computer Hardware         6,111           22         483-20 GP Computer Software         247           23         483-21 GP Computer Software         -           24         483-22 GP Computer Software         10           25         484-00 Vehicles         1,393           26         484-00 Vehicles - Leased         3,086           27         485-10 Heavy Work Equipment         402				635
10 11 GENERAL PLANT & EQUIPMENT 12		<u> </u>		
I1 GENERAL PLANT & EQUIPMENT         12 480-00 Land in Fee Simple       -         13 481-00 Land Rights       -         14 482-00 Structures & Improvements       -         15 - Frame Buildings       648         16 - Masonry Buildings       2,180         17 - Leasehold Improvement       374         18 Office Equipment & Furniture       -         19 483-30 GP Office Equipment       326         20 483-40 GP Furniture       1,159         21 483-10 GP Computer Hardware       6,111         22 483-20 GP Computer Software       247         23 483-21 GP Computer Software       -         24 483-22 GP Computer Software       10         25 484-00 Vehicles       1,393         26 484-00 Vehicles - Leased       3,086         27 485-10 Heavy Work Equipment       46         28 485-20 Heavy Mobile Equipment       402	- - - -	- -	30	00
12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - -	-	30	20
13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - -	-	30	
14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - -	-		30
15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - -		-	-
16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	3,331	3,979
18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402		-	13,825	16,005
19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(313)	501	562
20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	433	759
22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(567)	14,395	14,987
23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(1,517)	9,766	14,360
24     483-22 GP Computer Software     10       25     484-00 Vehicles     1,393       26     484-00 Vehicles - Leased     3,086       27     485-10 Heavy Work Equipment     46       28     485-20 Heavy Mobile Equipment     402	-	(475)	956	728
25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	39	49
27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(262)	3,050	4,181
28 485-20 Heavy Mobile Equipment 402	-	(1,908)	14,746	15,924
	-	(11)	(13)	22
29 486-00 Small Tools & Equipment 2 423	-	-	780	1,182
25 100 00 011411 10010 4 Equipment	-	(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	<u> </u>			
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.			- Sect 7-TAB 7	.5, Schedule 1

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

			Provision			
Line		2013	Adjust-		Accum	
No.	Account	(Cr.)	ments	Retirements	12/31/2012	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)

No.					Provision			
TRANSMISSION PLANT	ulated	mula	Accun		Adjust-	2013		Line
TRANSMISSION PLANT   2	12/31/2013	_		Retirements			Account	No.
2	(6)		(5)	(4)	(3)	(2)	(1)	
461-00 Transmission Laind Rights							TRANSMISSION PLANT	1
4   461-02 Land Rights - Mt. Hayes	\$ 401	5	\$ 401	\$ -	\$ -	\$ -	460-00 Land in Fee Simple	2
5         462-00 Compressor Structures         968         -         11,404           6         463-00 Measuring Structures         431         -         4,945           7         464-00 Other Structures & Improvements         174         -         (899)         31,915           8         465-00 Mains - INSPECTION         1,590         -         -         3,215           10         465-11 PT Transmission Pipeline - Whistler         600         -         -         2,111           11         465-30 Mt Hayes - Mains         93         -         -         147           12         465-10 Mains - Byron Creek         49         -         938           13         466-00 Compressor Equipment         5,241         -         (458)         64,898           14         466-00 Compressor Equipment         2,146         -         -         5,062           15         467-00 Mt Hayes - Measuring and Regulating Equipment         204         -         323           16         467-10 Measuring & Regulating Equipment         204         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           24         476-20 Structures & Equipment	-		-	-	-	-	461-00 Transmission Land Rights	3
6         463-00 Masauring Structures         431         -         4,945           7         464-00 Other Structures & Improvements         174         -         1,916           8         465-00 Mains         17,174         -         (899)         316,951           9         465-00 Mains - INSPECTION         1,590         -         -         3,215           10         465-11 IP Transmission Pipeline - Whistler         600         -         -         2,2111           11         465-30 Mt Hayes - Mains         33         -         147           2         465-10 Mains - Symor Creek         49         -         -         938           13         466-00 Compressor Equipment - OVERHAUL         2,146         -         -         5,062           467-00 Mt. Hayes - Measuring and Regulating Equipment         1,836         -         -         15,757           467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         4           467-20 Illemetrediate Pressure Whistler         13         -         -         -         4           468-00 Communication Structures & Equipment - Byron Creek         <	-		-	-	-	-	461-02 Land Rights - Mt. Hayes	4
7	12,372		11,404	-	-	968	462-00 Compressor Structures	5
8         465-00 Mains - INSPECTION         17,174         (899)         316,951           9         465-00 Mains - INSPECTION         1,590         -         3,215           10         465-11 IP Transmission Pipeline - Whistler         600         -         2,111           11         465-30 Mit Hayes - Mains         93         -         147           24 65-10 Mains - Syrno Creek         49         -         938           31         466-00 Compressor Equipment         5,241         (458)         64,96           44         466-00 Compressor Equipment - OVERHAUL         2,146         -         5,062           15         467-10 Measuring & Regulating Equipment         1,1536         -         15,757           467-20 Measuring & Regulating Equipment         1,1536         -         15,757           467-20 Telemetering         25         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         45           467-20 I Measuring & Regulating Equipment         468         -         -         45           468-03 Communication Structures & Equipment         468         -         -         2         2           472-10 Measuring & Regulating Equipment         600	5,376		4,945	-	-	431	463-00 Measuring Structures	6
9 465-00 Mains - INSPECTION 1,590	2,090		1,916	-	-	174	464-00 Other Structures & Improvements	7
10	333,226		316,951	(899)	-	17,174	465-00 Mains	8
11	4,805		3,215	-	-	1,590	465-00 Mains - INSPECTION	9
12	2,711		2,111	-	-	600	465-11 IP Transmission Pipeline - Whistler	10
13         466-00 Compressor Equipment         5,241         . (458)         64,696           14         486-00 Compressor Equipment - OVERHAUL         2,146         -         -         5,062           15         467-00 Mt. Hayes - Measuring and Regulating Equipment         204         -         -         323           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         2         6         -         -         2         6         -         -         -         2         6         -         -         -         -         -         -         -         -	240		147	-	-	93	465-30 Mt Hayes - Mains	11
14         466-00 Compressor Equipment - OVERHAUL         2,146         -         -         3,062           15         467-00 Mt. Hayes - Measuring and Regulating Equipment         1,000         -         -         3,23           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-21 IP Intermediate Pressure Whistler         13         -         -         45           20         468-00 Communication Structures & Equipment - Byron Creek         -         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         2,254           24         470-00 Land in Fee Simple         -         -         -         2           24         470-00 Structures & Improvements         600         -         -         5,940           27         472-10 Structures & Improvements - Byron Creek         5         -         -         32           28         473-00 Services - LILO         2,543         -         -	987		938	-	-	49	465-10 Mains - Byron Creek	12
15         467-00 Mt. Hayes - Measuring and Regulating Equipment         204         -         -         323           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         45           20         468-00 Communication Structures & Equipment         468         -         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         -         26           24         470-00 Land in Fee Simple         -         -         -         -         -         26           25         471-00 Distribution Land Rights         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -	69,479		64,696	(458)	-	5,241	466-00 Compressor Equipment	13
16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         4           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         - </td <td>7,208</td> <td></td> <td>5,062</td> <td>-</td> <td>-</td> <td>2,146</td> <td>466-00 Compressor Equipment - OVERHAUL</td> <td>14</td>	7,208		5,062	-	-	2,146	466-00 Compressor Equipment - OVERHAUL	14
17         467-20 Telemetering         25         - (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         3,254           20         468-00 Communication Structures & Equipment         468         3,254           21         TOTAL TRANSMISSION         31,012         (1,968)         436,991           22         TOTAL TRANSMISSION         31,012         (1,968)         436,991           23         DISTRIBUTION PLANT         26         26         471-00 Distribution Land Rights         26           25         471-00 Distribution Land Rights         32         32           26         472-00 Structures & Improvements - Byron Creek         5 32         28           28         473-00 Services - LILO         2,543         36           28         473-00 Services - LILO         2,543         36           30         474-00 House Regulators & Meter Installations - LILO         598         359           31         474-00 House Regulators & Meter Installations - LILO         598         33	527		323	-	-	204	467-00 Mt. Hayes - Measuring and Regulating Equipment	15
18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         32,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         26           25         471-00 Distribution Land Rights         -         -         -         -         26           25         472-00 Structures & Improvements         600         -         -         5,940           26         472-00 Structures & Improvements - Byron Creek         5         -         -         32           28         473-00 Services - LILO         2,543         -         -         4,363           30         474-00 House Regulators & Meter Installations         12,549         -         (852)         24,588           31         474-00 House Regulators & Meter Installations - LILO         598         -         -         1,302           24         477-00 Meters/Regulators Installations         11	17,593		15,757	-	-	1,836	467-10 Measuring & Regulating Equipment	16
19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         -         26           24         470-00 Land in Fee Simple         -         -         -         -         -         -           25         471-00 Distribution Land Rights         -	5,236		5,822	(611)	-	25	467-20 Telemetering	17
A68-00 Communication Structures & Equipment   A68   -   -   3,254	58		45	-	-	13	467-31 IP Intermediate Pressure Whistler	18
TOTAL TRANSMISSION   31,012	4		4	-	-	-	467-20 Measuring & Regulating Equipment - Byron Creek	19
DISTRIBUTION PLANT   24   470-00 Land in Fee Simple   -   -   -   -   26	3,722	_	3,254			468	468-00 Communication Structures & Equipment	20
23   DISTRIBUTION PLANT   24   470-00 Land in Fee Simple   -   -   -   -   26   25   471-00 Distribution Land Rights   -   -   -   -   -   -   -   26   25   471-00 Distribution Land Rights   -   -   -   -   -   -   -   -   -	466,035		436,991	(1,968)	-	31,012	TOTAL TRANSMISSION	21
24       470-00 Land in Fee Simple       -       -       -       -       26         25       471-00 Distribution Land Rights       -       -       -       -       -         26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Measuring & Regulating Installations       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39								22
25       471-00 Distribution Land Rights       -       -       -       -       -       -       5,940         26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       11,097       -       -       359         33       475-00 Mains - LILO       1,803       -       -       3,363         34       475-00 Mains - LILO       1,803       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204							DISTRIBUTION PLANT	23
26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       478-10 Meters       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -	26		26	-	-	-	470-00 Land in Fee Simple	24
27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       LILO <td>-</td> <td></td> <td>-</td> <td>-</td> <td>-</td> <td>-</td> <td>471-00 Distribution Land Rights</td> <td>25</td>	-		-	-	-	-	471-00 Distribution Land Rights	25
28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       LILO       524       -       -       1,184         41       478-20 Instruments       362	6,540		5,940	-	-	600	472-00 Structures & Improvements	26
29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -	37		32	-	-	5	472-10 Structures & Improvements - Byron Creek	27
30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       978         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -	198,182		180,822	(2,965)	-	20,325	473-00 Services	28
31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989 <td>6,906</td> <td></td> <td>4,363</td> <td>-</td> <td>-</td> <td>2,543</td> <td>473-00 Services - LILO</td> <td>29</td>	6,906		4,363	-	-	2,543	473-00 Services - LILO	29
32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	36,295		24,598	(852)	-	12,549	474-00 House Regulators & Meter Installations	30
33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	1,900		1,302	-	-	598	474-00 House Regulators & Meter Installations - LILO	31
34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	1,456		359	-	-	1,097	477-00 Meters/Regulators Installations	32
35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	389,929		374,894	(3,526)	-	18,561	475-00 Mains	33
36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	5,166		3,363		-	1,803	475-00 Mains - LILO	34
37     477-00 Telemetering     19     -     (83)     6,259       38     477-10 Measuring & Regulating Equipment - Byron Creek     -     -     -     -     204       39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989	1,250		978	-	-	272	476-00 Compressor Equipment	35
38     477-10 Measuring & Regulating Equipment - Byron Creek     -     -     -     -     204       39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	34,666		30,385	(585)	-	4,866	477-00 Measuring & Regulating Equipment	36
39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	6,195		6,259	(83)	-	19	477-00 Telemetering	37
40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	204		204	-	-	-	477-10 Measuring & Regulating Equipment - Byron Creek	38
41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	93,243		79,992	(4,370)	-	17,621	478-10 Meters	39
42       479-00 Other Distribution Equipment       -	1,708		1,184	-	-	524	478-11 Meters - LILO	40
43 TOTAL DISTRIBUTION 81,745 - (12,381) 715,989 44	1,650		1,288	-	-	362	478-20 Instruments	41
44		_					479-00 Other Distribution Equipment	42
	785,353	_	715,989	(12,381)	-	81,745	TOTAL DISTRIBUTION	43
								44
45 BIO GAS							BIO GAS	45
46 472-00 Bio Gas Struct. & Improvements	-		-	-	-	-	472-00 Bio Gas Struct. & Improvements	46
47 475-10 Bio Gas Mains – Municipal Land	-		-	-	-	-	475-10 Bio Gas Mains - Municipal Land	47
48 475-20 Bio Gas Mains – Private Land 9 7	16		7	-	-	9	475-20 Bio Gas Mains - Private Land	48
49 418-10 Bio Gas Purification Overhaul 143 81	224		81	-	-	143	418-10 Bio Gas Purification Overhaul	49
50 418-20 Bio Gas Purification Upgrader 286 162	448		162	-	-	286	418-20 Bio Gas Purification Upgrader	50
51 474-10 Bio Gas Reg & Meter Installations 186 189	375		189	-	-	186	474-10 Bio Gas Reg & Meter Installations	51
52 478-30 Bio Gas Meters51	71		<u>2</u> 0			51	478-30 Bio Gas Meters	52
53 TOTAL BIO-GAS <u>675</u> <u>459</u>	1,134		459	-		675	TOTAL BIO-GAS	53

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

				Pro	ovision						
Line			2013		djust-			Acc	um	ulated	
No.	Account		(Cr.)		nents	Re	tirements	12/31/2012			31/2013
	(1)		(2)		(3)	<u> </u>	(4)	(5)	_		(6)
1	Natural Gas for Transportation										
2	476-10 NG Transportation CNG Dispensing Equipment	\$	253	\$	-	\$	-	\$ 20	5	\$	458
3	476-20 NG Transportation LNG Dispensing Equipment	•	207	•	-	•	-	17	0	•	377
4	476-30 NG Transportation CNG Foundations		56		-		-	4	5		101
5	476-40 NG Transportation LNG Foundations		46		-		-	3	8		84
6	476-50 NG Transportation LNG Pumps		196		-		-	16	1		357
7	476-60 NG Transportation CNG Dehydrator		20		-		-	1	6		36
8	476-70 NG Transportation LNG Dehydrator		-		-		-	-			-
9	TOTAL NG FOR TRANSP		778		-		-	63	5	-	1,413
10									_	-	
11	GENERAL PLANT & EQUIPMENT										
12	480-00 Land in Fee Simple		_		_		_	3	ი		30
13	481-00 Land Rights		_		_		_	-	•		-
14	482-00 Structures & Improvements				_		_	_			_
15	- Frame Buildings		648		-		(3)	3,97	a		4,624
16	- Masonry Buildings		2,440				(0)	16,00			18,445
17	- Leasehold Improvement		373				(146)	56			789
18	Office Equipment & Furniture		-		-		(140)	50.	_		709
19	483-30 GP Office Equipment		351		-		_	75	n		1.110
20	483-40 GP Furniture		1,147		-		(1,954)	14,98			14,180
21	483-10 GP Computer Hardware		,		-		. , ,	,			
22	483-20 GP Computer nardware		6,942 204		-		(6,581)	14,36 72			14,721 721
23	483-21 GP Computer Software		204		-		(211)	12	2		121
			-		-		-	-	^		-
24	483-22 GP Computer Software 484-00 Vehicles		10		-		(1.400)	4 10			59
25			1,832		-		(1,409)	4,18			4,604
26 27	484-00 Vehicles - Leased		3,239		-		(1,716)	15,92 2			17,447
	485-10 Heavy Work Equipment		46		-		-				68
28	485-20 Heavy Mobile Equipment		461		-		(4.057)	1,18			1,643
29	486-00 Small Tools & Equipment		2,513		-		(1,357)	21,33			22,492
30	487-00 Equipment on Customer's Premises		1		-		-	(	5)		(4)
31	- VRA Compressor Installation Costs		-		-		-	-			-
32	488-00 Communications Equipment		-		-		- (400)	-	_		-
33	- Telephone		555		-		(408)	5,06			5,216
34	- Radio		306		-		(34)	2,69			2,967
35	489-00 Other General Equipment				-		- (10.010)		<u>2)</u>		(2)
36	TOTAL GENERAL		21,068		-		(13,819)	101,86	1		109,110
37											
38	UNCLASSIFIED PLANT										
39	499 Plant Suspense		-		-						-
40	TOTAL UNCLASSIFIED		-		-						-
41		_				_			_		.=
42	TOTALS	\$	162,036	\$	-	\$	(41,343)	\$ 1,338,16	<u>/_</u>	\$ 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	- Se	ect 7-TAB	7.5, Scl	hedule 13	3		- Sect 7-TA	В7	.5, Sch	nedule 18

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

			Pr	ovision								
Line		Provision	O	oen Bal	R	emoval	Proce	eds on		En	ding	
No.	Account	(Cr.)	Tr	ansfers		Costs	Dis	posal	12/3	31/2011	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											
		40		210								267
8 9	462-00 Compressor Structures	48 10		219 95		-		-		-		267
10	463-00 Measuring Structures 464-00 Other Structures & Improvements	9		95		-		-		-		105 9
11	465-00 Mains	1,691		2.672		-		-		-		4,363
12	466-00 Compressor Equipment	501		404		-		-		-		4,363 905
13	467-10 Measuring & Regulating Equipment	80		72		-		-				152
14	468-00 Communication Structures & Equipment	87		- 12								87
15	TOTAL TRANSMISSION	2,426		3,462			-				-	5,888
16	TOTAL THANOMIODION	2,420		0,402			-				-	3,000
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, Sc	hedule 13					- S	ect 7-TAB	7.5, Sc	hedule 18
39												

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

				Pro	vision								
Line		Pr	ovision	Ad	ljust-	R	emoval	Proc	eeds on		End	ding	
No.	Account		(Cr.)	m	ents		Costs	Dis	posal	12/	/31/2012	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	- Se	ct 7-TAB 7	7.5, Sch	edule 13	3				- :	Sect 7-TAB	7.5, Sc	hedule 18
39													

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

Line		Balance		2012 FO	RECAST	Balance	
No.	Particulars	12/31/2011	Adjustment	Additions	Retirements	12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 2	CIAC						
3 4	Distribution Contributions	\$ 250,340	\$ -	\$ 6,517	\$ -	\$ 256,857	
5 6	Transmission Contributions	116,849	-	10,750	-	127,599	
7 8	Others	-	-	-	-	-	
9 10 11	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	- 15,864	-	-	(5,106)	10,758	
12 13	FEW Contribution for Whistler Pipeline Government Loans Contribution	- 49,123	-	-	(20,000)	- 29,123	
14	Government Loans Contribution	49,123	-	-	(20,000)	29,123	
15 16	Biomethane	-	-	-	-	-	
17 18 19 20	TOTAL Contributions	432,176	-	17,267	(25,106)	424,337	- Sect 7-TAB 7.5, Schedule 18
21 22	Amortization						
23 24	Distribution Contributions	(65,154)	-	(6,351)	-	(71,505)	
25 26	Transmission Contributions	(33,438)	-	(2,203)	-	(35,641)	
27 28	Others	10	-	10	-	20	
29 30 31	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	(9,302)	-	(1,664)	5,106	(5,860)	
32 33 34	FEW Contribution for Whistler Pipeline Government Loans Contribution	-	-	-	-	-	
35 36	Biomethane	-	-	-	-	-	
37 38	TOTAL CIAC Amortization	(107,884)	-	(10,208)	5,106	(112,986)	- Sect 7-TAB 7.5, Schedule 18
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		Balance		2013 FO	RECAST	Balance	
No.	Particulars	12/31/2012	Adjustment	Additions	Retirements	12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 2	CIAC						
3	Distribution Contributions	\$ 256,857	\$ -	\$ 6,581	\$ -	\$ 263,438	
5 6	Transmission Contributions	127,599	-	750	-	128,349	
7 8	Others	-	-	-	-	-	
9 10 11	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	- 10,758	-	-	(204)	- 10,554	
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13 14	Government Loans Contribution	29,123	-	-	(4,123)	25,000	
15 16	Biomethane						
17 18 19 20	TOTAL Contributions	424,337	-	7,331	(4,327)	427,341	- Sect 7-TAB 7.5, Schedule 18
21 22	Amortization						
23 24	Distribution Contributions	(71,505)	-	(6,537)	-	(78,042)	
25 26	Transmission Contributions	(35,641)	-	(2,299)	-	(37,940)	
27 28	Others	20	-	10	-	30	
29 30 31	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	(5,860)	-	(1,332)	204	(6,988)	
32 33	FEW Contribution for Whistler Pipeline Government Loans Contribution	-	-	-	-	-	
34 35 36	Biomethane	-	-	-	-	-	
37 38	TOTAL CIAC Amortization	(112,986)	-	(10,158)	204	(122,940)	- Sect 7-TAB 7.5, Schedule 18
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 (1)	Forecast Balance 12/31/2011 (2)	Opening Bal. Transfer / Adjustment (3)	Gross Additions (4)	Less- Taxes (5)	Net Additions (6)	Amortization Expense (7)	Reco Rider (8)	veries Tax on Rider (9)	Balance 12/31/2012 (10)	Mid-Year Average 2012 (11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	\$ (23,385)	\$ -	\$ 31,179	\$ (7,795)	. ,	\$ -	\$ -	\$ -	\$ (0)	\$ (11,692)
3	Midstream Cost Reconciliation Account (MCRA)	18,725	-	-	-	-	-	(8,322)		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	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)		(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 <sup>´</sup>	-	-	-	(66)

FortisBC Energy Utilities May 16, 2011 Section 7 TAB 7.5

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

40

Cross Reference

Mid-Year Forecast Opening Line Balance Bal. Transfer / Gross Less-Net Amortization Recoveries Balance Average 12/31/2011 Additions Additions Rider Tax on Rider 12/31/2012 Particulars Adjustment Taxes Expense 2012 No. (1) (4) (5) (6) (7)(8) (9) (10)(11)Cost of Current Applications 2 2009 ROE & Cost of Capital Application 621 \$ 713 \$ \$ \$ \$ \$ (184) \$ \$ \$ 529 \$ 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 Long Term Resource Plan Application 136 70 53 162 7 (18)188 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 (434)434 Pipeline Contribution Costs Variance Account (217)14 15 Other Pension & OPEB Funding 16 (30,602)(76,859)(76,859)(107,461)(69,032)17 Deferred Removal Costs 3.363 (1.682)1.682 2.522 18,739 18 (6,176)11,935 12,249 Gains and Losses on Asset Disposition (628)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 80 120 (40)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 75,131 75,131 (8,066)67,065 33,533 (6,176)6,176 25 26 Residual Deferred Charges 27 684 684 SCP Tax Reassessment 684 28 Earnings Sharing Mechanism 29 Carbon Tax Cost of Service (66)66 (33)30 **OSC Certification Compliance** (59)59 (30)47 31 Deferred ROE Variance (47)0 (24)32 Sales Margin Differential 464 (464)33 FEW 2009 Revenue Requirement Application (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 61,507 45,699 (199) \$ 1,243 61,107 40,223 (7,733) \$ 27,071 (15.809)(4.974) \$ \$ \$ \$ 39

- Sect 7-TAB 7.5, Schedule 18

- Sect 7-TAB 7.5, Schedule 13

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TAB 7.5 Schedule 38

#### 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	Reco	veries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
140.	(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	Ψ -	Ψ -	Ψ -	Ψ -	Ψ -	(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	-	-	-	-	-	-	-	-	-	-

May 16, 2011

Section 7 TAB 7.5 Schedule 39

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

(\$000s)

Line No.	Particulars	Forecast Opening Balance Bal. Transfer / Gross 12/31/2012 Adjustment Additions		Less- Net Taxes Additions		Amortization Expense	Recoveri Rider Ta	es x 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	, in the state of											
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	<u>Other</u>											
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 37	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-	
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		2012						
No.	Particulars	FC	RECAST	FC	RECAST	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	

May 16, 2011

Section 7 TAB 7.5 Schedule 41

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

			2012			2013		_		
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	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			<u>-</u> '		,					
8										
9										
10										

11

Section 7 TAB 7.5 Schedule 42

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

Line No.	Particulars	Amount	2012 Lead Days Expense to Payment	Dollar Days	Amount	2013 Lead Days Expense to Payment	Dollar Days	Cross Reference
<u> </u>	(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	

FortisBC Energy Utilities

May 16, 2011

Section 7 TAB 7.5 Schedule 43

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

Note: \* Excludes Land, Software CIAC, and WIP.

Line		2012	2013	
No.	Particulars	FORECAST	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		<del></del>	· · · · · · · · · · · · · · · · · · ·	
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	<b>,</b>	( , -)	(, - ,	
16	FIT Liability/Asset - Opening Balance	(337,894)	(354,428)	
17	3	( , ,	( , -,	
18	FIT Liability/Asset - Mid Year	(346,162)	(361,341)	- Sect 7-TAB 7.5, Schedule 18
19		· · ·		
20				

FortisBC Energy Utilities WEIGHTED AVERAGE RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 2012 (\$000s) May 16, 2011

Section 7 TAB 7.5 Schedule 44

Line No.	Particulars (4)	Am	llization ount	<u>%</u>	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	()	2)	(3)	(4)	(5)	(6)	(7)
1								
2	2012 FORECAST							
3	Long-Term Debt	\$ 1,9	974,672	55.22%	6.54%	3.61%	\$ 129,149	- Sect 7-TAB 7.5, Schedule 46
4	Unfunded Debt							
5	Adjustment, Revised Rates	1	171,106	4.78%	2.75%	0.13%	4,705	
6	Common Equity	1,4	130,519	40.00%	9.62%	3.85%	 137,616	- Sect 7-TAB 7.5, Schedule 5
7			_	<u> </u>				
8		\$ 3,5	576,297	100.00%		7.59%	\$ 271,470	- Sect 7-TAB 7.5, Schedule 18

FortisBC Energy Utilities WEIGHTED AVERAGE RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 2013 (\$000s) May 16, 2011

Section 7 TAB 7.5 Schedule 45

Line	(4000)	Ca	pitalization		Average Embedded	Cost	Earned			
No.	Particulars		Amount	%	Cost	Component	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		

Cross Reference

May 16, 2011

Section 7 TAB 7.5 Schedule 46

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 (Ser	ies A), using weighted average	capital structure.					Average E	Embedded Cost	6.54%
33	**Includes adjustment of \$0 for BC Hydro Premium (Series B	), using weighted average capi	al structure.							
0.4	``								0	

<sup>-</sup> Sect 7-TAB 7.5, Schedule 44

34

Cross Reference

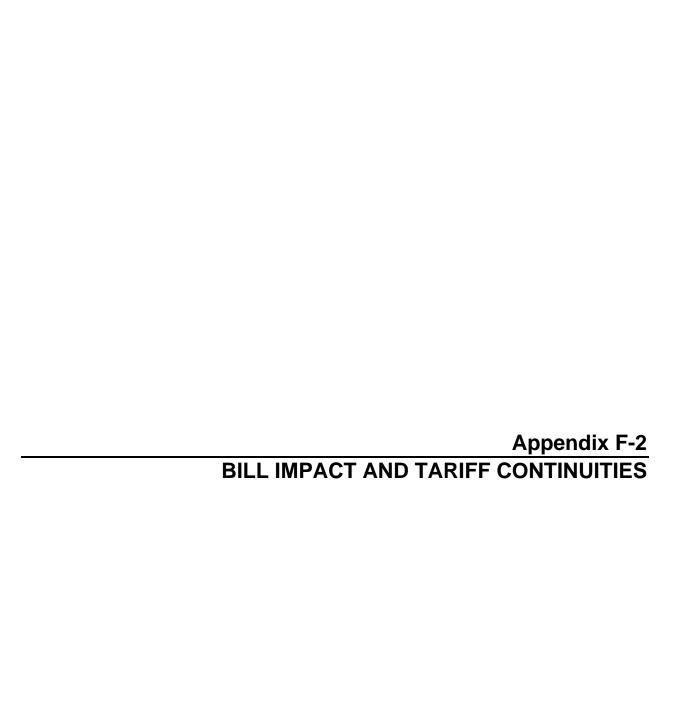
May 16, 2011

Section 7 TAB 7.5 Schedule 47

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

	(\$000S)				Data da al		NI-1	E#***		
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 3	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
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 13	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
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 - Kalauma							6.413%	23,749	1 500
22	LILO Obligations - Kelowna LILO Obligations - Nelson							7.696%	23,749 3,794	1,523 292
23 24	LILO Obligations - Neison							8.929%	11,323	1,011
2 <del>4</del> 25	LILO Obligations - Vernori LILO Obligations - Prince George							7.862%	29,142	2,291
26	LILO Obligations - Prince George							7.050%	29,142	195
27	LILO Obligations - Greston							7.030 /6	2,700	193
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 (Seri	es A) Tusing weighted average	canital structure					Average F	mbedded Cost	6.56%
33	**Includes adjustment of \$3,216 for BC Hydro Premium (Serie	,	•					Average L	inibodaca Oost	0.3076
00	includes adjustifient of \$5,210 for BC rigaro Premium (Sent	es b), using weignted average	capital Structure.						0 . 7 7 4 0 7	

<sup>-</sup> Sect 7-TAB 7.5, Schedule 45





#### 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		
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

#### FORTISBC ENERGY INC.

#### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED JANUARY 1, 2012 RATES

BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

APPENDIX F-2 TAB 1.1.1 PAGE 1

SCHEDULE 1

	RATE SCHEDULE 1:				DE	LIVERY MARGIN	ı			
	RESIDENTIAL SERVICE	EXISTING	JANUARY 1, 2011 R	RATES	RELATE	CHARGES CH	ANGES	PROPOSEI	JANUARY 1, 2012	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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)	_			_			_		

APPENDIX F-2 TAB 1.1.1 PAGE 2 SCHEDULE 2

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

R.A	ATE SCHEDULE 2:				DEI	LIVERY MARGIN				
SM	MALL COMMERCIAL SERVICE	EXISTING .	JANUARY 1, 2011 R	ATES	RELATED	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 2012	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1 <u>Del</u>	elivery Margin Related Charges									
	sic 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 Sub	btotal 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 <u>Cor</u>	mmodity 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 Sub	btotal 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 <b>Co</b> s	ost 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 Rid	der 1 Propane Surcharge (Revelstoke only)		\$8.254			\$0.000			\$8.254	
20										
21										
	ost of Gas Recovery Related Charges for Revelstoke		\$14.123			\$0.000			\$14.123	
23 per	er GJ (Includes Rider 1, excludes Rider 8)	_			=			=		

APPENDIX F-2 TAB 1.1.1 PAGE 3 SCHEDULE 3

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 3:				DE	LIVERY MARGIN	ı			
	LARGE COMMERCIAL SERVICE	EXISTING	JANUARY 1, 2011 F	RATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	Diday 4 Decreas Comphessor (Developles and v)		\$8.556			\$0.000			\$8.556	
19	Rider 1 Propane Surcharge (Revelstoke only)		\$8.556			\$0.000			\$8.556	
	Coat of Coa Bassiani Balated Channes for Bassiatal		644400			<b>#0.000</b>			644400	
	-	=	\$14.123		=	\$0.000		=	\$14.123	
23	per GJ (Includes Rider 1, excludes Rider 8)									
20 21 22 23	Cost of Gas Recovery Related Charges for Revelstoke per GJ (Includes Rider 1, excludes Rider 8)	=	<b>\$14.123</b>		=	\$0.000		-	\$14.123	

APPENDIX F-2 TAB 1.1.1 PAGE 4 SCHEDULE 4

BCUC ORDE	R NO.G-XX	X-11 G-	-XXX-11
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	RATE SCHEDULE 4:				DE	LIVERY MARGIN	ı				
	SEASONAL SERVICE	EXISTING	JANUARY 1, 2011 R	ATES	RELATE	CHARGES CH	ANGES	PROPOSED JANUARY 1, 2012 RATES			
Line		Lower			Lower			Lower			
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	
_	Delivery Margin Related Charges										
	Basic Charge per day	\$14.4230	\$14.4230	\$14.4230	\$0.0000	\$0.0000	\$0.0000	\$14.4230	\$14.4230	\$14.4230	
3											
	Delivery Charge per GJ	20.054	*****	***		***	20.004	***	***	40.005	
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		***	***	** ***		***	***	**		40.000	
	Rider 2 2009 ROE Rate Rider	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	
	Rider 3 ESM	(\$0.014)	(\$0.014)	(\$0.014)	\$0.014	\$0.014	\$0.014	\$0.000	\$0.000	\$0.000	
10	0										
_	Commodity Related Charges										
	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											
	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											
	Subtotal Off -Peak Commodity Related Charges per GJ										
1	(a) Off-Peak Period	\$5.332	\$5.317	\$5.353	\$0.000	\$0.000	\$0.000	\$5.332	\$5.317	\$5.353	
	(b) Extension Period	\$5.332	\$5.317	\$5.353	\$0.000	\$0.000	\$0.000	\$5.332	\$5.317	\$5.353	
24											
25											
26											
	Unauthorized Gas Charge per gigajoule	Balancing, Backsto Order No. G-110-00		r BCUC				Balancing, Backs Order No. G-110	topping and UOR	per BCUC	
28 0	during peak period	Order No. G-110-00	J.					Order No. G-110	-00.		
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	
						_					

APPENDIX F-2 TAB 1.1.1 PAGE 5 SCHEDULE 5

#### BCUC ORDER NO.G-XXX-11 G-XXX-11

	RATE SCHEDULE 5				DE	LIVERY MARGIN	I			
	GENERAL FIRM SERVICE	EXISTING	JANUARY 1, 2011 F	ATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	3. P	,	•	,	• • • • • • • • • • • • • • • • • • • •	,	,	• • • • • • • • • • • • • • • • • • • •	• • • • • • • • • • • • • • • • • • • •	,
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

APPENDIX F-2 TAB 1.1.1 PAGE 6 SCHEDULE 6

BCUC C	RDER NO	.G-XXX-11	G-XXX-11
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	RATE SCHEDULE 6:				DE	LIVERY MARGIN	ı			
	NGV - STATIONS	EXISTING	JANUARY 1, 2011 R	ATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
			· · · · · · · · · · · · · · · · · · ·			·	· · · · · · · · · · · · · · · · · · ·			

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

APPENDIX F-2 TAB 1.1.1 PAGE 6.1 SCHEDULE 6A

	RATE SCHEDULE 6A: NGV - VRA's			
_ine			DELIVERY MARGIN	
No.	Particulars	EXISTING JANUARY 1, 2011 RATES	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			<del></del>	
22 23	Total Variable Cost per gigajoule	\$13.770	\$0.252	\$14.022
23	Total variable Cost per gigajoule	<u> </u>	Φυ.202	<u> </u>

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

APPENDIX F-2 TAB 1.1.1 PAGE 7 SCHEDULE 7

	RATE SCHEDULE 7:				DEI	LIVERY MARGIN				
	INTERRUPTIBLE SALES	EXISTING	JANUARY 1, 2011 R	ATES	RELATED	CHARGES CHA	ANGES	PROPOSEI	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		Balancing Backst	opping and UOR pe	er BCUC				Balancing, Backs	topping and UOR	per BCUC
16	Charges per gigajoule for UOR Gas	Order No. G-110-0		5. 2000				Order No. G-110-		po. 2000
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
	Total Variable Cost per gigajoule	\$6.392	\$6.377	\$6.413	\$0.080	\$0.080	\$0.080	\$6.472	\$6.457	\$6.4

APPENDIX F-2 TAB 1.1.1 PAGE 8 SCHEDULE 22

RATE SCHEDULE 22					DE	LIVERY MARGIN	I			
LARGE INDUSTRIAL	. T-SERVICE	EFFEC	TIVE JANUARY 1, 2	2011	RELATE	D CHARGES CHA	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1 Basic Charge per Mo	onth	\$3,664.00	\$3,664.00	\$3,664.00	\$0.00	\$0.00	\$0.00	\$3,664.00	\$3,664.00	\$3,664.00
	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 F	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
8 9 Charges per gigajou	le for UOR Gas	Balancing, Bac Order No. G-1	kstopping and UOF 10-00.	R per BCUC				Balancing, Back Order No. G-110	stopping and UOF 0-00.	R per BCUC
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 p	or gigaioulo									
	n 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
` '	n 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	ir and including Nov. 1 and Mai. 31	ψ1.10	\$1.10	11/a	ψ0.00	ψ0.00	IVa	ψ1.10 	ψ1.10	IVa
	le for Backstopping Gas	Balancing, Backs Order No. G-110	stopping and UOR p -00.	per BCUC				Balancing, Back Order No. G-11	stopping and UOF 0-00.	R per BCUC
23 24 Administration Char	ge 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 pe	er gigajoule	\$0.781	\$0.781	\$0.781	\$0.057	\$0.057	\$0.057	\$0.838	\$0.838	\$0.838

APPENDIX F-2 TAB 1.1.1 PAGE 9 SCHEDULE 22A

	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE			
Line No.	Particulars	EFFECTIVE JANUARY 1, 2011	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1 2	INLAND SERVICE AREA			
3	Basic Charge per Month	\$4,810.00	\$0.00	\$4,810.00
5	Delivery Charge per gigajoule - Firm (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				Balancing, Backstopping and UOR per BCUC
25 26	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Order No. G-110-00.
27				
28	Replacement Gas	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30		p.ao 20 1 0.00.11		p.do 20 1 0.00.10
31	Administration Charge per Month	\$78.00	\$0.00	\$78.00
32		******	*	Ţ
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 10 SCHEDULE 22B

	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE			DELIVERY MARGIN	ı		
		EFFECTIVE JANUARY 1, 2	011	RELATED CHARGES CH	ANGES	PROPOSED JANUARY 1, 2012	RATES
Line		Columbia	Elkview	Columbia	Elkview	Columbia	Elkview
No.	Particulars	Except Elkview	Coal	Except Elkview	Coal	Except 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			Balancing, Backstopping ar	
17	Charges per gigajoule for UOR Gas	BCUC Order No. G-110-	00.			BCUC Order No. G-110-00	).
18		L					
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			Balancing, Backstopping ar	
23	Charges per gigajoule for Backstopping Gas	BCUC Order No. G-110-0				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
						-	-

#### APPENDIX F-2 TAB 1.1.1 PAGE 11 SCHEDULE 23

RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EEEE	CTIVE JANUARY 1, 2	2011		LIVERY MARGII D CHARGES CH		PPOPOSEI	) JANUARY 1, 201	DATES
Line	Lower	CTIVE JANUART 1, 2	2011	Lower	D CHARGES CH	ANGES	Lower	JANUART 1, 201.	ZRAIES
No. Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
8 Sales									
9 (a) Charge per gigajoule for Balancing Gas 10 (b) Charge per gigajoule for Backstopping	Dalarionig, Dat	ckstopping, Replacer er No. G-110-00.	ment and UOR					stopping, Replace Order No. G-110-	
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 12 SCHEDULE 25

	RATE SCHEDULE 25				DE	LIVERY MARGIN	١			
	GENERAL FIRM T-SERVICE	EFFEC <sup>*</sup>	TIVE JANUARY 1, 2	011	RELATE	D CHARGES CH	ANGES	PROPOSEI	JANUARY 1, 2012	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		215010	0.45.0.40	045.040	04.050	24.050	04.050	040.000	040.000	040.000
3	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 gigajoule (Interr. MTQ)	\$0.645	\$0.645	\$0.645	\$0.051	\$0.051	\$0.051	\$0.696	\$0.696	\$0.696
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		stopping, Replacen						stopping, Replace	
12 13	<ul><li>(b) Charge per gigajoule for Backstopping Gas</li><li>(c) Replacement Gas</li></ul>	UOR per BCUC	Order No. G-110-0	0.				OOR per BCOC	Order No. G-110	.00.
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)	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
19	Mad 5 Low	(ψ0.021)	(ψ0.021)	(ψ0.021)	ψ0.021	Ψ0.021	Ψ0.021	ψ0.000	ψ0.000	ψ0.000
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 13 SCHEDULE 26

	RATE SCHEDULE 26:					LIVERY MARGIN				
	NATURAL GAS VEHICLE T-SERVICE		TIVE JANUARY 1, 2	011		D CHARGES CHA	ANGES		JANUARY 1, 2012	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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										
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	Administration onlying per month.	Ψ70.00	ψ/ 0.00	ψ10.00	ψ0.00	ψ0.00	ψ0.00	Ψ70.00	Ψ10.00	ψ10.00
8	Sales									
10 11	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas	Balancing, Backs Order No. G-110	stopping and UOR I-00.	per BCUC				Balancing, Bacl BCUC Order No	kstopping and UO b. G-110-00.	R per
12 13	(d) Charge per gigajoule for UOR Gas									
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 16	Rider 3 ESM	(\$0.039)	(\$0.039)	(\$0.039)	\$0.039	\$0.039	\$0.039	\$0.000	\$0.000	\$0.000
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
"	. Stat. Talladio Gook pol. gigajoulo	ψο.σσσ =	<del></del>	φο.σσσ	<del></del>	<del>40.202</del>	ψ0. <b>L</b> 0L	Ψ0.001	φο.σσ1	ψο.σσ1

APPENDIX F-2 TAB 1.1.1 PAGE 14 SCHEDULE 27

	ATE SCHEDULE 27:	FFF-03	TIVE JANUARY 4 O	044		LIVERY MARGIN		PROPOSE	) IANIIIA B.V. 4. 004	DATES
	ITERRUPTIBLE T-SERVICE		TIVE JANUARY 1, 2	U11		D CHARGES CH	ANGES		JANUARY 1, 201	ZRATES
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 <b>B</b> a	asic Charge per Month	\$880.00	\$880.00	\$880.00	\$0.00	\$0.00	\$0.00	\$880.00	\$880.00	\$880.00
2										
4 De	elivery 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 <b>A</b> d	dministration Charge per Month	\$78.00	\$78.00	\$78.00	\$0.00	\$0.00	\$0.00	\$78.00	\$78.00	\$78.00
7 8										
9 <b>Sa</b> 10 11 12	ales  (a) Charge per gigajoule for Balancing Gas  (b) Charge per gigajoule for Backstopping Gas  (d) Charge per gigajoule for UOR Gas	Balancing, Backs Order No. G-110	stopping and UOR I-00.	per BCUC				Balancing, Bac BCUC Order N	kstopping and UC o. G-110-00.	R per
13 14 <b>Ri</b> o	der 2 2009 ROE Rate Rider	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
15 <b>Ri</b>	der 3 ESM	(\$0.013)	(\$0.013)	(\$0.013)	\$0.013	\$0.013	\$0.013	\$0.000	\$0.000	\$0.000
16 17										
18 19 To	otal 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 Annual No. Particular EXISTING JANUARY 1, 2011 RATES PROPOSED JANUARY 1, 2012 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.389 \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% 3 Basic Charge davs x davs x 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% 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% (\$0.020) = (\$1.9000) (\$0.032)(\$3.0400)(\$1.1400) 8 Rider 5 RSAM 95.0 GJ x 95.0 GJ x (\$0.012)-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 GJ x \$0.009 \$0.8550 95.0 GJ x \$0.009 0.8550 \$0.0000 0.00% 95.0 \$0.000 Midstream Related Charges Subtotal 14 \$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 \$1,008.87 95.0 \$1,036.61 \$27.74 2.75% \$10.620 \$10.912 \$0.292 20 21 INLAND SERVICE AREA **Delivery Margin Related Charges** 22 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 \$3.275 = \$245.6250 GJ x \$3.531 = \$264.8250 \$19.2000 2.33% Delivery Charge 75.0 GJ x 75.0 \$0.256 26 \$0.000 = Rider 2 2009 ROE Rate Rider 75.0 GJ x \$0.000 = \$0.0000 75.0 GJ x \$0.0000 \$0.000 \$0.0000 0.00% 27 (\$0.048) = \$0.000 = 0.44% Rider 3 ESM 75.0 GJ x (\$3.6000)75.0 GJ x \$0.0000 \$0.048 \$3,6000 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 \$382.61 \$404.51 Subtotal Delivery Margin Related Charges \$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 \$0.00 0.00% 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 37 \$441.90 \$441.90 \$0.00 0.00% Subtotal Commodity Related Charges 38 39 Total (with effective \$/GJ rate) 75.0 \$824.51 \$846.41 \$21.90 2.66% \$10.993 75.0 \$11.285 \$0.292 40 41 **COLUMBIA SERVICE AREA** 42 Delivery Margin Related Charges 43 365.25 \$0.389 = \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% Basic Charge days x days x 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 \$0.000 = GJ x \$0.000 = \$0.0000 Rider 2 2009 ROE Rate Rider 80.0 GJ x \$0.0000 80.0 \$0.0000 \$0.000 0.00% 47 (\$0.048) = \$0.000 = 0.44% Rider 3 ESM 0.08 GJ x (\$3.8400)80.0 GJ x \$0.0000 \$0.048 \$3.8400 48 Rider 5 RSAM (\$0.020) = (\$1.6000)(\$0.032)(\$2.5600) (\$0.012) (\$0.9600)-0.11% 80.0 GJ x 80.0 GJ x 49 Subtotal Delivery Margin Related Charges \$398.64 \$422.00 \$23.36 2.68% 50 51 Commodity Related Charges 52 0.08 GJ x \$1.355 \$108.4000 80.0 GJ x \$1.355 \$108.4000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge \$0.7200 53 GJ x \$0.009 80.0 GJ x \$0.009 \$0.7200 \$0.000 \$0.0000 0.00% Rider 8 Unbundling Recovery 80.0 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

\$873.20

0.08

\$896.56

\$11.207

\$10.915 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.

