Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

February 21, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI) Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018 (the Application)

Evidentiary Update dated February 21, 2014

On June 10, 2013, FEI filed the Application referenced above. On July 16, 2013, FEI filed an Evidentiary Update reflecting the British Columbia Utilities Commission (Commission) Order G-75-13 regarding Phase 1 of the Generic Cost of Capital Proceeding and Order G-88-13 in respect of FEI's Application to Amend Rate Schedule 16 on a Permanent Basis, as well as minor corrections to the financial schedules. In accordance with Commission Order G-9-14 setting out the Regulatory Timetable for the review of the Application, on August 23, 2013 FEI filed responses to Information Request (IR) No. 1 and on November 27, 2013 FEI filed responses to IR No. 2. Prior to the receipt of IR No. 2, on September 6, 2013, FEI filed a second Evidentiary Update (Exhibit B-15) reflecting an increase in the enacted Corporate Tax Rate and various changes that were identified in preparing the responses to IR No.1.

At the time of filing responses to IR No. 2 FEI committed to providing a final Evidentiary Update including actual 2013 operating and maintenance expense (O&M) and capital expenditures. This final Evidentiary Update reflects these two updates, as well as other changes related to the actual O&M and capital updates, including actual 2013 deferred charges. Further, the Evidentiary Update reflects the impacts of Special Direction No. 5 to the Commission (Order in Council No. 557, dated November 27, 2013), Commission Order G-210-13 regarding the Biomethane Service Offering, and a few minor updates identified in preparing the responses to IR No. 2. Each of these items is described below, and the impact on the revenue requirements and delivery rates is also specified in Table 3 below.

FORTIS BC

UPDATE OF 2013 PROJECTED TO 2013 ACTUAL

1. O&M

2013 Actual O&M has been updated in Tables C3-1 and C3-2. Updating the actual results has affected the 2013 Base; and Tables C3-3 and C3-5 have also been updated as those changes have been reflected in the 2014 through 2018 forecast O&M. FEI has not updated the various departmental tables in Section C3 as the updated departmental figures are already evident from the four tables listed below.

Table 1 below provides a summary of the variances between the 2013 Actual and the 2013 Projection by department. Following the table, FEI has provided explanations of the variances by department and identified the variances as either sustainable or temporary.

Table 1: O&M 2013 Actual Compared to 2013 Projection ($000s)

	2013 Actual	2013 Projection	2013 Act vs. Proj
Operations	64,237	63,509	728
Customer Service [1]	36,630	41,825	(5,195)
Energy Solutions & External Relations	19,022	19,215	(193)
Energy Supply & Resource Dev	3,937	4,000	(63)
Information Technology	24,249	24,217	33
Engineering Services & PM	15,297	15,456	(159)
Operations Support	11,718	11,867	(150)
Facilities	9,230	9,249	(19)
Environment Health & Safety	2,680	2,681	(1)
Finance & Regulatory Services	12,872	13,279	(407)
Human Resources	8,305	8,458	(153)
Governance	7,995	7,935	60
Corporate	(248)	(358)	110
	215,924	221,333	(5,409)

1 Before deferral of Customer Service O&M for 2013 Actual and Projection

2013 Actual O&M was $5.4 million less than the 2013 Projection that formed the Base O&M for the O&M Formula described in Section B6 of the Application. Of this $5.4 million, $3 million was captured in the Customer Service Variance deferral account and will be returned to customers, bringing the total amount deferred in 2013 in that account to $13.234 million.

Ten of the departments had variances from the Projection that were $200 thousand or less, with a total variance for all of these ten departments of $535 thousand, or less than 0.25%. Accordingly, the 2013 Base has not been adjusted for these ten departments. The departments with significant variances were Operations, Customer Service, and Finance and Regulatory Affairs. Each of these is discussed further below.

Operations:

The additional O&M in the Operations department in 2013 was primarily due to higher activity levels for leak repairs TPIP activities (cathodic protection evaluations, pipe integrity assessments, natural hazards) and vegetation management. Of the $728 thousand in higher spending realized, $220 thousand is required to be carried forward to the PBR Period to manage higher levels of vegetation management activities that are forecast over the upcoming years.

Customer Service:

Customer Service realized savings in 2013 as compared to the Projection of $5.2 million mainly related to reduction in mass market bad debt, reduction in repeat call volumes, cost savings in bill printing and postage, as well as fewer meter reads. Of this amount, $1.9 million (which includes the reduction of temporary employees discussed in the responses to the BCUC IR 2.251 series totaling $373 thousand) is sustainable and expected to be a permanent variance while $3.3 million is temporary as Customer Service is expecting an increase in outbound call volumes, increased postage costs and to meet meter reading service levels for regular and special reads.