0.08

Total (with effective \$/GJ rate)

59

2.68%

\$23.36

## 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 Annual No. Particular EXISTING JANUARY 1, 2011 RATES PROPOSED JANUARY 1, 2012 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.816 \$298.08 \$0.816 = \$298.08 \$0.00 \$0.00 0.00% Basic Charge days 365.25 days x \$2.714 = \$2.907 = \$57.9000 2.02% **Delivery Charge** 300.0 GJ x \$814.2000 300.0 GJ x \$872.1000 \$0.193 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% 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 \$1.095.48 \$1.160.58 \$65.10 2.27% Subtotal Delivery Margin Related Charges 10 11 Commodity Related Charges 12 300.0 GJ x \$1.327 \$398.1000 \$1.327 \$398.1000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge 300.0 GJ x 13 Rider 8 Unbundling Recovery 300.0 GJ \$0.000 \$0.0000 300.0 GJ x \$0.000 \$0.0000 \$0.000 \$0.0000 0.00% 14 \$398.10 \$398.10 \$0.00 Midstream Related Charges Subtotal 0.00% 15 16 300.0 \$4.568 \$1,370,40 \$4.568 \$1.370.40 \$0.000 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) G.I x 300.0 G.I x 17 Subtotal Commodity Related Charges \$1,768.50 \$1,768.50 \$0.00 0.00% 18 19 Total (with effective \$/GJ rate) 300.0 \$2,863.98 \$9.547 300.0 \$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 GJ x \$0.000 = \$0.0000 0.00% Rider 2 2009 ROE Rate Rider 250.0 \$0.000 = \$0.0000 250.0 GJ x \$0,0000 \$0,000 27 250.0 GJ x (\$0.036) =250.0 \$0.000 = \$0.0000 \$9.0000 0.37% (\$9.0000) GJ x \$0.036 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 \$325.25 Midstream Related Charges Subtotal \$325.25 \$0.00 0.00% 35 \$4.568 36 \$4.568 \$1,142.00 \$1,142.00 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) 250.0 GJ x 250.0 GJ x \$0.000 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 \$0.816 = \$0.816 = 0.00% Basic Charge 365.25 days x \$298.08 365.25 days x \$298.08 \$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 \$0.000 = Rider 2 2009 ROE Rate Rider 320.0 GJ x \$0.000 = \$0.0000 320.0 GJ x \$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 (\$10.2400) (\$3.8400) Rider 5 RSAM 320.0 GJ x (\$0.020) =(\$6.4000)320.0 GJx(\$0.032) =(\$0.012)-0.13% 49 \$1,148.64 \$69.44 Subtotal Delivery Margin Related Charges \$1,218.08 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% Rider 8 Unbundling Recovery \$0.0000 53 320.0 GJ x \$0.000 320.0 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 56 320.0 \$4.568 \$4.568 \$1,461.76 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) GJ x \$1,461.76 320.0 GJ x \$0.000 57 \$1,891.20 \$0.00 Subtotal Commodity Related Charges \$1,891.20 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%

# 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 J	ANUARY 1, 2011	RATES		PROPOSED	JANUARY 1, 2012	2 RATES		Annual Increase/Decrease	e
1	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volur	ma	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
2	Delivery Margin Related Charges	Voidi		rate	Απιααιψ	Voidi	iic	rate	Allitual ψ	rate	Απιααιψ	Total Allidai biii
3 4	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%
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	2,000.0	00 A		\$2.850.40	2,000.0	00 A		\$2.850.40	ψο.σσσ	\$0.00	0.00%
15					<del>-</del> ,				<del>+</del> =,••••		75.55	
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	<u>Delivery Margin Related Charges</u>											
23 24	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%
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				_	<del>***,*********************************</del>			_	¥1,75=11=1	•	<b>7</b>	
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			' <u>-</u>	\$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	Total (with effective E/C I rate)				********				*** ***		4.00.00	4.050/
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	COLUMBIA GERVICE AREA											
41	COLUMBIA SERVICE AREA											
42 43	<u>Delivery Marqin Related Charges</u> 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%
43	Basic Grange	303.23	uays x	φ4.334 <b>-</b>	\$1,590.24	303.23	uays x	φ4.334 -	\$1,590.24	\$0.00	\$0.00	0.00%
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	0,000.0	00 A	(\$0.020)	\$9,081.24	0,000.0	00 X	(40.002)	\$9,625.74	(40.0.2)	\$544.50	1.97%
50				_	<del>+</del> • • • • • • • • • • • • • • • • • • •			_	40,020111	,	***************************************	
51	Commodity Related Charges	1										
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	<del>-</del>	I										
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	I		_	\$18,493.20			_	\$18,493.20	•	\$0.00	0.00%
58	T. I. C. W. W. W. (1990)	1		_				_				
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%

# 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 J	ANUARY 1, 2011	RATES		PROPOSED	JANUARY 1, 2012	2 RATES	ı	Annual ncrease/Decrease	e
						.,.		-				% of Previous
1 2	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	Total Annual Bill
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	2000 Change		aayo x	V 20	ψο,σσσ.σΞ.τσ		uajo x	V	ψο,σσσ.σΞ.τσ	ψ0.00	ψ0.00	0.0070
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 12	Subtotal Delivery Margin Related Charges			_	\$7,622.52			_	\$8,135.52	-	\$513.00	1.41%
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	Orlandiforized Gas Grialge During Feak Fellod (flot forecast)											
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	Dolivon, Chargo											
33	Delivery Charge (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			· · · · · <u>-</u>	\$10,898.52				\$11,782.02	_	\$883.50	1.46%
38												
39	Commodity Related Charges											
40	Midstream Cost Recovery Charge		0.1	20.740	*********		0.1	00.740	** ***	***	** ***	0.000/
41	(a) Off-Peak Period	9,300.0	GJ x GJ x	\$0.749 = \$0.749 =	\$6,965.7000	9,300.0 0.0	GJ x GJ x	\$0.749 = \$0.749 =	\$6,965.7000	\$0.000 \$0.000	\$0.0000	0.00% 0.00%
42 43	(b) Extension Period Commodity Cost Recovery Charge	0.0	GJ X	\$0.749 =	\$0.0000	0.0	GJ X	\$0.749 =	\$0.0000	\$0.000	\$0.0000	0.00%
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	(-)			*	*******			*	,	40.000	*******	
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%

# 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 .	IANUARY 1, 20	11 RATES		PROPO	SED JANUARY 1,	2012 RATES		Annual Increase/Decrease	e
1 2	LOWER MAINLAND SERVICE AREA	Volu	me	Rate	Annual \$		Volume	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
3 4 5	<u>Delivery Marqin Related Charges</u> Basic Charge	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
6 7	Demand Charge	58.5	GJ x	\$15.943	=\$11,191.	<b>99</b> 5	8.5 GJ	x \$16.996	=\$11,931.19	\$1.053	\$739.20	0.97%
9 10 11 12	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,700.0 9,700.0 9,700.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	0000 9,70 7000) 9,70	0.0 GJ	x \$0.000		\$0.051 \$0.000 \$0.021	\$494.7000 \$0.0000 \$203.7000 \$698.40	0.65% 0.00% 0.27% <b>0.92%</b>
13 14 15 16 17	Commodity Related Charges  Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,700.0 9,700.0	GJ x GJ x	\$0.764 \$4.568		9,70			= \$7,410.8000 = \$44,309.6000 \$51,720.40	\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
18 19	Total (with effective \$/GJ rate)	9,700.0		\$7.836	\$76,009.	9,70	0.0	\$7.984	\$77,446.79	\$0.148	\$1,437.60	1.89%
	Delivery Margin Related Charges	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
24 25	Demand Charge	82.0	GJ x	\$15.943	=\$15,687.	<b>91</b> 8	2.0 GJ	x \$16.996	=\$16,724.06	\$1.053	\$1,036.15	1.05%
26 27 28 29	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	12,800.0 12,800.0 12,800.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	0000 12,80 8000) 12,80	0.0 GJ	x \$0.000	= \$8,908.8000 = \$0.0000 = \$0.0000 \$8,908.80	\$0.051 \$0.000 \$0.021	\$652.8000 \$0.0000 \$268.8000 <b>\$921.60</b>	0.66% 0.00% 0.27% <b>0.93%</b>
30 31 32 33 34 35	Commodity Related Charges  Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	12,800.0 12,800.0	GJ x GJ x	\$0.749 \$4.568		1000 12,80				\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
36 37	Total (with effective \$/GJ rate)	12,800.0		\$7.717	\$98,776.	12,80	0.0	\$7.870	\$100,734.46	\$0.153	\$1,957.75	1.98%
	COLUMBIA SERVICE AREA <u>Delivery Marqin Related Charqes</u> Basic Charge	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
	Demand Charge	55.4	GJ x	\$15.943	= \$10,598.	<b>)1</b> 5	5.4 GJ	x \$16.996	= \$11,298.94	\$1.053	\$700.03	0.97%
44 45 46 47 48	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,100.0 9,100.0 9,100.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	9,10 (1000) 9,10	0.0 GJ	x \$0.000	, . ,	\$0.051 \$0.000 \$0.021	\$464.1000 \$0.0000 \$191.1000 \$655.20	0.64% 0.00% 0.27% <b>0.91%</b>
49 50 51 52	Commodity Related Charges Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,100.0 9,100.0	GJ x GJ x	\$0.785 \$4.568		9,10				\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
53 54	Total (with effective \$/GJ rate)	9,100.0		\$7.916	\$72,033.	9,10	0.0	\$8.065	\$73,388.84	\$0.149	\$1,355.23	1.88%

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

Line											Annual	
No.	Particular Particular	. —	EXISTING J	ANUARY 1, 2011 F	RATES	. ———	PROPOSED	JANUARY 1, 201	12 RATES		ncrease/Decrease	
1		Volur	ne	Rate	Annual \$	Volur	ne	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			· / <u>-</u>	\$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												
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		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		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		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					\$43,679.10			_	\$46,677.90		\$2,998.80	2.94%
27												
28												
29		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		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					\$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%

# 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 Particular		EXISTING J	JANUARY 1, 20	11 RATES		PROPOSED	JANUARY 1, 2	2012 RATES		Annual Increase/Decrease	
1		Volu	ıme	Rate	Annual \$	Volun	ne	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 m	nonths x	\$880.00	=\$10,560.00	\$0.00	\$0.00	0.00%
5 6	Delivery Charge	8.100.0	GJ x	\$1.073	<b>\$8.691.3000</b>	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		8.100.0	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
8	Rider 3 ESM	8,100.0	GJ x	(\$0.013)		8,100.0	GJ x	\$0.000		\$0.013	\$105.3000	0.17%
9	Rider 4 Reserve for Future Use	8,100.0	GJ x	\$0.000		8,100.0	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
10		2,		******	\$8,586.00	2,12212		******	\$9,234.00	******	\$648.00	1.04%
11	Captotal Bollion, margin Holaton Charges				<del></del>				<b>40,2000</b>		<del>\$0.0.00</del>	
12	Commodity Related Charges											
13		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		8,100.0	GJ x	\$4.568	= \$37,000.8000	\$0.000	\$0.0000	0.00%
15		.,		,	\$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 m	nonths 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		4,000.0	GJ x	\$0.000		\$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		4,000.0	GJ x	\$0.749	, ,	4,000.0	GJ x	\$0.749	, ,	\$0.000	\$0.0000	0.00%
35		4,000.0	GJ x	\$4.568	Ψ10,E12.0000	4,000.0	GJ x	\$4.568		\$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												
39												
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%

#### APPENDIX F-2 TAB 1.1.2 PAGE 8

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

No.	Particular		EFFECTIV	E JANUARY 1,	2011		PROPOSED J	IANUARY 1, 20	12 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	ume	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	LOWER MAINLAND SERVICE AREA				<u> </u>							
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	Total (with effective \$/GJ rate)	407.005.0		40.077	£400 000 07	407.005.0		00.004	£400 F00 00	00.057	*********	0.500/
19	Total (with enective \$700 rate)	467,305.6	ı,	\$0.877	\$409,869.67	467,305.6	_	\$0.934	\$436,506.09	\$0.057	\$26,636.42	6.50%

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

Ann	nual

Line

No.	Particular		EFFECTIV	E JANUARY 1,	2011	P	ROPOSED J	ANUARY 1, 20°	12 RATES		Increase/Decrease	
1		Volui	me	Rate	Annual \$	Volu	me	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		= \$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	,	584,475.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	(\$0.009)		584,475.8	GJ x	\$0.000		\$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	,	28,607.9	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	(\$0.009)		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	T. I. I. W. W. W. W. W. W. L. I.											
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%

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

ine				Annual
Nο	Particular	EFFECTIVE IANIJARY 1 2011	PROPOSED IANUARY 1 2012 RATES	Increase/Dec

1.5			K.	ATE SCHEDU	ILE 22B - LARGE INL	DUSTRIAL 1-S	EKVICE				A	
Line No.	Particular	. ———	EFFECTIV	E JANUARY 1,	2011	Р	ROPOSED JA	ANUARY 1, 201	12 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	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%
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%
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	\$0.086		457,345.8	GJ x	\$0.092		\$0.006	\$2,744.0748	0.88%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x		= \$0.0000	457,345.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	(\$0.006)		457,345.8	GJ x	\$0.000		\$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	Delivery Observed Intermediate MTO											
12	Delivery Charge - Interruptible MTQ	6 700 4	C L v	\$0.802	- 05 200 2040	6 700 4	01.4	<b>CO OFF</b>	-	<b>60.053</b>	#256 0472	0.11%
13 14	- Apr. 1 to Nov. 1 - Nov. 1 to Apr. 1	6,732.4 0.0	GJ x GJ x			6,732.4 0.0	GJ x GJ x	\$0.855 \$1.231		\$0.053 \$0.076	\$356.8172 \$0.0000	0.11%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ X			6,732.4	GJ X	\$0.000		\$0.076	\$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	(\$0.006)		6,732.4	GJ X	\$0.000		\$0.000	\$40.3944	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)	0,732.4	00 x	(ψ0.000)	\$5,358.99	0,732.4	00 X	ψ0.000	\$5,756.20	ψ0.000	\$397.21	0.13%
18	Transportation Interruptible (Benvery Orlarge Interruptible WT Q)				Ψ0,000.00				ψο,100.20		ψοστ.Στ	0.1070
19	Non-Standard Charges (not forecast )											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21	3 · · · · · · · · · · · · · · · · · · ·											
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	basic Gliarge	12	IIIOIIIII X	φ4,337.00	- \$34,444.00	12	months x	φ4,557.00	- <del>\$34,444.00</del>	φ0.00	φυ.υυ	0.00 /8
30 31	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%
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		= \$0.0000	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			0.0	GJ x	\$0.214		\$0.013	\$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	\$0.287		14,503.1	GJ x	\$0.306		\$0.019	\$275.5589	0.16%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x			14,503.1	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x		· · · /	14,503.1	GJ x	\$0.000		\$0.002	\$29.0062	0.02%
42 43	Rider 4 Reserve for Future Use	14,503.1	GJ x	\$0.000		14,503.1	GJ x	\$0.000		\$0.000	\$0.0000 \$304.57	0.00% <b>0.18%</b>
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				\$4,133.38				\$4,437.95		\$3U4.3 <i>f</i>	0.16%
45	Non-Standard Charges (not forecast )											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47	23.4, 23and Garonargo, Dalanoing Gorvice, Dackstopping Gas											
48	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
49										72.30	72.50	
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%

## FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line			K.F	I E SCHEDU	LE 23 - L	LARGE COMI	WERCIAL 1-5	ERVICE					Annual	
No.	Particular		EFFECTIVE	JANUARY 1, 2	2011		P	ROPOSED JA	NUARY 1, 201	2 RATE	3		Increase/Decrease	
1		Volum	e	Rate	Aı	nnual \$	Volu	me	Rate		Annual \$	Rate	Annual \$	% of Previous Annual Bill
	LOWER MAINLAND SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	1,590.24	\$0.00	\$0.00	0.00%
5 6	Administration Charge	12	months x	\$78.00	=	\$936.00	12	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
7 8 9 10	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,100.0 4,100.0 4,100.0 4,100.0	GJ x GJ x GJ x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (	9,503.8000 \$0.0000 \$114.8000) (\$82.0000) <b>0,307.00</b>	4,100.0 4,100.0 4,100.0 4,100.0	GJ x GJ x GJ x	\$2.467 \$0.000 \$0.000 (\$0.032)	- - -	0,114.7000 \$0.0000 \$0.0000 (\$131.2000) <b>39,983.50</b>	\$0.149 \$0.000 \$0.028 (\$0.012)	\$610.9000 \$0.0000 \$114.8000 (\$49.2000) \$676.50	5.16% 0.00% 0.97% -0.42% <b>5.72%</b>
13 14 15	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas													
16 17	Total (with effective \$/GJ rate)	4,100.0		\$2.886	\$11	,833.24	4,100.0		\$3.051	\$1	2,509.74	\$0.165	\$676.50	5.72%
18 19	INLAND SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	51,590.24	\$0.00	\$0.00	0.00%
20 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 25 26 27 28	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,700.0 4,700.0 4,700.0 4,700.0	G1 x G1 x G1 x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (:	0,894.6000 \$0.0000 \$131.6000) (\$94.0000) <b>0,669.00</b>	4,700.0 4,700.0 4,700.0 4,700.0	G1 x G1 x G1 x	\$2.467 \$0.000 \$0.000 (\$0.032)	- ·	1,594.9000 \$0.0000 \$0.0000 (\$150.4000) 1,444.50	\$0.149 \$0.000 \$0.028 (\$0.012)	\$700.3000 \$0.0000 \$131.6000 (\$56.4000) <b>\$775.50</b>	5.31% 0.00% 1.00% -0.43% 5.88%
29 30 31 32 33	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas  Iotal (with effective \$/GJ rate)	4,700.0		\$2.807	\$13	3,195.24	4,700.0		\$2.972	<b>\$</b> 1	3,970.74	\$0.165 <u> </u>	\$775.50	5.88%
34 35	COLUMBIA SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	61,590.24	\$0.00	\$0.00	0.00%
36 37 38	Administration Charge	12	months x	\$78.00	=	\$936.00	12	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
39 40 41 42 43 44	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,200.0 4,200.0 4,200.0 4,200.0	GJ x GJ x GJ x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (:	0,735.6000 \$0.0000 \$117.6000) (\$84.0000) 0,534.00	4,200.0 4,200.0 4,200.0 4,200.0	GJ x GJ x GJ x	\$2.467 \$0.000 \$0.000 (\$0.032)	<u> </u>	0,361.4000 \$0.0000 \$0.0000 (\$134.4000) <b>0,227.00</b>	\$0.149 \$0.000 \$0.028 (\$0.012)	\$625.8000 \$0.0000 \$117.6000 (\$50.4000) <b>\$693.00</b>	5.19% 0.00% 0.98% -0.42% <b>5.75%</b>
45 46 47	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas													
	Total (with effective \$/GJ rate)	4,200.0		\$2.871	\$	512,060.24	4,200.0		\$3.036	\$1	2,753.24	\$0.165	\$693.00	5.75%

Annual

# 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, 2	2011	P	ROPOSED JA	NUARY 1, 201	12 RATES		Increase/Decrease	
_		)/-l		D-t-	A 1 @	\/-l-		D-4-	A 6	D-t-	A   6	% of Previous
2	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	Annual Bill
	Basic Charge	12	months x	\$587.00	= \$7,044.00	12	months x	\$587.00	= \$7,044.00	\$0.00	\$0.00	0.00%
	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		\$0.021	\$400.8102	1.04%
12	Transportation - Firm				\$11,909.79				\$13,284.00	_	\$1,374.21	3.57%
13 14 15 16	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas											
	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											
	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	Dasic Orlarge	12	monuis x	ψ507.00	Ψ1,044.00	12	months x	ψ307.00	Ψ1,044.00	Ψ0.00	ψ0.00	0.0070
	Administration Charge	12	months x	\$78.00	=\$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
24 25	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%
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		= \$0.0000	40,670.5	GJ x		= \$0.0000	\$0.000	\$0.0000	0.00%
28	Rider 3 ESM	40,670.5	GJ x	(\$0.021)		40,670.5	GJ x	\$0.000		\$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	T. I. C. W. W. W. W. W. W. W.											
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	COLUMBIA SERVICE											
36 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	basic Charge	12	monuis x	φ367.00	- \$1,044.00	12	monuis x	φ367.00	- φ1,044.00	φ0.00 _	φυ.υυ	0.00 /6
	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
40				******						_	70.00	
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									·	_	<u> </u>	
43	Delivery Charge	30,357.8	GJ x		= \$19,580.7810	30,357.8	GJ x	Ψ0.000	= \$21,129.0288	\$0.051	\$1,548.2478	2.51%
44	Rider 2 2009 ROE Rate Rider	30,357.8	GJ x		= \$0.0000	30,357.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
45	Rider 3 ESM	30,357.8	GJ x	(\$0.021)		30,357.8	GJ x	\$0.000		\$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 )											
46 49	UOR, Balancing gas, Backstopping Gas, Replacement Gas	ĺ										
50	Oort, Datarioning gas, Dackstopping Gas, Repideement Gas											
	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%
										I		

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

				RATE SCHE	DUI	LE 27 - INTERRUI	PTIBLE T-SER	RVICE						
Line No.		. —	EFFECTIVE	E JANUARY 1,	201	1	F	PROPOSED JA	NUARY 1, 201	2 RAT	TES		Annual Increase/Decrease	
1		Volu	ıme	Rate		Annual \$	Volu	ıme	Rate	_	Annual \$	Rate	Annual \$	% of Previous Annual Bill
3	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	i 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 8 9 10	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM	53,957.0 53,957.0 53,957.0	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$57,895.8610 \$0.0000 (\$701.4410) <b>\$57,194.42</b>	53,957.0 53,957.0 53,957.0	GJ x GJ x GJ x	Ŧ	<u>-</u>	\$61,510.9800 \$0.0000 \$0.0000 <b>\$61,510.98</b>	\$0.067 \$0.000 \$0.013	\$3,615.1190 \$0.0000 \$701.4410 <b>\$4,316.56</b>	5.26% 0.00% 1.02% <b>6.28%</b>
11 12 13 14 15	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas 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%
17 18 19 20	B INLAND SERVICE AREA Basic Charge	12	months x	\$880.00	=_	\$10,560.00	12	months x	\$880.00	=	\$10,560.00	\$0.00 <u> </u>	\$0.00	0.00%
21 22	Administration Charge	12.0	months x	\$78.00	=_	\$936.00	12.0	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
23 24 25 26 27 28	B Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible	48,903.9 48,903.9 48,903.9	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$0.0000	48,903.9 48,903.9 48,903.9	GJ x GJ x	\$1.140 \$0.000 \$0.000	-	\$55,750.4460 \$0.0000 \$0.0000 <b>\$55,750.45</b>	\$0.067 \$0.000 \$0.013	\$3,276.5613 \$0.0000 \$635.7507 \$3,912.32	5.17% 0.00% 1.00% <b>6.18%</b>
29 30 31 32 33	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas Total (with effective \$/GJ rate)	48,903.9	-	\$1.295	=	\$63,334.13	48,903.9	-	\$1.375	_	\$67,246.45	\$0.080 _	\$3,912.32	6.18%
35 36	COLUMBIA SERVICE AREA Basic Charge	12	months x	\$880.00	=_	\$10,560.00	12	months x	\$880.00	<u> </u>	\$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 41 42 43 44	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible	7,733.8 7,733.8 7,733.8	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$8,298.3674 \$0.0000 (\$100.5394) \$8,197.83	7,733.8 7,733.8 7,733.8	GJ x GJ x	******	= = = =	\$8,816.5320 \$0.0000 \$0.0000 \$8,816.53	\$0.067 \$0.000 \$0.013	\$518.1646 \$0.0000 \$100.5394 <b>\$618.70</b>	0.82% 0.00% 0.16% <b>0.98%</b>
45 46 47 48	Non-Standard Charges (not forecast )     UOR, Balancing gas, Backstopping Gas	7,733.8	=	\$2.546	_	\$19,693.83	7,733.8	-	\$2.626		\$20,312.53	\$0.080 <u> </u>	\$618.70	0.98%

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.

49 Total (with effective \$/GJ rate)

#### 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

APPENDIX F-2 TAB 1.1.2 PAGE 14

Line No.	PARTICULARS		EXISTING JA	NUARY 1, 2011 RA	ATES	F	PROPOSED J	ANUARY 1, 2012 R	ATES		Annual Increase/Decreas	e
1	INLAND SERVICE AREA	Volu	me	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	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	\$0.230	\$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ X	(\$0.048) =	(\$2.4000)	50.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$2.4000	0.23%
10	Rider 5 RSAM	50.0	GJ X	(\$0.020) =	(\$2.4000)	50.0	GJ x	(\$0.032) =	(\$1.6000)	(\$0.048	(\$0.6000)	-0.06%
11	Subtotal Delivery Margin Related Charges	00.0	00 X _	\$3.207	\$302.43	00.0	00 X _	\$3.499	\$317.03	(\$0.012)	\$14.60	1.37%
12	, с		_		·		_					
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 18	Subtotal Commodity Related Charges		_	\$15.214	\$760.70		_	\$15.214	\$760.70		\$0.00	0.00%
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 24	Basic Charge	365.25	days x	\$0.816 =	\$298.08	365.25	days x	\$0.816 =	\$298.08	\$0.00	\$0.00	0.00%
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 30	Subtotal Delivery Margin Related Charges		_	\$2.658	\$962.58		_	\$2.875	\$1,016.83		\$54.25	1.21%
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 35	Rider 1 Propane Surcharge Subtotal Commodity Related Charges	250.0	GJ x	\$8.254 = \$14.123	\$2,063.5000 <b>\$3,530.75</b>	250.0	GJ x	\$8.254 = \$14.123	\$2,063.5000 <b>\$3,530.75</b>	\$0.000	\$0.0000 <b>\$0.00</b>	0.00% <b>0.00%</b>
36	Subtotal Commodity Nelated Charges		-	φ14.125	45,550.75		_	φ14.123	\$3,330.73		φυ.υυ	0.00 /8
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 40	Rate 3 - Large Commercial  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			,	<b>4</b>	* -,		,	******	* 1,7221_ 1	******	*****	
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 46	Rider 3 ESM Rider 5 RSAM	4,500.0 4,500.0	GJ x GJ x	(\$0.028) = (\$0.020) =	(\$126.0000) (\$90.0000)	4,500.0 4,500.0	GJ x GJ x	\$0.000 = (\$0.032) =	\$0.0000 (\$144.0000)	\$0.028	\$126.0000 (\$54.0000)	0.17% -0.07%
47	Subtotal Delivery Margin Related Charges	4,500.0	GJ X _	\$2.270	\$11,805.24	4,500.0	G3 X	(\$0.032) = \$2.435	\$12,547.74	(\$0.012)	\$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 52	Cost of Gas Rider 1 Propane Surcharge	4,500.0 4,500.0	GJ x GJ x	\$4.568 = \$8.556 =	\$20,556.0000 \$38,502.0000	4,500.0 4,500.0	GJ x GJ x	\$4.568 = \$8.556 =	\$20,556.0000 \$38,502.0000	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
53	Subtotal Commodity Related Charges	4,300.0	30 A _	\$14.123	\$63,553.50	7,500.0	OU ^ _	\$14.123	\$63,553.50	Ψ0.000	\$0.000 \$0.00	0.00%
54	, ,		_				_				-	
55	Total (with effective \$/GJ rate)	<u>4,500.0</u>		\$16.746	\$75,358.74	4,500.0		\$16.911	\$76,101.24	\$0.165	\$742.50	0.99%
		.1				l						

#### FORTISBC ENERGY INC.

#### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY

#### PROPOSED JANUARY 1, 2013 RATES

APPENDIX F-2 TAB 1.2.1 PAGE 1 SCHEDULE 1

PAGE 14

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 1:		_		DE	LIVERY MARGIN	1	·		
	RESIDENTIAL SERVICE	PROPOSEI	) JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSEI	D JANUARY 1, 2013	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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)	=	·		=	-		=	·	

APPENDIX F-2 TAB 1.2.1 PAGE 2 SCHEDULE 2

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 2:				DE	LIVERY MARGIN	ı			
	SMALL COMMERCIAL SERVICE	PROPOSEI	JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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)	=			=			=		

APPENDIX F-2 TAB 1.2.1 PAGE 3 SCHEDULE 3

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 3:				DE	LIVERY MARGIN				
	LARGE COMMERCIAL SERVICE	PROPOSED	JANUARY 1, 2012	RATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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 17	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
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)	_			=			=		
	, , , , , , , , , , , , , , , , , , , ,									

APPENDIX F-2 TAB 1.2.1 PAGE 4 SCHEDULE 4

#### BCUC ORDER NO.G-XXX-11 G-XXX-11

	RATE SCHEDULE 4:				DE	LIVERY MARGIN	ı			
	SEASONAL SERVICE	PROPOSEI	D JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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		Balancing, Backsto	enning and LIOD no	or DCHC				Delensing Deals	inn	) === BCHC
27	Unauthorized Gas Charge per gigajoule	Order No. G-110-0		SI BCOC				Order No. G-110	topping and UOF -00.	c per BCUC
28	during peak period									
29										
30	Total Wasiable Cost non signicula, between									
31 32	Total Variable Cost per gigajoule between  (a) Off-Peak Period	\$6.267	\$6.252	\$6.288	\$0.103	\$0.103	\$0.103	\$6.370	\$6.355	\$6.391
33		\$7.044	\$7.029	\$7.065	\$0.103	\$0.103	\$0.103	\$7.147	\$7.132	\$7.168
33	(D) EXIGINION PENOU	<u>Φ1.044</u>	\$1.029	COU. 1¢	φυ. 103	φυ. 103	φυ. 103	Φ1.141	φ1.132	φ1.108

APPENDIX F-2 TAB 1.2.1 PAGE 5 SCHEDULE 5

	RATE SCHEDULE 5 GENERAL FIRM SERVICE	PROPOSEI	D JANUARY 1, 2012	RATES		LIVERY MARGIN		PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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										

\$6.049

\$0.065

\$0.065

\$0.065

\$6.093

\$6.028

\$6.013

17 18

19 Total Variable Cost per gigajoule

\$6.078

\$6.114

APPENDIX F-2 TAB 1.2.1 PAGE 6 SCHEDULE 6

	RATE SCHEDULE 6: NGV - STATIONS	PROPOSEI	D JANUARY 1, 2012	RATES		LIVERY MARGIN		PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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

APPENDIX F-2 TAB 1.2.1 PAGE 6.1 SCHEDULE 6A

	RATE SCHEDULE 6A: NGV - VRA's			
ine		7	DELIVERY MARGIN	
10.	Particulars	PROPOSED JANUARY 1, 2012 RATES	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				
	Commodity Related Charges			
2	Cost of Gas (Commodity Cost Recovery Charge) per GJ	\$4.568	\$0.000	\$4.568
3	Midstream Cost Recovery Charge per GJ	\$0.353	\$0.000	\$0.353
4	Subtotal Commodity Related Charges per GJ	\$4.921	\$0.000	\$4.921
5				
6	Compression Charge per gigajoule	\$5.28	\$0.00	\$5.28
7				
8	Minimum Channa	\$125.00	\$0.00	\$125.00
9	Minimum Charges	\$125.00	\$0.00	\$125.00
.0				
22			<del></del>	<del></del>
	Total Variable Cost per gigajoule	\$14.022	\$0.266	\$14.288

APPENDIX F-2 TAB 1.2.1 PAGE 7 SCHEDULE 7

	RATE SCHEDULE 7:				DE	LIVERY MARGIN	ı			
	INTERRUPTIBLE SALES	PROPOSE	D JANUARY 1, 2012	RATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		Rolonoina Rooks	topping and UOR p	or BCHC				Balancing, Backs	stanning and LIOP	nor BCHC
16	Charges per gigajoule for UOR Gas	Order No. G-110-		el BCOC				Order No. G-110		per BCOC
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
							-			

#### FORTISBC ENERGY INC.

### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED JANUARY 1, 2013 RATES

#### BCUC ORDER NO.G-XXX-11

PAGE 14

APPENDIX F-2 TAB 1.2.1 PAGE 8

SCHEDULE 22

	RATE SCHEDULE 22:				DE	LIVERY MARGIN	I			
	LARGE INDUSTRIAL T-SERVICE	PROPO	SED JANUARY 1, 2	2012	RELATED	CHARGES CHA	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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 Bac	stopping and UOF	R ner BCLIC				Palansina Pask	stopping and UOF	nor PCHC
9	Charges per gigajoule for UOR Gas	Order No. G-11		( pc/ 2000				Order No. G-110		t per BCOC
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	Demand Surcharge per gigajodie	\$17.00	\$17.00	\$17.00	φυ.υυ	φυ.υυ	φυ.υυ	\$17.00	φ17.00	φ17.00
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		topping and UOR	per BCUC				Balancing, Back Order No. G-110	stopping and UOF 0-00.	R per BCUC
21		Order No. G-110-	.00.							
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	Administration charge per month	Ψ7 0.00	Ψ7 0.00	Ψ70.00	ψ0.00	Ψ0.00	ψ0.00	Ψ70.00	Ψ7 0.00	ψ10.00
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
	. Jan. 1 a. a. a. a door por gigajouio	Ψ0.000	ψ0.000	ψυ.υυυ	Ψ0.001	ψ0.001	ψ0.001	Ψ0.000	ψ0.000	ψ0.000

#### APPENDIX F-2 TAB 1.2.1 PAGE 9 SCHEDULE 22A

	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE			
Line			DELIVERY MARGIN	
No.	Particulars	PROPOSED JANUARY 1, 2012	RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1 2	INLAND SERVICE AREA			
3 4	Basic Charge per Month	\$4,810.00	\$0.00	\$4,810.00
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		Balancing, Backstopping and UOR per BCUC
15	Charges per gigajoule for UOR Gas	Order No. G-110-00.		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		D D		Balancing, Backstopping and UOR per BCUC
25 26	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Order No. G-110-00.
27				
28	Replacement Gas	Sumas Daily Price		Sumas Daily Price
29	·	plus 20 Percent		plus 20 Percent
30		<b>,</b>		,
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 10 SCHEDULE 22B

	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE			DELIVERY MARON			
	LARGE INDUSTRIAL 1-SERVICE	PROPOSED IANUARY 4	1042	DELIVERY MARGIN		DDODOSED JANUARY 4 2042	DATES
Line		PROPOSED JANUARY 1, 2 Columbia	Elkview	RELATED CHARGES CH. Columbia	Elkview	PROPOSED JANUARY 1, 2013 Columbia	Elkview
No.	Particulars	Except Elkview	Coal	Except Elkview	Coal	Except Elkview	Coal
140.	(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				Balancing, Backstopping a	
17	Charges per gigajoule for UOR Gas	BCUC Order No. G-110-	00.			BCUC Order No. G-110-0	0.
18							
19							
20	Demand Surchage per gigajoule	\$17.00	\$17.00	\$0.00	\$0.00	\$17.00	\$17.00
21	0 1 007		·				·
22		Balancing, Backstopping	and LIOP por			Balancing, Backstopping a	nd UOR per
23	Charges per gigajoule for Backstopping Gas	BCUC Order No. G-110-				BCUC Order No. G-110-0	
24	333,333						
25							
26	Administration Charge per Month	\$78.00	\$78.00	\$0.00	\$0.00	\$78.00	\$78.00
27	, animinon and on a go por mornin	Ψ. σ.σσ	ψ. σ.σσ	φο.σσ	ψ0.00	φ. σ.σσ	ψ. σ.σσ
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
		<u> </u>	72.200		73321	<u> </u>	<del>+1.300</del>

#### APPENDIX F-2 TAB 1.2.1 PAGE 11 SCHEDULE 23

	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	PROPO	OSED JANUARY 1, 2	2012		LIVERY MARGIN		PPOPOSEF	) JANUARY 1, 201;	DATES
Line	LANGE COMMERCIAL 1-SERVICE	Lower	JSED JANUART 1, 2	2012	Lower	D CHARGES CH	ANGES	Lower	JANUART 1, 201.	RAIES
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	Dell'arma Olivania manaritari tanda	00.407	00.407	00.407	00.400	00.400	00.400	<b>#0.055</b>	<b>#0.055</b>	00.055
3	Delivery Charge per gigajoule	\$2.467	\$2.467	\$2.467	\$0.188	\$0.188	\$0.188	\$2.655	\$2.655	\$2.655
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 10 11	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas (c) Replacement Gas	Balancing, Backstopping, Replacement and UOR per BCUC Order No. G-110-00.							stopping, Replace Order No. G-110-	
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	Rider 5 RSAM	(\$0.032)	(\$0.032)	(\$0.032)	\$0.000	\$0.000	\$0.000	(\$0.032)	(\$0.032)	(\$0.032)
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 12 SCHEDULE 25