Finance and Regulatory Affairs:

Finance and Regulatory Affairs' O&M was $407 thousand less than projected. Approximately half of this amount, or $180 thousand, is considered sustainable, representing permanent labour savings due to integration activities in the regulatory administration and financial reporting areas that were able to be realized earlier than anticipated. The remainder is due to a high level of staff vacancies and turnover that resulted in temporary savings.

These three adjustments above, when combined with the $334 thousand increase in the Base O&M for the Facilities department described further below, result in an overall decrease to the 2013 Base O&M of $1.5 million. The revised 2013 Base O&M is now $229.5 million instead of $231 million. An updated Section B6 of the Application (FEI 2014 Proposed PBR) has been provided that reflects these revisions to O&M. In addition, the 2013 Actual and 2014 Formula O&M have been adjusted in the Financial Schedules in Section E.

2. *Capital Expenditures*

2013 Actual Capital Expenditures have been updated in Table C4-1. The 2013 Actual capital expenditures were $6.4 million higher than the 2013 Projection, after removing the Biomethane interconnect facilities as discussed further below. Expenditures were higher in all areas with the exception of Distribution System Reinforcements. Overall, the combined 2012 and 2013 Actual spending was $5.3 million above the 2012 and 2013 Approved. These updated actual capital expenditures do not affect the capital expenditure forecasts for 2014 to 2018, or the 2013 Base for the formula, since the 2013 Base for capital expenditures was set from the 2013 Approved. The 2013 Actual Capital Expenditures have been updated into the Financial Schedules in Section E and affect the opening rate base for the 2014 Forecast. FEI has also provided an updated Table C4-2 which is only affected by the removal of the Biomethane interconnect facilities from the capital expenditure base.

3. Deferred Charges

To align with the changes to reflect actual 2013 O&M and capital expenditures noted above, FEI has also updated the balances in the deferred charges to reflect 2013 actual additions.[1] Accordingly, FEI has also recalculated 2014 amortization expense to reflect the 2013 actual balances. There are also changes to the deferred charges to reflect the amended and new regulations that are discussed further below. Specifically, FEI has determined that the Fueling Station Variance Account[2] is no longer required and has withdrawn the request to discontinue the CNG and LNG Recoveries deferral account given the changes to n. The net impact of all changes to deferred charges, including changes related to Natural Gas for Transportation outlined in the changes to legislation section below, is a decrease in the forecast 2014 rate base of $11.5 million and a decrease to the forecast 2014 amortization expense of $1.3 million.

Schedules 47 through 50 of the Revised Section E Financial Schedules reflect the changes to deferred charges discussed above.

AMENDED AND NEW LEGISLATION

In November 2013, two pieces of legislation came into effect: (1) BC Regulation 235/2013, amending the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) (the Amended GGRR); and (2) BC Regulation 245/2013, Special Direction No. 5 to the British Columbia Utilities Commission (Commission) regarding FEI's (and other FortisBC Energy Utilities') Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) services (Direction No. 5) (collectively the New Regulations). Special Direction No.5 contains, among other items, the following requirements on page 3:

> *3 In setting rates under the Act for a utility, the Commission must do the following:*
>
> *(a) treat CNG service and LNG service, and all other costs and revenues related to those services, as part of the utility's natural gas class of service;*
>
> *(b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;*

On January 30, 2014, in response to the New Regulations, FEI filed a letter[3] requesting the following clarification and approvals from the Commission with respect to FEI's Natural Gas for Transportation service:

1) Clarification that any revenue shortfalls from non-guaranteed volumes and un-recovered capital costs for CNG/LNG fueling stations undertaken under the

[1] FEI has also amended the 2013 property tax expense given the update to the corresponding property tax variance deferral
[2] See Appendix H Section 5.1 for further discussion
[3] FEI has included this letter as Attachment 1 to this Evidentiary Update

GGRR remain in FEI's natural gas rate base and are fully recoverable in the rates of FEI's customers that are not under a fixed rate[4];

2) An order transferring the CNG fueling station services provided to BFI from the CNG class of service to the natural gas class of service;[5] and,

3) An order transferring the existing CNG and LNG fueling stations undertaken under the GGRR from the separate classes of service for such CNG and LNG fueling stations to the natural gas class of service.

This request is currently before the Commission.

Thus, pursuant to section 3(a) and (b) of the Special Direction and assuming approval of items 2 and 3 of FEI's letter filed on January 30, 2014, FEI has included all CNG and LNG fueling station services within its natural gas class of service. That is, FEI will no longer be classifying its CNG and LNG stations into the four separate classes of service as identified in Appendix H of Exhibit B-1.

The legislation and the inclusion of CNG and LNG fueling station services within the natural gas class of service results in both the addition of items previously captured in the separate classes of service into the delivery revenue requirement, and also updates to the amounts forecast for these items as discussed in Appendix H. These changes are summarized as follows:

- An update to 2013 and 2014 net plant in service to reflect CNG and LNG fueling stations in plant accounts 476-10 through 476-70, as shown in Schedules 35 and 38 of the updated Section E Financial Schedules. The 2014 forecast capital additions for CNG and LNG fueling stations are $3.8 million and are identified Schedule 38 of Section E. The 2014 forecast capital expenditures are $3.4 million and are excluded from the formula calculation of 2014 capital expenditures as shown in Section B Table B6-8. They are included in the financial schedules on a forecast basis since these costs are directly tied to incremental revenue that is not part of the formula approach;

- An update to deferred charges as follows;

4 Fixed rate is used as defined in Special Direction No. 5, where it means a charge for natural gas service not subject to adjustment based on changes to the revenue requirements of a utility.

5 FEI notes that the fueling station services provided to Waste Management Canada Corporation and to Vedder Transport Ltd. were approved within the existing traditional natural gas for distribution class of service.

Table 2: Changes in NGT Deferrals ($000s)

Deferral	Particulars	September 6, 2013 Evidentiary Update 2014 Mid- Year Balance	February 21, 2014 Evidentiary Update 2014 Mid-Year Balance	Change in 2014 Mid Year Balance	Change in 2014 Amortization Expense
NGT Incentives	Revised based on 2013 actuals and market interest in the program	18,860	9,345	(9,515)	(1,048)
FSVA	No longer required	228	133	(95)	(28)
CNG/LNG Recoveries	To return un-forecast excess recoveries	(6)	(31)	(25)	(51)

- An increase to 2014 forecast sales volume of 80 TJs, and based on adopting Rate Schedule 46 for LNG customers on a go forward basis, a reduction of $93 thousand in revenue and a reduction of $434 thousand in delivery margin as reflected in Section E, Schedules 8 and 10 as well as updated Tables C1-5, C1-6, C1-8 and C1-9.[6] As well, 2014 CNG and LNG Service Recoveries of $1.4 million have been included in the revenue requirements based on the forecasts provided in Appendix H and are shown in Table C2-1 and Schedule 13 of Section E Financial Schedules;

- The removal of $289 thousand in NGT Station O&M from the 2013 Base for the formula, which is now included in the revenue requirements on a forecast basis since these costs are directly tied to incremental revenue that is not part of the formula approach. The 2014 forecast for the NGT Station O&M is $433 thousand as shown in Section B, Table B6-5 and Schedule 14 of Section E Financial Schedules.

- An increase of $334 thousand to the Facilities department 2013 Base O&M in Table C3-2 to account for the Tilbury rent recoveries that will no longer occur. As discussed further below, the Special Direction provides for the expansion of the Tilbury LNG facility which requires the use of property that has been previously rented out to a third party. FEI has not received rent revenue for this portion of the property since November of 2013.; and

The Special Direction also provides for an expansion of the Tilbury LNG facility such that the lesser of the capital costs of constructing the expansion facility and $400 million is to be included in FEI's natural gas class of service rate base; however, because FEI is still in the early stages of project development, the expansion of the Tilbury facility is not included in this Evidentiary Update. As such, the Tilbury expansion and any net impact on the revenue requirement will be discussed in future FEI annual review filings. In addition, and similar to

[6] Although a nominal increase in volume, a reduction to revenue and gross margin at existing rates occurs because the Rate Schedule 46 is lower than the Rate Schedule 16 delivery rate embedded in the September 6, 2013 Evidentiary Update

the treatment of CNG and LNG fueling station costs, all capital and operating costs associated with the expansion of the Tilbury LNG facility will be included on a forecast basis and not captured under the PBR formula.

The revised Section E Financial Schedules reflect all changes associated with the amendments to legislation and inclusion of CNG and LNG services within the natural gas class of service. The changes noted above, and the implications of the legislation on the forecast of NGT related activities, necessitate a significant revision to Appendix H of the Application. Thus, FEI has revised Appendix H in its entirety and included with Attachment 4 as noted below.