	RATE SCHEDULE 25				DE	LIVERY MARGIN	N			
	GENERAL FIRM T-SERVICE	PROP	OSED JANUARY 1, 2	2012	RELATE	D CHARGES CH	ANGES	PROPOSEI	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
5 6	Delivery Charge per gigajoule (Interr. MTQ)	\$0.696	\$0.696	\$0.696	\$0.065	\$0.065	\$0.065	\$0.761	\$0.761	\$0.761
7	Administration Charge per Month	\$78.00	\$78.00	\$78.00	\$0.00	\$0.00	\$0.00	\$78.00	\$78.00	\$78.00
8										
10	Sales									
11 12	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas		stopping, Replacer Order No. G-110-0						kstopping, Replace COrder No. G-110	
13 14	(c) Replacement Gas (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		<u> </u>	<del></del>		<u> </u>			· <del></del>	·	
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 13 SCHEDULE 26

RATE SCHEDULE 26:				DE	LIVERY MARGIN	ı			
NATURAL GAS VEHICLE T-SERVICE	PROPO	SED JANUARY 1, 2	012	RELATE	CHARGES CH	ANGES	PROPOSED	JANUARY 1, 2013	RATES
Line	Lower			Lower			Lower		
No. Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	******	*	******	*****	*****	*****	<b>4</b> . 5.55	7	******
8 9 Sales									
10 (a) Charge per gigajoule for Balancing Gas	Order No. C 110	stopping and UOR	per BCUC				Balancing, Back	kstopping and UO	R per
<ul><li>(b) Charge per gigajoule for Backstopping Gas</li><li>(d) Charge per gigajoule for UOR Gas</li></ul>	Graci No. G-110	0-00.					Bood Graci N	J. G-110-00.	
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				<del></del>					
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 14 SCHEDULE 27

RATE SCHEDULE 27:					LIVERY MARGIN				
INTERRUPTIBLE T-SERVICE		SED JANUARY 1, 2	2012		D CHARGES CH	ANGES		JANUARY 1, 201	3 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 2	\$880.00	\$880.00	\$880.00	\$0.00	\$0.00	\$0.00	\$880.00	\$880.00	\$880.00
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 7 8	\$78.00	\$78.00	\$78.00	\$0.00	\$0.00	\$0.00	\$78.00	\$78.00	\$78.00
9 Sales 10 (a) Charge per gigajoule for Balancing Gas 11 (b) Charge per gigajoule for Backstopping Gas 12 (d) Charge per gigajoule for UOR Gas		Balancing, Backstopping and UOR per BCUC Order No. G-110-00.					Balancing, Bac BCUC Order N	kstopping and UC o. G-110-00.	PR per
13 14 Rider 2 2009 ROE Rate Rider 15 Rider 3 ESM	\$0.000 \$0.000	\$0.000 \$0.000	\$0.000 \$0.000	\$0.000 \$0.000	\$0.000 \$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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.389 \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% 3 Basic Charge davs x davs x 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% 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% (\$0.032)(\$3.0400) (\$0.032)(\$3,0400) \$0.0000 8 Rider 5 RSAM 95.0 GJ x 95.0 GJ x \$0.000 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 GJ x \$0.009 \$0.8550 95.0 GJ x \$0.009 0.8550 \$0.0000 0.00% 95.0 \$0.000 Midstream Related Charges Subtotal 14 \$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 Total (with effective \$/GJ rate) 19 95.0 \$1,036.61 95.0 \$1,067.48 \$30.87 2.98% \$10.912 \$11.237 \$0.325 20 21 INLAND SERVICE AREA **Delivery Margin Related Charges** 22 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 \$3.531 = \$264.8250 GJ x \$3.856 = \$289.2000 \$0.325 \$24.3750 2.88% Delivery Charge 75.0 GJ x 75.0 26 Rider 2 2009 ROE Rate Rider \$0.000 = 75.0 GJ x \$0.000 = \$0.0000 75.0 GJ x \$0.0000 \$0.000 \$0.0000 0.00% 27 \$0.000 = 75.0 \$0.000 = 0.00% Rider 3 ESM 75.0 GJ x \$0.0000 GJ x \$0.0000 \$0.000 \$0.0000 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 \$404.51 \$428.88 Subtotal Delivery Margin Related Charges \$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 \$0.00 0.00% 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 37 \$441.90 \$441.90 \$0.00 0.00% Subtotal Commodity Related Charges 38 39 Total (with effective \$/GJ rate) 75.0 \$846.41 \$870.78 \$24.37 2.88% \$11.285 75.0 \$11.610 \$0.325 40 41 **COLUMBIA SERVICE AREA** 42 Delivery Margin Related Charges 43 365.25 \$0.389 = \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% Basic Charge days x days x 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 GJ x \$0.000 = GJ x \$0.000 = \$0.000 \$0.0000 Rider 2 2009 ROE Rate Rider 80.0 \$0.0000 80.0 \$0.0000 0.00% 47 \$0.000 \$0.000 = \$0.0000 0.00% Rider 3 ESM 0.08 GJ x \$0.0000 80.0 GJ x \$0.0000 \$0.000 48 Rider 5 RSAM (\$0.032)(\$2.5600)80.0 (\$0.032)(\$2.5600) \$0.000 \$0.0000 0.00% 80.0 GJ x GJ x 49 Subtotal Delivery Margin Related Charges \$422.00 \$448.00 \$26.00 2.90% 50 51 Commodity Related Charges 52 0.08 GJ x \$1.355 \$108.4000 80.0 GJ x \$1.355 \$108.4000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge \$0.7200 53 GJ x \$0.009 80.0 GJ x \$0.009 \$0.7200 \$0.000 \$0.0000 0.00% Rider 8 Unbundling Recovery 80.0 54 Midstream Related Charges Subtotal \$109.12 \$109.12 \$0.00 0.00% 55 56 0.00% Cost of Gas (Commodity Cost Recovery Charge) 0.08 GJ x \$4.568 \$365.44 80.0 GJ x \$4.568 \$365.44 \$0.000 \$0.00 57 Subtotal Commodity Related Charges \$474.56 80.0 \$474.56 \$0.00 0.00% 58 Total (with effective \$/GJ rate) 59 \$896.56 0.08 \$922.56 \$26.00 2.90%

\$11.532

## 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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 Delivery Margin Related Charges 365.25 \$0.816 \$298.08 365.25 \$0.816 = \$298.08 \$0.00 \$0.00 0.00% Basic Charge days days x \$2.907 = \$872.1000 \$3.152 = \$945.6000 \$73.5000 2.51% **Delivery Charge** 300.0 GJ x 300.0 GJ x \$0.245 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% 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 12 300.0 GJ x \$1.327 \$398.1000 300.0 \$1.327 \$398.1000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge GJ x 13 Rider 8 Unbundling Recovery 300.0 GJ \$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 16 300.0 \$4.568 \$1,370,40 \$4.568 \$1.370.40 \$0.000 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) G.I x 300.0 G.I x 17 Subtotal Commodity Related Charges \$1,768.50 \$1,768.50 \$0.00 0.00% 18 19 Total (with effective \$/GJ rate) 300.0 \$2,929.08 \$3,002.58 \$9.764 300.0 \$10.009 \$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% 26 250.0 GJ x \$0.000 = 250.0 GJ x \$0.000 = \$0.0000 Rider 2 2009 ROE Rate Rider \$0,0000 \$0,0000 \$0,000 0.00% 27 Rider 3 ESM 250.0 GJ x \$0.000 = 250.0 GJ x \$0.000 = \$0.0000 \$0.000 \$0.0000 0.00% \$0.0000 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 \$0.0000 250.0 GJ x \$0.000 \$0.0000 250.0 GJ x \$0.000 \$0.0000 \$0.000 0.00% 34 \$325.25 Midstream Related Charges Subtotal \$325.25 \$0.00 0.00% 35 \$4.568 36 \$4.568 \$1,142.00 \$1,142.00 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) 250.0 GJ x 250.0 GJ x \$0.000 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 \$0.816 = \$0.816 = 0.00% Basic Charge 365.25 days x \$298.08 365.25 days x \$298.08 \$0.00 \$0.00 44 45 \$2.907 = \$1,008.6400 Delivery Charge 320.0 GJ x \$930.2400 320.0 GJ x \$3.152 = \$0.245 \$78.4000 2.52% 46 \$0.000 = \$0.000 = Rider 2 2009 ROE Rate Rider 320.0 GJ x \$0.0000 320.0 GJ x \$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 (\$10.2400) (\$10.2400) Rider 5 RSAM 320.0 GJ x (\$0.032) =320.0 GJx(\$0.032) =\$0.000 \$0.0000 0.00% 49 \$1,218.08 \$1,296.48 Subtotal Delivery Margin Related Charges \$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% Rider 8 Unbundling Recovery 53 320.0 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 56 320.0 \$4.568 \$1,461.76 \$4.568 \$1,461.76 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) GJ x 320.0 GJ x \$0.000 57 \$1,891.20 \$0.00 Subtotal Commodity Related Charges \$1,891.20 0.00% 58 59 Total (with effective \$/GJ rate) 2.52% 320.0 \$9.717 \$3,109.28 320.0 \$9.962 \$3,187.68 \$0.245 \$78.40

## 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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 Delivery Margin Related Charges 365 25 \$4.354 = \$1.590.24 365 25 \$4.354 = \$1.590.24 \$0.00 \$0.00 0.00% 3 Basic Charge days x davs x 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% 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% 2.800.0 (\$0.032) = (\$89.6000) 2.800.0 (\$0.032) = (\$89,6000) \$0.000 \$0.0000 8 Rider 5 RSAM GJ x GJ x 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% Rider 8 Unbundling Recovery 13 2,800.0 GJ x \$0.000 \$0.0000 2,800.0 GJ x \$0.000 \$0.0000 \$0.0000 0.00% \$0.000 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 Total (with effective \$/GJ rate) 2,800.0 \$24,049.04 \$24,575.44 \$526.40 19 \$8.589 2,800.0 \$8.777 \$0.188 2.19% 20 21 INLAND SERVICE AREA 22 Delivery Margin Related Charges 23 Basic Charge \$4.354 = \$1,590.24 \$4.354 = \$1,590.24 \$0.00 \$0.00 0.00% 365.25 days x 365.25 days x 24 25 Delivery Charge 2.600.0 G.I x \$2.467 = \$6 414 2000 2.600.0 G.I 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 2,600.0 (\$0.032) (\$83.2000) Rider 5 RSAM GJ x 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 \$0.999 = 32 2.600.0 GJ x \$0.999 \$2,597,4000 2.600.0 \$2,597.4000 \$0.000 \$0.0000 0.00% G.I x Midstream Cost Recovery Charge 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% \$2,597.40 34 Midstream Related Charges Subtotal \$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 \$4.568 \$11,876.80 \$0.00 0.00% 2,600.0 GJ x \$0.000 37 \$0.00 \$14,474,20 \$14,474,20 Subtotal Commodity Related Charges 0.00% 38 39 Total (with effective \$/GJ rate) 2.600.0 \$22,395,44 2.600.0 \$22,884.24 \$488.80 2.18% \$8 614 \$8.802 \$0.188 40 41 **COLUMBIA SERVICE AREA** 42 Delivery Margin Related Charges 43 \$4.354 = \$1,590.24 \$4.354 = \$1,590.24 \$0.00 0.00% Basic Charge 365.25 days x 365.25 days x \$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 GJx\$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 \$3,418.8000 52 3,300.0 \$1.036 = 3,300.0 \$1.036 = \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge GJ x GJx\$3,418.8000 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 0.00% Midstream Related Charges Subtotal \$3,418.80 \$3.418.80 \$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 \$18,493.20 \$18,493.20 \$0.00 Subtotal Commodity Related Charges 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 \$620.40 2.21%

# 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, 201	12 RATES		PROPOSED	JANUARY 1, 201	3 RATES	ı	Annual ncrease/Decrease	е
		1										% of Previous
1 2	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volui	me	Rate	Annual \$	Rate	Annual \$	Total Annual Bill
3	Delivery Marqin 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		217	uays x	Ψ14.425 -	ψ5,000.5210	214	uays x	ψ1 <del>4.42</del> 5 -	ψ3,000.3210	ψ0.00	Ψ0.00	0.0070
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		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		5,400.0	GJ x	\$0.000 =	70.000	5,400.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
11				-	\$8,135.52			_	\$8,691.72	-	\$556.20	1.51%
12												
13 14	Commodity Related Charges  Midstream Cost Recovery Charge											
15		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		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	0.0	00 X	ψ0.70-	ψ0.0000	0.0	00 X	ψ0.704	ψ0.0000	ψ0.000	ψ0.0000	0.0070
18		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		0.0	GJ x	\$4.568 =		0.0	GJ x	\$4.568 =	\$0.0000	\$0.000	\$0.0000	0.00%
20				_						_		-
21				_	\$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		3,400.0		-	\$30,920.32	5,400.0		_	\$37,404.52	-	\$330.20	1.3176
27												
28	INLAND SERVICE AREA											
29												
30		214	days x	\$14.423 =	\$3,086.5216	214	days x	\$14.423 =	\$3,086.5216	\$0.00	\$0.00	0.00%
31	•		,				,					
32												
33		9,300.0	GJ x	\$0.935 =	,	9,300.0	GJ x	\$1.038 =	\$9,653.4000	\$0.103	\$957.9000	1.56%
34		0.0	GJ x	\$1.712 =		0.0	GJ x	\$1.815 =	\$0.0000	\$0.103	\$0.0000	0.00%
35		9,300.0	GJ x	\$0.000 =	ψ0.0000	9,300.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
36		9,300.0	GJ x	\$0.000 =	77	9,300.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
37 38				-	\$11,782.02			_	\$12,739.92	-	\$957.90	1.56%
39												
40												
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		0.0	GJ x	\$0.749 =		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		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 50												
50 51		9,300.0			\$61,230.12	9,300.0			\$62,188.02		\$957.90	1.56%
31	rotal dailing on-i bak i bliba	3,500.0		=	Ψ01,230.12	3,500.0		_	ψυΣ, 100.02	=	ψυυτ.υυ	1.5070

# 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 Particular		PROPOSED	JANUARY 1, 2	2012 RAT	ES		PROPOSED	) JANUARY 1, 20	13 RATES		Annual Increase/Decrease	e
1 2	LOWER MAINLAND SERVICE AREA	Volu	ıme	Rate		Annual \$	Vol	ume	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
3 4 5	<u>Delivery Marqin Related Charges</u> Basic Charge	12	months x	\$587.00	=	\$7,044.00	12	months x	\$587.00 = <u></u>	\$7,044.00	\$0.00	\$0.00	0.00%
6 7	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%
8 9 10 11 12	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,700.0 9,700.0 9,700.0	GJ x GJ x GJ x	\$0.696 \$0.000 \$0.000		\$6,751.2000 \$0.0000 \$0.0000 <b>\$6,751.20</b>	9,700.0 9,700.0 9,700.0	GJ x GJ x GJ x	\$0.761 = \$0.000 = \$0.000 =	\$7,381.7000 \$0.0000 \$0.0000 \$7,381.70	\$0.065 \$0.000 \$0.000	\$630.5000 \$0.0000 \$0.0000 <b>\$630.50</b>	0.81% 0.00% 0.00% <b>0.81%</b>
13 14 15 16 17	Commodity Related Charges  Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,700.0 9,700.0	GJ x GJ x	\$0.764 \$4.568		\$7,410.8000 \$44,309.6000 <b>\$51,720.40</b>	9,700.0 9,700.0	GJ x GJ x	\$0.764 = \$4.568 =	\$7,410.8000 \$44,309.6000 <b>\$51,720.40</b>	\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
18 19	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%
20 21 22	Delivery Margin Related Charges	12	months x	\$587.00	=	\$7,044.00	12	months x	\$587.00 = <u></u>	\$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 27 28 29	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	12,800.0 12,800.0 12,800.0	GJ x GJ x GJ x	\$0.696 \$0.000 \$0.000		\$8,908.8000 \$0.0000 \$0.0000 <b>\$8,908.80</b>	12,800.0 12,800.0 12,800.0	GJ x GJ x GJ x	\$0.761 = \$0.000 = \$0.000 =	\$9,740.8000 \$0.0000 \$0.0000 \$9,740.80	\$0.065 \$0.000 \$0.000	\$832.0000 \$0.0000 \$0.0000 \$832.00	0.83% 0.00% 0.00% <b>0.83%</b>
30 31 32 33 34 35	Commodity Related Charges Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	12,800.0 12,800.0	GJ x GJ x	\$0.749 \$4.568		\$9,587.2000 \$58,470.4000 <b>\$68,057.60</b>	12,800.0 12,800.0	GJ x GJ x	\$0.749 = \$4.568 =	\$9,587.2000 \$58,470.4000 <b>\$68,057.60</b>	\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
36 37	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%
38 39 40 41	Delivery Margin Related Charges	12	months x	\$587.00	=	\$7,044.00	12	months x	\$587.00 = <u></u>	\$7,044.00	\$0.00	\$0.00	0.00%
	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%
44 45 46 47 48	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,100.0 9,100.0 9,100.0	GJ x GJ x GJ x	\$0.696 \$0.000 \$0.000		\$6,333.6000 \$0.0000 \$0.0000 <b>\$6,333.60</b>	9,100.0 9,100.0 9,100.0	GJ x GJ x GJ x	\$0.761 = \$0.000 = \$0.000 =	\$6,925.1000 \$0.0000 \$0.0000 <b>\$6,925.10</b>	\$0.065 \$0.000 \$0.000	\$591.5000 \$0.0000 \$0.0000 <b>\$591.50</b>	PAGE 13 0.00% 0.00% <b>0.81%</b>
49 50 51 52	Commodity Related Charges Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,100.0 9,100.0	GJ x GJ x	\$0.785 \$4.568		\$7,143.5000 \$41,568.8000 <b>\$48,712.30</b>	9,100.0 9,100.0	GJ x GJ x	\$0.785 = \$4.568 =	\$7,143.5000 \$41,568.8000 <b>\$48,712.30</b>	\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
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%

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

				RATE	SCHEDULE 6 - NGV -	STATIONS						
Line No.			PROPOSED .	JANUARY 1, 201	2 RATES		PROPOSED	JANUARY 1, 201	3 RATES		Annual Increase/Decrease	
1		Volur	ne	Rate	Annual \$	Volu	me	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		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		2,900.0	GJ X	\$4.568 =	\$1,023.7000	2,900.0	GJ X	\$4.568 =	\$13,247.2000	\$0.000	\$0.0000	0.00%
14	, ,	2,300.0	00 X	Ψ4.500	\$14,270.90	2,300.0	00 X	Ψ4.500	\$14,270.90	ψ0.000	\$0.00	0.00%
15				_	ψ1+,210.00			_	ψ1+, <b>210.00</b>		ψ0.00	0.0070
16		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		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 25		11,900.0	GJ x GJ x	\$0.000 = \$0.000 =	\$0.0000	11,900.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
25 26		11,900.0	GJ X	\$0.000 =_	\$0.0000 \$46,677.90	11,900.0	GJ X	\$0.000 =	\$0.0000 <b>\$49,843.30</b>	\$0.000	\$0.0000 <b>\$3,165.40</b>	0.00% <b>3.01%</b>
27	Subtotal Delivery Margin Related Charges			_	\$40,077.90			_	\$49,043.30		<b>\$3,103.40</b>	3.01%
28	Commodity Related Charges											
29		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		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%

# 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 Particular		PROPOSED	JANUARY 1,	2012 RA	ATES		PROPOSED	JANUARY 1,	2013 RATES		Annual Increase/Decrease	
1		Volu	ıme	Rate		Annual \$	Volun	ne	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 m	onths 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		\$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		\$0.000	\$0.0000	0.00%
8	Rider 3 ESM	8,100.0	GJ x	Ψ0.000		\$0.0000	8,100.0	GJ x	\$0.000		\$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		\$0.000	\$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges					\$9,234.00				\$9,930.60		\$696.60	1.11%
11													
12		0.400.0		00 704		** *** ****	0.400.0		00 704	***********	***	******	0.000/
13		8,100.0	GJ x	\$0.764		\$6,188.4000	8,100.0	GJ x	\$0.764		\$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		\$0.000	\$0.0000	0.00%
15						\$43,189.20				\$43,189.20		\$0.00	0.00%
16													
17	3,												
18													
19 20		8,100.0		\$7,776		\$62,983.20	8,100.0		\$7.862	\$63.679.80	\$0.086	\$696.60	1.11%
20	Total (with enective \$/63 rate)	8,100.0		\$7.776		\$62,983.20	8,100.0		\$7.862	\$63,679.80	\$0.086	9090.00	1.11%
22													
23													
24 25	<u>Delivery Margin Related Charges</u> Basic Charge	10		\$880.00	_	\$10,560.00	40	onths x	\$880.00	= \$10,560.00	\$0.00	\$0.00	0.00%
		12	months x	\$880.00		\$10,560.00	12 m	iontns 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		4,000.0	GJ X	\$0.000		\$4,560.0000	4,000.0	GJ X	\$0.000		\$0.086	\$344.0000	0.95%
26 29		4,000.0	GJ X	\$0.000		\$0.0000	4,000.0	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
30		4,000.0	GJ X	\$0.000		\$0.0000	4,000.0	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges	4,000.0	GJ X	\$0.000		\$4.560.00	4,000.0	GJ X	\$0.000	\$4.904.00	\$0.000	\$344.00	0.00% <b>0.95%</b>
32						\$4,560.00				\$4,904.00		\$344.00	0.95%
33	Commodity Related Charges												
34		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		4,000.0	GJ X			\$18,272.0000	4,000.0	GJ X	\$4.568	, ,	\$0.000	\$0.0000	0.00%
36		4,000.0	GJ X	φ4.506		\$21,268.00	4,000.0	GJ X	φ4.506	\$21,268.00	\$0.000	\$0.000	0.00%
37	Subtotal Gas Gales - Lixed (Commodity Related Charge)					\$21,200.00				\$21,200.00		φυ.υυ	0.00 /6
38	Non-Standard Charges ( not forecast )										ĺ		
39													
40											ĺ		
41		4,000.0		\$9.097		\$36,388.00	4,000.0		\$9.183	\$36,732.00	\$0.086	\$344.00	0.95%

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

Particular   Proposition   P		RATE SCHEDOLE 22 - LANGE HIDDSTRIAE 1-SERVICE													
Volume   Rate   Annual   Service   Annual   S				PROPOSE	D JANUARY 1,	201	2		PROPOSED J	ANUARY 1, 201	3 R	ATES			
3 Basic Charge  12 months x \$3,664.00 = \$43,968.00  12 months x \$3,664.00 = \$43,968.00  12 months x \$3,664.00 = \$43,968.00  13 months x \$3,664.00 = \$43,968.00  14 months x \$3,664.00 = \$43,968.00  15 months x \$3,664.00 = \$43,968.00  16 Delivery Charge - Interruptible MTQ  17 Rider 2 2009 ROE Rate Rider  467,305.6 GJ x \$0.000 = \$0.0000  467,305.6 GJ x \$0.000 = \$0	1		Volu	ıme	Rate		Annual \$	Volu	ıme	Rate	_	Annual \$	Rate	Annual \$	
4 5 6 Delivery Charge - Interruptible MTQ 467,305.6 GJ x \$0.838 = \$391,602.0928 467,305.6 GJ x \$0.000 = \$0.0000 \$0.000 \$0	2	LOWER MAINLAND SERVICE AREA													
7 Rider 2 2009 ROE Rate Rider 467,305.6 GJ x \$0.000 = \$0.0000 8 Rider 3 ESM 467,305.6 GJ x \$0.000 = \$0.0000 \$0	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%
7 Rider 2 2009 ROE Rate Rider 467,305.6 GJ x \$0.000 = \$0.0000 8 Rider 3 ESM 467,305.6 GJ x \$0.000 = \$0.0000 \$0	4	· ·													
7 Rider 2 2009 ROE Rate Rider 467,305.6 GJ x \$0.000 = \$0.0000 8 Rider 3 ESM 467,305.6 GJ x \$0.000 = \$0.0000 \$0	5														
7 Rider 2 2009 ROE Rate Rider 467,305.6 GJ x \$0.000 = \$0.0000 8 Rider 3 ESM 467,305.6 GJ x \$0.000 = \$0.0000 \$0	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%
9 Transportation - Interruptible \$\frac{\$391,602.09}{\$391,602.09}\$\$\$\$ \$\$10 \$\$11 \$\$ \$\$10 \$\$11 \$\$ \$\$12 Non-Standard Charges (not forecast ) \$\$13 \$\$ \$\$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 \$\$ \$\$0.00 \$\$0.00 \$\$0.00 \$\$ \$\$12 months x \$78.00 = \$936.00 \$\$ \$\$13 months x \$78.00 = \$936.00 \$\$ \$\$14 months x \$78.00 = \$936.00 \$\$ \$\$12 months x \$78.00 = \$936.00 \$\$ \$\$13 months x \$78.00 = \$936.00 \$\$ \$\$14 months x \$78.00 = \$936.00 \$\$ \$\$14 months x \$78.00 = \$936.00 \$\$ \$\$15 month	7		467,305.6	GJ x	\$0.000	=	\$0.0000	467,305.6	GJ x	\$0.000	=	\$0.0000	\$0.000	\$0.0000	0.00%
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  13 months x \$78.00 = \$936.00  14 months x \$78.00 = \$936.00  15 months x \$78.00 = \$936.00	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%
11	9	Transportation - Interruptible					\$391,602.09				_	\$420,107.73	-	\$28,505.64	6.53%
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	10										_		-		
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	11														
14 15 16 Administration Charge 12 months x \$78.00 = \$936.00 17 18  14 15 16 Administration Charge 12 months x \$78.00 = \$936.00 12 months x \$78.00 = \$936.00 13 months x \$78.00 = \$936.00 14 12 months x \$78.00 = \$936.00 13 months x \$78.00 = \$936.00	12	Non-Standard Charges (not forecast )													
15 16 Administration Charge 12 months x \$78.00 = \$936.00 17 18 10 12 months x \$78.00 = \$936.00 12 months x \$78.00 = \$936.00 13 months x \$78.00 = \$936.00 14 months x \$78.00 = \$936.00 15 months x \$78.00 = \$936.00	13	UOR, Demand Surcharge, Balancing Service, Backstopping Gas													
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	14														
17 18	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												_		
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%															
	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%

#### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

			1.	A. E 00.1.ED	LL LLA LANGE IN							
Line No.	Particular		PROPOSE	D JANUARY 1,	2012	PF	ROPOSED J	ANUARY 1, 201	3 RATES		Annual Increase/Decrease	
1		Volun	ne	Rate	Annual \$	Volun	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2 3 4	INLAND SERVICE AREA 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%
5 6 7	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%
8 9 10 11 12 13	Delivery Charge - Firm MTQ Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Firm (Delivery Charge Firm MTQ)	584,475.8 584,475.8 584,475.8	GJ x GJ x	\$0.093 \$0.000 \$0.000		584,475.8 584,475.8 584,475.8	GJ x GJ x	\$0.100 \$0.000 \$0.000		\$0.007 \$0.000 \$0.000 _	\$4,091.3306 \$0.0000 \$0.0000 <b>\$4,091.33</b>	0.73% 0.00% 0.00% <b>0.73%</b>
14 15 16 17 18 19 20 21	Delivery Charge - Interruptible MTQ Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible (Delivery Charge Interruptible MTQ)  Non-Standard Charges (not forecast )	28,607.9 28,607.9 28,607.9	GJ x	\$1.061 \$0.000 \$0.000	= \$30,352.9819 = \$0.0000 = \$0.0000 \$30,352.98	28,607.9 28,607.9 28,607.9	GJ x	\$1.134 \$0.000 \$0.000		\$0.073 \$0.000 \$0.000 _	\$2,088.3767 \$0.0000 \$0.0000 \$2,088.38	0.37% 0.00% 0.00% <b>0.37%</b>
22 23 24 25 26 27 28	UOR, Demand Surcharge, Balancing Service, Backstopping Gas  Administration Charge  Total (with effective \$/GJ rate)	12	months x	\$78.00	= \$936.00 \$560.923.59		months x	\$78.00 \$1.020	= \$936.00 \$595.974.46	\$0.00 <u> </u>	\$0.00 \$35,050,87	0.00% 6.25%
	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.:

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

Line				Annual
No	Particular	PROPOSED JANUARY 1, 2012	PROPOSED IANIJARY 1 2013 RATES	Increase/Decre

No.	Particular		PROPOSE	D JANUARY 1,	2012	F	PROPOSED J	ANUARY 1, 201	3 RATES		Increase/Decrease	
												% of Previous
1		Volu	me	Rate	Annual \$	Volu	ıme	Rate	Annual \$	Rate	Annual \$	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%
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	Transportation - Firm Demand (Delivery Onlarge Firm DTQ)	2,211.0	00 X	ψ0.570	- ΨΖΖΙ,013.04	2,211.0	00 X	ψ3.243	- ΨΣ-13,311.00	ψ0.007	ψ17,703.2 <del>4</del>	3.3370
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	0.700.4	0.1	***	<b>AF 75</b> 0 0000	0.700.4	0.1	00.004	*******	***	****	0.400/
13	- Apr. 1 to Nov. 1	6,732.4	GJ x	\$0.855		6,732.4	GJ x	\$0.921		\$0.066	\$444.3384	0.13%
14 15	- Nov. 1 to Apr. 1 Rider 2 2009 ROE Rate Rider	0.0 6,732.4	GJ x GJ x	\$1.231 \$0.000		0.0 6.732.4	GJ x GJ x	\$1.327 \$0.000		\$0.096 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
16	Rider 3 ESM	6,732.4	GJ X	\$0.000		6,732.4	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
17		0,732.4	GJ X	φ0.000	\$5,756.20	0,732.4	GJ X	\$0.000	\$6,200.54	φ0.000	\$444.34	0.13%
18	Transportation - interruptible (Delivery Onlarge interruptible in tag)				ψ5,7 30.20				ψ0,200.54	-	Ψ-1-1-1-1	0.1370
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		10		0.4.507.00	45444400	40		0.4.507.00	45444400	20.00	***	
28 29	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%
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	Transportation - Firm Demand (Delivery Charge Firm DTQ)	2,070.0	GJ X	φ1.947	- \$02,301.00	2,070.0	GU X	\$2.099	- \$07,231.30	Ψ0.132	\$4,070.00	2.7076
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		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 GJ x	\$0.214 \$0.306		0.0	GJ x GJ x	\$0.231 \$0.330		\$0.017	\$0.0000	0.00% 0.19%
39 40	- Nov. 1 to Apr. 1 Rider 2 2009 ROE Rate Rider	14,503.1 14,503.1	GJ X GJ X	\$0.000		14,503.1 14,503.1	GJ X	\$0.330 \$0.000	+ -,	\$0.024 \$0.000	\$348.0744 \$0.0000	0.19%
41	Rider 3 ESM	14,503.1	GJ X	\$0.000		14,503.1	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
42	Rider 4 Reserve for Future Use	14,503.1	GJ X	\$0.000		14,503.1	GJ x		= \$0.0000	\$0.000	\$0.0000	0.00%
43		14,505.1	00 X	ψ0.000	\$4,437.95	14,505.1	00 X	ψ0.000	\$4,786.02	Ψ0.000	\$348.07	0.19%
44					ψ-1,-101.00				Ψ-1,1 00.02	-	ΨΟ-ΤΟΙΟΙ	0.1070
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%

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

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Line			KATE SCHEDU	LE 23 - LARGE COIV	WERCIAL I-SERVIC	CE			Annual	
No.	Particular	PRO	POSED JANUARY 1,	2012	PROPO	OSED JANUARY 1, 201	13 RATES		Increase/Decrease	
1	LOWER MANUAND SERVICE AREA	Volume	Rate	Annual \$	Volume	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
3	LOWER MAINLAND SERVICE AREA Basic Charge	12 month	hs x \$132.52	= \$1,590.24	12 mont	ths x \$132.52	= \$1,590.24	\$0.00	\$0.00	0.00%
5 6	Administration Charge	12 month	hs x \$78.00	= \$936.00	12 mont	ths x \$78.00	= \$936.00	\$0.00	\$0.00	0.00%
7 8 9 10 11 12	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,100.0 4,100.0	GJ x \$2.467 GJ x \$0.000 GJ x \$0.000 GJ x (\$0.032)	= \$0.0000 = \$0.0000	4,100.0 4,100.0	GJ x \$2.655 GJ x \$0.000 GJ x \$0.000 GJ x (\$0.032)	= \$0.0000 = \$0.0000	\$0.188 \$0.000 \$0.000 \$0.000 	\$770.8000 \$0.0000 \$0.0000 \$0.0000 \$770.80	6.16% 0.00% 0.00% 0.00% <b>6.16%</b>
13 14 15	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas									
16 17	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%
18 19 20	INLAND SERVICE AREA Basic Charge	12 month	hs x \$132.52	=\$1,590.24	12 mont	ths x \$132.52	=\$1,590.24	\$0.00	\$0.00	0.00%
21 22	Administration Charge	12 month	hs x \$78.00	=\$936.00	12 mont	ths x \$78.00	= \$936.00	\$0.00	\$0.00	0.00%
23 24 25 26 27 28	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,700.0 4,700.0			4,700.0 4,700.0	GJ x \$2.655 GJ x \$0.000 GJ x \$0.000 GJ x (\$0.032)	= \$0.0000	\$0.188 \$0.000 \$0.000 \$0.000	\$883.6000 \$0.0000 \$0.0000 \$0.0000 \$883.60	6.32% 0.00% 0.00% 0.00% 6.32%
29 30 31	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas									
32 33	lotal (with effective \$/GJ rate)	4,700.0	\$2.972	\$13,970.74	4,700.0	\$3.160	\$14,854.34	\$0.188 <u>=</u>	\$883.60	6.32%
34 35 36	COLUMBIA SERVICE AREA Basic Charge	12 month	hs x \$132.52	=\$1,590.24	12 mont	ths x \$132.52	=\$1,590.24	\$0.00	\$0.00	0.00%
37 38	Administration Charge	12 month	hs x \$78.00	=\$936.00	12 mont	ths x \$78.00	=\$936.00	\$0.00	\$0.00	0.00%
39 40 41 42 43 44 45	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm Non-Standard Charges (not forecast )	4,200.0 4,200.0	GJ x \$0.000 GJ x \$0.000	,	4,200.0 4,200.0	GJ x \$2.655 GJ x \$0.000 GJ x \$0.000 GJ x (\$0.032)	= \$0.0000 = \$0.0000	\$0.188 \$0.000 \$0.000 \$0.000 	\$789.6000 \$0.0000 \$0.0000 \$0.0000 \$789.60	6.19% 0.00% 0.00% 0.00% 6.19%
46 47	UOR, Balancing gas, Backstopping Gas, Replacement Gas  Total (with effective \$/GJ rate)	4,200.0	\$3.036	\$12,753.24	4,200.0	\$3.224	<b>\$13,542.84</b>	\$ <i>0.188</i>	\$789.60	6.19%
40		4,200.0	φ3.030	φ12,133.24	4,200.0	φ3.224	ψ13,342.04	φυ. 100	φ103.00	0.13/0

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

Line						ERAL FIRM 1-SERVICE					Annual	
No.	Particular	. ———	PROPOSEI	) JANUARY 1,	2012		PROPOSED JA	ANUARY 1, 201	3 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	ıme	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2												
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%
5	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	=\$936.00	\$0.00	\$0.00	0.00%
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%
9	Delivery Charge	19,086.2	GJ x	\$0.696	= \$13,283.9952	19,086.2	GJ x		= \$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		= \$0.0000	\$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 13	Transportation - Firm				\$13,284.00				\$14,524.60	-	\$1,240.60	3.02%
14 15 16	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas	214										
17 18	Total (with effective \$/GJ rate)	19,086.2	<u>.</u>	\$2.153	\$41,088.12	19,086.2	=	\$2.299	\$43,877.68	\$0.146 =	\$2,789.56	6.79%
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 25	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%
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		= \$0.0000	\$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 32	Non-Standard Charges (not forecast ) 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	(	40,070.0		ψ1.500	ψ10,040.01	40,070.0	=	φ2.707	ψου,στο.41	φο.140	ψ0,001.04	1.01 /0
36	COLUMBIA SERVICE											
37 38	Basic Charge	12	months x	\$587.00	= \$7,044.00	12	months x	\$587.00	= \$7,044.00	\$0.00	\$0.00	0.00%
39 40	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	=\$936.00	\$0.00	\$0.00	0.00%
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	,	\$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		= \$0.0000	\$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	23.4, Balanong gao, Baokotopping Gao, Nopidocinent Gao											
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%
						1						

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

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

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.

49 Total (with effective \$/GJ rate)

#### 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

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Line No.	PARTICULARS		PROPOSED J	IANUARY 1, 2012	RATES	F	PROPOSED J	JANUARY 1, 2013 F	RATES		Annual Increase/Decreas	e
1	INLAND SERVICE AREA	Volu	ime	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	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 =		50.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
10	Rider 5 RSAM	50.0	GJ x	(\$0.032) =		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	Organization Deleted Observes											
13 14	Commodity Related Charges  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 =		50.0	GJ X	\$4.568 =	\$228.4000	\$0.000	\$0.0000	0.00%
16	Rider 1 Propane Surcharge	50.0	GJ x			50.0	GJ x	\$9.331 =	\$466.5500	\$0.000	\$0.0000	0.00%
17	Subtotal Commodity Related Charges	00.0	- CO X	\$15.214	\$760.70	00.0	- × -	\$15.214	\$760.70	ψο.σσσ	\$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 23	Delivery Margin Related Charges 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	Basic Griange	303.23	uays x	ψ0.010 -	Ψ230.00	303.23	uays x	ψο.στο –	Ψ230.00	Ψ0.00	ψ0.00	0.0070
25	Delivery Charge	250.0	GJ x	\$2.907 =		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 =		250.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
27 28	Rider 3 ESM Rider 5 RSAM	250.0 250.0	GJ x GJ x	\$0.000 = (\$0.032) =		250.0 250.0	GJ x GJ x	\$0.000 = (\$0.032) =	\$0.0000 (\$8.0000)	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
29	Subtotal Delivery Margin Related Charges	250.0	GJ X _	\$2.875	\$1,016.83	230.0	GJ ^ _	\$3.120	\$1,078.08	φ0.000	\$61.25	1.35%
30			-				_		. ,		***************************************	
31	Commodity Related Charges											
32 33	Midstream Cost Recovery Charge Cost of Gas	250.0 250.0	GJ x GJ x	\$1.301 = \$4.568 =		250.0 250.0	GJ x GJ x	\$1.301 = \$4.568 =	\$325.2500 \$1,142.0000	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
34	Rider 1 Propane Surcharge	250.0	GJ X	\$8.254 =		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 affective \$10 Lyata)	250.0		£40.400	¢4 547 50	250.0		£40.405	£4 COO OO	<b>#0.04</b> 5	\$C4.0E	4.250/
38	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%
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 =		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) =		4,500.0	GJ x	(\$0.032) =	(\$144.0000)	\$0.000	\$0.0000	0.00%
47 48	Subtotal Delivery Margin Related Charges		-	\$2.435	\$12,547.74		_	\$2.623	\$13,393.74		\$846.00	1.11%
49	Commodity Related Charges											
50	Midstream Cost Recovery Charge	4,500.0	GJ x	\$0.999 =	+ -,	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 =	<del>+</del> ,	4,500.0	GJ x	\$4.568 =	\$20,556.0000	\$0.000	\$0.0000	0.00%
52 53	Rider 1 Propane Surcharge Subtotal Commodity Related Charges	4,500.0	GJ x	\$8.556 = \$14.123	\$38,502.0000 <b>\$63,553.50</b>	4,500.0	GJ x	\$8.556 = \$14.123	\$38,502.0000 <b>\$63,553.50</b>	\$0.000	\$0.0000 <b>\$0.00</b>	0.00% <b>0.00%</b>
53 54	Subtotal Colliniouity Incidied Charges		-	ψ14.123	φυσ,σσο.συ		_	φ14.123	φυ <b>υ,υυο.</b> ου		φυ.υυ	0.00%
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.

APPENDIX F-2

TAB 1.2.2

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

Appendix F-2 Tab 3.1 Page 1

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		(, ,			<u> </u>		
14	Total Variable Charges	(\$/GJ)	\$ 15.315	\$	16.079	\$ 0.764	<u>4.99%</u>
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

Appendix F-2 Tab 3.2 Page 1

Line No	Particulars		Proposed Rate January 1, 2012	Proposed Rate January 1, 2013	Increase / (Decrease)	Increase / (Decrease)
	(1)		(2)	(3)	(4)	(5)
1 2	Tariff Rates					
3	Basic Charge	(\$/Day)	\$0.2464	\$0.2464	\$0.0000	0.00%
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 8	Total Cost Recovery Charges	(\$/GJ)	\$16.503	\$17.786	\$1.2830	7.77%
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	<u>0.00%</u>
13						
14	Total Variable Charges	(\$/GJ)	\$ 16.079	\$ 17.362	<u>\$ 1.283</u>	<u>7.98%</u>
15 16						
17	Bill Impact Estimates					
18						
19 20	Annual Residential Usage	(GJ)	90	90		
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.		PF	ROPOSED	JANUARY 1, 201	2 R	ATES	PI	ROPOSED	JANUARY 1, 2	013 I	RATES	Annua	I Increase/(Deci	rease)
1 2	Rate 25 Transportation Service	Volur	ne	Rate		Annual \$	Volu	me	Rate	-	Annual \$	Rate	Annual \$	% of Previous Annual Bill
3 4	Transportation Delivery Charges													
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 n	nonths x	\$1,945.00			12 ו	months x	\$1,975.00			\$30.00	\$0.0000	0.00%
10														
11	Administration Charge per month	12 n	nonths x	\$202.00	=	\$2,424.0000	12 ו	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	Cummany of Annual Delivery, Administration and Commodity Charges													
18	Summary of Annual Delivery, Administration and Commodity Charges 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)	0,090	GJ	\$0.000	=	\$0.0000	0,090	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%
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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### **List of Appendices**

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**B** – Historical Company Info and Past Directives

C - Forecasting Data

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L - Financial Matters

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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

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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:

## FORTISBC ENERGY UTILITIES 2012-2013 REVENUE REQUIREMENTS AND RATES APPLICATION



- 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:

- 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<sup>20</sup>

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.

Section 7.1 to 7.4, Schedule 2 and 3

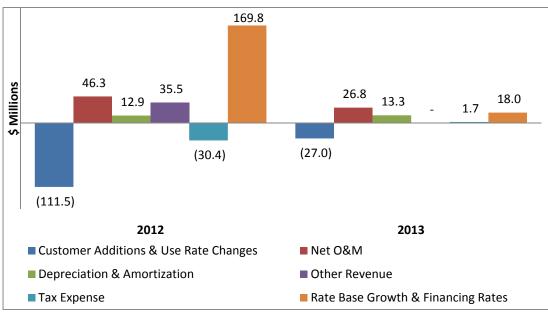


Figure 3.3-12: Fort Nelson Revenue Deficiency Components<sup>44</sup>

#### 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.

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.

45 Section 7.4, Schedules 4 to 9

Section 7.4, Schedule 1



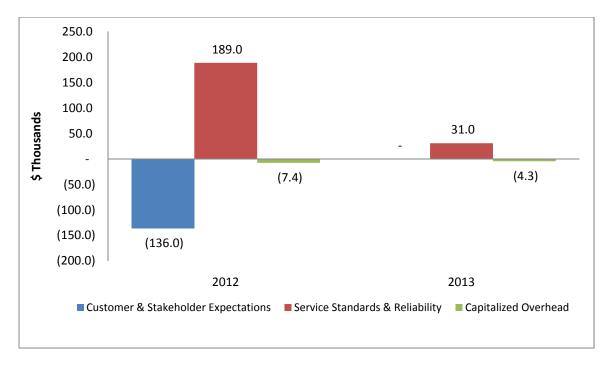


Figure 3.3-13: O&M Funding Results in Increased Revenue Requirements<sup>46</sup>

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.

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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	
				Cost of
(\$ thousands)	Reference	Total	Cost of Gas	Service <sup>1</sup>
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 Servi	ce & Rate Base	(2,158)	-	(2,158)
FEW Transportation	n Charge	(2,585)	-	(2,585)
Squamish Transpor	tation Charge	(416)	(416)	-
Total Amalgamation	Adjustments	(5,159)	(12,440)	7,281
Amalgamated FEU Co	ost of Service	\$ 1,508,865	\$ 728,927	\$ 779,938
<sup>1</sup> Cost of service exclu	uding 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).<sup>47</sup> 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.<sup>48</sup>

## 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). 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. The second results in 2013 and 2013 a

#### *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). 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<sup>53</sup> (the "Special Direction") since 1995.<sup>54</sup> 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

has passed, the Squamish Gas TSA continues to remain in effect thus keeping the Special Direction in effect.

<sup>47</sup> Section 7.1, Schedules 2 and 3

<sup>&</sup>lt;sup>48</sup> Appendix F-2, Tab 1.1.1 and Tab 1.2.1, Page 1

<sup>&</sup>lt;sup>49</sup> Section 7.3, Schedules 2 and 3

<sup>&</sup>lt;sup>50</sup> Appendix F-2, Tab 3.1 and Tab 3.2, Page 1

<sup>&</sup>lt;sup>51</sup> Section 7.4, Schedules 2 and 3

<sup>&</sup>lt;sup>52</sup> Appendix F-2, Tab 4.1.1 and Tab 4.2.1, Page 1

<sup>&</sup>lt;sup>53</sup> OIC No. 1510 (Dec. 13, 1995).

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



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.

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

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

## **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:

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(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	2010	2011	2011	2012	2013
	Approved	<b>Actual</b>	<b>Approved</b>	<b>Projection</b>	<b>Forecast</b>	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		2010		2011		2011		2012	2013	
	App	oroved		Actual	Αŗ	proved	Pr	ojection	F	orecast	F	orecast
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.

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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

Section 6: Rate Base Page 377



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.

Section 7 TAB 7.5 Schedule 1

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No.	Particulars	FEI		FEVI	F	FEW	F	N	Total	Ad	justments	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	2,900	\$ 740,068	\$	(12,440) 1 \$	727,627	
2	GCVA Amortization	 -		(8,124)		-		-	(8,124)		<u> </u>	(8,124)	- Sect 7-TAB 7.5, Schedule 7
3 4	Net Cost of Gas	659,338		66,213		3,493	:	2,900	731,944		(12,440)	719,503	
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) <sup>2</sup>	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) <sup>3</sup>	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 <sup>5</sup>	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													

- 1 FEI LNG Mitigation to FEVI (\$12) MM, FEVI Squamish Wheeling from FEI (\$0.4) MM
- 2 FEVI Wheeling (\$3.5) MM to FEI, FEW Wheeling (\$2.5) MM to FEVI
- 3 FEVI amortization of Whistler Contribution \$0.25 MM offset by FEW amortization of Contribution deferral (\$0.29) MM
- 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
- 5 Change in Rate Base impact on Income Taxes
- 6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes

Section 7 TAB 7.5 Schedule 2

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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) <sup>1</sup> \$	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 <sup>4</sup>	(26,074)	- Sect 7-TAB 7.5, Schedule 8
10	Income Taxes	30,160	7,440	542	55	38,197	10 <sup>5</sup>	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									

- 1 FEI LNG Mitigation to FEVI (\$12) MM, FEVI Squamish Wheeling from FEI (\$0.4) MM
- 2 FEVI Wheeling (\$3.5) MM to FEI, FEW Wheeling (\$2.5) MM to FEVI
- 3 FEVI amortization of Whistler Contribution \$0.25 MM offset by FEW amortization of Contribution deferral (\$0.29) MM
- 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
- 5 Change in Rate Base impact on Income Taxes
- 6 Short Term Interest Rate assumed to be FEI; Long Term Debt and Short Term Debt ratio changes

Section 7 TAB 7.5 Schedule 3

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Line	Particulara	FEI	FEVI	FEW	FN	Total	٨٨	iuatmonta	FEU	Cross Reference
No.	Particulars (1)					Total	Ad	justments		
	(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	\$ (432,176)	- Sect 7-TAB 7.5, Schedule 34
14	Adjustment - Opening Bal Adjt	-	2,484	-	-	2,484		(2,484)	-	
15	CIAC, Ending	(183,107)	(254,306)	(186)	(1,287)	(438,886)		14,550 <sup>1</sup>	(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) <sup>1</sup>	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 <sup>3</sup>	(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

<sup>1</sup> FEVI CIAC - Pipeline Contribution from FEW

<sup>2</sup> FEW's contribution deferral to FEVI for pipeline

<sup>3</sup> Applying FEI Lead/Lag days to FEVI and FEW expense/revenue

Section 7 TAB 7.5

Schedule 4

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No.	Particulars		FEI		FEVI	F	EW	F	=N		Total	Ad	justments		FEU	Cross Refe	erence
	(1)		(2)		(3)		(4)	(	(5)		(6)		(7)		(8)	(9)	
1	Gas Plant in Service, Beginning	\$	3,770,188	\$	1,317,524	\$	17,203	\$ 12	2,525	\$	5,117,440			\$	5,117,445	- Sect 7-TAB 7.5, S	Schedule 25
2	Adjustment - CPCNs / Opening Bal Adjt		-		-		-		-		-				-		
3	Gas Plant in Service, Ending		3,904,928		1,344,362		17,637	1:	2,919		5,279,846				5,279,855	- Sect 7-TAB 7.5, S	Schedule 25
4																	
5	Accumulated Depreciation Beginning - Plant	\$	(1,014,039)	\$	(318,482)	\$	(2,933)	\$ (2	2,718)	\$	(1,338,172)			\$	(1,338,167)	- Sect 7-TAB 7.5, S	Schedule 31
6	Adjustment - CPCNs / Opening Bal Adjt		-		-		-		-		-				-		
7 8	Accumulated Depreciation Ending - Plant		(1,105,609)		(346,979)		(3,200)	(;	3,076)		(1,458,864)				(1,458,860)	- Sect 7-TAB 7.5, S	Schedule 31
9	Negative Salvage Depreciation Beginning - Plant	\$	(7,994)	\$	(12,476)	\$	(74)	\$	_	\$	(20,544)			\$	(20 543)	- Sect 7-TAB 7.5, S	Schedule 33
10	Adjustment - CPCNs / Opening Bal Adjt	Ψ	(,,00.)	Ψ	-	Ψ	-	Ψ	_	٣	(=0,0 : 1)			Ψ	(20,0.0)	000(7 17.2 7.0, 0	30000.00
11	Negative Salvage Depreciation Ending - Plant		(11,805)		(15,874)		(150)		_		(27,829)				(27,825)	- Sect 7-TAB 7.5, S	Schedule 33
12			, , ,		, , ,		, ,				, , ,				, ,		
13	CIAC, Beginning	\$	(183,107)	\$	(254,306)	\$	(186)	\$ (	1,287)	\$	(438,886)	\$	14,550 <sup>1</sup>	\$	(424,337)	- Sect 7-TAB 7.5, S	Schedule 35
14	Adjustment - Opening Bal Adjt		-		-		-		-		-				-		
15	CIAC, Ending		(189,803)		(250,614)		(186)	(	1,287)		(441,890)		14,550 <sup>1</sup>		(427,341)	- Sect 7-TAB 7.5, S	Schedule 35
16																	
17	Accumulated Amortization Beginning - CIAC	\$	49,913	\$	63,319	\$	22	\$	490	\$	113,744	\$	(755) <sup>1</sup>	\$	112,986	- Sect 7-TAB 7.5, S	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, 8	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	9,028	\$	3,454,398	\$	13,669	\$	3,468,077		
24																	
25	Adjustment to 13-Month Average		-		-		-		-		<del>-</del>				-		
26	Work in Progress, No AFUDC		17,110		2,285		23		-		19,418				19,418		
27	Unamortized Deferred Charges		38,574		3,891	2	26,703		82		69,250		(13,435) 2			- Sect 7-TAB 7.5, S	
28	Cash Working Capital		(1,963)		476		61		12		(1,414)		328 <sup>3</sup>		,	- Sect 7-TAB 7.5, S	
29	Other Working Capital		101,622		10,436		635		4		112,697				*	- Sect 7-TAB 7.5, S	
30	Future Income Taxes Regulatory Asset		282,359		76,663		2,319		-		361,341					- Sect 7-TAB 7.5, S	
31	Future Income Taxes Regulatory Liability		(282,359)		(76,663)		(2,319)		-		(361,341)				, , ,	- Sect 7-TAB 7.5, S	Schedule 43
32	LILO Benefit	_	(1,316)		-		-		-		(1,316)				(1,316)		
33	Utility Rate Base	\$	2,788,327	\$	814,078	\$ 4	41,502	\$ 9	9,126	\$	3,653,033	\$	562	\$	3,653,604	- Sect 7-TAB 7.5, S	Schedule 45
34																	

<sup>1</sup> FEVI CIAC - Pipeline Contribution from FEW

<sup>2</sup> FEW's contribution deferral to FEVI for pipeline

<sup>3</sup> 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

2 Impact of Rate Base Change \$0.04 MM, Impact of rounding Weighted Average ROE to 2 decimals \$0.05 MM

Section 7 TAB 7.5 Schedule 5

Line

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(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, S	chedule 18
1 Rate Base \$ 2,736,507 \$ 787,864 \$ 42,139 \$ 8,889 \$ 3,575,399 \$ 897 \$ 3,576,297 - Sect 7-TAB 7.5, S	chedule 18
2	
3 Equity Thickness 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00% 40.00%	chedule 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, S	chedule 44
5 ROE9.50% 10.00% 10.00% 9.50% 9.62% 19.62% - Sect 7-TAB 7.5, S	chedule 44
6 Equity Earned Return 103,987 31,515 1,686 338 137,525 91 2 137,616 - Sect 7-TAB 7.5, S	chedule 44
7	
8 Long Term Debt % of Capital Structure <u>57.82% 46.39% 47.46% 57.30% 55.18%</u> <u>55.22%</u> - Sect 7-TAB 7.5, S	
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, S	
10 Average Rate <u>6.73% 5.75% 5.11% 6.73% 6.53%</u> <u>6.53%</u> - <u>6.54%</u> - Sect 7-TAB 7.5, S	chedule 44
11 LTD Earned Return 106,548 21,003 1,022 343 128,916 233 129,149 - Sect 7-TAB 7.5, S	chedule 44
12	
13 Short Term Debt % of Capital Structure 2.18% 13.61% 12.54% 2.69% 4.82% 4.82% 4.78% - Sect 7-TAB 7.5, S	chedule 44
14 Short Term Debt 59,787 107,192 5,283 239 172,501 (1,395) 171,106 - Sect 7-TAB 7.5, S	chedule 44
15 Average Rate 2.75% 4.25% 3.75% 2.93% 3.71% 2.75% - Sect 7-TAB 7.5, S	chedule 44
16 STD Earned Return 1,644 4,556 198 7 6,405 (1,700) 4,705 - Sect 7-TAB 7.5, S	chedule 44
17	
18 Total Earned Return \$\frac{12,179}{57,074}\$ \frac{2,906}{57,074}\$ \frac{688}{272,846}\$ \frac{1,376}{572,846}\$ - Sect 7-TAB 7.5, S	chedule 44
19	
20 Notes	
21 1 Calculation of Weigted Average ROE	
22 Total Equity Return 137,525 (Line 6, Column 6)	
Eguity Portion of Rate Base 1,430,160 (Line 4, Column 6)	
24 Weighted Average ROE 9.62% (Line 22 / Line 23)	

2 Impact of Rate Base Change \$0.02 MM, Impact of rounding Weighted Average ROE to 2 decimals \$0.04 MM

Section 7 TAB 7.5 Schedule 6

Line

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No.	Particulars	FEI	FEVI	FEW	FN	Total	Change	FEU	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1 2	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
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	140,591	- Sect 7-TAB 7.5, Schedule 45
7		-							
8	Long Term Debt % of Capital Structure	56.76%	42.99%		56.25%	53.59%			
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		N	otes						
21		_		Weigted Ave	rage ROE				
22				ity Return		140,526	(Line 6, Colum	n 6)	
23				rtion of Rate	Base	1,461,213	(Line 4, Colum		
24				l Average RC	-	9.62%	(Line 22 / Line	,	
			5.9			0.0270	(=:::: == / =:::0	,	

Section 7 TAB 7.5 Schedule 7

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

Line		2012	2013		
No.	Particulars	FORECAST	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)	<u> </u>	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	

Section 7 TAB 7.5 Schedule 8

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

Line			2012		2013			
No.	Particulars	FO	RECAST	FO	FORECAST		hange	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

FortisBC Energy Utilities

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Section 7 TAB 7.5 Schedule 9

# OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013

(\$000)

Lina	(4000)		2012		2013	
Line No.	Particulars	FΩ	RECAST		RECAST	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

Section 7 TAB 7.5

Schedule 10

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

Line **BCUC** 2012 2013 **FORECAST FORECAST** Cross Reference No. **Particulars** Reference (1) (2)(5)1 Distribution Supervision 100-11 \$ 13,305 \$ 13,825 2 3 Operation Centre - Distribution 100-21 12,743 13,443 4,587 Asset Management - Distribution 100-22 3,259 Preventative Maintenance - Distribution 100-23 3,202 3,483 5 Distribution Operations - General 100-24 7,003 7,355 6 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 Distribution Corrective - Leak Repair 100-33 1,374 1.415 Distribution Corrective - Stations 100-34 773 793 14 Distribution Corrective - General 100-35 638 987 15 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 Right of Way 200-22 730 808 23 24 Compression 200-23 2.171 2,239 25 Gas Control 200-24 2,848 3,000 Transmission Pipeline Integrity Project (TPIP) 26 200-25 2,611 2,797 27 Transmission Operations Total 200-20 11,983 12,610 28 Pipeline - Maintenance 200-31 2,830 2,684 30 Compression - Maintenance 200-32 1,624 1,764 TPIP - Maintenance 31 200-33 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 2,937 797 37 LNG Plant Maintenance 300-21 824 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 43 400 **Measurement Total** 7,491 7,861

# OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)

OF ENTITION A NUMBER OF THE PROPERTY OF THE PR
FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013
(\$000)

Line	(\$000)	BCUC	2012	2013	
No.	Particulars	Reference	FORECAST	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	240000 4 001.11000 1044.				
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	900-30	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		500			
41	Total Gross O&M Expenses		261,127	273,766	
42	. ota. Grood Odin Experiees		201,127	210,100	
43	Less: Capitalized Overhood		(26 EE0)	(20 227)	
43	Less: Capitalized Overhead		(36,558)	(38,327)	
44	Total O&M Expenses		\$ 224,569	\$ 235,438	- Sect 7-TAB 7.5, Schedule 7
46				,	

Section 7

Schedule 11

TAB 7.5

## FortisBC Energy Utilities

May 16, 2011 Section 7 TAB 7.5 Schedule 12

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

Line No.	Particulars (1)	2012 RECAST (2)	2013 RECAST (3)	 Change (4)	Cross Reference (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			2012		2013			
No.	Particulars	FC	DRECAST	FC	DRECAST	C	Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
4	Depreciation & Removal Provision							
0	Depreciation & Removal Provision							
2	Degraciation Function	Φ	150,000	Φ	150 400	Φ	0.000	Cook 7 TAD 7 F. Cobodula 00 0 01
3	Depreciation Expense	\$	152,890	\$	159,498	\$	6,608	- Sect 7-TAB 7.5, Schedule 28 & 31
4			(,,,,,,,,)		( ===)			0
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			- 70 - 0		,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,			
17	TOTAL	\$	171,197	\$	191,565	\$	20,368	- Sect 7-TAB 7.5, Schedule 7

Schedule 13

FortisBC Energy Utilities May 16, 2011

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

Section 7
TAB 7.5
Schedule 14

Line		2012	2013		
No.	Particulars	FORECAST	<b>FORECAST</b>	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

FortisBC Energy Utilities May 16, 2011

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

Line No.	Particulars (1)	2012 FORECAST (2)	2013 FORECAST (3)	Change (4)	Cross Reference (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)	<del>-</del>	
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

Section 7 TAB 7.5

Schedule 15

May 16, 2011

Section 7 **TAB** 7.5 Schedule 16

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

Line	Class	CCA Data	12/31/2011	A divistments	2012 Net	2012	12/31/2012
No.	Class	CCA Rate	UCC Balance	Adjustments	Additions	CCA (C)	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

Section 7 TAB 7.5 Schedule 17

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

Line			12/31/2012		2013 Net	2013	12/31/2013
No.	Class	CCA Rate	UCC Balance	Adjustments	Additions	CCA	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, S	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 3	Opening Balance Adjustment Gas Plant in Service, Ending	- E 117 //E	- 5,279,855	- 162,410	- Sect 7-TAB 7.5, Schedule 22 & 25
3 4	Gas Flant in Service, Ending	5,117,445	5,279,655	102,410	- Sect 7-1AB 7.5, Scriedule 22 & 25
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 8	Accumulated Depreciation Ending - Plant	(1,338,167)	(1,458,860)	(120,693)	- Sect 7-TAB 7.5, Schedule 28 & 31
9	Negative Salvage Beginning	\$ -	\$ (20,543)	\$ (20,543)	- Sect 7-TAB 7.5, Schedule 32 & 33
10	Opening Balance Adjustment	(13,597)	<del>-</del>	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	ψ (402,170)	ψ (+2+,557)	Ψ 7,009	- Sect 7-17D 7.5, Schedule 54 & 55
15	CIAC, Ending	(424,337)	(427,341)	(3,004)	- Sect 7-TAB 7.5, Schedule 34 & 35
16	, <b>3</b>	( ,== ,	( ,- ,	(-, ,	-,
17	Accumulated Amortization Beginning - CIAC	\$ 107,884	\$ 112,986	\$ 5,102	- Sect 7-TAB 7.5, Schedule 34 & 35
18	Opening Balance Adjustment	-	-	-	
19 20	Accumulated Amortization Ending - CIAC	112,986	122,940	9,954	- Sect 7-TAB 7.5, Schedule 34 & 35
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

Schedule 18

## FortisBC Energy Utilities

May 16, 2011

Section 7

CAPITAL EXPENDITURES AND PLANT ADDITIONS FOR THE YEARS ENDING DECEMBER 31, 2012 TO 2013 (\$000) TAB 7.5 Schedule 19

Line No.	Particulars		2012 orecast		2013 Forecast	Cross Reference
110.	(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	Total Decider Conital Evenenditures	Φ	105.050	ф	100.040	
8	Total Regular Capital Expenditures	\$	165,250	\$	160,648	
9	On said Decises OPONIS					
10	Special Projects - CPCN's Customer Care Enhancement		14.010			
11			14,916		-	
12	Kootenay River Xing		1,223		-	
13 14	Victoria Regional Office Total CPCN's	\$	4,782 20,921	Φ.	<del>-</del>	
	Total GPGINS	Φ	20,921	\$		
15						
16	TOTAL CARITAL EVENIDITURES	Φ	100 171	ф	100.040	
17	TOTAL CAPITAL EXPENDITURES	\$	186,171	\$	160,648	
18						
19	RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS					
20	RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS					
21 22	Degular Canital					
23	Regular Capital Regular Capital Expenditures	\$	165,250	Φ	160,648	
23 24	Add - Opening WIP	Ф	38,957	\$	38,957	
25	Less - Closing WIP		(38,957)		(38,957)	
26	Capital Vehicle Lease Addition		3,180		2,860	
20 27	Add - AFUDC		2,088		1,916	
28	Add - Overhead Capitalized		36,556		38,329	- Sect 7-TAB 7.5, Schedule 22 & 25
29	Add - Overnead Capitalized		30,330		30,329	- Sect 7-1AB 7.5, Schedule 22 & 25
30	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	\$	207,073	\$	203,753	
31	TO THE THE GOLD IN THE PRODUCTION OF GRAPH BY GETTINGE	Ψ	207,070	<u> </u>	200,700	
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			1,072			
40	TOTAL CPCN ADDITIONS	\$	104,589	\$	-	- Sect 7-TAB 7.5, Schedule 22 & 25
41		Ψ	10 1,000	Ψ		2001
42	TOTAL PLANT ADDITIONS	\$	311,662	\$	203,753	
<b>-7</b>	TOTAL LINE ADDITIONS	Ψ	311,002	Ψ	200,700	

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

Line No.	Particulars	Balance 12/31/2011	СР	'CN'S		112 itions		2012 .FUDC		2012 CapOH	Reti	rements		ansfers/ ecovery		lance 31/2012	Mid-year GPIS for Depreciation	
	(1)	(2)		(3)	(4	4)		(5)		(6)		(7)		(8)		(9)		(10)
	INTANOIDI E DI ANT																	
1	INTANGIBLE PLANT	Φ.	•		Φ.		Φ.		•		Φ.		Φ.		•		•	
2	, , ,	\$ -	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
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	-	2,325		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
26 27				-		-		-		-		-		-				
	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	309		-		-		-		-		-		-		309		309
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-		-		-		-		-		-		-				7.004
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	<u> </u>	PCN'S		)12 litions	2012 AFUD		:012 apOH	Re	tirements_	ansfers/ ecovery	Balance 2/31/2012	-year GPIS 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	2	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		-	2	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		-		33,154		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)

FortisBC Energy Utilities

45

Line No.	Particulars			2011 CPCN'S Additions AFUDC			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	_	-	_	_	(1,201)	_	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	TOTAL GENETIAL	271,007	02,041	20,073	200		(0,277)		024,302	004,512
38	UNCLASSIFIED PLANT									
39	499 Plant Suspense		_	-	_	-	_	_	_	_
40	TOTAL UNCLASSIFIED								· <del></del>	· <del></del>
41	TO THE UNULAGOII IED					-			· <del></del>	. —
42	TOTAL CAPITAL	\$ 4,833,448	\$ 104,589	\$ 168,429	\$ 2,088	\$ 36,556	\$ (27,665)	\$ -	\$ 5,117,445	\$ 5,014,011
	TOTAL OAT HAL	ψ 4,000,440	\$ 104,589	ψ 100,429	ψ 2,000	ψ 30,336	ψ (∠1,003)	ψ -	ψ 5,117,445	φ 5,014,011
43	Cross Deference	C+7 TAD 7	C Oalbaalule 40						C 7 TAD =	7.5.0-1-1-1-10
44	Cross Reference	- Sect 7-TAB 7.		3 17 F. Cabadula	. 10				- Sect /-TAB /	7.5, Schedule 18

- 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	CF	PCN'S		2013 Additions		2013 AFUDC		2013 apOH	Reti	rements		ansfers/ ecovery	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	720		_		_		_		_		_		_		-		-
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	1,307		_		=		=		-		=		=		1,307		1,307
11	461-00 Transmission Land Rights	51,348		-		328		-		-		-		-		51,676		51,512
		,		-		320		-		-		-		-				
12	461-10 Transmission Land Rights - Byron Creek	15 24		-		-		-		-		-		-		15 24		15
13	461-13 IP Land Rights Whistler			-		-		-		-		-		-				24
14	471-00 Distribution Land Rights	3,184		-		-		-		-		-		-		3,184		3,184
15	471-10 Distribution Land Rights - Byron Creek	-		-		-		-		-		(0.750)		-				-
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 Equipmen	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 Hay	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)	, _		-		-		-		-		-		-		´-		, <u>-</u>
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
	- :::= :::: ::::::= : :::=::===					.,,500										, , , , <del>,</del> ,		

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	-	-	-	-	- 1	-	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	<u> </u>	-			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)

FortisBC Energy Utilities

45

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
· <u> </u>	(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				,		ĺ				
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	<ul> <li>VRA Compressor Installation Costs</li> </ul>	-	-	-	-	-	-	-	-	-
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.							- Sect 7-TAB 7	.5, Schedule 18
1 =			Coot 7 TAE	7 F Cabadula 1	10					

- Sect 7-TAB 7.5, Schedule 19

Section 7 TAB 7.5 Schedule 26

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

			Pro	ovision						
Line		 2012	А	djust-			Accumulate		ed	
No.	Account	(Cr.)	ments		Retirements		12/31/2011	12	12/31/2012	
	(1)	 (2)		(3)	(4	ł)	(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)	- 1,170				(001)	0,100		0,001	
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)	1,021				_	-		1,010	
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	
43	TO TAL IVIANOPACTORED	 1,201				(001)	20,030		31,304	

Section 7 TAB 7.5 Schedule 27

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

				Р	rovision						
Line		-	2012	-	Adjust-			Accumulated			
No.	Account		(Cr.)		ments	Retirements		12/31/2011	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		- (0.070)		- (4.005)	1,742		1,916	
8	465-00 Mains		16,691		(2,672)		(1,065)	303,997		316,951	
9 10	465-00 Mains - INSPECTION		1,276 600		-		-	1,939 1,511		3,215	
11	465-11 IP Transmission Pipeline - Whistler 465-30 Mt Hayes - Mains		93		-		-	1,511 54		2,111 147	
12	•		93 49		-		-	889		938	
13	465-10 Mains - Byron Creek 466-00 Compressor Equipment		5,027		(404)		(547)	60,620		64,696	
14	466-00 Compressor Equipment - OVERHAUL		1,908		(404)		(347)	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		-		-		- (4.070)	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 42	478-20 Instruments		362		-		-	926		1,288	
42	479-00 Other Distribution Equipment TOTAL DISTRIBUTION		78,995		(10,136)		(12,916)	660,046		715,989	
43 44	TOTAL DISTRIBUTION		76,995		(10,136)		(12,910)	000,040		715,969	
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         Account         (Cr.)           No.         Account         (Cr.)           (1)         (2)           1         Natural Gas for Transportation         (1)           2         476-10 NG Transportation CNG Dispensing Equipment         \$154           3         476-20 NG Transportation LNG Dispensing Equipment         127           4         476-30 NG Transportation CNG Foundations         34           5         476-40 NG Transportation LNG Pumps         120           7         476-60 NG Transportation LNG Dehydrator         12           8         476-70 NG Transportation LNG Dehydrator         -           9         TOTAL NG FOR TRANSP         475           10         480-00 Land in Fee Simple         -           11         GENERAL PLANT & EQUIPMENT         -           12         480-00 Land Rights         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         - <th>Adjust-ments (3) </th> <th>\$</th> <th>\$ 51 43 11 10 41 4 4 - 160 30 30</th> <th>\$ 205 170 45 38 161 16 - 635</th>	Adjust-ments (3)	\$	\$ 51 43 11 10 41 4 4 - 160 30 30	\$ 205 170 45 38 161 16 - 635
Natural Gas for Transportation   2	(3)	(4) \$ - - - - - -	\$ 51 43 11 10 41 4 -	\$ 205 170 45 38 161 16 -
1         Natural Gas for Transportation           2         476-10 NG Transportation CNG Dispensing Equipment         154           3         476-20 NG Transportation LNG Dispensing Equipment         127           4         476-30 NG Transportation CNG Foundations         34           5         476-40 NG Transportation LNG Foundations         28           6         476-50 NG Transportation LNG Pumps         120           7         476-60 NG Transportation LNG Dehydrator         12           8         476-70 NG Transportation LNG Dehydrator         -           9         TOTAL NG FOR TRANSP         475           10         475           11         GENERAL PLANT & EQUIPMENT         -           12         480-00 Land in Fee Simple         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         -           20         483-40 GP Furniture         1,159           21         483-10 GP Computer Software	'	\$ - - - - - -	\$ 51 43 11 10 41 4 -	\$ 205 170 45 38 161 16 -
2       476-10 NG Transportation CNG Dispensing Equipment       \$ 154         3       476-20 NG Transportation LNG Dispensing Equipment       127         4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation LNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       481-00 Land Rights       -         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Software       247         23       483-21 GP Computer Software       247         24 </th <th>- - - -</th> <th>- - - - -</th> <th>43 11 10 41 4 - 160</th> <th>170 45 38 161 16 -</th>	- - - -	- - - - -	43 11 10 41 4 - 160	170 45 38 161 16 -
3       476-20 NG Transportation LNG Dispensing Equipment       127         4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25 <td< td=""><td>- - - -</td><td>- - - - -</td><td>43 11 10 41 4 - 160</td><td>170 45 38 161 16 -</td></td<>	- - - -	- - - - -	43 11 10 41 4 - 160	170 45 38 161 16 -
4       476-30 NG Transportation CNG Foundations       34         5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       -         24       483-22 GP Computer Software       -         24       483-20 GP Computer Software       10         25       484-00 Vehicles	- - - - - - - - - - - - - - - - - - -	-	11 10 41 4 - 160	45 38 161 16 - - 635
5       476-40 NG Transportation LNG Foundations       28         6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       480-00 Land NG FOR TRANSP       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment <td< td=""><td></td><td>- - - - - - -</td><td>10 41 4 - 160</td><td>38 161 16 - 635</td></td<>		- - - - - - -	10 41 4 - 160	38 161 16 - 635
6       476-50 NG Transportation LNG Pumps       120         7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-40 GP Furniture       1,159         20       483-40 GP Furniture       6,111         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       1         24       483-22 GP Computer Software       1         24       483-20 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased <td></td> <td>-</td> <td>41 4 - 160</td> <td>161 16 - 635</td>		-	41 4 - 160	161 16 - 635
7       476-60 NG Transportation CNG Dehydrator       12         8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Mobile Equipment       402		-	160	635
8       476-70 NG Transportation LNG Dehydrator       -         9       TOTAL NG FOR TRANSP       475         10       -         11       GENERAL PLANT & EQUIPMENT         12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - - - - - -	- - - -	160	635
9         TOTAL NG FOR TRANSP         475           10         GENERAL PLANT & EQUIPMENT           12         480-00 Land in Fee Simple         -           13         481-00 Land Rights         -           14         482-00 Structures & Improvements         -           15         - Frame Buildings         648           16         - Masonry Buildings         2,180           17         - Leasehold Improvement         374           18         Office Equipment & Furniture         -           19         483-30 GP Office Equipment         326           20         483-40 GP Furniture         1,159           21         483-10 GP Computer Hardware         6,111           22         483-20 GP Computer Software         247           23         483-21 GP Computer Software         -           24         483-22 GP Computer Software         10           25         484-00 Vehicles         1,393           26         484-00 Vehicles - Leased         3,086           27         485-10 Heavy Work Equipment         402				635
10 11 GENERAL PLANT & EQUIPMENT 12		<u> </u>		
I1 GENERAL PLANT & EQUIPMENT         12 480-00 Land in Fee Simple       -         13 481-00 Land Rights       -         14 482-00 Structures & Improvements       -         15 - Frame Buildings       648         16 - Masonry Buildings       2,180         17 - Leasehold Improvement       374         18 Office Equipment & Furniture       -         19 483-30 GP Office Equipment       326         20 483-40 GP Furniture       1,159         21 483-10 GP Computer Hardware       6,111         22 483-20 GP Computer Software       247         23 483-21 GP Computer Software       -         24 483-22 GP Computer Software       10         25 484-00 Vehicles       1,393         26 484-00 Vehicles - Leased       3,086         27 485-10 Heavy Work Equipment       46         28 485-20 Heavy Mobile Equipment       402	- - - -	- -	30	00
12       480-00 Land in Fee Simple       -         13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - -	-	30	20
13       481-00 Land Rights       -         14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - - -	-	30	
14       482-00 Structures & Improvements       -         15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - -	-		30
15       - Frame Buildings       648         16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       1         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	- - -		-	-
16       - Masonry Buildings       2,180         17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
17       - Leasehold Improvement       374         18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	3,331	3,979
18       Office Equipment & Furniture       -         19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402		-	13,825	16,005
19       483-30 GP Office Equipment       326         20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(313)	501	562
20       483-40 GP Furniture       1,159         21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
21       483-10 GP Computer Hardware       6,111         22       483-20 GP Computer Software       247         23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	433	759
22     483-20 GP Computer Software     247       23     483-21 GP Computer Software     -       24     483-22 GP Computer Software     10       25     484-00 Vehicles     1,393       26     484-00 Vehicles - Leased     3,086       27     485-10 Heavy Work Equipment     46       28     485-20 Heavy Mobile Equipment     402	-	(567)	14,395	14,987
23       483-21 GP Computer Software       -         24       483-22 GP Computer Software       10         25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(1,517)	9,766	14,360
24     483-22 GP Computer Software     10       25     484-00 Vehicles     1,393       26     484-00 Vehicles - Leased     3,086       27     485-10 Heavy Work Equipment     46       28     485-20 Heavy Mobile Equipment     402	-	(475)	956	728
25       484-00 Vehicles       1,393         26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	-	-
26       484-00 Vehicles - Leased       3,086         27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	-	39	49
27       485-10 Heavy Work Equipment       46         28       485-20 Heavy Mobile Equipment       402	-	(262)	3,050	4,181
28 485-20 Heavy Mobile Equipment 402	-	(1,908)	14,746	15,924
	-	(11)	(13)	22
29 486-00 Small Tools & Equipment 2 423	-	-	780	1,182
25 100 00 011411 10010 4 Equipment	-	(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	<u> </u>			
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.			- Sect 7-TAB 7	.5, Schedule 1

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

			Provision		_			
Line		2013	Adjust-		Accumulated			
No.	Account	(Cr.)	ments	Retirements	12/31/2012	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)

No.					Provision			
TRANSMISSION PLANT	ulated	mula	Accun		Adjust-	2013		Line
TRANSMISSION PLANT   2	12/31/2013	_		Retirements			Account	No.
2	(6)		(5)	(4)	(3)	(2)	(1)	
461-00 Transmission Laind Rights							TRANSMISSION PLANT	1
4   461-02 Land Rights - Mt. Hayes	\$ 401	5	\$ 401	\$ -	\$ -	\$ -	460-00 Land in Fee Simple	2
5         462-00 Compressor Structures         968         -         11,404           6         463-00 Measuring Structures         431         -         4,945           7         464-00 Other Structures & Improvements         174         -         (899)         31,915           8         465-00 Mains - INSPECTION         1,590         -         -         3,215           10         465-11 PT Transmission Pipeline - Whistler         600         -         -         2,111           11         465-30 Mt Hayes - Mains         93         -         -         147           12         465-10 Mains - Byron Creek         49         -         938           13         466-00 Compressor Equipment         5,241         -         (458)         64,898           14         466-00 Compressor Equipment         2,146         -         -         5,062           15         467-00 Mt Hayes - Measuring and Regulating Equipment         204         -         323           16         467-10 Measuring & Regulating Equipment         204         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           24         470-20 Structures & Equipment	-		-	-	-	-	461-00 Transmission Land Rights	3
6         463-00 Masauring Structures         431         -         4,945           7         464-00 Other Structures & Improvements         174         -         1,916           8         465-00 Mains         17,174         -         (899)         316,951           9         465-00 Mains - INSPECTION         1,590         -         -         3,215           10         465-11 IP Transmission Pipeline - Whistler         600         -         -         2,2111           11         465-30 Mt Hayes - Mains         33         -         147           2         465-10 Mains - Symor Creek         49         -         -         938           13         466-00 Compressor Equipment - OVERHAUL         2,146         -         -         5,062           467-00 Mt. Hayes - Measuring and Regulating Equipment         1,836         -         -         15,757           467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         4           467-20 Illemetridiate Pressure Whistler         13         -         -         -         4           468-00 Communication Structures & Equipment - Byron Creek         <	-		-	-	-	-	461-02 Land Rights - Mt. Hayes	4
7	12,372		11,404	-	-	968	462-00 Compressor Structures	5
8         465-00 Mains - INSPECTION         17,174         (899)         316,951           9         465-00 Mains - INSPECTION         1,590         -         3,215           10         465-11 IP Transmission Pipeline - Whistler         600         -         2,111           11         465-30 Mit Hayes - Mains         93         -         147           24 65-10 Mains - Syrno Creek         49         -         938           31         466-00 Compressor Equipment         5,241         (458)         64,96           44         466-00 Compressor Equipment - OVERHAUL         2,146         -         5,062           15         467-10 Measuring & Regulating Equipment         1,1536         -         15,757           467-20 Measuring & Regulating Equipment         1,1536         -         15,757           467-20 Telemetering         25         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         45           467-20 I Measuring & Regulating Equipment         468         -         -         45           468-03 Communication Structures & Equipment         468         -         -         2         2           472-10 Measuring & Regulating Equipment         600	5,376		4,945	-	-	431	463-00 Measuring Structures	6
9 465-00 Mains - INSPECTION 1,590	2,090		1,916	-	-	174	464-00 Other Structures & Improvements	7
10	333,226		316,951	(899)	-	17,174	465-00 Mains	8
11	4,805		3,215	-	-	1,590	465-00 Mains - INSPECTION	9
12	2,711		2,111	-	-	600	465-11 IP Transmission Pipeline - Whistler	10
13         466-00 Compressor Equipment         5,241         . (458)         64,696           14         486-00 Compressor Equipment - OVERHAUL         2,146         -         -         5,062           15         467-00 Mt. Hayes - Measuring and Regulating Equipment         204         -         -         323           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         2         6         -         -         2         6         -         -         -         2         6         -         -         -         -         -         -         -         -	240		147	-	-	93	465-30 Mt Hayes - Mains	11
14         466-00 Compressor Equipment - OVERHAUL         2,146         -         -         3,062           15         467-00 Mt. Hayes - Measuring and Regulating Equipment         1,000         -         -         3,23           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-21 IP Intermediate Pressure Whistler         13         -         -         45           20         468-00 Communication Structures & Equipment - Byron Creek         -         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         2,254           24         470-00 Land in Fee Simple         -         -         -         2           24         470-00 Structures & Improvements         600         -         -         5,940           27         472-10 Structures & Improvements - Byron Creek         5         -         -         32           28         473-00 Services - LILO         2,543         -         -	987		938	-	-	49	465-10 Mains - Byron Creek	12
15         467-00 Mt. Hayes - Measuring and Regulating Equipment         204         -         -         323           16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         45           20         468-00 Communication Structures & Equipment         468         -         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         -         26           24         470-00 Land in Fee Simple         -         -         -         -         -         26           25         471-00 Distribution Land Rights         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -         -	69,479		64,696	(458)	-	5,241	466-00 Compressor Equipment	13
16         467-10 Measuring & Regulating Equipment         1,836         -         -         15,757           17         467-20 Telemetering         25         -         (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         -         -         4           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         - </td <td>7,208</td> <td></td> <td>5,062</td> <td>-</td> <td>-</td> <td>2,146</td> <td>466-00 Compressor Equipment - OVERHAUL</td> <td>14</td>	7,208		5,062	-	-	2,146	466-00 Compressor Equipment - OVERHAUL	14
17         467-20 Telemetering         25         - (611)         5,822           18         467-31 IP Intermediate Pressure Whistler         13         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         3,254           20         468-00 Communication Structures & Equipment         468         3,254           21         TOTAL TRANSMISSION         31,012         (1,968)         436,991           22         TOTAL TRANSMISSION         31,012         (1,968)         436,991           23         DISTRIBUTION PLANT         26         26         471-00 Distribution Land Rights         26           25         471-00 Distribution Land Rights         32         32           26         472-00 Structures & Improvements - Byron Creek         5 32         28           28         473-00 Services - LILO         2,543         36           28         473-00 Services - LILO         2,543         36           30         474-00 House Regulators & Meter Installations - LILO         598         359           31         474-00 House Regulators & Meter Installations - LILO         598         33	527		323	-	-	204	467-00 Mt. Hayes - Measuring and Regulating Equipment	15
18         467-31 IP Intermediate Pressure Whistler         13         -         -         45           19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         32,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         26           25         471-00 Distribution Land Rights         -         -         -         -         26           25         472-00 Structures & Improvements         600         -         -         5,940           26         472-00 Structures & Improvements - Byron Creek         5         -         -         32           28         473-00 Services - LILO         2,543         -         -         4,363           30         474-00 House Regulators & Meter Installations         12,549         -         (852)         24,588           31         474-00 House Regulators & Meter Installations - LILO         598         -         -         1,302           24         477-00 Meters/Regulators Installations         11	17,593		15,757	-	-	1,836	467-10 Measuring & Regulating Equipment	16
19         467-20 Measuring & Regulating Equipment - Byron Creek         -         -         -         -         4           20         468-00 Communication Structures & Equipment         468         -         -         3,254           21         TOTAL TRANSMISSION         31,012         -         (1,968)         436,991           22         DISTRIBUTION PLANT         -         -         -         -         26           24         470-00 Land in Fee Simple         -         -         -         -         -         -           25         471-00 Distribution Land Rights         -	5,236		5,822	(611)	-	25	467-20 Telemetering	17
A68-00 Communication Structures & Equipment   A68   -   -   3,254	58		45	-	-	13	467-31 IP Intermediate Pressure Whistler	18
TOTAL TRANSMISSION   31,012	4		4	-	-	-	467-20 Measuring & Regulating Equipment - Byron Creek	19
DISTRIBUTION PLANT   24   470-00 Land in Fee Simple   -   -   -   -   26	3,722	_	3,254			468	468-00 Communication Structures & Equipment	20
23   DISTRIBUTION PLANT   24   470-00 Land in Fee Simple   -   -   -   -   26   25   471-00 Distribution Land Rights   -   -   -   -   -   -   -   26   25   471-00 Distribution Land Rights   -   -   -   -   -   -   -   -   -	466,035		436,991	(1,968)	-	31,012	TOTAL TRANSMISSION	21
24       470-00 Land in Fee Simple       -       -       -       -       26         25       471-00 Distribution Land Rights       -       -       -       -       -         26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Measuring & Regulating Installations       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39								22
25       471-00 Distribution Land Rights       -       -       -       -       -       -       5,940         26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       11,097       -       -       359         33       475-00 Mains - LILO       1,803       -       -       3,363         34       475-00 Mains - LILO       1,803       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204							DISTRIBUTION PLANT	23
26       472-00 Structures & Improvements       600       -       -       5,940         27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       478-10 Meters       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -	26		26	-	-	-	470-00 Land in Fee Simple	24
27       472-10 Structures & Improvements - Byron Creek       5       -       -       32         28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       LILO <td>-</td> <td></td> <td>-</td> <td>-</td> <td>-</td> <td>-</td> <td>471-00 Distribution Land Rights</td> <td>25</td>	-		-	-	-	-	471-00 Distribution Land Rights	25
28       473-00 Services       20,325       -       (2,965)       180,822         29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       LILO       524       -       -       1,184         41       478-20 Instruments       362	6,540		5,940	-	-	600	472-00 Structures & Improvements	26
29       473-00 Services - LILO       2,543       -       -       4,363         30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -	37		32	-	-	5	472-10 Structures & Improvements - Byron Creek	27
30       474-00 House Regulators & Meter Installations       12,549       -       (852)       24,598         31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       978         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -	198,182		180,822	(2,965)	-	20,325	473-00 Services	28
31       474-00 House Regulators & Meter Installations - LILO       598       -       -       1,302         32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989 <td>6,906</td> <td></td> <td>4,363</td> <td>-</td> <td>-</td> <td>2,543</td> <td>473-00 Services - LILO</td> <td>29</td>	6,906		4,363	-	-	2,543	473-00 Services - LILO	29
32       477-00 Meters/Regulators Installations       1,097       -       -       359         33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	36,295		24,598	(852)	-	12,549	474-00 House Regulators & Meter Installations	30
33       475-00 Mains       18,561       -       (3,526)       374,894         34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	1,900		1,302	-	-	598	474-00 House Regulators & Meter Installations - LILO	31
34       475-00 Mains - LILO       1,803       -       -       3,363         35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	1,456		359	-	-	1,097	477-00 Meters/Regulators Installations	32
35       476-00 Compressor Equipment       272       -       -       978         36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	389,929		374,894	(3,526)	-	18,561	475-00 Mains	33
36       477-00 Measuring & Regulating Equipment       4,866       -       (585)       30,385         37       477-00 Telemetering       19       -       (83)       6,259         38       477-10 Measuring & Regulating Equipment - Byron Creek       -       -       -       -       204         39       478-10 Meters       17,621       -       (4,370)       79,992         40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989	5,166		3,363	- 1	-	1,803	475-00 Mains - LILO	34
37     477-00 Telemetering     19     -     (83)     6,259       38     477-10 Measuring & Regulating Equipment - Byron Creek     -     -     -     -     204       39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989	1,250		978	-	-	272	476-00 Compressor Equipment	35
38     477-10 Measuring & Regulating Equipment - Byron Creek     -     -     -     -     204       39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	34,666		30,385	(585)	-	4,866	477-00 Measuring & Regulating Equipment	36
39     478-10 Meters     17,621     -     (4,370)     79,992       40     478-11 Meters - LILO     524     -     -     1,184       41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	6,195		6,259	(83)	-	19	477-00 Telemetering	37
40       478-11 Meters - LILO       524       -       -       1,184         41       478-20 Instruments       362       -       -       1,288         42       479-00 Other Distribution Equipment       -       -       -       -       -         43       TOTAL DISTRIBUTION       81,745       -       (12,381)       715,989         44	204		204	-	-	-	477-10 Measuring & Regulating Equipment - Byron Creek	38
41     478-20 Instruments     362     -     -     1,288       42     479-00 Other Distribution Equipment     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	93,243		79,992	(4,370)	-	17,621	478-10 Meters	39
42     479-00 Other Distribution Equipment     -     -     -     -       43     TOTAL DISTRIBUTION     81,745     -     (12,381)     715,989       44	1,708		1,184	-	-	524	478-11 Meters - LILO	40
43 TOTAL DISTRIBUTION 81,745 - (12,381) 715,989 44	1,650		1,288	-	-	362	478-20 Instruments	41
44		_					479-00 Other Distribution Equipment	42
	785,353	_	715,989	(12,381)	-	81,745	TOTAL DISTRIBUTION	43
								44
45 BIO GAS							BIO GAS	45
46 472-00 Bio Gas Struct. & Improvements	-		-	-	-	-	472-00 Bio Gas Struct. & Improvements	46
47 475-10 Bio Gas Mains – Municipal Land	-		-	-	-	-	475-10 Bio Gas Mains - Municipal Land	47
48 475-20 Bio Gas Mains – Private Land 9 7	16		7	-	-	9	475-20 Bio Gas Mains - Private Land	48
49 418-10 Bio Gas Purification Overhaul 143 81	224		81	-	-	143	418-10 Bio Gas Purification Overhaul	49
50 418-20 Bio Gas Purification Upgrader 286 162	448		162	-	-	286	418-20 Bio Gas Purification Upgrader	50
51 474-10 Bio Gas Reg & Meter Installations 186 189	375		189	-	-	186	474-10 Bio Gas Reg & Meter Installations	51
52 478-30 Bio Gas Meters51	71		<u>2</u> 0			51	478-30 Bio Gas Meters	52
53 TOTAL BIO-GAS <u>675</u> <u>459</u>	1,134		459	-		675	TOTAL BIO-GAS	53

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

Line			2013		ovision djust-			Acc	um	ulated	
No.	Account		(Cr.)		nents	Re	tirements	12/31/2012			31/2013
	(1)		(2)		(3)	<u> </u>	(4)	(5)	_		(6)
1	Natural Gas for Transportation										
2	476-10 NG Transportation CNG Dispensing Equipment	\$	253	\$	-	\$	-	\$ 20	5	\$	458
3	476-20 NG Transportation LNG Dispensing Equipment	•	207	•	-	•	-	17	0	•	377
4	476-30 NG Transportation CNG Foundations		56		-		-	4	5		101
5	476-40 NG Transportation LNG Foundations		46		-		-	3	8		84
6	476-50 NG Transportation LNG Pumps		196		-		-	16	1		357
7	476-60 NG Transportation CNG Dehydrator		20		-		-	1	6		36
8	476-70 NG Transportation LNG Dehydrator		-		-		-	-			-
9	TOTAL NG FOR TRANSP		778		-		-	63	5	-	1,413
10									_	-	
11	GENERAL PLANT & EQUIPMENT										
12	480-00 Land in Fee Simple		_		_		_	3	ი		30
13	481-00 Land Rights		_		_		_	-	•		-
14	482-00 Structures & Improvements				_		_	_			_
15	- Frame Buildings		648		-		(3)	3,97	a		4,624
16	- Masonry Buildings		2,440				(0)	16,00			18,445
17	- Leasehold Improvement		373				(146)	56			789
18	Office Equipment & Furniture		-		-		(140)	50.	_		709
19	483-30 GP Office Equipment		351		-		_	75	n		1.110
20	483-40 GP Furniture		1,147		-		(1,954)	14,98			14,180
21	483-10 GP Computer Hardware		,		-		. , ,	,			
22	483-20 GP Computer nardware		6,942 204		-		(6,581)	14,36 72			14,721 721
23	483-21 GP Computer Software		204		-		(211)	12	2		121
			-		-		-	-	^		-
24	483-22 GP Computer Software 484-00 Vehicles		10		-		(1.400)	4 10			59
25			1,832		-		(1,409)	4,18			4,604
26 27	484-00 Vehicles - Leased		3,239		-		(1,716)	15,92 2			17,447
	485-10 Heavy Work Equipment		46		-		-				68
28	485-20 Heavy Mobile Equipment		461		-		(4.057)	1,18			1,643
29	486-00 Small Tools & Equipment		2,513		-		(1,357)	21,33			22,492
30	487-00 Equipment on Customer's Premises		1		-		-	(	5)		(4)
31	- VRA Compressor Installation Costs		-		-		-	-			-
32	488-00 Communications Equipment		-		-		- (400)	-	_		-
33	- Telephone		555		-		(408)	5,06			5,216
34	- Radio		306		-		(34)	2,69			2,967
35	489-00 Other General Equipment				-		- (10.010)		<u>2)</u>		(2)
36	TOTAL GENERAL		21,068		-		(13,819)	101,86	1		109,110
37											
38	UNCLASSIFIED PLANT										
39	499 Plant Suspense		-		-						-
40	TOTAL UNCLASSIFIED		-		-						-
41		_				_			_		.=
42	TOTALS	\$	162,036	\$	-	\$	(41,343)	\$ 1,338,16	<u>/_</u>	\$ 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	- Se	ect 7-TAB	7.5, Scl	hedule 13	3		- Sect 7-TA	В7	.5, Sch	nedule 18

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

		Provision										
Line		Provision	O	oen Bal	R	emoval	Proce	eds on		En	ding	
No.	Account	(Cr.)	Tr	ansfers		Costs	Dis	posal	12/3	31/2011	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											
		40		210								267
8 9	462-00 Compressor Structures	48 10		219 95		-		-		-		267
10	463-00 Measuring Structures 464-00 Other Structures & Improvements	9		95		-		-		-		105 9
11	465-00 Mains	1,691		2.672		-		-		-		4,363
12	466-00 Compressor Equipment	501		404		-		-		-		4,363 905
13	467-10 Measuring & Regulating Equipment	80		72		-		-				152
14	468-00 Communication Structures & Equipment	87		- 12								87
15	TOTAL TRANSMISSION	2,426		3,462			-				-	5,888
16	TOTAL THANOMIODION	2,420		0,402			-				-	3,000
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, Sc	hedule 13					- S	ect 7-TAB	7.5, Sc	hedule 18
39												

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

				Pro	vision								
Line		Pr	ovision	Ad	ljust-	R	emoval	Proc	eeds on		End	ding	
No.	Account		(Cr.)	m	ents		Costs	Dis	posal	12/	/31/2012	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	- Se	ct 7-TAB 7	7.5, Sch	edule 13	3				- :	Sect 7-TAB	7.5, Sc	hedule 18
39													

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

Line		Balance		2012 FO	RECAST	Balance	
No.	Particulars	12/31/2011	Adjustment	Additions	Retirements	12/31/2012	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 2	CIAC						
3 4	Distribution Contributions	\$ 250,340	\$ -	\$ 6,517	\$ -	\$ 256,857	
5 6	Transmission Contributions	116,849	-	10,750	-	127,599	
7 8	Others	-	-	-	-	-	
9 10 11	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	- 15,864	-	-	(5,106)	10,758	
12 13	FEW Contribution for Whistler Pipeline Government Loans Contribution	- 49,123	-	-	(20,000)	- 29,123	
14	Government Loans Contribution	49,123	-	-	(20,000)	29,123	
15 16	Biomethane	-	-	-	-	-	
17 18 19 20	TOTAL Contributions	432,176	-	17,267	(25,106)	424,337	- Sect 7-TAB 7.5, Schedule 18
21 22	Amortization						
23 24	Distribution Contributions	(65,154)	-	(6,351)	-	(71,505)	
25 26	Transmission Contributions	(33,438)	-	(2,203)	-	(35,641)	
27 28	Others	10	-	10	-	20	
29 30 31	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	(9,302)	-	(1,664)	5,106	(5,860)	
32 33 34	FEW Contribution for Whistler Pipeline Government Loans Contribution	-	-	-	-	-	
35 36	Biomethane	-	-	-	-	-	
37 38	TOTAL CIAC Amortization	(107,884)	-	(10,208)	5,106	(112,986)	- Sect 7-TAB 7.5, Schedule 18
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		Balance		2013 FO	RECAST	Balance	
No.	Particulars	12/31/2012	Adjustment	Additions	Retirements	12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1 2	CIAC						
3	Distribution Contributions	\$ 256,857	\$ -	\$ 6,581	\$ -	\$ 263,438	
5 6	Transmission Contributions	127,599	-	750	-	128,349	
7 8	Others	-	-	-	-	-	
9 10 11	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	- 10,758	-	-	(204)	- 10,554	
12	FEW Contribution for Whistler Pipeline	-	-	-	-	-	
13 14	Government Loans Contribution	29,123	-	-	(4,123)	25,000	
15 16	Biomethane						
17 18 19 20	TOTAL Contributions	424,337	-	7,331	(4,327)	427,341	- Sect 7-TAB 7.5, Schedule 18
21 22	Amortization						
23 24	Distribution Contributions	(71,505)	-	(6,537)	-	(78,042)	
25 26	Transmission Contributions	(35,641)	-	(2,299)	-	(37,940)	
27 28	Others	20	-	10	-	30	
29 30 31	Software Tax Savings - Non-Infrastructure - Infrastructure/Custom	(5,860)	-	(1,332)	204	(6,988)	
32 33	FEW Contribution for Whistler Pipeline Government Loans Contribution	-	-	-	-	-	
34 35 36	Biomethane	-	-	-	-	-	
37 38	TOTAL CIAC Amortization	(112,986)	-	(10,158)	204	(122,940)	- Sect 7-TAB 7.5, Schedule 18
39	NET CONTRIBUTIONS	\$ 311,351	\$ -	\$ (2,827)	\$ (4,123)	\$ 304,401	

May 16, 2011

Section 7 TAB 7.5 Schedule 36

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

Line No.	Particulars (1)	Forecast Balance 12/31/2011 (2)	Opening Bal. Transfer / Adjustment (3)	Gross Additions (4)	Less- Taxes (5)	Net Additions (6)	Amortization Expense (7)	Reco Rider (8)	veries Tax on Rider (9)	Balance 12/31/2012 (10)	Mid-Year Average 2012 (11)
1	Margin Related										
2	Commodity Cost Reconciliation Account (CCRA)	\$ (23,385)	\$ -	\$ 31,179	\$ (7,795)	. ,	\$ -	\$ -	\$ -	\$ (0)	\$ (11,692)
3	Midstream Cost Reconciliation Account (MCRA)	18,725	-	-	-	-	-	(8,322)		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	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)		(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 <sup>´</sup>	-	-	-	(66)

FortisBC Energy Utilities May 16, 2011 Section 7 TAB 7.5

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

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Cross Reference

Mid-Year Forecast Opening Line Balance Bal. Transfer / Gross Less-Net Amortization Recoveries Balance Average 12/31/2011 Additions Additions Rider Tax on Rider 12/31/2012 Particulars Adjustment Taxes Expense 2012 No. (1) (4) (5) (6) (7)(8) (9) (10)(11)Cost of Current Applications 2 2009 ROE & Cost of Capital Application 621 \$ 713 \$ \$ \$ \$ \$ (184) \$ \$ \$ 529 \$ 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 Long Term Resource Plan Application 136 70 53 162 7 (18)188 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 (434)434 Pipeline Contribution Costs Variance Account (217)14 15 Other Pension & OPEB Funding 16 (30,602)(76,859)(76,859)(107,461)(69,032)17 Deferred Removal Costs 3.363 (1.682)1.682 2.522 18,739 18 (6,176)11,935 12,249 Gains and Losses on Asset Disposition (628)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 80 120 (40)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 75,131 75,131 (8,066)67,065 33,533 (6,176)6,176 25 26 Residual Deferred Charges 27 684 684 SCP Tax Reassessment 684 28 Earnings Sharing Mechanism 29 Carbon Tax Cost of Service (66)66 (33)30 OSC Certification Compliance (59)59 (30)47 31 Deferred ROE Variance (47)0 (24)32 Sales Margin Differential 464 (464)33 FEW 2009 Revenue Requirement Application (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 61,507 45,699 (199) \$ 1,243 61,107 40,223 (7,733) \$ 27,071 (15.809)(4.974) \$ \$ \$ \$ 39

- Sect 7-TAB 7.5, Schedule 18

- Sect 7-TAB 7.5, Schedule 13

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TAB 7.5 Schedule 38

## 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	Reco	veries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
140.	(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	Ψ -	Ψ -	Ψ -	Ψ -	Ψ -	(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	-	-	-	-	-	-	-	-	-	-

May 16, 2011

Section 7 TAB 7.5 Schedule 39

### 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	Recoveri Rider Ta	es x 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	, in the state of										
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	<u>Other</u>										
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 37	Residual Rider Disposition	-	-	-	-	-	-	-	-	-	-
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			2012	2013		
No.	Particulars	FORECAST 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	

May 16, 2011

Section 7 TAB 7.5 Schedule 41

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

			2012			2013		
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	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			<u>-</u> '		,			
8								
9								
10								

11

Section 7 TAB 7.5 Schedule 42

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

Line No.	Particulars	Amount	2012 Lead Days Expense to Payment	Dollar Days	Amount	2013 Lead Days Expense to Payment	Dollar Days	Cross Reference
<u> </u>	(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	

FortisBC Energy Utilities

May 16, 2011

Section 7 TAB 7.5 Schedule 43

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

Note: \* Excludes Land, Software CIAC, and WIP.

Line		2012	2013	
No.	Particulars	FORECAST	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		<del></del>	· · · · · · · · · · · · · · · · · · ·	
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	<b>,</b> ,	( , -)	(, - ,	
16	FIT Liability/Asset - Opening Balance	(337,894)	(354,428)	
17	3	( , ,	( , -,	
18	FIT Liability/Asset - Mid Year	(346,162)	(361,341)	- Sect 7-TAB 7.5, Schedule 18
19		· · ·		
20				

FortisBC Energy Utilities WEIGHTED AVERAGE RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 2012 (\$000s) May 16, 2011

Section 7 TAB 7.5 Schedule 44

Line No.	Particulars (4)	Am	llization ount	<u>%</u>	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	()	2)	(3)	(4)	(5)	(6)	(7)
1								
2	2012 FORECAST							
3	Long-Term Debt	\$ 1,9	974,672	55.22%	6.54%	3.61%	\$ 129,149	- Sect 7-TAB 7.5, Schedule 46
4	Unfunded Debt							
5	Adjustment, Revised Rates	1	171,106	4.78%	2.75%	0.13%	4,705	
6	Common Equity	1,4	130,519	40.00%	9.62%	3.85%	 137,616	- Sect 7-TAB 7.5, Schedule 5
7			_	<u> </u>				
8		\$ 3,5	576,297	100.00%		7.59%	\$ 271,470	- Sect 7-TAB 7.5, Schedule 18

FortisBC Energy Utilities WEIGHTED AVERAGE RETURN ON CAPITAL FOR THE YEAR ENDING DECEMBER 31, 2013 (\$000s) May 16, 2011

Section 7 TAB 7.5 Schedule 45

Line	(4000)	Ca	pitalization		Average Embedded	Cost	Earned	
No.	Particulars		Amount	%	Cost	Component	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

Cross Reference

May 16, 2011

Section 7 TAB 7.5 Schedule 46

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 (Ser	ies A), using weighted average	capital structure.					Average E	Embedded Cost	6.54%
33	**Includes adjustment of \$0 for BC Hydro Premium (Series B	), using weighted average capi	al structure.							
0.4	` '								0	

<sup>-</sup> Sect 7-TAB 7.5, Schedule 44

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Cross Reference

May 16, 2011

Section 7 TAB 7.5 Schedule 47

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

	(\$000S)				Data da al		NI-1	E#***		
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 3	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
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 13	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
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 - Kalauma							6.413%	23,749	1 500
22	LILO Obligations - Kelowna LILO Obligations - Nelson							7.696%	23,749 3,794	1,523 292
23 24	LILO Obligations - Neison							8.929%	11,323	1,011
2 <del>4</del> 25	LILO Obligations - Vernori LILO Obligations - Prince George							7.862%	29,142	2,291
26	LILO Obligations - Prince George							7.050%	29,142	195
27	LILO Obligations - Greston							7.030 /6	2,700	193
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 (Seri	es A) Tusing weighted average	canital structure					Average F	mbedded Cost	6.56%
33	**Includes adjustment of \$3,216 for BC Hydro Premium (Serie	,	•					Average L	inibodaca Oost	0.3076
00	includes adjustifient of \$5,210 for BC rigaro Premium (Sent	es b), using weignted average	capital Structure.						0 . 7 7 4 0 7	

<sup>-</sup> 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)

(I) 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
	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
New Account	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
New Account	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
	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
Amortization Period Change- New or Modified	Interest Variance Account	FEW, FN	Section 6.3.3.5; change from 1 year to 3 year amortization period, commencing January 1, 2012
Wodified	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	<ol> <li>Section 6.3.2.1;</li> <li>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;</li> <li>The allocation of the 2012 and 2013 EEC rate base deferral account additions amongst Mainland, Vancouver Island and Whistler on an average customer basis;</li> <li>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.</li> </ol>
	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
Discontinuance	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:

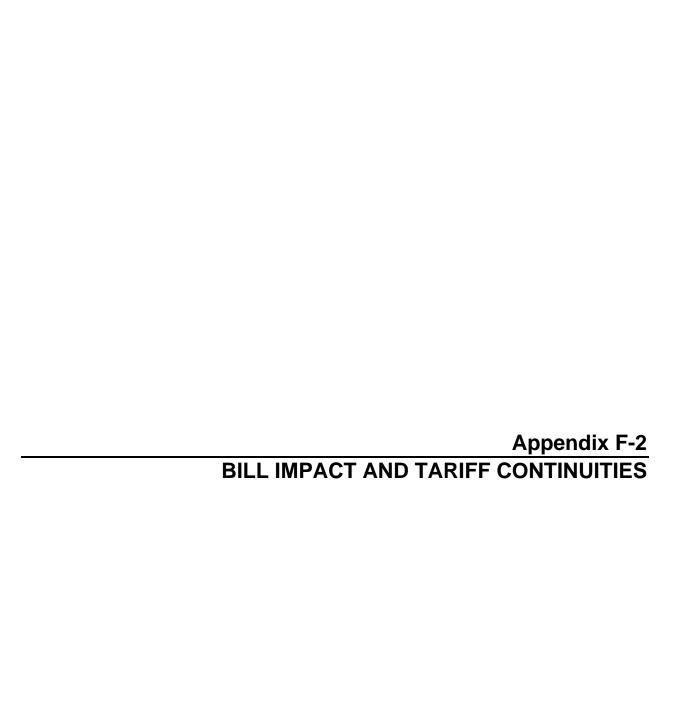
- 1. The rationale for requesting an NSP, or alternatively a written hearing process.
- 2. The request for interim rates effective January 1, 2012, pursuant to section 89 of the UCA and section 15 of the Administrative Tribunals Act. The rationale for the request for interim rates is that, based on the 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.





### 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

### FORTISBC ENERGY INC.

### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED JANUARY 1, 2012 RATES

BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

APPENDIX F-2 TAB 1.1.1 PAGE 1

SCHEDULE 1

	RATE SCHEDULE 1:				DE	LIVERY MARGIN	ı			
	RESIDENTIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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.

# FORTISBC ENERGY INC. CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED JANUARY 1, 2012 RATES

APPENDIX F-2 TAB 1.1.1 PAGE 2 SCHEDULE 2

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

R.A	ATE SCHEDULE 2:				DEI	LIVERY MARGIN				
SM	MALL COMMERCIAL SERVICE	EXISTING JANUARY 1, 2011 RATES			RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2012 RATES		
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1 <u>Del</u>	elivery Margin Related Charges									
	sic 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 Sub	btotal 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 <u>Cor</u>	mmodity 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 Sub	btotal 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 <b>Co</b> s	ost 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 Rid	der 1 Propane Surcharge (Revelstoke only)		\$8.254			\$0.000			\$8.254	
20										
21										
	ost of Gas Recovery Related Charges for Revelstoke		\$14.123			\$0.000			\$14.123	
23 per	er 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.

APPENDIX F-2 TAB 1.1.1 PAGE 3 SCHEDULE 3

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 3:				DE	LIVERY MARGIN	ı			
	LARGE COMMERCIAL SERVICE	EXISTING	JANUARY 1, 2011 F	RATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	Diday 4 Decreas Comphessor (Developely, and v)		\$8.556			\$0.000			\$8.556	
19	Rider 1 Propane Surcharge (Revelstoke only)		\$8.556			\$0.000			\$8.556	
	Coat of Coa Bassiani Balated Channes for Bassiatal		644400			<b>#0.000</b>			644400	
	-	=	\$14.123		=	\$0.000		=	\$14.123	
23	per GJ (Includes Rider 1, excludes Rider 8)									
20 21 22 23	Cost of Gas Recovery Related Charges for Revelstoke per GJ (Includes Rider 1, excludes Rider 8)	=	<b>\$14.123</b>		=	\$0.000		-	\$14.123	

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

APPENDIX F-2 TAB 1.1.1 PAGE 4 SCHEDULE 4

BCUC ORDE	R NO.G-XX	X-11 G-	-XXX-11
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	RATE SCHEDULE 4:				DE	LIVERY MARGIN	ı			
	SEASONAL SERVICE	EXISTING	JANUARY 1, 2011 R	ATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
_	Delivery Margin Related Charges									
	Basic Charge per day	\$14.4230	\$14.4230	\$14.4230	\$0.0000	\$0.0000	\$0.0000	\$14.4230	\$14.4230	\$14.4230
3										
	Delivery Charge per GJ	20.054	*****	***		***	20.004	***	***	40.005
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		***	***	** ***		***	***	**		40.000
	Rider 2 2009 ROE Rate Rider	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
	Rider 3 ESM	(\$0.014)	(\$0.014)	(\$0.014)	\$0.014	\$0.014	\$0.014	\$0.000	\$0.000	\$0.000
10	0									
_	Commodity Related Charges									
	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										
	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										
	Subtotal Off -Peak Commodity Related Charges per GJ									
1	(a) Off-Peak Period	\$5.332	\$5.317	\$5.353	\$0.000	\$0.000	\$0.000	\$5.332	\$5.317	\$5.353
	(b) Extension Period	\$5.332	\$5.317	\$5.353	\$0.000	\$0.000	\$0.000	\$5.332	\$5.317	\$5.353
24										
25										
26										
	Unauthorized Gas Charge per gigajoule	Balancing, Backsto Order No. G-110-00		r BCUC				Balancing, Backs Order No. G-110	topping and UOR	per BCUC
28 0	during peak period	Order No. G-110-00	J.					Order No. G-110	-00.	
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.

APPENDIX F-2 TAB 1.1.1 PAGE 5 SCHEDULE 5

#### BCUC ORDER NO.G-XXX-11 G-XXX-11

	RATE SCHEDULE 5				DE	LIVERY MARGIN	I			
	GENERAL FIRM SERVICE	EXISTING	JANUARY 1, 2011 F	ATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	3. P	,	•	,	• • • • • • • • • • • • • • • • • • • •	,	,	• • • • • • • • • • • • • • • • • • • •	• • • • • • • • • • • • • • • • • • • •	,
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

APPENDIX F-2 TAB 1.1.1 PAGE 6 SCHEDULE 6

BCUC C	RDER NO	.G-XXX-11	G-XXX-11
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	RATE SCHEDULE 6:				DE	LIVERY MARGIN	ı			
	NGV - STATIONS	EXISTING	JANUARY 1, 2011 R	ATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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.

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

APPENDIX F-2 TAB 1.1.1 PAGE 6.1 SCHEDULE 6A

	RATE SCHEDULE 6A: NGV - VRA's			
_ine			DELIVERY MARGIN	
No.	Particulars	EXISTING JANUARY 1, 2011 RATES	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			<del></del>	
22 23	Total Variable Cost per gigajoule	\$13.770	\$0.252	\$14.022
23	Total variable Cost per gigajoule	<u> </u>	Φυ.202	<u> </u>

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

APPENDIX F-2 TAB 1.1.1 PAGE 7 SCHEDULE 7

	RATE SCHEDULE 7:				DEI	LIVERY MARGIN				
	INTERRUPTIBLE SALES	EXISTING	JANUARY 1, 2011 R	ATES	RELATED	CHARGES CHA	ANGES	PROPOSEI	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		Balancing Backst	opping and UOR pe	er BCUC				Balancing, Backs	topping and UOR	per BCUC
16	Charges per gigajoule for UOR Gas	Order No. G-110-0		5. 2000				Order No. G-110-		po. 2000
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
	Total Variable Cost per gigajoule	\$6.392	\$6.377	\$6.413	\$0.080	\$0.080	\$0.080	\$6.472	\$6.457	\$6.4

APPENDIX F-2 TAB 1.1.1 PAGE 8 SCHEDULE 22

RATE SCHEDULE 22					DE	LIVERY MARGIN	I			
LARGE INDUSTRIAL	. T-SERVICE	EFFEC	TIVE JANUARY 1, 2	2011	RELATE	D CHARGES CHA	ANGES	PROPOSE	D JANUARY 1, 201	2 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	Mainland	Inland	Columbia
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1 Basic Charge per Mo	onth	\$3,664.00	\$3,664.00	\$3,664.00	\$0.00	\$0.00	\$0.00	\$3,664.00	\$3,664.00	\$3,664.00
	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 F	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
8 9 Charges per gigajou	le for UOR Gas	Balancing, Bac Order No. G-1	kstopping and UOF 10-00.	R per BCUC				Balancing, Back Order No. G-110	stopping and UOF 0-00.	R per BCUC
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 p	or gigaioulo									
	n 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
` '	n 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	ir and including Nov. 1 and Mai. 31	ψ1.10	\$1.10	11/a	ψ0.00	ψ0.00	IVa	ψ1.10 	ψ1.10	IVa
	le for Backstopping Gas	Balancing, Backs Order No. G-110	stopping and UOR p -00.	per BCUC				Balancing, Back Order No. G-11	stopping and UOF 0-00.	R per BCUC
23 24 Administration Char	ge 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 pe	er gigajoule	\$0.781	\$0.781	\$0.781	\$0.057	\$0.057	\$0.057	\$0.838	\$0.838	\$0.838

APPENDIX F-2 TAB 1.1.1 PAGE 9 SCHEDULE 22A

	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE			
Line No.	Particulars	EFFECTIVE JANUARY 1, 2011	DELIVERY MARGIN RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2012 RATES
	(1)	(2)	(3)	(4)
1 2	INLAND SERVICE AREA			
3	Basic Charge per Month	\$4,810.00	\$0.00	\$4,810.00
5	Delivery Charge per gigajoule - Firm (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				Balancing, Backstopping and UOR per BCUC
25 26	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Order No. G-110-00.
27				
28	Replacement Gas	Sumas Daily Price		Sumas Daily Price
29		plus 20 Percent		plus 20 Percent
30		p.ao 20 1 0.00.11		p.do 20 1 0.00.10
31	Administration Charge per Month	\$78.00	\$0.00	\$78.00
32		******	*	Ţ
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 10 SCHEDULE 22B

	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE			DELIVERY MARGIN	ı		
		EFFECTIVE JANUARY 1, 2	011	RELATED CHARGES CH	ANGES	PROPOSED JANUARY 1, 2012	RATES
Line		Columbia	Elkview	Columbia	Elkview	Columbia	Elkview
No.	Particulars	Except Elkview	Coal	Except Elkview	Coal	Except 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			Balancing, Backstopping ar	
17	Charges per gigajoule for UOR Gas	BCUC Order No. G-110-	00.			BCUC Order No. G-110-00	).
18		L					
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			Balancing, Backstopping ar	
23	Charges per gigajoule for Backstopping Gas	BCUC Order No. G-110-0				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
						-	-

#### APPENDIX F-2 TAB 1.1.1 PAGE 11 SCHEDULE 23

RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	EEEE	CTIVE JANUARY 1, 2	2011		LIVERY MARGII D CHARGES CH		PPOPOSEI	) JANUARY 1, 201	DATES
Line	Lower	CTIVE JANUART 1, 2	2011	Lower			Lower		
No. Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
8 Sales									
9 (a) Charge per gigajoule for Balancing Gas 10 (b) Charge per gigajoule for Backstopping	Dalarionig, Dat	ckstopping, Replacer er No. G-110-00.	ment and UOR					stopping, Replace Order No. G-110-	
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 12 SCHEDULE 25

	RATE SCHEDULE 25				DE	LIVERY MARGIN	١			
	GENERAL FIRM T-SERVICE	EFFEC <sup>*</sup>	TIVE JANUARY 1, 2	011	RELATE	D CHARGES CH	ANGES	PROPOSEI	JANUARY 1, 2012	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		215010	0.45.0.40	045.040	04.050	24.050	04.050	040.000	040.000	040.000
3	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 gigajoule (Interr. MTQ)	\$0.645	\$0.645	\$0.645	\$0.051	\$0.051	\$0.051	\$0.696	\$0.696	\$0.696
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		stopping, Replacen						stopping, Replace Order No. G-110	
12 13	<ul><li>(b) Charge per gigajoule for Backstopping Gas</li><li>(c) Replacement Gas</li></ul>	UOR per BCUC	Order No. G-110-0	0.				OOR per BCOC	Order No. G-110	.00.
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)	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
19	Mad 5 Low	(ψ0.021)	(ψ0.021)	(ψ0.021)	ψ0.021	Ψ0.021	Ψ0.021	ψ0.000	ψ0.000	ψ0.000
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

#### APPENDIX F-2 TAB 1.1.1 PAGE 13 SCHEDULE 26

	RATE SCHEDULE 26:					LIVERY MARGIN					
	NATURAL GAS VEHICLE T-SERVICE		TIVE JANUARY 1, 2	011		D CHARGES CH	ANGES		(9) (10		
Line		Lower			Lower			Lower			
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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											
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	Administration onlying per month.	Ψ70.00	ψ/ 0.00	ψ10.00	ψ0.00	ψ0.00	ψ0.00	Ψ70.00	Ψ10.00	ψ10.00	
8	Sales										
10 11	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas	Balancing, Backs Order No. G-110	stopping and UOR I-00.	per BCUC				Balancing, Bacl BCUC Order No	kstopping and UO b. G-110-00.	R per	
12 13	(d) Charge per gigajoule for UOR Gas										
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 16	Rider 3 ESM	(\$0.039)	(\$0.039)	(\$0.039)	\$0.039	\$0.039	\$0.039	\$0.000	\$0.000	\$0.000	
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	
"	. Stat. Talladio Gook pol. gigajoulo	ψο.σσσ =	<del></del>	φο.σσσ	<del></del>	<del>40.202</del>	ψ0. <b>L</b> 0L	Ψ0.001	φο.σσ1	ψο.σσ1	

APPENDIX F-2 TAB 1.1.1 PAGE 14 SCHEDULE 27

	ATE SCHEDULE 27:	FFF-03	TIVE JANUARY 4 O	044		LIVERY MARGIN		PROPOSE	) IANIIIA B.V. 4. 004	DATES
	ITERRUPTIBLE T-SERVICE		TIVE JANUARY 1, 2	U11		D CHARGES CH	ANGES		JANUARY 1, 201	ZRATES
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 <b>B</b> a	asic Charge per Month	\$880.00	\$880.00	\$880.00	\$0.00	\$0.00	\$0.00	\$880.00	\$880.00	\$880.00
2										
4 De	elivery 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 <b>A</b> d	dministration Charge per Month	\$78.00	\$78.00	\$78.00	\$0.00	\$0.00	\$0.00	\$78.00	\$78.00	\$78.00
7 8										
9 <b>Sa</b> 10 11 12	ales  (a) Charge per gigajoule for Balancing Gas  (b) Charge per gigajoule for Backstopping Gas  (d) Charge per gigajoule for UOR Gas	Balancing, Backs Order No. G-110	stopping and UOR I-00.	per BCUC				Balancing, Bac BCUC Order N	kstopping and UC o. G-110-00.	R per
13 14 <b>Ri</b> o	der 2 2009 ROE Rate Rider	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
15 <b>Ri</b>	der 3 ESM	(\$0.013)	(\$0.013)	(\$0.013)	\$0.013	\$0.013	\$0.013	\$0.000	\$0.000	\$0.000
16 17										
18 19 To	otal 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 Annual No. Particular EXISTING JANUARY 1, 2011 RATES PROPOSED JANUARY 1, 2012 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.389 \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% 3 Basic Charge davs x davs x 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% 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% (\$0.020) = (\$1.9000) (\$0.032)(\$3.0400)(\$1.1400) 8 Rider 5 RSAM 95.0 GJ x 95.0 GJ x (\$0.012)-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 GJ x \$0.009 \$0.8550 95.0 GJ x \$0.009 0.8550 \$0.0000 0.00% 95.0 \$0.000 Midstream Related Charges Subtotal 14 \$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 \$1,008.87 95.0 \$1,036.61 \$27.74 2.75% \$10.620 \$10.912 \$0.292 20 21 INLAND SERVICE AREA **Delivery Margin Related Charges** 22 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 \$3.275 = \$245.6250 GJ x \$3.531 = \$264.8250 \$19.2000 2.33% Delivery Charge 75.0 GJ x 75.0 \$0.256 26 \$0.000 = Rider 2 2009 ROE Rate Rider 75.0 GJ x \$0.000 = \$0.0000 75.0 GJ x \$0.0000 \$0.000 \$0.0000 0.00% 27 (\$0.048) = \$0.000 = 0.44% Rider 3 ESM 75.0 GJ x (\$3.6000)75.0 GJ x \$0.0000 \$0.048 \$3,6000 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 \$382.61 \$404.51 Subtotal Delivery Margin Related Charges \$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 \$0.00 0.00% 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 37 \$441.90 \$441.90 \$0.00 0.00% Subtotal Commodity Related Charges 38 39 Total (with effective \$/GJ rate) 75.0 \$824.51 \$846.41 \$21.90 2.66% \$10.993 75.0 \$11.285 \$0.292 40 41 **COLUMBIA SERVICE AREA** 42 Delivery Margin Related Charges 43 365.25 \$0.389 = \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% Basic Charge days x days x 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 \$0.000 = GJ x \$0.000 = \$0.0000 Rider 2 2009 ROE Rate Rider 80.0 GJ x \$0.0000 80.0 \$0.0000 \$0.000 0.00% 47 (\$0.048) = \$0.000 = 0.44% Rider 3 ESM 0.08 GJ x (\$3.8400)80.0 GJ x \$0.0000 \$0.048 \$3.8400 48 Rider 5 RSAM (\$0.020) = (\$1.6000)(\$0.032)(\$2.5600) (\$0.012) (\$0.9600)-0.11% 80.0 GJ x 80.0 GJ x 49 Subtotal Delivery Margin Related Charges \$398.64 \$422.00 \$23.36 2.68% 50 51 Commodity Related Charges 52 0.08 GJ x \$1.355 \$108.4000 80.0 GJ x \$1.355 \$108.4000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge \$0.7200 53 GJ x \$0.009 80.0 GJ x \$0.009 \$0.7200 \$0.000 \$0.0000 0.00% Rider 8 Unbundling Recovery 80.0 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

\$873.20

0.08

\$896.56

\$11.207

\$10.915 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.

0.08

Total (with effective \$/GJ rate)

59

2.68%

\$23.36

### 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 Annual No. Particular EXISTING JANUARY 1, 2011 RATES PROPOSED JANUARY 1, 2012 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.816 \$298.08 \$0.816 = \$298.08 \$0.00 \$0.00 0.00% Basic Charge days 365.25 days x \$2.714 = \$2.907 = \$57.9000 2.02% **Delivery Charge** 300.0 GJ x \$814.2000 300.0 GJ x \$872.1000 \$0.193 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% 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 \$1.095.48 \$1.160.58 \$65.10 2.27% Subtotal Delivery Margin Related Charges 10 11 Commodity Related Charges 12 300.0 GJ x \$1.327 \$398.1000 \$1.327 \$398.1000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge 300.0 GJ x 13 Rider 8 Unbundling Recovery 300.0 GJ \$0.000 \$0.0000 300.0 GJ x \$0.000 \$0.0000 \$0.000 \$0.0000 0.00% 14 \$398.10 \$398.10 \$0.00 Midstream Related Charges Subtotal 0.00% 15 16 300.0 \$4.568 \$1,370,40 \$4.568 \$1.370.40 \$0.000 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) G.I x 300.0 G.I x 17 Subtotal Commodity Related Charges \$1,768.50 \$1,768.50 \$0.00 0.00% 18 19 Total (with effective \$/GJ rate) 300.0 \$2,863.98 \$9.547 300.0 \$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 GJ x \$0.000 = \$0.0000 0.00% Rider 2 2009 ROE Rate Rider 250.0 \$0.000 = \$0.0000 250.0 GJ x \$0,0000 \$0,000 27 250.0 GJ x (\$0.036) = 250.0 \$0.000 = \$0.0000 \$9.0000 0.37% (\$9.0000) GJ x \$0.036 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 \$325.25 Midstream Related Charges Subtotal \$325.25 \$0.00 0.00% 35 \$4.568 36 \$4.568 \$1,142.00 \$1,142.00 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) 250.0 GJ x 250.0 GJ x \$0.000 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 \$0.816 = \$0.816 = 0.00% Basic Charge 365.25 days x \$298.08 365.25 days x \$298.08 \$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 \$0.000 = Rider 2 2009 ROE Rate Rider 320.0 GJ x \$0.000 = \$0.0000 320.0 GJ x \$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 (\$10.2400) (\$3.8400) Rider 5 RSAM 320.0 GJ x (\$0.020) =(\$6.4000)320.0 GJx(\$0.032) =(\$0.012)-0.13% 49 \$1,148.64 \$69.44 Subtotal Delivery Margin Related Charges \$1,218.08 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% Rider 8 Unbundling Recovery \$0.0000 53 320.0 GJ x \$0.000 320.0 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 56 320.0 \$4.568 \$4.568 \$1,461.76 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) GJ x \$1,461.76 320.0 GJ x \$0.000 57 \$1,891.20 \$0.00 Subtotal Commodity Related Charges \$1,891.20 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%

### 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 Particular		EXISTING J	ANUARY 1, 2011	RATES		PROPOSED	JANUARY 1, 2012	2 RATES		Annual Increase/Decrease	e
1	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volur	ma	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
2	Delivery Margin Related Charges	Voidi		rate	Απιααιψ	Voidi	iic	rate	Allitual ψ	rate	Απιααιψ	Total Allidai biii
3 4	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%
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	2,000.0	00 A		\$2.850.40	2,000.0	00 A		\$2.850.40	ψο.σσσ	\$0.00	0.00%
15					<del>-</del> ,				<del>+</del> =,••••		70.00	
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	<u>Delivery Margin Related Charges</u>											
23 24	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%
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				_	<del>***,*********************************</del>			_	¥1,75=11=1	•	<b>7</b>	
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			' <u>-</u>	\$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	Total (with effective E/C I rate)				********				*** ***		4.00.00	4.050/
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	COLUMBIA GERVICE AREA											
41	COLUMBIA SERVICE AREA											
42 43	<u>Delivery Marqin Related Charges</u> 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%
43	Basic Grange	303.23	uays x	φ4.334 <b>-</b>	\$1,590.24	303.23	uays x	φ4.334 -	\$1,590.24	\$0.00	\$0.00	0.00%
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	0,000.0	00 A	(\$0.020)	\$9,081.24	0,000.0	00 X	(40.002)	\$9,625.74	(40.0.2)	\$544.50	1.97%
50				_	<del>+</del> • • • • • • • • • • • • • • • • • • •			_	40,020111	,	***************************************	
51	Commodity Related Charges	1										
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	<del>-</del>	I										
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	I		_	\$18,493.20			_	\$18,493.20	•	\$0.00	0.00%
58	T. I. C. W. W. W. (1990)	1		_				_				
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%

### 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 J	ANUARY 1, 2011	RATES	PROPOSED JANUARY 1, 2012 RATES				Annual Increase/Decrease			
						.,.		-				% of Previous	
1 2	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	Total Annual Bill	
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	2000 Change		aayo x	V 20	ψο,σσσ.σ2.τσ		uajo x	V	ψο,σσσ.σΞ.τσ	ψ0.00	ψ0.00	0.0070	
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 12	Subtotal Delivery Margin Related Charges			_	\$7,622.52			_	\$8,135.52	-	\$513.00	1.41%	
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	Orlandiforized Gas Grialge During Feak Fellod (flot forecast)												
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	Dolivon, Chargo												
33	Delivery Charge (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			· · · · · <u>-</u>	\$10,898.52				\$11,782.02	_	\$883.50	1.46%	
38													
39	Commodity Related Charges												
40	Midstream Cost Recovery Charge		0.1	20.740	*********		0.1	00.740	** ***	***	** ***	0.000/	
41	(a) Off-Peak Period	9,300.0	GJ x GJ x	\$0.749 = \$0.749 =	\$6,965.7000	9,300.0 0.0	GJ x GJ x	\$0.749 = \$0.749 =	\$6,965.7000	\$0.000 \$0.000	\$0.0000	0.00% 0.00%	
42 43	(b) Extension Period Commodity Cost Recovery Charge	0.0	GJ X	\$0.749 =	\$0.0000	0.0	GJ X	\$0.749 =	\$0.0000	\$0.000	\$0.0000	0.00%	
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	(-)			*	*******			*	,	40.000	*******		
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%	

### 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 .	IANUARY 1, 20	11 RATES		PROPO	SED JANUARY 1,	2012 RATES		Annual Increase/Decrease	e
1 2	LOWER MAINLAND SERVICE AREA	Volu	me	Rate	Annual \$		Volume	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
3 4 5	<u>Delivery Marqin Related Charges</u> Basic Charge	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
6 7	Demand Charge	58.5	GJ x	\$15.943	=\$11,191.	<b>99</b> 5	8.5 GJ	x \$16.996	=\$11,931.19	\$1.053	\$739.20	0.97%
9 10 11 12	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,700.0 9,700.0 9,700.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	0000 9,70 7000) 9,70	0.0 GJ	x \$0.000		\$0.051 \$0.000 \$0.021	\$494.7000 \$0.0000 \$203.7000 \$698.40	0.65% 0.00% 0.27% <b>0.92%</b>
13 14 15 16 17	Commodity Related Charges  Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,700.0 9,700.0	GJ x GJ x	\$0.764 \$4.568		9,70			= \$7,410.8000 = \$44,309.6000 \$51,720.40	\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
18 19	Total (with effective \$/GJ rate)	9,700.0		\$7.836	\$76,009.	9,70	0.0	\$7.984	\$77,446.79	\$0.148	\$1,437.60	1.89%
	Delivery Margin Related Charges	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
24 25	Demand Charge	82.0	GJ x	\$15.943	=\$15,687.	<b>91</b> 8	2.0 GJ	x \$16.996	=\$16,724.06	\$1.053	\$1,036.15	1.05%
26 27 28 29	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	12,800.0 12,800.0 12,800.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	0000 12,80 8000) 12,80	0.0 GJ	x \$0.000	= \$8,908.8000 = \$0.0000 = \$0.0000 \$8,908.80	\$0.051 \$0.000 \$0.021	\$652.8000 \$0.0000 \$268.8000 <b>\$921.60</b>	0.66% 0.00% 0.27% <b>0.93%</b>
30 31 32 33 34 35	Commodity Related Charges  Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	12,800.0 12,800.0	GJ x GJ x	\$0.749 \$4.568		1000 12,80				\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
36 37	Total (with effective \$/GJ rate)	12,800.0		\$7.717	\$98,776.	12,80	0.0	\$7.870	\$100,734.46	\$0.153	\$1,957.75	1.98%
	COLUMBIA SERVICE AREA <u>Delivery Marqin Related Charqes</u> Basic Charge	12	months x	\$587.00	=\$7,044.	00	12 months	x \$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
	Demand Charge	55.4	GJ x	\$15.943	= \$10,598.	<b>)1</b> 5	5.4 GJ	x \$16.996	= \$11,298.94	\$1.053	\$700.03	0.97%
44 45 46 47 48	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Subtotal Delivery Margin Related Charges	9,100.0 9,100.0 9,100.0	GJ x GJ x	\$0.645 \$0.000 (\$0.021)	= \$0.	9,10 (1000) 9,10	0.0 GJ	x \$0.000	, . ,	\$0.051 \$0.000 \$0.021	\$464.1000 \$0.0000 \$191.1000 \$655.20	0.64% 0.00% 0.27% <b>0.91%</b>
49 50 51 52	Commodity Related Charges Midstream Cost Recovery Charge Commodity Cost Recovery Charge Subtotal Gas Commodity Cost (Commodity Related Charge)	9,100.0 9,100.0	GJ x GJ x	\$0.785 \$4.568		9,10				\$0.000 \$0.000	\$0.0000 \$0.0000 <b>\$0.00</b>	0.00% 0.00% <b>0.00%</b>
53 54	Total (with effective \$/GJ rate)	9,100.0		\$7.916	\$72,033.	9,10	0.0	\$8.065	\$73,388.84	\$0.149	\$1,355.23	1.88%

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

Line											Annual	
No.	Particular Particular	. —	EXISTING J	ANUARY 1, 2011 F	RATES	. ———	PROPOSED	JANUARY 1, 201	12 RATES		ncrease/Decrease	
1		Volur	ne	Rate	Annual \$	Volur	ne	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			· / <u>-</u>	\$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												
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		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		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		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					\$43,679.10			_	\$46,677.90		\$2,998.80	2.94%
27												
28												
29		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		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					\$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%

### 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 Particular		EXISTING J	JANUARY 1, 20	11 RATES		PROPOSED	JANUARY 1, 2	2012 RATES		Annual Increase/Decrease	
1		Volu	ıme	Rate	Annual \$	Volun	ne	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 m	nonths x	\$880.00	=\$10,560.00	\$0.00	\$0.00	0.00%
5 6	Delivery Charge	8.100.0	GJ x	\$1.073	<b>\$8.691.3000</b>	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		8.100.0	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
8	Rider 3 ESM	8,100.0	GJ x	(\$0.013)		8,100.0	GJ x	\$0.000		\$0.013	\$105.3000	0.17%
9	Rider 4 Reserve for Future Use	8,100.0	GJ x	\$0.000		8,100.0	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
10		2,		******	\$8,586.00	2,12212		******	\$9,234.00	******	\$648.00	1.04%
11	Captotal Bollion, margin Holaton Charges				<del></del>				<b>40,2000</b>		<del>\$0.0.00</del>	
12	Commodity Related Charges											
13		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		8,100.0	GJ x	\$4.568	= \$37,000.8000	\$0.000	\$0.0000	0.00%
15		.,		,	\$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 m	nonths 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		4,000.0	GJ x	\$0.000		\$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		4,000.0	GJ x	\$0.749	, ,	4,000.0	GJ x	\$0.749	, ,	\$0.000	\$0.0000	0.00%
35		4,000.0	GJ x	\$4.568	Ψ10,E12.0000	4,000.0	GJ x	\$4.568		\$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												
39												
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%

#### APPENDIX F-2 TAB 1.1.2 PAGE 8

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

	RATE SCHEDULE 22 - LANGE INDUSTRIAL 1-SERVICE												
Line No.			EFFECTIV	E JANUARY 1,	2011		F	PROPOSED J	ANUARY 1, 201	2 RATES		Annual Increase/Decrease	
1		Volu	me	Rate		Annual \$	Volu	ıme	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	LOWER MAINLAND SERVICE AREA												
3	Basic Charge	12	months x	\$3,664.00	= 5	\$43,968.00	12	months x	\$3,664.00	= \$43,968.00	\$0.00	\$0.00	0.00%
4						. ,							
5	i e e e e e e e e e e e e e e e e e e e												
6	Delivery Charge - Interruptible MTQ	467,305.6	GJ x	\$0.790	= \$3	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				\$3	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	\$4	409,869.67	467,305.6		\$0.934	\$436,506.09	\$0.057	\$26,636.42	6.50%

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

	RATE SCHEDULE 22A - LANGE HADDSTRIAE 1-SERVICE											
Line No.	Particular		EFFECTIV	E JANUARY 1,	2011	PF	ROPOSED J	ANUARY 1, 201	12 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volun	ne	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												
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	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	, , , , , , , ,	584.475.8	GJ X	\$0.093		\$0.000	\$0.0000	0.00%
11	Rider 3 ESM	584,475.8	GJ x	(\$0.009)		584,475.8	GJ x	\$0.000		\$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		28,607.9	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
17	Rider 3 ESM	28,607.9	GJ x	(\$0.009)		28,607.9	GJ x	\$0.000		\$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	corr, comand caronal go, calanoning corrido, cachetoppining cac											
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	T. I. I. W. W. W. W. W. W.											
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%

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

ine				Annual
Nο	Particular	EFFECTIVE IANIJARY 1 2011	PROPOSED IANUARY 1 2012 RATES	Increase/Dec

1.5			K.	ATE SCHEDU	ILE 22B - LARGE INL	DUSTRIAL 1-S	EKVICE				A	
Line No.	Particular	. ———	EFFECTIV	E JANUARY 1,	2011	P	ROPOSED JA	ANUARY 1, 201	12 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	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%
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%
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	\$0.086	* /	457,345.8	GJ x	\$0.092		\$0.006	\$2,744.0748	0.88%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x		= \$0.0000	457,345.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
9	Rider 3 ESM	457,345.8	GJ x	(\$0.006)		457,345.8	GJ x	\$0.000		\$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	Delivery Observed Intermediate MTO											
12	Delivery Charge - Interruptible MTQ	6 700 4	C L v	\$0.802	- 05 200 2040	6 700 4	01.4	<b>CO OFF</b>	-	<b>60.053</b>	#256 0470	0.11%
13 14	- Apr. 1 to Nov. 1 - Nov. 1 to Apr. 1	6,732.4 0.0	GJ x GJ x			6,732.4 0.0	GJ x GJ x	\$0.855 \$1.231		\$0.053 \$0.076	\$356.8172 \$0.0000	0.11%
15	Rider 2 2009 ROE Rate Rider	6,732.4	GJ X			6,732.4	GJ X	\$0.000		\$0.076	\$0.0000	0.00%
16	Rider 3 ESM	6,732.4	GJ x	(\$0.006)		6,732.4	GJ X	\$0.000		\$0.006	\$40.3944	0.01%
17	Transportation - Interruptible (Delivery Charge Interruptible MTQ)	0,732.4	00 x	(ψ0.000)	\$5,358.99	0,732.4	00 X	ψ0.000	\$5,756.20	ψ0.000	\$397.21	0.13%
18	Transportation Interruptible (Benvery Orlarge Interruptible WT Q)				Ψ0,000.00				ψο,100.20		ψοστ.Στ	0.1070
19	Non-Standard Charges (not forecast )											
20	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
21	3 · · · · · · · · · · · · · · · · · · ·											
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	basic Gliarge	12	IIIOIIIII X	φ4,337.00	- \$34,444.00	12	months x	φ4,557.00	- <del>\$34,444.00</del>	φ0.00	φυ.υυ	0.00 /8
30 31	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%
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		= \$0.0000	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			0.0	GJ x	\$0.214		\$0.013	\$0.0000	0.00%
39	- Nov. 1 to Apr. 1	14,503.1	GJ x	\$0.287		14,503.1	GJ x	\$0.306		\$0.019	\$275.5589	0.16%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x			14,503.1	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x		· · · /	14,503.1	GJ x	\$0.000		\$0.002	\$29.0062	0.02%
42 43	Rider 4 Reserve for Future Use	14,503.1	GJ x	\$0.000		14,503.1	GJ x	\$0.000		\$0.000	\$0.0000 \$304.57	0.00% <b>0.18%</b>
43	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				\$4,133.38				\$4,437.95		\$3U4.3 <i>f</i>	0.16%
45	Non-Standard Charges (not forecast )											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47	23.4, 23and Garonargo, Dalanoing Gorvice, Dackstopping Gas											
48	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
49										72.30	7	
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%

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line			K.F	I E SCHEDU	LE 23 - L	LARGE COMI	WERCIAL 1-5	ERVICE					Annual	
No.	Particular		EFFECTIVE	JANUARY 1, 2	2011		P	ROPOSED JA	NUARY 1, 201	2 RATE	3		Increase/Decrease	
1		Volum	e	Rate	Aı	nnual \$	Volu	me	Rate		Annual \$	Rate	Annual \$	% of Previous Annual Bill
	LOWER MAINLAND SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	1,590.24	\$0.00	\$0.00	0.00%
5 6	Administration Charge	12	months x	\$78.00	=	\$936.00	12	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
7 8 9 10	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,100.0 4,100.0 4,100.0 4,100.0	GJ x GJ x GJ x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (	9,503.8000 \$0.0000 \$114.8000) (\$82.0000) <b>0,307.00</b>	4,100.0 4,100.0 4,100.0 4,100.0	GJ x GJ x GJ x	\$2.467 \$0.000 \$0.000 (\$0.032)	- - -	0,114.7000 \$0.0000 \$0.0000 (\$131.2000) <b>39,983.50</b>	\$0.149 \$0.000 \$0.028 (\$0.012)	\$610.9000 \$0.0000 \$114.8000 (\$49.2000) \$676.50	5.16% 0.00% 0.97% -0.42% <b>5.72%</b>
13 14 15	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas													
16 17	Total (with effective \$/GJ rate)	4,100.0		\$2.886	\$11	,833.24	4,100.0		\$3.051	\$1	2,509.74	\$0.165	\$676.50	5.72%
18 19	INLAND SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	51,590.24	\$0.00	\$0.00	0.00%
20 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 25 26 27 28	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,700.0 4,700.0 4,700.0 4,700.0	G1 x G1 x G1 x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (:	0,894.6000 \$0.0000 \$131.6000) (\$94.0000) <b>0,669.00</b>	4,700.0 4,700.0 4,700.0 4,700.0	G1 x G1 x G1 x	\$2.467 \$0.000 \$0.000 (\$0.032)	- ·	1,594.9000 \$0.0000 \$0.0000 (\$150.4000) 1,444.50	\$0.149 \$0.000 \$0.028 (\$0.012)	\$700.3000 \$0.0000 \$131.6000 (\$56.4000) <b>\$775.50</b>	5.31% 0.00% 1.00% -0.43% 5.88%
29 30 31 32 33	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas  Iotal (with effective \$/GJ rate)	4,700.0		\$2.807	\$13	3,195.24	4,700.0		\$2.972	<b>\$</b> 1	3,970.74	\$0.165 <u> </u>	\$775.50	5.88%
34 35	COLUMBIA SERVICE AREA Basic Charge	12	months x	\$132.52	=\$1	,590.24	12	months x	\$132.52	=	61,590.24	\$0.00	\$0.00	0.00%
36 37 38	Administration Charge	12	months x	\$78.00	=	\$936.00	12	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
39 40 41 42 43 44	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Rider 5 RSAM Transportation - Firm	4,200.0 4,200.0 4,200.0 4,200.0	GJ x GJ x GJ x	\$2.318 \$0.000 (\$0.028) (\$0.020)	= (:	0,735.6000 \$0.0000 \$117.6000) (\$84.0000) 0,534.00	4,200.0 4,200.0 4,200.0 4,200.0	GJ x GJ x GJ x	\$2.467 \$0.000 \$0.000 (\$0.032)	<u> </u>	0,361.4000 \$0.0000 \$0.0000 (\$134.4000) <b>0,227.00</b>	\$0.149 \$0.000 \$0.028 (\$0.012)	\$625.8000 \$0.0000 \$117.6000 (\$50.4000) <b>\$693.00</b>	5.19% 0.00% 0.98% -0.42% <b>5.75%</b>
45 46 47	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas													
	Total (with effective \$/GJ rate)	4,200.0		\$2.871	\$	512,060.24	4,200.0		\$3.036	\$1	2,753.24	\$0.165	\$693.00	5.75%

Annual

### 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, 2	2011	P	ROPOSED JA	NUARY 1, 201	12 RATES		Increase/Decrease	
		)/-l		D-t-	A 1 @	\/-l-		D-4-	A 6	D-t-	A   6	% of Previous
2	LOWER MAINLAND SERVICE AREA	Volun	ne	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	Annual Bill
	Basic Charge	12	months x	\$587.00	= \$7,044.00	12	months x	\$587.00	= \$7,044.00	\$0.00	\$0.00	0.00%
	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		\$0.021	\$400.8102	1.04%
12	Transportation - Firm				\$11,909.79				\$13,284.00	_	\$1,374.21	3.57%
13 14 15 16	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas											
	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											
	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	Dasic Orlarge	12	monuis x	ψ507.00	Ψ1,044.00	12	months x	ψ307.00	Ψ1,044.00	Ψ0.00	ψ0.00	0.0070
	Administration Charge	12	months x	\$78.00	=\$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
24 25	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%
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		= \$0.0000	40,670.5	GJ x		= \$0.0000	\$0.000	\$0.0000	0.00%
28	Rider 3 ESM	40,670.5	GJ x	(\$0.021)		40,670.5	GJ x	\$0.000		\$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	T. I. C. W. W. W. W. W. W. W.											
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	COLUMBIA SERVICE											
36 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	basic Charge	12	monuis x	φ367.00	- \$1,044.00	12	monuis x	φ367.00	- φ1,044.00	φ0.00 _	φυ.υυ	0.00 /6
	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
40				******				******		_	70.00	
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									·	_	<u> </u>	
43	Delivery Charge	30,357.8	GJ x		= \$19,580.7810	30,357.8	GJ x	Ψ0.000	= \$21,129.0288	\$0.051	\$1,548.2478	2.51%
44	Rider 2 2009 ROE Rate Rider	30,357.8	GJ x		= \$0.0000	30,357.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
45	Rider 3 ESM	30,357.8	GJ x	(\$0.021)		30,357.8	GJ x	\$0.000		\$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 )											
46 49	UOR, Balancing gas, Backstopping Gas, Replacement Gas	ĺ										
50	Oort, Datarioning gas, Dackstopping Gas, Repideement Gas											
	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%
										I		

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

				RATE SCHE	DUI	LE 27 - INTERRUI	PTIBLE T-SER	RVICE						
Line No.		. —	EFFECTIVE	E JANUARY 1,	201	1	F	PROPOSED JA	NUARY 1, 201	2 RAT	TES		Annual Increase/Decrease	
1		Volu	ıme	Rate		Annual \$	Volu	ıme	Rate	_	Annual \$	Rate	Annual \$	% of Previous Annual Bill
3	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	i 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 8 9 10	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM	53,957.0 53,957.0 53,957.0	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$57,895.8610 \$0.0000 (\$701.4410) <b>\$57,194.42</b>	53,957.0 53,957.0 53,957.0	GJ x GJ x GJ x	Ŧ	<u>-</u>	\$61,510.9800 \$0.0000 \$0.0000 <b>\$61,510.98</b>	\$0.067 \$0.000 \$0.013	\$3,615.1190 \$0.0000 \$701.4410 <b>\$4,316.56</b>	5.26% 0.00% 1.02% <b>6.28%</b>
11 12 13 14 15	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas 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%
17 18 19 20	B INLAND SERVICE AREA Basic Charge	12	months x	\$880.00	=_	\$10,560.00	12	months x	\$880.00	=	\$10,560.00	\$0.00 <u> </u>	\$0.00	0.00%
21 22	Administration Charge	12.0	months x	\$78.00	=_	\$936.00	12.0	months x	\$78.00	=	\$936.00	\$0.00	\$0.00	0.00%
23 24 25 26 27 28	B Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible	48,903.9 48,903.9 48,903.9	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$0.0000	48,903.9 48,903.9 48,903.9	GJ x GJ x	\$1.140 \$0.000 \$0.000	-	\$55,750.4460 \$0.0000 \$0.0000 <b>\$55,750.45</b>	\$0.067 \$0.000 \$0.013	\$3,276.5613 \$0.0000 \$635.7507 \$3,912.32	5.17% 0.00% 1.00% <b>6.18%</b>
29 30 31 32 33	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas Total (with effective \$/GJ rate)	48,903.9	-	\$1.295	=	\$63,334.13	48,903.9	-	\$1.375	_	\$67,246.45	\$0.080 _	\$3,912.32	6.18%
35 36	COLUMBIA SERVICE AREA Basic Charge	12	months x	\$880.00	=_	\$10,560.00	12	months x	\$880.00	<u> </u>	\$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 41 42 43 44	Delivery Charge Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible	7,733.8 7,733.8 7,733.8	GJ x GJ x	\$1.073 \$0.000 (\$0.013)	=	\$8,298.3674 \$0.0000 (\$100.5394) \$8,197.83	7,733.8 7,733.8 7,733.8	GJ x GJ x		= = = =	\$8,816.5320 \$0.0000 \$0.0000 \$8,816.53	\$0.067 \$0.000 \$0.013	\$518.1646 \$0.0000 \$100.5394 <b>\$618.70</b>	0.82% 0.00% 0.16% <b>0.98%</b>
45 46 47 48	Non-Standard Charges (not forecast )     UOR, Balancing gas, Backstopping Gas	7,733.8	=	\$2.546	_	\$19,693.83	7,733.8	-	\$2.626		\$20,312.53	\$0.080 <u> </u>	\$618.70	0.98%

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.

49 Total (with effective \$/GJ rate)

#### 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

APPENDIX F-2 TAB 1.1.2 PAGE 14

Line No.	PARTICULARS		EXISTING JA	NUARY 1, 2011 RA	ATES	F	PROPOSED J	ANUARY 1, 2012 R	ATES		Annual Increase/Decreas	e
1	INLAND SERVICE AREA	Volu	me	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	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	\$0.230	\$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ X	(\$0.048) =	(\$2.4000)	50.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$2.4000	0.23%
10	Rider 5 RSAM	50.0	GJ X	(\$0.020) =	(\$2.4000)	50.0	GJ x	(\$0.032) =	(\$1.6000)	(\$0.048	(\$0.6000)	-0.06%
11	Subtotal Delivery Margin Related Charges	00.0	00 x _	\$3.207	\$302.43	00.0	00 X _	\$3.499	\$317.03	(\$0.012)	\$14.60	1.37%
12	, с		_		·		_					
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 18	Subtotal Commodity Related Charges		_	\$15.214	\$760.70		_	\$15.214	\$760.70		\$0.00	0.00%
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 24	Basic Charge	365.25	days x	\$0.816 =	\$298.08	365.25	days x	\$0.816 =	\$298.08	\$0.00	\$0.00	0.00%
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 30	Subtotal Delivery Margin Related Charges		_	\$2.658	\$962.58		_	\$2.875	\$1,016.83		\$54.25	1.21%
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 35	Rider 1 Propane Surcharge Subtotal Commodity Related Charges	250.0	GJ x	\$8.254 = \$14.123	\$2,063.5000 <b>\$3,530.75</b>	250.0	GJ x	\$8.254 = \$14.123	\$2,063.5000 <b>\$3,530.75</b>	\$0.000	\$0.0000 <b>\$0.00</b>	0.00% <b>0.00%</b>
36	Subtotal Commodity Nelated Charges		-	φ14.125	45,550.75		_	φ14.123	\$3,330.73		φυ.υυ	0.00 /8
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 40	Rate 3 - Large Commercial 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			,	<b>4</b>	* .,		,	******	* 1,7221_ 1	******	*****	
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 46	Rider 3 ESM Rider 5 RSAM	4,500.0 4,500.0	GJ x GJ x	(\$0.028) = (\$0.020) =	(\$126.0000) (\$90.0000)	4,500.0 4,500.0	GJ x GJ x	\$0.000 = (\$0.032) =	\$0.0000 (\$144.0000)	\$0.028	\$126.0000 (\$54.0000)	0.17% -0.07%
47	Subtotal Delivery Margin Related Charges	4,500.0	GJ X _	\$2.270	\$11,805.24	4,500.0	G3 X	(\$0.032) = \$2.435	\$12,547.74	(\$0.012)	\$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 52	Cost of Gas Rider 1 Propane Surcharge	4,500.0 4,500.0	GJ x GJ x	\$4.568 = \$8.556 =	\$20,556.0000 \$38,502.0000	4,500.0 4,500.0	GJ x GJ x	\$4.568 = \$8.556 =	\$20,556.0000 \$38,502.0000	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
53	Subtotal Commodity Related Charges	4,300.0	30 A _	\$14.123	\$63,553.50	7,500.0	OU ^ _	\$14.123	\$63,553.50	Ψ0.000	\$0.000 \$0.00	0.00%
54	,		_				_				-	
55	Total (with effective \$/GJ rate)	<u>4,500.0</u>		\$16.746	\$75,358.74	4,500.0		\$16.911	\$76,101.24	\$0.165	\$742.50	0.99%
		.1				l						

#### FORTISBC ENERGY INC.

### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY

#### PROPOSED JANUARY 1, 2013 RATES

APPENDIX F-2 TAB 1.2.1 PAGE 1 SCHEDULE 1

PAGE 14

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 1:		_		DE	LIVERY MARGIN	1	·		
	RESIDENTIAL SERVICE	PROPOSEI	) JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSEI	D JANUARY 1, 2013	RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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)	=	·		=	-		=	·	

APPENDIX F-2 TAB 1.2.1 PAGE 2 SCHEDULE 2

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 2:				DE	LIVERY MARGIN	ı			
	SMALL COMMERCIAL SERVICE	PROPOSEI	JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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)	=			=			=		

APPENDIX F-2 TAB 1.2.1 PAGE 3 SCHEDULE 3

#### BCUC ORDER NO.G-XXX-11 G-XXX-11 and G-XXX-11

	RATE SCHEDULE 3:				DE	LIVERY MARGIN				
	LARGE COMMERCIAL SERVICE	PROPOSED	JANUARY 1, 2012	RATES	RELATE	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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 17	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
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)	_			=			=		
	, , , , , , , , , , , , , , , , , , , ,									

APPENDIX F-2 TAB 1.2.1 PAGE 4 SCHEDULE 4

#### BCUC ORDER NO.G-XXX-11 G-XXX-11

	RATE SCHEDULE 4:				DE	LIVERY MARGIN	ı			
	SEASONAL SERVICE	PROPOSEI	D JANUARY 1, 2012	RATES	RELATE	D CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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		Balancing, Backsto	enning and LIOD no	or DCHC				Delensing Deals	inn	) === BCHC
27	Unauthorized Gas Charge per gigajoule	Order No. G-110-0		SI BCOC				Order No. G-110	topping and UOF -00.	c per BCUC
28	during peak period									
29										
30	Total Wasiable Cost non signicula, between									
31 32	Total Variable Cost per gigajoule between  (a) Off-Peak Period	\$6.267	\$6.252	\$6.288	\$0.103	\$0.103	\$0.103	\$6.370	\$6.355	\$6.391
33		\$7.044	\$7.029	\$7.065	\$0.103	\$0.103	\$0.103	\$7.147	\$7.132	\$7.168
33	(D) EXIGINION PENOU	<u>Φ1.044</u>	\$1.029	COU. 1¢	φυ. 103	φυ. 103	φυ. 103	Φ1.141	φ1.132	φ1.108

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

APPENDIX F-2 TAB 1.2.1 PAGE 5 SCHEDULE 5

	RATE SCHEDULE 5 GENERAL FIRM SERVICE	PROPOSEI	D JANUARY 1, 2012	RATES		LIVERY MARGIN		PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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										

\$6.049

\$0.065

\$0.065

\$0.065

\$6.093

\$6.028

\$6.013

17 18

19 Total Variable Cost per gigajoule

\$6.078

\$6.114

APPENDIX F-2 TAB 1.2.1 PAGE 6 SCHEDULE 6

BCUC	ORDER	NO.G-X	XX-11 (	3-XXX-1
RCOC	OKDEK	NO.G-X	XX-11 (	3-XXX-1

	RATE SCHEDULE 6:				DE	LIVERY MARGIN	I			
	NGV - STATIONS	PROPOSEI	D JANUARY 1, 2012	RATES	RELATED	CHARGES CH	ANGES	PROPOSE	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	\$2.004
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
ı										_

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

APPENDIX F-2 TAB 1.2.1 PAGE 6.1 SCHEDULE 6A

	RATE SCHEDULE 6A: NGV - VRA's			
ine		7	DELIVERY MARGIN	
10.	Particulars	PROPOSED JANUARY 1, 2012 RATES	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				
	Commodity Related Charges			
2	Cost of Gas (Commodity Cost Recovery Charge) per GJ	\$4.568	\$0.000	\$4.568
3	Midstream Cost Recovery Charge per GJ	\$0.353	\$0.000	\$0.353
4	Subtotal Commodity Related Charges per GJ	\$4.921	\$0.000	\$4.921
5				
6	Compression Charge per gigajoule	\$5.28	\$0.00	\$5.28
7				
8	Minimum Channa	\$125.00	\$0.00	\$125.00
9	Minimum Charges	\$125.00	\$0.00	\$125.00
.0				
22			<del></del>	<del></del>
	Total Variable Cost per gigajoule	\$14.022	\$0.266	\$14.288

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

APPENDIX F-2 TAB 1.2.1 PAGE 7 SCHEDULE 7

	RATE SCHEDULE 7:				DE	LIVERY MARGIN	ı			
	INTERRUPTIBLE SALES	PROPOSED JANUARY 1, 2012 RATES			RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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		Rolonoina Rooks	topping and UOR p	or BCHC				Balancing, Backs	stanning and LIOP	nor BCHC
16	Charges per gigajoule for UOR Gas	Order No. G-110-		el BCOC				Order No. G-110		per BCOC
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

### FORTISBC ENERGY INC.

### CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY PROPOSED JANUARY 1, 2013 RATES

#### BCUC ORDER NO.G-XXX-11

PAGE 14

APPENDIX F-2 TAB 1.2.1 PAGE 8

SCHEDULE 22

	RATE SCHEDULE 22:				DELIVERY MARGIN					
	LARGE INDUSTRIAL T-SERVICE	PROPOSED JANUARY 1, 2012			RELATED CHARGES CHANGES			PROPOSED JANUARY 1, 2013 RATES		
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
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 Bac	estonning and LIOF	R ner BCLIC				Dalansina Book	atanning and LIOF	nor PCHC
9	Charges per gigajoule for UOR Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.						Balancing, Backstopping and UOR per BCU 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	Demand Surcharge per gigajodie	\$17.00	\$17.00	\$17.00	φυ.υυ	φυ.υυ	φυ.υυ	\$17.00	φ17.00	φ17.00
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						Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		
21		Order No. G-110-	.00.							
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	Administration charge per month	Ψ7 0.00	Ψ7 0.00	Ψ70.00	ψ0.00	Ψ0.00	ψ0.00	ψ7 0.00	Ψ70.00	ψ10.00
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
	. Jan. 1 a. a. a. a door por gigajouio	Ψ0.000	ψ0.000	ψυ.υυυ	Ψ0.001	ψ0.001	ψ0.001	Ψ0.000	ψ0.000	ψ0.000

#### APPENDIX F-2 TAB 1.2.1 PAGE 9 SCHEDULE 22A

	RATE SCHEDULE 22A: LARGE INDUSTRIAL T-SERVICE			
Line			DELIVERY MARGIN	
No.	Particulars	PROPOSED JANUARY 1, 2012	RELATED CHARGES CHANGES	PROPOSED JANUARY 1, 2013 RATES
	(1)	(2)	(3)	(4)
1 2	INLAND SERVICE AREA			
3 4	Basic Charge per Month	\$4,810.00	\$0.00	\$4,810.00
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		Balancing, Backstopping and UOR per BCUC
15	Charges per gigajoule for UOR Gas	Order No. G-110-00.		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		D D		Balancing, Backstopping and UOR per BCUC
25 26	Charges per gigajoule for Backstopping Gas	Balancing, Backstopping and UOR per BCUC Order No. G-110-00.		Order No. G-110-00.
27				
28	Replacement Gas	Sumas Daily Price		Sumas Daily Price
29	·	plus 20 Percent		plus 20 Percent
30		<b>,</b>		,
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 10 SCHEDULE 22B

	RATE SCHEDULE 22B: LARGE INDUSTRIAL T-SERVICE			DELIVERY MARON			
	LARGE INDUSTRIAL 1-SERVICE	PROPOSED IANUARY 4	1042	DELIVERY MARGIN		DDODOSED JANUARY 4 2042	DATES
Line		PROPOSED JANUARY 1, 2 Columbia	Elkview	RELATED CHARGES CH. Columbia	Elkview	PROPOSED JANUARY 1, 2013 Columbia	Elkview
No.	Particulars	Except Elkview	Coal	Except Elkview	Coal	Except Elkview	Coal
140.	(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				Balancing, Backstopping a	
17	Charges per gigajoule for UOR Gas	BCUC Order No. G-110-	00.			BCUC Order No. G-110-0	0.
18							
19							
20	Demand Surchage per gigajoule	\$17.00	\$17.00	\$0.00	\$0.00	\$17.00	\$17.00
21	0 1 007		·				·
22		Balancing, Backstopping	and LIOP por			Balancing, Backstopping a	nd UOR per
23	Charges per gigajoule for Backstopping Gas	BCUC Order No. G-110-				BCUC Order No. G-110-0	
24	333,333						
25							
26	Administration Charge per Month	\$78.00	\$78.00	\$0.00	\$0.00	\$78.00	\$78.00
27	, animinon and on a go por mornin	Ψ. σ.σσ	ψ. σ.σσ	\$6.65	ψ0.00	φ. σ.σσ	ψ. σ.σσ
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
		<u> </u>	72.200		73321	<u> </u>	<del>+1.300</del>

#### APPENDIX F-2 TAB 1.2.1 PAGE 11 SCHEDULE 23

	RATE SCHEDULE 23: LARGE COMMERCIAL T-SERVICE	PROPO	OSED JANUARY 1, 2	2012		LIVERY MARGIN		PPOPOSET	) JANUARY 1, 201;	DATES
Line	LANGE COMMERCIAL 1-SERVICE	Lower	JSED JANUART 1, 2	2012	Lower	D CHARGES CH	ANGES	Lower	JANUART 1, 201.	RAIES
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	Dell'arma Olivania manaritari tanda	00.407	00.407	00.407	00.400	00.400	00.400	<b>#0.055</b>	<b>#0.055</b>	00.055
3	Delivery Charge per gigajoule	\$2.467	\$2.467	\$2.467	\$0.188	\$0.188	\$0.188	\$2.655	\$2.655	\$2.655
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 10 11	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas (c) Replacement Gas	Balancing, Back per BCUC Order	stopping, Replacer r No. G-110-00.	ment and UOR					stopping, Replace Order No. G-110-	
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	Rider 5 RSAM	(\$0.032)	(\$0.032)	(\$0.032)	\$0.000	\$0.000	\$0.000	(\$0.032)	(\$0.032)	(\$0.032)
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 12 SCHEDULE 25

	RATE SCHEDULE 25				DE	LIVERY MARGIN	N			
	GENERAL FIRM T-SERVICE	PROP	OSED JANUARY 1, 2	2012	RELATE	D CHARGES CH	ANGES	PROPOSEI	D JANUARY 1, 201	3 RATES
Line		Lower			Lower			Lower		
No.	Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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
5 6	Delivery Charge per gigajoule (Interr. MTQ)	\$0.696	\$0.696	\$0.696	\$0.065	\$0.065	\$0.065	\$0.761	\$0.761	\$0.761
7	Administration Charge per Month	\$78.00	\$78.00	\$78.00	\$0.00	\$0.00	\$0.00	\$78.00	\$78.00	\$78.00
8										
10	Sales									
11 12	(a) Charge per gigajoule for Balancing Gas (b) Charge per gigajoule for Backstopping Gas		stopping, Replacer Order No. G-110-0						kstopping, Replace COrder No. G-110	
13 14	(c) Replacement Gas (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		<u> </u>	<del></del>		<u> </u>			· <del></del>	·	
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

#### APPENDIX F-2 TAB 1.2.1 PAGE 13 SCHEDULE 26

RATE SCHEDULE 26:					DI	ELIVERY MARGIN	I			
NATURAL GAS VEHICLE T-SERV	/ICE	PROP	OSED JANUARY 1, 2	012	RELATE	D CHARGES CH	ANGES	PROPOSEI	D JANUARY 1, 201	RATES
Line		Lower			Lower			Lower		
No. Particulars		Mainland	Inland	Columbia	Mainland	Inland	Columbia	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 (Ir	terr. MTQ)	\$3.861	\$3.861	\$3.861	\$0.266	\$0.266	\$0.266	\$4.127	\$4.127	\$4.127
5 6 Administration Charge per Mont	1	\$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 11 (b) Charge per gigajoule	•	Balancing, Bac Order No. G-11	kstopping and UOR 0-00.	per BCUC				Balancing, Bac BCUC Order N	kstopping and UO lo. G-110-00.	R per
12 (d) Charge per gigajoule	for UOR Gas									
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 <b>Rider 3 ESM</b>		\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000	\$0.000
17										
<ul><li>18</li><li>19 Total Variable Cost per gigajoule</li></ul>		\$3.861	\$3.861	\$3.861	\$0.266	\$0.266	\$0.266	\$4.127	\$4.127	\$4.127
13 Total variable dost per gigajoule		ψ3.001	ψ3.001	ψ3.001	Ψ0.200	ψ0.200	ψ0.200	Ψ4.127	ψ4.121	ψ4.121

#### APPENDIX F-2 TAB 1.2.1 PAGE 14 SCHEDULE 27

RATE SCHEDULE 27:				DE	LIVERY MARGIN	1			
INTERRUPTIBLE T-SERVICE	PROPO	SED JANUARY 1, 2	2012	RELATE	D CHARGES CH	ANGES	PROPOSED	JANUARY 1, 2013	RATES
Line	Lower			Lower			Lower		
No. Particulars	Mainland	Inland	Columbia	Mainland	Inland	Columbia	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	<b>\$10.00</b>	ψ. σ.σσ	ψ. σ.σσ	Ψ0.00	ψ0.00	<b>\$</b> 0.00	φ. σ.σσ	ψ. σ.σσ	ψ, σ.σσ
8 9 Sales									
10 (a) Charge per gigajoule for Balancing Gas	Order No. C 11	stopping and UOR	per BCUC				Balancing, Back BCUC Order No	kstopping and UO	R per
<ul> <li>(b) Charge per gigajoule for Backstopping Gas</li> <li>(d) Charge per gigajoule for UOR Gas</li> </ul>	5	0 00.					2000 0.46. 11	0. 0 1.0 00.	
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
	= =====================================	7	<u> </u>	70.000	+0.000	+0.000	ψ1.220	71.220	ψ1.220

#### 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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 **Delivery Margin Related Charges** 365.25 \$0.389 \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% 3 Basic Charge davs x davs x 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% 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% (\$0.032)(\$3.0400) (\$0.032)(\$3,0400) \$0.0000 8 Rider 5 RSAM 95.0 GJ x 95.0 GJ x \$0.000 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 GJ x \$0.009 \$0.8550 95.0 GJ x \$0.009 0.8550 \$0.0000 0.00% 95.0 \$0.000 Midstream Related Charges Subtotal 14 \$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 Total (with effective \$/GJ rate) 19 95.0 \$1,036.61 95.0 \$1,067.48 \$30.87 2.98% \$10.912 \$11.237 \$0.325 20 21 INLAND SERVICE AREA **Delivery Margin Related Charges** 22 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 \$3.531 = \$264.8250 GJ x \$3.856 = \$289.2000 \$0.325 \$24.3750 2.88% Delivery Charge 75.0 GJ x 75.0 26 Rider 2 2009 ROE Rate Rider \$0.000 = 75.0 GJ x \$0.000 = \$0.0000 75.0 GJ x \$0.0000 \$0.000 \$0.0000 0.00% 27 \$0.000 = 75.0 \$0.000 = 0.00% Rider 3 ESM 75.0 GJ x \$0.0000 GJ x \$0.0000 \$0.000 \$0.0000 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 \$404.51 \$428.88 Subtotal Delivery Margin Related Charges \$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 \$0.00 0.00% 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 37 \$441.90 \$441.90 \$0.00 0.00% Subtotal Commodity Related Charges 38 39 Total (with effective \$/GJ rate) 75.0 \$846.41 \$870.78 \$24.37 2.88% \$11.285 75.0 \$11.610 \$0.325 40 41 **COLUMBIA SERVICE AREA** 42 Delivery Margin Related Charges 43 365.25 \$0.389 = \$142.08 365.25 \$0.389 = \$142.08 \$0.00 \$0.00 0.00% Basic Charge days x days x 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 GJ x \$0.000 = GJ x \$0.000 = \$0.000 \$0.0000 Rider 2 2009 ROE Rate Rider 80.0 \$0.0000 80.0 \$0.0000 0.00% 47 \$0.000 \$0.000 = \$0.0000 0.00% Rider 3 ESM 0.08 GJ x \$0.0000 80.0 GJ x \$0.0000 \$0.000 48 Rider 5 RSAM (\$0.032)(\$2.5600)80.0 (\$0.032)(\$2.5600) \$0.000 \$0.0000 0.00% 80.0 GJ x GJ x 49 Subtotal Delivery Margin Related Charges \$422.00 \$448.00 \$26.00 2.90% 50 51 Commodity Related Charges 52 0.08 GJ x \$1.355 \$108.4000 80.0 GJ x \$1.355 \$108.4000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge \$0.7200 53 GJ x \$0.009 80.0 GJ x \$0.009 \$0.7200 \$0.000 \$0.0000 0.00% Rider 8 Unbundling Recovery 80.0 54 Midstream Related Charges Subtotal \$109.12 \$109.12 \$0.00 0.00% 55 56 0.00% Cost of Gas (Commodity Cost Recovery Charge) 0.08 GJ x \$4.568 \$365.44 80.0 GJ x \$4.568 \$365.44 \$0.000 \$0.00 57 Subtotal Commodity Related Charges \$474.56 80.0 \$474.56 \$0.00 0.00% 58 Total (with effective \$/GJ rate) 59 \$896.56 0.08 \$922.56 \$26.00 2.90%

\$11.532

#### 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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 Delivery Margin Related Charges 365.25 \$0.816 \$298.08 365.25 \$0.816 = \$298.08 \$0.00 \$0.00 0.00% Basic Charge days days x \$2.907 = \$872.1000 \$3.152 = \$945.6000 \$73.5000 2.51% **Delivery Charge** 300.0 GJ x 300.0 GJ x \$0.245 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% 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 (\$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 12 300.0 GJ x \$1.327 \$398.1000 300.0 GJ x \$1.327 \$398.1000 \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge 13 Rider 8 Unbundling Recovery 300.0 GJ \$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 16 300.0 \$4.568 \$1,370,40 \$4.568 \$1.370.40 \$0.000 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) G.I x 300.0 G.I x 17 Subtotal Commodity Related Charges \$1,768.50 \$1,768.50 \$0.00 0.00% 18 19 Total (with effective \$/GJ rate) 300.0 \$2,929.08 \$3,002.58 \$9.764 300.0 \$10.009 \$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% 26 250.0 GJ x \$0.000 = 250.0 GJ x \$0.000 = \$0.000 \$0.0000 0.00% Rider 2 2009 ROE Rate Rider \$0,0000 \$0,0000 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% Rider 5 RSAM 28 250.0 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 \$0.0000 Rider 8 Unbundling Recovery 250.0 GJ x \$0.000 \$0.0000 250.0 GJ x \$0.000 \$0.0000 \$0.000 0.00% 34 \$325.25 Midstream Related Charges Subtotal \$325.25 \$0.00 0.00% 35 250.0 36 \$4.568 \$1,142.00 \$4.568 \$1,142.00 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) GJ x 250.0 GJ x \$0.000 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 \$0.816 = \$298.08 \$0.816 = 0.00% Basic Charge 365.25 days x 365.25 days x \$298.08 \$0.00 \$0.00 44 45 \$2.907 = \$1,008.6400 Delivery Charge 320.0 GJ x \$930.2400 320.0 GJ x \$3.152 = \$0.245 \$78.4000 2.52% 46 \$0.000 = \$0.000 = 0.00% Rider 2 2009 ROE Rate Rider 320.0 GJ x \$0.0000 320.0 GJ x \$0.0000 \$0.000 \$0.0000 47 Rider 3 FSM 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 (\$10.2400) (\$10.2400) 320.0 GJ x (\$0.032) =320.0 GJx(\$0.032) =\$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 56 320.0 \$4.568 \$1,461.76 \$4.568 \$1,461.76 \$0.00 0.00% Cost of Gas (Commodity Cost Recovery Charge) GJ x 320.0 GJ x \$0.000 57 \$1,891.20 \$0.00 Subtotal Commodity Related Charges \$1,891.20 0.00% 58

\$3,109.28

320.0

\$9.962

\$3,187.68

\$0.245

\$78.40

2.52%

\$9.717 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.

320.0

59

Total (with effective \$/GJ rate)

### 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 Annual No. Particular PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES Increase/Decrease % of Previous LOWER MAINLAND SERVICE AREA Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill 2 Delivery Margin Related Charges 365 25 \$4.354 = \$1.590.24 365 25 \$4.354 = \$1.590.24 \$0.00 \$0.00 0.00% 3 Basic Charge days x davs x 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% Rider 5 RSAM 2.800.0 (\$0.032) = (\$89.6000) 2.800.0 (\$0.032) = (\$89,6000) \$0.000 \$0.0000 8 GJ x GJ x 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 \$0.0000 0.00% \$0.000 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 Total (with effective \$/GJ rate) 2,800.0 \$24,575.44 \$526.40 19 \$8.589 \$24,049.04 2,800.0 \$8.777 \$0.188 2.19% 20 21 INLAND SERVICE AREA 22 Delivery Margin Related Charges 23 Basic Charge \$4.354 = \$1,590.24 \$4.354 = \$1,590.24 \$0.00 \$0.00 0.00% 365.25 days x 365.25 days x 24 25 Delivery Charge 2.600.0 G.I x \$2.467 = \$6 414 2000 2.600.0 G.I 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 2,600.0 (\$0.032) (\$83.2000) Rider 5 RSAM GJ x 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 2.600.0 GJ x \$0.999 \$2,597,4000 2.600.0 \$0.999 = \$2,597.4000 \$0.000 \$0.0000 0.00% G.I x Midstream Cost Recovery Charge 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% \$2,597.40 34 Midstream Related Charges Subtotal \$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 \$4.568 \$11,876.80 \$0.00 0.00% 2,600.0 GJ x \$0.000 37 \$0.00 \$14,474,20 \$14,474,20 Subtotal Commodity Related Charges 0.00% 38 39 Total (with effective \$/GJ rate) 2.600.0 \$22,395,44 2.600.0 \$22,884.24 \$488.80 2.18% \$8 614 \$8.802 \$0.188 40 41 COLUMBIA SERVICE AREA 42 Delivery Margin Related Charges 43 \$4.354 = \$1,590.24 \$4.354 = \$1,590.24 \$0.00 0.00% Basic Charge 365.25 days x 365.25 days x \$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 GJx\$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 \$3,418.8000 52 3,300.0 \$1.036 = 3,300.0 GJ x \$1.036 = \$0.000 \$0.0000 0.00% Midstream Cost Recovery Charge GJ x \$3,418.8000 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 \$18,493.20 \$18,493.20 \$0.00 Subtotal Commodity Related Charges 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%

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

			KA	IE SCHEDULI	E 4 - SEASONAL SER\	ICE						
Line No.	Particular		PROPOSED	JANUARY 1, 20	12 RATES		PROPOSED	JANUARY 1, 20	13 RATES		Annual Increase/Decrease	<b>.</b>
						1			ļ.			% of Previous
1		Volun	ne	Rate	Annual \$	Volur	ne	Rate	Annual \$	Rate	Annual \$	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 =		5,400.0	GJ x	\$1.038 =	\$5,605.2000	\$0.103	\$556.2000	1.51%
8	(b) Extension Period	0.0	GJ x	\$1.712 =		0.0	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 =	40.000	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 =		5,400.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
	Subtotal Delivery Margin Related Charges				\$8,135.52			_	\$8,691.72		\$556.20	1.51%
12												
	Commodity Related Charges											
14	Midstream Cost Recovery Charge											
15	(a) Off-Peak Period	5,400.0	GJ x	\$0.764 =		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 =	,	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 22	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				\$28,792.80			-	\$28,792.80		\$0.00	0.00%
	Unauthorized Gas Charge During Peak Period (not forecast)											
24	onauthorized Gas Charge Duning Feak Fellod (not lorecast)											
	Total during Off-Peak Period	5,400.0			\$36,928.32	5,400.0			\$37,484.52		\$556.20	1.51%
26	rotal dalling on rotal onod	0,100.0			<del>400,020.02</del>			=	<del>\\ \\ \\ \\ \\ \\ \\ \\ \\ \\ \\ \\ \\ </del>		<del>+000.20</del>	
27												
	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 =		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								<u>-</u>				
	Subtotal Cost of Gas (Commodity Related Charges) Off-Peak				\$49,448.10			_	\$49,448.10		\$0.00	0.00%
48								_			·	
	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%

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

Volume   Volume   Volume   Volume   Volume   Volume   Volume   Volume   Volume   Annual S   Volume   Ann	Line No.	Particular		PROPOSED	JANUARY 1, 2	2012 RATES		PROPOSE	ED JANUARY 1, 2	2013 RATES		Annual Increase/Decreas	e
Delivery Marin Robinson Charges   12 months x \$387.00   2 months x \$387.00   3 months x \$38	1		Volu	ıme	Rate	Annual \$		Volume	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
Delivery Margin Related Changes   12 months x \$887.00		LOWER MAINLAND SERVICE AREA			ruto	7 tilliadi ψ	-	VOIGITIC	rute	7 timaar ψ	rate	7 timidai ψ	Total 7 tillidal Bill
Delivery Charge													
Commont Charge   Sept		Basic Charge	12	months x	\$587.00	= \$7,044.00		12 months x	\$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
Believery Charge   9,700   G.J. x   50,696   8,87512000   9,700   G.J. x   50,000   50,0000	6	Demand Charge	58.5	GJ x	\$16.996	=\$11,931.19	5	3.5 GJ x	\$18.324	=\$12,863.45	\$1.328	\$932.26	1.20%
Packer 2 2006 ROCK Rate Rater   9,700.0		Delivery Charge	9,700.0	GJ x	\$0.696	= \$6,751.20	9,70	0.0 GJ x	\$0.761	= \$7,381.7000	\$0.065	\$630.5000	0.81%
11 Substal Delivery Margin Related Charges	9		9,700.0	GJ x	\$0.000	= \$0.00	9,70	0.0 GJ x	\$0.000	= \$0.0000	\$0.000	\$0.0000	0.00%
Commodity Related Charges   9,700.0   GJ x   \$0.784   \$7,410.8000   9,700.0   GJ x   \$0.784   \$7,410.8000   9,700.0   GJ x   \$0.784   \$1,740.8000   9,700.0   GJ x   \$1,728.40   \$1,728.	10	Rider 3 ESM	9,700.0	GJ x	\$0.000		9,70	0.0 GJ x	\$0.000		\$0.000	\$0.0000	0.00%
13   Commodity Cost Recovery Charge   9,700.0 GJ x \$0.764   \$7.410.8000   9,700.0 GJ x \$0.764   \$7.410.8000   9,700.0 GJ x \$4.568   \$34.300.6000   9,700.0 GJ x \$4.568   \$4.4000   9,700.0 GJ x \$4.568   9,700.		Subtotal Delivery Margin Related Charges				\$6,751.20	_			\$7,381.70		\$630.50	0.81%
Midstream Cost Recovery Charge   9,700.0 GJ x \$0.764   \$7,7416.8000   9,700.0 GJ x \$4.598   \$14,309.8000   0,00%   \$44,309.8000   \$0.0000   \$0.00%   \$51,720.40   \$0.00%   \$51,720.40   \$0.00%   \$51,720.40   \$0.00%   \$51,720.40   \$0.00%		Commodity Related Charges											
16 Subtoral Gas Commodity Cost (Commodity Related Charge) 17 18 Total (with effective \$ GLZ rate) 18 Total (with effective \$ GLZ rate) 19	14		9,700.0	GJ x	\$0.764	= \$7,410.80	9,70	0.0 GJ x	\$0.764	= \$7,410.8000	\$0.000	\$0.0000	0.00%
18   Total (with effective \$\color{\color{1}{1}\)   18   Total (with effective \$\color{\color{1}{1}\)   19   19   19   19   19   19   19   1	15	Commodity Cost Recovery Charge	9,700.0	GJ x	\$4.568	= \$44,309.60	9,70	0.0 GJ x	\$4.568	= \$44,309.6000	\$0.000	\$0.0000	0.00%
18 Total (with effective \$\sigma total (with effective \$\sigma \sigma \text{total (with effective \$\sigma \sigma \sigma \text{total (with effective \$\sigma \sigma \sigma \sigma \sigma \text{total (with effective \$\sigma \sigma \sigma \text{total (with effective \$\sigma \sigma \sigma \text{total (with effective \$\sigma \sigma		Subtotal Gas Commodity Cost (Commodity Related Charge)				\$51,720.40	_			\$51,720.40		\$0.00	0.00%
Name	18	Total (with effective \$/GJ rate)	9,700.0		\$7.984	\$77,446.79	9,70	0.0	\$8.145	\$79,009.55	\$0.161	\$1,562.76	2.02%
21   Basic Charge   12   months x   \$587.00   = \$7,044.00   12   months x   \$587.00   = \$7,044.00   12   months x   \$587.00   = \$7,044.00   \$0.00		INLAND SERVICE AREA											
24   Demand Charge													
24 Demand Charge  5 Delivery Charge  12,800, GJ x \$16,996 = \$16,724.06   82.0 GJ x \$18,324 = \$18,030.82   \$1,326		Basic Charge	12	months x	\$587.00	= \$7,044.00		12 months x	\$587.00	=\$7,044.00	\$0.00	\$0.00	0.00%
Delivery Charge		Demand Charge	82.0	GJ x	\$16.996	= \$16,724.06	8	2.0 GJ x	\$18.324	= \$18,030.82	\$1.328	\$1,306.76	1.30%
27   Rider 2 2008 ROE Rate Rider   12,800.0   GJ x   \$0,000   =   \$0,0000   12,800.0   GJ x   \$0,000   =   \$0,0000   \$0,000   \$		•											-
28 Rider 3 ESM 29 Subtoral Delivery Margin Related Charges 30 Subtoral Delivery Margin Related Charges 31 Commodity Related Charges 32 Midstream Cost Recovery Charge 33 Expression of Total (with effective \$(GJ rate)) 34 Subtoral Delivery Margin Related Charges 35 Total (with effective \$(GJ rate)) 36 Total (with effective \$(GJ rate)) 37 COLUMBIA SERVICE AREA 39 Delivery Margin Related Charges 40 Basic Charge 41 Delivery Margin Related Charges 42 Delivery Charge 43 Delivery Charge 44 Delivery Charge 45 Rider 2 2009 ROE Rate Rider 46 Rider 3 ESM 46 Commodity Related Charges 46 Rider 3 ESM 470 Subtoral Delivery Margin Related Charges 47 Subtoral Delivery Margin Related Charges 48 Subtoral Delivery Margin Related Charges 49 Delivery Charge 40 Subtoral Delivery Margin Related Charges 40 Delivery Charge 41 Delivery Charge 42 Delivery Charge 43 Delivery Charge 44 Delivery Charge 45 Rider 2 2009 ROE Rate Rider 46 Rider 3 ESM 46 Commodity Related Charges 56 Midstream Cost Recovery Charge 57 Midstream Cost Recovery Charge 58 Subtoral Charges													
Subtotal Delivery Margin Related Charges   Subtotal Delivery Margin Related Charges   Subtotal Delivery Margin Related Charges   12,800.0 GJ x \$0.749 = \$9,587.2000   12,800.0 GJ x \$0.749 = \$9,587.2000   12,800.0 GJ x \$4.568 = \$58,470.4000   12,800.0 GJ x \$4.													
31 Commodity Related Charges 32 Midstream Cost Recovery Charge 33 Midstream Cost Recovery Charge 34 Subtotal Gas Commodity Related Charges 35 Commodity Related Charges 36 Total (with effective \$/GJ rate) 37 COLUMBIA SERVICE AREA 38 Each Charges 39 Delivery Margin Related Charges 40 Demand Charge 41 Delivery Charge 42 Demand Charge 43 Delivery Charge 44 Delivery Charge 45 Rider 2 S009 ROE Rate Rider 47 Subtotal Delivery Margin Related Charges 48 Subtotal Delivery Margin Related Charges 49 (Midstream Cost Recovery Charge) 40 Rider 3 ESM 40 Demand Charge 40 Demand Charge 41 Delivery Charge 42 Demand Charge 43 Delivery Margin Related Charges 44 Delivery Charge 45 Rider 3 ESM 46 Rider 3 ESM 47 Subtotal Delivery Margin Related Charges 48 Midstream Cost Recovery Charge 49 (Commodity Related Charges) 49 (Commodity Related Charges) 40 Demand Charge 40 Demand Charge 41 Delivery Charge 42 Demand Charge 43 Delivery Margin Related Charges 44 Delivery Charge 45 Rider 3 ESM 46 Rider 3 ESM 47 Subtotal Delivery Margin Related Charges 48 Midstream Cost Recovery Charge 49 (Commodity Related Charges 40 Demand Charge 40 Demand Charge 40 Demand Charge 41 Delivery Charge 42 Demand Charge 43 Delivery Charge 44 Delivery Charge 45 Rider 3 ESM 46 Rider 3 ESM 47 Subtotal Delivery Margin Related Charges 48 Delivery Margin Related Charges 49 (Commodity Related Charges 40 Demand Charges 40 Demand Charges 41 Delivery Margin Related Charges 41 Delivery Margin Related Charges 42 Demand Charges 43 Subtotal Gas Commodity Related Charges 44 Delivery Margin Related Charges 45 Statistics 46 Rider 3 ESM 47 Subtotal Charges 47 Subtotal Gas Commodity Related Charges 48 Statistics 49 Commodity Related Charges 40 Demand Charges 41 Delivery Margin Related Charges 41 Delivery Margin Related Charges 41 Delivery Margin Related Charges 42 Demand Charges 43 Delivery Margin Related Charges 44 Demand Charges 45 Statistics 46 Rider 3 ESM 47 Statistics 47 Statistics 48 Statistics 48 Statistics			12,800.0	GJ x	\$0.000		12,80	0.0 GJ x	\$0.000		\$0.000		
Commodity Related Charges   12,800.0   GJ x   \$0.749   = \$9,587.2000   12,800.0   GJ x   \$4.568   = \$58,470.4000   12,800.0   12,800.0   GJ x   \$4.568   = \$58,470.4000   \$0.00%   \$0.00%   \$0.000   \$0.000   \$0.00%   \$0.000   \$0.00%   \$0.000   \$0.000   \$0.00%   \$0.000   \$0.00%   \$0.000   \$0.00		Subtotal Delivery Margin Related Charges				\$8,908.80	_			\$9,740.80		\$832.00	0.83%
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   \$0.000		Commodity Related Charges											
Subtotal Gas Commodity Cost Recovery Charge   12,800.0   GJ x   \$4.568   \$58,470.4000   \$58,057.60   \$58,057.60   \$12,800.0   \$58,057.60   \$12,800.0   \$68,057.60   \$12,800.0   \$68,057.60   \$12,800.0   \$12,800			12 800 0	G.L x	\$0.749	= \$9.587.20	00 12.80	00 G.Lx	\$0.749	= \$9 587 2000	\$0,000	\$0,0000	0.00%
\$68,057.60 \$0.00 \$0.00%  \$7.870 \$100,734.46 \$12,800.0 \$88.037 \$102,873.22 \$0.167 \$2,138.76 \$2.12%  \$7.870 \$100,734.46 \$12,800.0 \$88.037 \$102,873.22 \$0.167 \$2,138.76 \$2.12%  \$7.870 \$100,734.46 \$12,800.0 \$88.037 \$102,873.22 \$0.167 \$2,138.76 \$2.12%  \$7.870 \$100,734.46 \$12,800.0 \$88.037 \$102,873.22 \$0.167 \$2,138.76 \$2.12%  \$7.870 \$100,734.46 \$12,800.0 \$88.037 \$102,873.22 \$0.167 \$2,138.76 \$2.12%  \$7.870 \$100,734.46 \$12,800.0 \$12 months x \$587.00 \$12 m													
Total (with effective \$\(G\) fate)  Total (with effective \$\(G\) f			12,00010		*		,		*		******		
37 COLUMBIA SERVICE AREA 38 Delivery Margin Related Charges 40 Basic Charge 41	35												-
38 COLUMBIA SERVICE AREA 39 Delivery Margin Related Charges 40 Basic Charge 41 Demand Charge 42 Demand Charge 43 Delivery Charge 44 Delivery Charge 45 Rider 2 2009 ROE Rate Rider 46 Rider 3 ESM 47 Subtotal Delivery Margin Related Charges 48 Commodity Related Charges 49 Commodity Related Charge 50 Midstream Cost Recovery Charge 51 Commodity Cost Recovery Charge 52 Subtotal Gas Commodity Cost (Commodity Related Charge) 53 COLUMBIA SERVICE AREA 59 Delivery Margin Related Charges 55.4 GJ x \$16.996 = \$7,044.00 50.000 \$0.000 \$0.000 50.000 \$0.000 50.000		Total (with effective \$/GJ rate)	12,800.0		\$7.870	\$100,734.46	12,80	0.0	\$8.037	\$102,873.22	\$0.167	\$2,138.76	2.12%
Delivery Margin Related Charges   12 months x \$587.00   = \$7,044.00   12 months x \$587.00   = \$7,044.00   12 months x \$587.00   = \$7,044.00   \$0.00		COLUMBIA SERVICE AREA											
Basic Charge   12 months x   \$587.00   =   \$7,044.00   12 months x   \$587.00   =   \$7,044.00   \$0.00													
42 Demand Charge	40		12	months x	\$587.00	= \$7,044.00		12 months x	\$587.00	= \$7,044.00	\$0.00	\$0.00	0.00%
44 Delivery Charge 9,100.0 GJ x \$0.696 = \$6,333.6000 9,100.0 GJ x \$0.000 = \$0.0000 \$0.							_						
Ad   Delivery Charge   9,100.0   GJ x   \$0.696   = \$6,333.6000   9,100.0   GJ x   \$0.000   = \$0.0000   \$0.000		Demand Charge	55.4	GJ x	\$16.996	= \$11,298.94	<u> </u>	5.4 GJ x	\$18.324	= \$12,181.80	\$1.328	\$882.86	1.20%
45 Rider 2 2009 ROE Rate Rider 9,100.0 GJ x \$0.000 = \$0.0000 \$		Delivery Charge	9.100.0	GJ x	\$0.696	= \$6.333.60	9.10	0.0 GJ x	\$0.761	= \$6.925.1000	\$0.065	\$591.5000	PAGE 13
46 Rider 3 ESM 47 Subtotal Delivery Margin Related Charges 48 49 Commodity Related Charges 50 Midstream Cost Recovery Charge 51 Commodity Cost Recovery Charge 52 Subtotal Gas Commodity Cost (Commodity Related Charge) 53 Subtotal Gas Commodity Cost (Commodity Related Charge) 54 Pinon GJ x \$0.000 = \$0.0000 \$0.0													
48 49 Commodity Related Charges 50 Midstream Cost Recovery Charge 51 Commodity Cost Recovery Charge 52 Subtotal Gas Commodity Cost (Commodity Related Charge) 53 Subtotal Gas Commodity Cost (Commodity Related Charge) 54 Commodity Cost (Commodity Cost (Commodity Related Charge) 55 Substitution    9,100.0 GJ x \$0.785 = \$7,143.5000 \$0.000 \$0.00					\$0.000								0.00%
49 Commodity Related Charges 50 Midstream Cost Recovery Charge 51 Commodity Cost Recovery Charge 52 Subtotal Gas Commodity Cost (Commodity Related Charge) 53 Subtotal Gas Commodity Cost (Commodity Related Charge) 54 Commodity Related Charge) 55 Substitution Related Charge) 56 Substitution Related Charge) 57 Commodity Related Charge) 58 Substitution Related Charge) 59 (100.0 GJ x \$0.785 = \$7,143.5000 \$0.000 \$0.0		Subtotal Delivery Margin Related Charges				\$6,333.60				\$6,925.10		\$591.50	0.81%
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         9,100.0         GJ x         \$4.568 =         \$41,568.8000         9,100.0         GJ x         \$4.568 =         \$41,568.8000         9,100.0         GJ x         \$4.568 =         \$41,568.8000         \$0.000         \$0		Commodity Deleted Charges											
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 \$0.000			0.100.0	GLv	¢0.795	- \$7142.50	0 10	00 GL	¢0.785	- \$7 1/3 5000	90,000	ቁስ በባባባ	0.009/
52 Subtotal Gas Commodity Cost (Commodity Related Charge) \$48,712.30 \$0.00 0.00% 53 \$48,712.30													
53			9,100.0	GJ X	φ4.508		9,10	J.U GJ X	φ4.508		φυ.υυυ		
		Subtotal Sas Commodity Sost (Commodity Neiated Offarge)	1			φ40,112.30	-1			φτυ, ΓΙΖ.30		φυ.υυ	0.0070
		Total (with effective \$/GJ rate)	9,100.0		\$8.065	\$73,388.84	9,10	0.0	\$8.227	\$74,863.20	\$0.162	\$1, <u>4</u> 74.36	2.01%

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

Line											Annual	
No.	Particular	. —	PROPOSED.	JANUARY 1, 20	12 RATES		PROPOSED	JANUARY 1, 201	13 RATES		Increase/Decrease	
1		Volun	ne	Rate	Annual \$	Volur	me	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				'-				· <del>-</del>		·		
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				•						•		
	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 =	,	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 =		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 =		11,900.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
	Subtotal Delivery Margin Related Charges				\$46,677.90			_	\$49,843.30		\$3,165.40	3.01%
27												
28	Commodity Related Charges	44.000.0	0.1	***	*****	44.000.0	0.1	***	04.447.4000	***		0.000/
29	Midstream Cost Recovery Charge	11,900.0	GJ x	\$0.346 =	, ,	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 =		11,900.0	GJ x	\$4.568 =_	\$54,359.2000	\$0.000	\$0.0000	0.00%
	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%

### 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 Particular		PROPOSED	JANUARY 1,	2012 RA	ATES		PROPOSED	JANUARY 1,	2013 RATES		Annual Increase/Decrease	
1		Volu	ıme	Rate		Annual \$	Volun	ne	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 m	onths 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		\$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		\$0.000	\$0.0000	0.00%
8	Rider 3 ESM	8,100.0	GJ x	Ψ0.000		\$0.0000	8,100.0	GJ x	\$0.000		\$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		\$0.000	\$0.0000	0.00%
10	Subtotal Delivery Margin Related Charges					\$9,234.00				\$9,930.60		\$696.60	1.11%
11													
12		0.400.0		00 704		** *** ****	0.400.0		00 704	***********	***	******	0.000/
13		8,100.0	GJ x	\$0.764		\$6,188.4000	8,100.0	GJ x	\$0.764		\$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		\$0.000	\$0.0000	0.00%
15						\$43,189.20				\$43,189.20		\$0.00	0.00%
16													
17	3,												
18													
19 20		8,100.0		\$7,776		\$62,983.20	8,100.0		\$7.862	\$63.679.80	\$0.086	\$696.60	1.11%
20	Total (with enective \$/63 rate)	8,100.0		\$7.776		\$62,983.20	8,100.0		\$7.862	\$63,679.80	\$0.086	9090.00	1.11%
22													
23													
24 25	<u>Delivery Margin Related Charges</u> Basic Charge	10		\$880.00	_	\$10,560.00	40	onths x	\$880.00	= \$10,560.00	\$0.00	\$0.00	0.00%
		12	months x	\$880.00		\$10,560.00	12 m	iontns 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		4,000.0	GJ X	\$0.000		\$4,560.0000	4,000.0	GJ X	\$0.000		\$0.086	\$344.0000	0.95%
26 29		4,000.0	GJ X	\$0.000		\$0.0000	4,000.0	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
30		4,000.0	GJ X	\$0.000		\$0.0000	4,000.0	GJ X	\$0.000		\$0.000	\$0.0000	0.00%
31	Subtotal Delivery Margin Related Charges	4,000.0	GJ X	\$0.000		\$4.560.00	4,000.0	GJ X	\$0.000	\$4.904.00	\$0.000	\$344.00	0.00% <b>0.95%</b>
32						\$4,560.00				\$4,904.00		\$344.00	0.95%
33	Commodity Related Charges												
34		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		4,000.0	GJ X			\$18,272.0000	4,000.0	GJ X	\$4.568	, ,	\$0.000	\$0.0000	0.00%
36		4,000.0	GJ X	φ4.506		\$21,268.00	4,000.0	GJ X	φ4.506	\$21,268.00	\$0.000	\$0.000	0.00%
37	Subtotal Gas Gales - Lixed (Commodity Related Charge)					\$21,200.00				\$21,200.00		φυ.υυ	0.00 /6
38	Non-Standard Charges ( not forecast )										ĺ		
39													
40											ĺ		
41		4,000.0		\$9.097		\$36,388.00	4,000.0		\$9.183	\$36,732.00	\$0.086	\$344.00	0.95%

APPENDIX F-2 I TAB 1.2.2 PAGE 8

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 22 - LARGE INDUSTRIAL T-SERVICE

			•	CALL COLLED	OLL IL LANGE IND	OUTHING I OFICE						
Line No.	Particular		PROPOSE	D JANUARY 1,	2012	PROI	POSED JA	ANUARY 1, 2013	3 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volume	<u>:                                    </u>	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 mc	onths 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		467,305.6	GJ x	\$0.000	, .	\$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 mc	onths 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%

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 22A - LARGE INDUSTRIAL T-SERVICE

			107	* . L 00 L D 0	LL LLA LANGE IN							
Line No.	Particular		PROPOSEI	D JANUARY 1,	2012	P	ROPOSED JA	ANUARY 1, 2013	RATES		Annual Increase/Decrease	
1		Volum	ne	Rate	Annual \$	Volui	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
	INLAND SERVICE AREA Basic Charge	12 ।	months x	\$4,810.00	= \$57,720.00	12	months x	\$4,810.00	= \$57,720.00	\$0.00 <u></u>	\$0.00	0.00%
5 6 7	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 <u> </u>	\$28,871.16	5.15%
13	Delivery Charge - Firm MTQ Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Firm (Delivery Charge Firm MTQ)	584,475.8 584,475.8 584,475.8	G1 x G1 x	\$0.093 \$0.000 \$0.000	= \$0.0000	584,475.8 584,475.8 584,475.8	GJ x GJ x GJ x	\$0.100 \$0.000 \$0.000	= \$58,447.5800 = \$0.0000 = \$0.0000 \$58,447.58	\$0.007 \$0.000 \$0.000	\$4,091.3306 \$0.0000 \$0.0000 <b>\$4,091.33</b>	0.73% 0.00% 0.00% <b>0.73%</b>
19 20 21	Delivery Charge - Interruptible MTQ Rider 2 2009 ROE Rate Rider Rider 3 ESM Transportation - Interruptible (Delivery Charge Interruptible MTQ)  Non-Standard Charges (not forecast )	28,607.9 28,607.9 28,607.9	G1 x G1 x G1 x	\$1.061 \$0.000 \$0.000	= \$0.0000	28,607.9 28,607.9 28,607.9	Gl x Gl x	\$0.000	= \$32,441.3586 = \$0.0000 = \$0.0000 \$32,441.36	\$0.073 \$0.000 \$0.000 _	\$2,088.3767 \$0.0000 \$0.0000 \$2,088.38	0.37% 0.00% 0.00% <b>0.37%</b>
26 27	UOR, Demand Surcharge, Balancing Service, Backstopping Gas  Administration Charge  Total (with effective \$/GJ rate)		months x	\$78.00 \$0.960	= \$936.00 \$560,923.59	12 584,475.8	months x	\$78.00 \$1.020	= \$936.00 \$595,974.46	\$0.00 _ \$0.060 _	\$0.00 \$35,050.87	0.00% 6.25%

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 22B - LARGE INDUSTRIAL T-SERVICE

1 :			ĸ	ATE SCHEDU	JLE 22B - LARGE IN	DUSTRIAL 1-S	ERVICE				A1	
Line No.	Particular		PROPOSE	D JANUARY 1,	2012	F	PROPOSED JA	ANUARY 1, 201	3 RATES		Annual Increase/Decrease	
1		Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	COLUMBIA SERVICE - EXCEPT ELKVIEW COAL 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	Datio Charge		months x	φ4,007.00	Ψ04,444.00	12	monaro x	φ-1,007.00	ψο-1, 1-1-1.00	Ψ0.00	ψ0.00	0.0070
5 6	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%
7	Delivery Charge - Firm MTQ	457,345.8	GJ x	\$0.092		457,345.8	GJ x	+	= \$45,277.2342	\$0.007	\$3,201.4206	0.97%
8	Rider 2 2009 ROE Rate Rider	457,345.8	GJ x	\$0.000		457,345.8	GJ x	7	= \$0.0000	\$0.000	\$0.0000	0.00%
9 10	Rider 3 ESM Transportation - Firm (Delivery Charge Firm MTQ)	457,345.8	GJ x	\$0.000	= \$0.0000 \$42,075.81	457,345.8	GJ x	\$0.000	= \$0.0000 \$45,277.23	\$0.000	\$0.0000 \$3,201.42	0.00% <b>0.97%</b>
11	Transportation - Firm (Delivery Charge Firm WTQ)				\$42,075.61				\$45,277.25		\$3,201.42	0.97 76
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		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	N 0 1 10 ( 17 1)											
19												
20 21	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
22	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
23	Administration charge	12	monuis x	Ψ10.00	- ψ330.00	12	months x	Ψ10.00	- ψ330.00	Ψ0.00	ψ0.00	0.0070
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	, , , , , , , , , , , , , , , , , , , ,	101,010.2	=	φοτο	4000,000.00	101,010.2		ψοσσ	<del>+++++++++++++++++++++++++++++++++++++</del>	\$0.070	<del>+-1,01010</del>	0.1070
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	Delivery Charge Firm MTO	631,553.5	GJ x	\$0.092	- 050 100 0000	631,553.5	GJ x	\$0.099	- \$60,500,7065	\$0.007	£4 400 074E	2.45%
32 33	Delivery Charge - Firm MTQ Rider 2 2009 ROE Rate Rider	631,553.5	GJ X	\$0.092		631,553.5	GJ X		= \$62,523.7965 = \$0.0000	\$0.007	\$4,420.8745 \$0.0000	0.00%
34	Rider 3 ESM	631,553.5	GJ X	\$0.000		631,553.5	GJ X	\$0.000	+	\$0.000	\$0.0000	0.00%
35	Transportation - Firm (Delivery Charge Firm MTQ)	001,000.0	00 X	ψ0.000	\$58,102.92	001,000.0	00 X	ψ0.000	\$62,523.80	Ψ0.000	\$4,420.88	2.45%
36	Transportation Time (Bontory Sharge Time at				400,102.02				<del>+02,020.00</del>	•	<b>V</b> 1, 120.00	2.1070
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		14,503.1	GJ x	\$0.330		\$0.024	\$348.0744	0.19%
40	Rider 2 2009 ROE Rate Rider	14,503.1	GJ x	\$0.000	,	14,503.1	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
41	Rider 3 ESM	14,503.1	GJ x	\$0.000		14,503.1	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
42	Rider 4 Reserve for Future Use	14,503.1	GJ x	\$0.000		14,503.1	GJ x	\$0.000	= \$0.0000	\$0.000	\$0.0000	0.00%
43 44	Transportation - Interruptible (Delivery Charge Interruptible MTQ)				\$4,437.95				\$4,786.02		\$348.07	0.19%
44	Non-Standard Charges (not forecast )											
46	UOR, Demand Surcharge, Balancing Service, Backstopping Gas											
47	z z, z z and caronal go, zalanon g co. noc, zachotopping cao											
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	<b>.</b>	\$0.279	\$180,302.75	646,056.6	:	\$0.294	\$189,941.78	\$0.015	\$9,639.03	5.35%

Annual

### FORTISBC ENERGY INC. DELIVERY MARGIN RELATED CHARGES CHANGES BCUC ORDER NO.G-XXX-11

#### RATE SCHEDULE 23 - LARGE COMMERCIAL T-SERVICE

Line

No.	Particular		PROPOSEI	D JANUARY 1,	2012		PROPOSED JA	NUARY 1, 2013	RATES		Increase/Decrease	
1		Volu	ıme	Rate	Annual \$	Volu	ıma	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2	LOWER MAINLAND SERVICE AREA		inc	Nate	Απιαί		dilic	Nate	Απιααι φ	rate	Αιπααι φ	Allildai biii
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	D. I		0.1	00.407	040 444 7000	4 400 0	0.1	00.055	*** *** ***	00.400	A770 0000	0.400/
/	Delivery Charge	4,100.0	GJ x	\$2.467 \$0.000		4,100.0	GJ x GJ x	\$2.655 = \$0.000 =		\$0.188	\$770.8000	6.16%
9	Rider 2 2009 ROE Rate Rider Rider 3 ESM	4,100.0 4,100.0	GJ x GJ x	\$0.000	= \$0.0000 = \$0.0000	4,100.0 4,100.0	GJ X	\$0.000 =		\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
10	Rider 5 RSAM	4,100.0	GJ X	(\$0.032)		4,100.0	GJ X	(\$0.032) =		\$0.000	\$0.0000	0.00%
11	Transportation - Firm	4,100.0	GU X	(\$0.032)	\$9,983.50	4,100.0	GJ X	(\$0.032)	\$10,754.30	φυ.υυυ	\$770.80	6.16%
12	Transportation - Tim				ψ3,303.30	-			ψ10,7 34.30	_	ψ110.00	0.1070
13	Non-Standard Charges (not forecast )											
14	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
15	33.4, 44.4, 34.4, 4,44.4											
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		4,700.0	GJ x		\$12,478.5000	\$0.188	\$883.6000	6.32%
24	Rider 2 2009 ROE Rate Rider	4,700.0	GJ x	\$0.000		4,700.0	GJ x	\$0.000 =		\$0.000	\$0.0000	0.00%
25	Rider 3 ESM	4,700.0	GJ x	\$0.000		4,700.0	GJ x	\$0.000 =	·	\$0.000	\$0.0000	0.00%
26	Rider 5 RSAM	4,700.0	GJ x	(\$0.032)		4,700.0	GJ x	(\$0.032) =		\$0.000	\$0.0000	0.00%
27	Transportation - Firm				\$11,444.50	-			\$12,328.10	_	\$883.60	6.32%
28	Non Standard Charres (not forecast)											
29 30	Non-Standard Charges (not forecast ) UOR, Balancing gas, Backstopping Gas, Replacement Gas											
31	OOR, balancing gas, backstopping Gas, Replacement Gas											
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	, ,		=	,	<del>+10,010111</del>	-	=		<del></del>	-	*******	
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		4,200.0	GJ x		= \$11,151.0000	\$0.188	\$789.6000	6.19%
40	Rider 2 2009 ROE Rate Rider	4,200.0	GJ x	\$0.000		4,200.0	GJ x	\$0.000 =	·	\$0.000	\$0.0000	0.00%
41	Rider 3 ESM	4,200.0	GJ x	\$0.000		4,200.0	GJ x	\$0.000 =		\$0.000	\$0.0000	0.00%
42	Rider 5 RSAM	4,200.0	GJ x	(\$0.032)		4,200.0	GJ x	(\$0.032) =		\$0.000	\$0.0000	0.00%
43	Transportation - Firm				\$10,227.00	-			\$11,016.60	_	\$789.60	6.19%
44	Non Standard Charges (not forecast )	1										
45 46	Non-Standard Charges (not forecast )	1										
46 47	UOR, Balancing gas, Backstopping Gas, Replacement Gas	1										
	Total (with effective \$/GJ rate)	4 200 0		<b>#2.022</b>	¢10.750.04	4 200 0		\$2.22.4	¢12 E12 01	£0.400	\$700 CO	6 100/
48	Total (with offoline wood rate)	4,200.0	=	\$3.036	\$12,753.24	4,200.0	=	\$3.224	\$13,542.84	\$0.188	\$789.60	6.19%

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

				KATE SCHE	DULE 25 - GENERA	L FIRM 1-SER	VICE					
Line No.	Particular	. —	PROPOSEI	D JANUARY 1,	2012	F	PROPOSED JA	NUARY 1, 2013	B RATES .		Annual Increase/Decrease	
1		Volu	ime	Rate	Annual \$	Volu	ıme	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%
5 6	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
7 8	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%
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		= \$0.0000	\$0.000	\$0.0000	0.00%
11	Rider 3 ESM	19,086.2	GJ x	\$0.000		19,086.2	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
12	Transportation - Firm				\$13,284.00				\$14,524.60	_	\$1,240.60	3.02%
13 14 15	Non-Standard Charges (not forecast )  UOR, Balancing gas, Backstopping Gas, Replacement Gas	214										
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			_				_			_	<u> </u>	
19												
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	Administration Charge	40	mantha v	£70.00	- 6026.00	10	mantha v	670.00	- 6026.00	\$0.00	¢0.00	0.00%
22 23	Administration Charge	12	months x	\$78.00	= \$936.00	12	months x	\$78.00	= \$936.00	\$0.00	\$0.00	0.00%
24 25	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%
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										_	<u> </u>	
31 32 33	Non-Standard Charges (not forecast ) 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	( +,)	40,070.0	-	ψ1.500	ψ1 5,0 <del>1</del> 0.01	40,070.0	-	φ2.707	Ψου,στο.+1	φο.140	ψ0,001.04	1.01 /0
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		30,357.8	GJ x		= \$23,102.2858	\$0.065	\$1,973.2570	2.98%
44	Rider 2 2009 ROE Rate Rider	30,357.8	GJ x	\$0.000		30,357.8	GJ x	ψ0.000	= \$0.0000	\$0.000	\$0.0000	0.00%
45	Rider 3 ESM	30,357.8	GJ x	\$0.000		30,357.8	GJ x	\$0.000		\$0.000	\$0.0000	0.00%
46 47	Transportation - Firm				\$21,129.03				\$23,102.29	_	\$1,973.26	2.98%
47	Non-Standard Charges (not forecast )											
49	UOR, Balancing gas, Backstopping Gas, Replacement Gas											
50	20.1, Balanong guo, Buoliotopping Guo, Nopidocincili Guo											
	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%

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

Line Annual Particular PROPOSED JANUARY 1, 2012 PROPOSED JANUARY 1, 2013 RATES Increase/Decrease No. % of Previous Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Annual Bill 2 LOWER MAINLAND SERVICE AREA 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 Administration Charge 12 months x \$78.00 \$936.00 12 months x \$78.00 \$936.00 \$0.00 \$0.00 0.00% 6 53,957.0 GJ x \$1.140 \$61,510.9800 53,957.0 GJ x \$1.226 \$0.086 \$4,640.3020 6.36% 7 **Delivery Charge** = = \$66,151.2820 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% 8 Rider 3 ESM \$0.000 \$0.0000 53,957.0 \$0.0000 \$0.000 9 53,957.0 GJ x GJ x \$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 ) UOR, Balancing gas, Backstopping Gas 13 15 Total (with effective \$/GJ rate) 53.957.0 \$73.006.98 53.957.0 \$77.647.28 \$4.640.30 6.36% \$1.353 \$1 439 \$0.086 16 17 INLAND SERVICE AREA 18 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% Rider 2 2009 ROE Rate Rider GJ x \$0.000 48.903.9 GJ x \$0.000 0.00% 24 48.903.9 \$0.0000 \$0.0000 \$0.000 \$0.0000 25 Rider 3 ESM 48.903.9 \$0.000 \$0.0000 48.903.9 \$0.000 \$0.0000 \$0.000 0.00% GJ x GJ x \$0.0000 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 48,903.9 \$67,246.45 48,903.9 \$71,452.18 31 \$1.375 \$1.461 \$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 Administration Charge 38 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 7,733.8 \$0.0000 0.00% GJ x \$0.000 \$0.0000 GJ x \$0.000 \$0.000 \$0.0000 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

\$20,312.53

7,733.8

\$20,977.64

\$0.086

\$665.11

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.

\$2.626

7,733.8

48

49 Total (with effective \$/GJ rate)

#### 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

TAB 1.2.2 PAGE 14

APPENDIX F-2

Line No.	PARTICULARS	RATES		PROPOSED J	ANUARY 1, 2013 F	RATES	Annual Increase/Decrease					
1	INLAND SERVICE AREA	Volu	ime	Rate	Annual \$	Volur	me	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
2 3 4	Rate 1 - Residential Delivery Margin Related Charges											
5 6	Basic Charge	365.25	days x	\$0.389 =	\$142.08	365.25	days x	\$0.389 =	\$142.08	\$0.00	\$0.00	0.00%
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 =		50.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
9	Rider 3 ESM	50.0	GJ x	\$0.000 =		50.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
10	Rider 5 RSAM	50.0	GJ x	(\$0.032) =		50.0	GJ x	(\$0.032) =	(\$1.6000)	\$0.000	\$0.0000	0.00%
11 12	Subtotal Delivery Margin Related Charges		_	\$3.499	\$317.03		_	\$3.824	\$333.28		\$16.25	1.51%
13	Commodity Polated Charges											
14	Commodity Related Charges  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 =		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 =		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 22	Rate 2 - Small Commercial 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	Basis Sharge	000.20	dayo x	ψο.στο	Ψ200.00	000.20	dayo x	ψ0.010	Ψ200.00	Ψ0.00	ψ0.00	0.0070
25	Delivery Charge	250.0	GJ x	\$2.907 =		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 =		250.0	GJ x	\$0.000 =	\$0.0000	\$0.000	\$0.0000	0.00%
27 28	Rider 3 ESM Rider 5 RSAM	250.0 250.0	GJ x GJ x	\$0.000 = (\$0.032) =	\$0.0000 \$(\$8.0000)	250.0 250.0	GJ x GJ x	\$0.000 = (\$0.032) =	\$0.0000 (\$8.0000)	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
29	Subtotal Delivery Margin Related Charges	250.0	GJ X _	\$2.875	\$1,016.83	250.0	GJ X _	\$3.120	\$1,078.08	\$0.000	\$61.25	1.35%
30	g		_				_		<b>V</b> 1,01000			
31	Commodity Related Charges											
32	Midstream Cost Recovery Charge	250.0	GJ x	\$1.301 =		250.0	GJ x	\$1.301 =	\$325.2500	\$0.000	\$0.0000	0.00%
33 34	Cost of Gas Rider 1 Propane Surcharge	250.0 250.0	GJ x GJ x	\$4.568 = \$8.254 =		250.0 250.0	GJ x GJ x	\$4.568 = \$8.254 =	\$1,142.0000 \$2,063.5000	\$0.000 \$0.000	\$0.0000 \$0.0000	0.00% 0.00%
35	Subtotal Commodity Related Charges	200.0	00 X _	\$14.123	\$3,530.75	200.0	00 X _	\$14.123	\$3,530.75	Ψ0.000	\$0.00	0.00%
36			_				_					
37	Total (with effective \$/GJ rate)	<u>250.0</u>		\$18.190	\$4,547.58	250.0		\$18.435 =	\$4,608.83	\$0.2 <b>4</b> 5	\$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	Delivery Oherry	4.500.0	01	CO 407	¢44.404.5000	4.500.0	01	<b>#0.055</b>	644.047.5000	<b>#0.400</b>	<b>6040 0000</b>	4.440/
43 44	Delivery Charge Rider 2 2009 ROE Rate Rider	4,500.0 4.500.0	GJ x GJ x	\$2.467 = \$0.000 =		4,500.0 4.500.0	GJ x GJ x	\$2.655 = \$0.000 =	\$11,947.5000 \$0.0000	\$0.188 \$0.000	\$846.0000 \$0.0000	1.11% 0.00%
45	Rider 3 ESM	4,500.0	GJ X	\$0.000 =		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) =		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 =		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%
-	,			Ţ.3.0TT	Ţ,	-,,555.5			<del></del>	JU. 100		,

# 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	Rasia Daily Charge	\$1.3142	\$0.0000	\$1.3142
4	Basic Daily Charge Energy Charge per GJ	\$1.3142 \$12.373	\$0.000	\$1.3142 \$12.373
5	Lifelgy Grialge per Go	ψ12.373	φ0.000	ψ12.373
6	Minimum Monthly Charge	\$40.00	\$0.00	\$40.00
7				
8	Note: Where applicable, existing monthly January 1, 2010 basis	c chage rates are prorated to a daily equivalent f	or comparison purposes.	
9				
10 11	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
14				
15	Minimum Monthly Charge	\$10.50	\$0.00	\$10.50
16				
17	Note: Where applicable, existing monthly January 1, 2010 basis	c chage rates are prorated to a daily equivalent for	or comparison purposes.	
18 19	SMALL COMMERCIAL SERVICE RATE NO. 1 (SCS-1)			
20	SIMILE SOMMEROIDE OFFICE HATE NO. 1 (303-1)			
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 evicting monthly language 1, 2010 hasin	is above value are prevated to a dally any hyplant f	ior compositor nursecon	
27	Note: Where applicable, existing monthly January 1, 2010 basis	c criage rates are prorated to a daily equivalent in	or companson purposes.	
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 34	Minimum Monthly Charge	\$33.53	\$0.00	\$33.53
35	Note: Where applicable, existing monthly January 1, 2010 basis	c chage rates are prorated to a daily equivalent for	or 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	William World by Charge	ψ01.00	φ0.00	ψ01.00
44	Note: Where applicable, existing monthly January 1, 2010 basis	c chage rates are prorated to a daily equivalent for	or comparison purposes.	
45				
46	LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)			
47				
48 49	Basic Daily Charge Energy Charge per GJ	\$3.2138 \$12.311	\$0.0000 \$0.000	\$3.2138 \$12.311
50	Energy Charge per G3	\$12.511	\$0.000	\$12.311
51	Minimum Monthly Charge	\$97.82	\$0.00	\$97.82
52	, , , , , , , , , , , , , , , , , , , ,			
53	Note: Where applicable, existing monthly January 1, 2010 basis	c chage rates are prorated to a daily equivalent for	or comparison purposes.	
54				
55	LARGE COMMERCIAL SERVICE RATE NO. 3 (LCS-3)			
56	Desir Della Okassa	<b>60 0005</b>	<b>#</b> 0.0000	#0.000F
57 58	Basic Daily Charge	\$6.6205 \$12.015	\$0.0000 \$0.000	\$6.6205 \$12.015
59	Energy Charge per GJ	φ12.UI5	φυ.υυυ	φ12.015
60			\$0.00	\$201.51
	Minimum Monthly Charge	\$201.51		
61	Minimum Monthly Charge	\$201.51	φ0.00	φ201.01

# 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

		Effective Rate	Rate	Proposed Rate
Line No.	Particulars	January 1, 2010	Changes	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 f	or comparison purposes.	
9				
10	LARGE COMMERCIAL SERVICE RATE HIGH LOAD FACTOR	t (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 f	or comparison purposes.	
19				
20	LARGE COMMERCIAL SERVICE RATE INVERSE LOAD FAC	TOR 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 f	or 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 J	anuary 1, 20	10 Rates		Proposed Ra	ate January 1, 20	012 Rates		Annual Increase/Decrease	э
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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 J	anuary 1, 20	ates	F	Proposed Ra	ite January	1, 201	2 Rates	Annual Increase/Decrease			
1	FortisBC Energy Vancouver Island	Volu	me	Rate		Annual \$	Volur	me	Rate		Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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 .	lanuary 1, 20	10 Rates		· Proposed Ra	ate January 1, 20	12 Rates		Annual Increase/Decrease	е
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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)

No.	Particular		Existing J	anuary 1, 20	10 Rates		Proposed Ra	ate January 1, 2	2012 Rates		Annual Increase/Decrease			
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill		
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%		
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%		
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											Annual	
No.	Particular		Existing J	anuary 1, 20	0 Rates		Proposed Ra	ite January 1, 20	012 Rates		Increase/Decrease	9
												% of Previous
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	Total Annual Bill
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 J	anuary 1, 20	I0 Rates		Proposed Ra	ate January 1, 2	2012 Rates		Annual Increase/Decrease	9
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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.

#### APPENDIX F-2 TAB 2.1.2 PAGE 3

### 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 J	anuary 1, 20	I0 Rates		Proposed Ra	ate January 1, 20	112 Rates	Annual Increase/Decrease		
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
2	. or no 20 2 mon gy vanou von loi an a	- 1010		riaio	7 till dai y				7 ii ii ida.	11010	7 iiii dai y	Total / Illinda. Dill
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%
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

		January 1, 2012	Changes	January 1, 2013
	(1)	(2)	(3)	(4)
1	APARTMENT GENERAL SERVICE (AGS)			
2	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				
9				
10	RESIDENTIAL GENERAL SERVICE (RGS-1)			
11				
12	Basic Daily Charge	\$0.3450	\$0.0000	\$0.3450
13 14	Energy Charge per GJ	\$14.325	\$0.000	\$14.325
15	Minimum Monthly Charge	\$10.50	\$0.00	\$10.50
16	,g-	*****	*****	******
17				
18				
19 20	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
23				
24	Minimum Monthly Charge	\$9.45	\$0.00	\$9.45
25 26				
27				
28	SMALL COMMERCIAL SERVICE RATE NO. 2 (SCS-2)			
29				
30	Basic Daily Charge	\$1.1016	\$0.0000	\$1.1016
31 32	Energy Charge per GJ	\$16.455	\$0.000	\$16.455
33	Minimum Monthly Charge	\$33.53	\$0.00	\$33.53
34	, , , , , ,	*****	,	,
35				
36				
37 38	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
41				
42	Minimum Monthly Charge	\$61.00	\$0.00	\$61.00
43 44				
45				
46	LARGE COMMERCIAL SERVICE RATE NO. 2 (LCS-2)			
47				
48	Basic Daily Charge	\$3.2138	\$0.0000	\$3.2138
49 50	Energy Charge per GJ	\$12.311	\$0.000	\$12.311
51	Minimum Monthly Charge	\$97.82	\$0.00	\$97.82
52	, <del></del>	******	*****	Ţ31.0 <u>2</u>
53				
54				
55 56	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
59				
				0004.54
60 61	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

		Proposed Rate	Rate	Proposed Rate
Line No.	Particulars	January 1, 2012	Changes	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 FACTO	OR 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, 2	012 Rates		Proposed Ra	ate January 1, 2	013 Rates		Annual Increase/Decrease	e
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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, 2	2012 I	Rates	F	Proposed Ra	ate January	1, 20	13 Rates		Annual Increase/Decreas	e
1	FortisBC Energy Vancouver Island	Volu	me	Rate	_	Annual \$	Volu	me	Rate	-	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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 Annual No. Particular Proposed January 1, 2012 Rates Proposed Rate January 1, 2013 Rates Increase/Decrease % of Previous FortisBC Energy Vancouver Island Volume Rate Annual \$ Volume Rate Annual \$ Rate Annual \$ Total Annual Bill Basic Daily Charge \$113.40 \$0.3105 = \$113.40 0.00% 365.25 days x \$0.3105 = 365.25 days x \$0.0000 \$0.00 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 \$1,473.68 Total (with effective \$/GJ rate) 80.3 \$1,473.68 \$0.00 0.00% \$18.352 80.3 \$18.352 \$0.000

### 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)

No.	Particular		Proposed	January 1, 2	012 Rates		Proposed Ra	ate January 1,	2013 Rates		Annual Increase/Decreas	e
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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											Annual	
No.	Particular		Proposed	January 1, 2	012 Rates	F	Proposed Ra	ite January 1,	2013 Rates		Increase/Decrease	e
						]						% of Previous
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	Total Annual Bill
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, 2	012 Rates		Proposed Ra	ite January 1,	, 2013 Rates		Annual Increase/Decrease	e
1	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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%

#### APPENDIX F-2 TAB 2.2.2 PAGE 3

## 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, 20	012 Rates		Proposed Ra	ite January 1, 2	2013 Rates		Annual Increase/Decrease	e
1 2	FortisBC Energy Vancouver Island	Volu	me	Rate	Annual \$	Volu	me	Rate	Annual \$	Rate	Annual \$	% of Previous Total Annual Bill
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%
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%
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%

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

Appendix F-2 Tab 3.1 Page 1

Line No	Particulars		Effective Rate January 1, 2011		Proposed Rate January 1, 2012		Increase / (Decrease)	e) (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		(, ,				<u> </u>		
14	Total Variable Charges	(\$/GJ)	\$	15.315	\$	16.079	\$ 0.764	<u>4.99%</u>
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

Appendix F-2 Tab 3.2 Page 1

Line No	Particulars		Proposed Rate January 1, 2012	Proposed Rate January 1, 2013	Increase / (Decrease)	e) (Decrease)
	(1)		(2)	(3)	(4)	(5)
1 2	Tariff Rates					
3	Basic Charge	(\$/Day)	\$0.2464	\$0.2464	\$0.0000	0.00%
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 8	Total Cost Recovery Charges	(\$/GJ)	\$16.503	\$17.786	\$1.2830	7.77%
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	<u>0.00%</u>
13						
14	Total Variable Charges	(\$/GJ)	\$ 16.079	\$ 17.362	<u>\$ 1.283</u>	<u>7.98%</u>
15 16						
17	Bill Impact Estimates					
18						
19 20	Annual Residential Usage	(GJ)	90	90		
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

Rate 1	Line No.	Schedule	Tariff Page	Particulars	EXISTING RATE JANUARY 1, 2011	Delivery Related Changes	EFFECTIVE RATE JANUARY 1, 2012
Minimum Daily Charge   plus \$0.0391 times   plus \$0.0491 times   plus \$0.0492 times   plus \$0.0492 times   plus \$0.0097   plus \$0.0007				(3)			
Minimum Daily Charge   plus \$0.0391 times   the amount of the promotional incentive divided by \$100   functive divided by \$100		Rate 1	No. 1	Option A			
The amount of the promotional incentive divided by \$100 (includes the first 2 Gigajoules per month prorated to daily basis)				Minimum Daily Charge			
Delivery Charge per GJ   Sc.	4			plus \$0.0391 times			
Polivery Charge per Day   \$0.3141   \$0.0199   \$0.3340	5			the amount of the promotional			
Delivery Charge per Day   \$0.3141   \$0.0199   \$0.340	6			incentive divided by \$100			
Delivery Charge per Day   \$0.3141   \$0.0199   \$0.3340   \$0.0007	7			(includes the first 2 Gigajoules per month prorated to daily basis)			
Revenue Stabilization Adjustment Amount per Day   \$0.0022   \$0.000   \$0.0007   \$1.1	8						
Gas Cost Recovery Charge Prorated to Daily Basis   \$0.330   \$0.000   \$0.330   \$0.001   \$0.666   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.6663   \$0.017   \$0.0000   \$0.00000   \$0.0000   \$0.0000   \$0.0000   \$0.0000   \$0.00000   \$0.00000   \$0.00000   \$0.0000   \$0.000	9				\$0.3141	\$0.0199	\$0.3340
Minimum Daily Charge (includes first 2 gigajoules/month)   \$0.646   \$0.017   \$0.663	10				\$0.0022	(\$0.00)	(\$0.0007)
13							
Delivery Charge per GJ   \$2.410   \$0.160   \$2.570	12			Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.646	\$0.017	\$0.663
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     18	14						-
Next 28 Gigajoules in any month   \$7.458   \$0.116   \$7.574					·	( ' '	,
Delivery Charge per GJ   \$2.340   \$0.162   \$2.502							
Delivery Charge per GJ   \$2.340   \$0.162   \$2.502     Revenue Stabilization Adjustment Amount per GJ   \$0.033   \$0.044)   \$0.011     Gas Cost Recovery Charge per GJ   \$5.015   \$0.000   \$5.015     Excess of 30 Gigajoules in any month   \$7.388   \$0.118   \$7.506     Rate 1	17			Next 28 Gigajoules in any month	\$7.458	\$0.116	\$7.574
Revenue Stabilization Adjustment Amount per GJ   \$0.033   \$0.044   \$0.011							
Sac Cost Recovery Charge per GJ   \$5.015   \$0.000   \$5.015	19					*	*
Excess of 30 Gigajoules in any month   \$7.388   \$0.118   \$7.506	20				·	( ' '	,
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							
24				Excess of 30 Gigajoules in any month	\$7.388	\$0.118	\$7.506
Rate 1 No. 1.1   Option B	23						
Delivery Charge per Day   \$0.3141   \$0.0199   \$0.3340							
Delivery Charge per Day   \$0.3141   \$0.0199   \$0.3340		Rate 1	No. 1.1	Option B			
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       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       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							
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       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       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					·	· ·	·
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         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					·	( ' '	( ' '
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   \$30.000   \$5.015   \$30.000   \$30.005   \$30.00							
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       Telivery 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				Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.646	\$0.017	\$0.663
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       To 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							
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     The standard of the standard						* * * * * * * * * * * * * * * * * * * *	· ·
Next 28 Gigajoules in any month         \$7.458         \$0.116         \$7.574           36         Structure of the control of the c					·		
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							
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				Next 28 Gigajoules in any month	\$7.458	\$0.116	\$7.574
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							
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							
	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 2 3 4	Rate 2.1	No. 2	Delivery Charge per Day Revenue Stabilization Adjustment Amount per Day Gas Cost Recovery Charge Prorated to Daily Basis Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.9193 \$0.0022 \$0.330 \$1.251	\$0.0654 (\$0.0029) \$0.000 \$0.063	\$0.9847 (\$0.0007) \$0.330 <b>\$1.314</b>
5						
6 7 8 9			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$2.710 \$0.033 \$5.015 \$7.758	\$0.181 (\$0.044) \$0.000 \$0.137	\$2.891 (\$0.011) \$5.015 <b>\$7.895</b>
10 11 12 13 14 15			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$2.624 \$0.033 \$5.015 <b>\$7.672</b>	\$0.176 (\$0.044) \$0.000 \$0.132	\$2.800 (\$0.011) \$5.015 <b>\$7.804</b>
16 17 18 19	Rate 2.2	No. 2	Delivery Charge per Day Revenue Stabilization Adjustment Amount per Day Gas Cost Recovery Charge Prorated to Daily Basis Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.9193 \$0.0022 \$0.330 <b>\$1.251</b>	\$0.0654 (\$0.00) \$0.000 \$0.063	\$0.9847 (\$0.0007) \$0.330 <b>\$1.314</b>
20 21 22 23 24			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$2.710 \$0.033 \$5.015 <b>\$7.758</b>	\$0.181 (\$0.044) \$0.000 \$0.137	\$2.891 (\$0.011) \$5.015 <b>\$7.895</b>
25 26 27 28 29 30			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$2.624 \$0.033 \$5.015 <b>\$7.672</b>	\$0.176 (\$0.044) \$0.000 \$0.132	\$2.800 (\$0.011) \$5.015 <b>\$7.804</b>
31 32 33	Rate 2.3	No. 2.1	Delivery Charge per Month Gas Cost Recovery Charge per Month Minimum Monthly Charge (includes first 2 gigajoules)	\$28.08 \$10.030 <b>\$38.110</b>	\$1.83 \$0.00 \$1.827	\$29.91 \$10.030 <b>\$39.937</b>
34 35 36 37			Delivery Charge per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$3.450 \$5.015 <b>\$8.465</b>	\$0.225 \$0.000 \$0.225	\$3.675 \$5.015 <b>\$8.690</b>
38 39 40 41			Delivery Charge per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$3.362 \$5.015 <b>\$8.377</b>	\$0.219 \$0.000 \$0.219	\$3.581 \$5.015 <b>\$8.596</b>

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 (1)	Tariff Page (2)	Particulars (3)	JANUARY 1, 2011 EXISTING RATE (4)	Delivery Related Changes (5)	JANUARY 1, 2012 EFFECTIVE RATE (6)
1	Rate 3.1	No. 3	Delivery Charge			
2			First 20 Cinniquias in any manufi	<b>#2.040</b>	<b>#0.000</b>	<b>#2.040</b>
3 4			First 20 Gigajoules in any month Next 260 Gigajoules in any month	\$2.910 \$2.690	\$0.000 \$0.236	\$2.910 \$2.926
5			Excess over 280 Gigajoules in any month	\$2.090 \$2.174	\$0.230 \$0.159	\$2.333
6			Exocos over 200 digajoules in any month	Ψ2.17 -	ψ0.100	Ψ2.000
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 _				<u> </u>		
12 13	Rate 3.2	No. 3	Dolivery Charge			
14	Rate 3.2	NO. 3	Delivery Charge			
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 29			Next 260 Gigajoules in any month Excess over 280 Gigajoules in any month	\$2.690 \$2.174	\$0.236 \$0.159	\$2.926 \$2.333
30			Excess over 200 Gigajoules in any month	\$2.174	\$0.159	\$2.333
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				÷1.0.10	7300	75.010
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.

#### Appendix F-2 Tab 4.1.1 Page 4

# 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		Tariff		JANUARY 1, 2011	Delivery Related	JANUARY 1, 2012
No.	Schedule	Page	Particulars	EXISTING RATES	Changes	EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1 2	Rate 25	No. 4.21	Transportation Delivery Charge			
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)

Page 1

# 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	·	EXI	STING JAN	UARY 1, 201	1 RATES	PRC	POSED JA	NUARY 1, 201	2 RATES	Annu	al Increase/(Dec	crease)
1 2	Rate 1 Domestic Service Option B	Volu	ıme	Rate	Annual \$	Volu	ume	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
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				#200 O4				¢440.57		£10.66	4.700/
24 25	Delivery Charge (including RSAM) Commodity Charge				\$398.91 \$702.09				\$418.57 \$702.09		\$19.66 \$0.00	1.79% 0.00%
26	Total				\$1,101.00				\$1,120.66	-	\$19.66	1.79%

## RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXI	STING JAN	UARY 1, 201	I RATES	PR	OPOSED JA	NUARY 1, 20 <sup>-</sup>	2 RATES	Annua	al Increase/(Dec	rease)
												% of Previous
1	Rate 2.1 General Service	Volu	ime	Rate	Annual \$	Vo	lume	Rate	Annual \$	Rate	Annual \$	Annual Bill
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		<u>-</u>	\$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%

## RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		EXISTING JANUARY 1, 2011 RATES PROPOSED JANUARY 1, 2012 RATES					2 RATES	Annual Increase/(Decrease)		rease)		
											(	% of Previous
1	Rate 2.2 General Service	Volu	ime	Rate	Annual \$	Volu	ume	Rate	Annual \$	Rate	Annual \$	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		· <del>-</del>	\$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		· <u> </u>	\$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				-	_					_	<u> </u>	
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%

#### **RATE 25 - TRANSPORTATION SERVICE**

Line

No.		E	XISTING J	ANUARY 1, 201	1 RA	TES	PI	ROPOSED	JANUARY 1, 2	012 I	RATES	Annua	I Increase/(Dec	rease)
1 2	Rate 25 Transportation Service	Volun	ne	Rate	•	Annual \$	Volu	me	Rate	_	Annual \$	Rate	Annual \$	% of Previous Annual Bill
3 4	Transportation Delivery Charges													
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 n	nonths x	\$1,826.00			12	months x	\$1,945.00			\$119.00	\$0.0000	0.00%
10														
11	Administration Charge per month	12 n	nonths 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	Commence of Americal Delivery Administration and Commence it. Channel													
18 19	Summary of Annual Delivery, Administration and Commodity Charges 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)	0,890	GJ X	\$0.000	_	\$0.0000	0,890	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%
		.,		×=	-	,	.,			_	<del></del>	=	*******	

# 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 2	Rate 1	No. 1	Option A			
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 <b>\$0.663</b>	\$0.000 \$0.005	\$0.330 <b>\$0.668</b>
30			Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.003	\$0.005	\$00.00
31 32			Delivery Charge per C I	\$2.570	<b>#0.040</b>	\$2.612
			Delivery Charge per GJ	,	\$0.042	•
33			Revenue Stabilization Adjustment Amount per GJ	(\$0.011)	\$0.000	(\$0.011)
34 35			Gas Cost Recovery Charge per GJ  Next 28 Gigajoules in any month	\$5.015 <b>\$7.574</b>	\$0.000 \$0.042	\$5.015 <b>\$7.616</b>
36			Next 26 digajoules in any month	\$1.314	\$0.042	\$7.010
36 37			Delivery Charge per C I	\$2.502	(\$0.001)	¢2 E01
37 38			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ	\$2.502 (\$0.011)	(\$0.001) \$0.000	\$2.501 (\$0.011)
38 39			Gas Cost Recovery Charge per GJ	(\$0.011) \$5.015	\$0.000 \$0.000	(\$0.011) \$5.015
39 40			Excess of 30 Gigajoules in any month	\$7.506	(\$0.001)	\$7.505
			=======================================	<del>\$1.500</del>	(\$0.001)	ψ1.000

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 2 3 4	Rate 2.1	No. 2	Delivery Charge per Day Revenue Stabilization Adjustment Amount per Day Gas Cost Recovery Charge Prorated to Daily Basis Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.9847 (\$0.0007) \$0.330 \$1.314	\$0.0159 \$0.0000 \$0.000 \$0.016	\$1.0005 (\$0.0007) \$0.330 <b>\$1.330</b>
5			minimum bany onarge (includes in st 2 gigajoules/month)	ψ1.51 <del>+</del>	ψ0:010	Ψ1.330
6 7 8 9			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$2.891 (\$0.011) \$5.015 <b>\$7.895</b>	\$0.043 \$0.000 \$0.000 \$0.043	\$2.934 (\$0.011) \$5.015 <b>\$7.938</b>
11 12 13 14 15			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$2.800 (\$0.011) \$5.015 \$7.804	\$0.029 \$0.000 \$0.000 \$0.029	\$2.829 (\$0.011) \$5.015 <b>\$7.833</b>
16 17 18 19	Rate 2.2	No. 2	Delivery Charge per Day Revenue Stabilization Adjustment Amount per Day Gas Cost Recovery Charge Prorated to Daily Basis Minimum Daily Charge (includes first 2 gigajoules/month)	\$0.9847 (\$0.0007) \$0.330 <b>\$1.314</b>	\$0.0159 \$0.00 \$0.000 \$0.016	\$1.0005 (\$0.0007) \$0.330 <b>\$1.330</b>
20 21 22 23 24			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$2.891 (\$0.011) \$5.015 <b>\$7.895</b>	\$0.043 \$0.000 \$0.000 \$0.043	\$2.934 (\$0.011) \$5.015 <b>\$7.938</b>
25 26 27 28 29 30			Delivery Charge per GJ Revenue Stabilization Adjustment Amount per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$2.800 (\$0.011) \$5.015 <b>\$7.804</b>	\$0.029 \$0.000 \$0.000 \$0.029	\$2.829 (\$0.011) \$5.015 <b>\$7.833</b>
31 32 33	Rate 2.3	No. 2.1	Delivery Charge per Month Gas Cost Recovery Charge per Month Minimum Monthly Charge (includes first 2 gigajoules)	\$29.91 \$10.030 <b>\$39.937</b>	\$2.44 \$0.00 \$2.443	\$32.35 \$10.030 <b>\$42.380</b>
34 35 36 37			Delivery Charge per GJ Gas Cost Recovery Charge per GJ Next 28 Gigajoules in any month	\$3.675 \$5.015 <b>\$8.690</b>	\$0.300 \$0.000 \$0.300	\$3.975 \$5.015 <b>\$8.990</b>
38 39 40 41			Delivery Charge per GJ Gas Cost Recovery Charge per GJ Excess of 30 Gigajoules in any month	\$3.581 \$5.015 <b>\$8.596</b>	\$0.293 \$0.000 \$0.293	\$3.874 \$5.015 <b>\$8.889</b>

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

## Appendix F-2 Tab 4.2.1 Page 4

# 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		Tariff		JANUARY 1, 2012	Delivery Related	JANUARY 1, 2013
No.	Schedule	Page	Particulars	PROPOSED RATES	Changes	EFFECTIVE RATES
	(1)	(2)	(3)	(4)	(5)	(6)
1 2	Rate 25	No. 4.21	Transportation Delivery Charge			
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)

Page 1

# 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

Rate 1 Domestic Service Option B   Volume   Rate   Annual \$   Volume   Rate   Annual \$   Rate   Annual \$   A	Line No	).	PRC	POSED JA	NUARY 1, 201	2 RATES	PRO	POSED JA	NUARY 1, 201	3 RATES	Annu	al Increase/(De	crease)
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 6 Gas Cost Recovery Charge per Day 7 Minimum Daily Charge (includes the first 2 GJs/month) 8 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 \$0.002 \$0.000	1 2	Rate 1 Domestic Service Option B	Volu	ıme	Rate	Annual \$	Volu	ıme	Rate	Annual \$	Rate	Annual \$	% of Previous Annual Bill
5         Rider 5 - RSAM per day         365.25 days x         (\$0.0007)         -\$0.2557         365.25 days x         (\$0.0007)         -\$0.2557         \$0.0000	3	Daily Charge											
6 Gas Cost Recovery Charge per Day 7 Minimum Daily Charge (includes the first 2 GJs/month) 8 9 Next 28 Gigajoules in any month 10 Delivery Charge per GJ 11 Rider 5 - RSAM per GJ 12 Gas Cost Recovery Charge per GJ 13 Total Charges per GJ 14 15 Excess of 30 Gigajoules in any month  365.25 days x \$0.3295 \$120.3499 \$0.0000 \$0.	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%
7 Minimum Daily Charge (includes the first 2 GJs/month) 8 9 Next 28 Gigajoules in any month 10 Delivery Charge per GJ 11 Rider 5 - RSAM per GJ 116 GJ x (\$0.011) (\$1.2760) 12 Gas Cost Recovery Charge per GJ 13 Total Charges per GJ 14 15 Excess of 30 Gigajoules in any month  \$0.6628 \$242.0700 \$0.0628 \$242.0700 \$0.0682 \$244.0800 \$0.0055 \$2.0100 0.18 0.0055 \$0.0055 \$2.0100 0.18 0.005 0.005 0.005 0.005 0.005 0.005 0.005 0.005 0.005 0.005 0.005 0.006 0.005 0.005 0.006 0.005 0.006 0.006 0.006 0.006 0.007 0	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%
8 9 Next 28 Gigajoules in any month 10 Delivery Charge per GJ 11 Rider 5 - RSAM per GJ 116 GJ x (\$0.011) (\$1.2760) 12 Gas Cost Recovery Charge per GJ 13 Total Charges per GJ 14 15 Excess of 30 Gigajoules in any month	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%
9 Next 28 Gigajoules in any month 10 Delivery Charge per GJ 11 Rider 5 - RSAM per GJ 11 Gas Cost Recovery Charge per GJ 11 Total Charges per GJ 11 Total Charges per GJ 11 Excess of 30 Gigajoules in any month 12 Excess of 30 Gigajoules in any month 13 Excess of 30 Gigajoules in any month 14 Excess of 30 Gigajoules in any month 15 Excess of 30 Gigajoules in any month 16 GJ x \$2.570 \$298.1200 17 (\$0.011) (\$1.2760) 18 (\$0.011) (\$1.2760) 19 (\$0.02 \$0.000 \$0.	7	Minimum Daily Charge (includes the first 2 GJs/month)		· · · · · ·	\$0.6628	\$242.0700			\$0.6682	\$244.0800	\$0.0055	\$2.0100	0.18%
10 Delivery Charge per GJ 11 Rider 5 - RSAM per GJ 11 GJ x \$2.570 \$298.1200 11 Gas Cost Recovery Charge per GJ 11 Total Charges per GJ 11 Excess of 30 Gigajoules in any month 12 Excess of 30 Gigajoules in any month 13 Delivery Charge per GJ 14 Sequence of Sunday \$2.570 \$298.1200 15 GJ x \$2.570 \$298.1200 16 GJ x \$2.612 \$302.9920 \$0.042 \$4.8720 0.43 16 GJ x \$0.001 \$0.000 \$0.000 \$0.000 16 GJ x \$5.015 \$581.7400 \$0.000 \$0.000 \$0.000 \$0.000 17 Sequence of Sunday \$1.600 \$1.2760 18 Sequence of Sunday \$1.600 \$1.2760 19 Sequence of Sunday \$1.600 \$1.2760 10 Sequence of Sunday \$1.600 \$1.2760 11 GJ x \$1.2760 11	8												
11       Rider 5 - RSAM per GJ       116       GJ x       (\$0.011)       (\$1.2760)       \$0.000       \$0	9	Next 28 Gigajoules in any month											
12 Gas Cost Recovery Charge per GJ 13 Total Charges per GJ 14 15 Excess of 30 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%
13 Total Charges per GJ \$7.574 \$878.5800 \$7.616 \$883.4600 \$0.042 \$4.8800 0.44  14	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%
14 15 Excess of 30 Gigajoules in any month	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%
15 Excess of 30 Gigajoules in any month	13	Total Charges per GJ		_	\$7.574	\$878.5800		_	\$7.616	\$883.4600	\$0.042	\$4.8800	0.44%
	14												
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	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 0.00	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 <u>\$5.015</u> <u>\$0.0000</u> 0 GJ x <u>\$5.015</u> <u>\$0.0000</u> <u>\$0.000</u> <u>\$0.000</u> <u>\$0.000</u> <u>0.000</u>	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	19	Total Charges per GJ			\$7.506	\$0.0000			\$7.505	\$0.0000	(\$0.001)	\$0.0000	0.00%
20													_
		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 (Individual POAM)						0440.57				C405.44		<b>#C 00</b>	0.040/
						,				•			0.61% 0.00%
											-		0.61%

## RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		PROPOSED JANUARY 1, 2012 RATES PROPOSED JANUARY 1, 2013 RATES				3 RATES	Annu	al Increase/(Dec	crease)			
												% of Previous
1	Rate 2.1 General Service	Volu	me	Rate	Annual \$	Vo	lume	Rate	Annual \$	Rate	Annual \$	Annual Bill
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%

## RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		PRC	POSED JA	NUARY 1, 201	2 RATES	PRO	POSED JAI	NUARY 1, 201	3 RATES	Annual Increase/(Decrease)		rease)
												% of Previous
1	Rate 2.2 General Service	Volu	ime	Rate	Annual \$	Volu	ıme	Rate	Annual \$	Rate	Annual \$	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 =	Ψ0,00=00	3,076	GJ x	\$2.934 =	φο,ο=οο .ο	\$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) =		\$0.000	\$0.0000	0.00%
12	Gas Cost Recovery Charge per GJ	3,076	GJ x		\$15,426.1400	3,076	GJ x	\$5.015 =	, ,, , , , , , , , , , , , , , , , , , ,	\$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 =		\$0.029	\$0.0000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	(\$0.011) =	\$0.0000	0	GJ x	(\$0.011) =	· ·	\$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 =	· · · · · · · · · · · · · · · · · · ·	\$0.000	\$0.0000	0.00%
19	Total Charges per GJ			\$7.804	\$0.0000			\$7.833	\$0.0000	\$0.029	\$0.0000	0.00%
20				<u>-</u>								
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	. <u>-</u>	\$0.00	0.00%
26	Total			-	\$24,764.95				\$24,903.01		\$138.06	0.56%

#### **RATE 25 - TRANSPORTATION SERVICE**

Line

No.		PF	ROPOSED	JANUARY 1, 201	2 R	ATES	PI	ROPOSED	JANUARY 1, 2	013 I	RATES	Annua	I Increase/(Deci	rease)
1 2	Rate 25 Transportation Service	Volur	ne	Rate		Annual \$	Volume		Rate		Annual \$	Rate	Annual \$	% of Previous Annual Bill
3 4	Transportation Delivery Charges													
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 n	nonths x	\$1,945.00			12 ו	months x	\$1,975.00			\$30.00	\$0.0000	0.00%
10														
11	Administration Charge per month	12 n	nonths x	\$202.00	=	\$2,424.0000	12 ו	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	Cummany of Annual Delivery, Administration and Commodity Charges													
18	Summary of Annual Delivery, Administration and Commodity Charges 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)	0,090	GJ	\$0.000	=	\$0.0000	0,090	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%
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%