BIOMETHANE SERVICE OFFERING

On December 11, 2013, the Commission issued Order G-210-13 and Reasons for Decision (the Decision) which approved the continuance of the Biomethane Program on a permanent basis with certain modifications as described in the Decision and as clarified in Letter L-10-14. The Decision specified that all costs of the Program must be captured in the Biomethane Variance Account (BVA) for recovery from those customers who participate in the program, through the Biomethane Energy Recovery Charge (BERC). Thus, revisions are required to remove the interconnection and gross O&M costs of the Program that will no longer be recovered through the delivery rates of all non-bypass customers.

Therefore, pursuant to Order G-210-13 and Letter L-10-14, the changes to the revenue requirement forecast as a result of the Biomethane Program are summarized as follows:

- As clarified by Letter L-10-14, the interconnection costs associated with the seven projects approved prior to Order G-210-13 have not been transferred to the BVA. For the determination of the formula capital expenditures, FEI has excluded all Biomethane capital expenditures from the determination of formula capital expenditures but included interconnection costs associated with the seven approved projects in its actual and forecast costs;

- To align with the 2014 First Quarter Report on the BVA as filed on February 19, 2014, FEI has updated the 2014 forecast interconnection capital expenditures for the seven approved projects from $3.9 million to $3.7 million and the 2014 forecast upgrader capital expenditures to $1.5 million as shown in Table B6-8. The total 2014 forecast Biomethane capital additions are $7.9 million, representing $3.5 million for interconnection facilities and $4.4 million for upgrader facilities as shown on Schedule 37 of Section E Financial Schedules.

- The interconnection facilities remains in the delivery cost of service, but the addition of the upgraders creates an offsetting recovery of their associated net cost of service from the Biomethane Variance Account (BVA) as shown in Table C2-1. In 2014, the net cost of service related to the 2014 upgrader additions is a credit due to the high capital cost allowance rate associated with upgraders. The result is a decrease to Other Recoveries of $128 thousand in 2014 as shown in Table C2-1 and Schedule 13 of Section E to reflect changes to the cost service impacts of forecasted projects, specifically depreciation expense, income taxes and earned return transferred to the BVA;

- The removal of $410 thousand in Biomethane program O&M from the 2013 Base for the formula, which is now included as a flow-through item outside of the formula. The 2014 forecast O&M is $590 thousand as shown in Section B, Table B6-5. Of this amount, $570 thousand is transferred to the BVA as shown on Schedules 15 and 18 of Section E Financial Schedules. Approximately $20 thousand remains in the gross O&M for recovery through delivery rates because this O&M is associated with the existing approved seven interconnection projects; and,

- An update to the amount shown in Appendix F-5 Non-Rate Base Deferrals and Section E Financial Schedules to reflect the 2013 actual non-rate base BVA ending balance of $0.963 million as provided in the 2014 First Quarter Report on the BVA filed with the Commission on February 19, 2014.

The revised Section E Financial Schedules, included with Attachment 4 to this filing, reflect all revenue requirement changes associated with the Biomethane Program.

INFORMATION REQUESTS

FEI has also identified two information request responses that require an update. None of these changes have an impact on the revised Section E Financial Schedules or 2014 delivery rate proposals:

IR Reference	Summary of Change
BCUC IR 1.188.2	Revision to include actual 2013 Communications and Advertising Costs that are now available. Please refer to Attachment 2 of this filing for the revised response as requested by Commission staff.
CEC PBR IR 3.15.2	Revision required to the actual BC Stat Can AWE column. This correction was identified and reflected in the response to BCUC PBR IR 3.4.1 but inadvertently excluded from this response. Please refer to Attachment 3 of this filing for the revised response.

A summary of the changes to the revenue requirement and delivery rate proposals for FEI for 2014-2018 is provided in Table 3 below. As discussed in the Application, FEI is only requesting approval of 2014 delivery rates at this time.

Table 3: Revised Revenue Requirement and Delivery Rate Changes, 2014-2018

	Proposed Delivery Rate Change					
	2014	**2015**	**2016**	**2017**	**2018**	**Total**
Evidentiary Update July 16th, 2013	0.97%	1.16%	1.73%	0.84%	2.59%	7.28%
Increase (Decrease)	0.45%	-0.15%	0.01%	0.01%	0.02%	0.34%
Evidentiary Update September 6th, 2013	1.42%	1.01%	1.74%	0.85%	2.60%	7.62%
Increase (Decrease)	-0.83%	0.56%	0.60%	0.23%	-0.38%	0.18%
Evidentiary Update February 21, 2014	**0.59%**	**1.57%**	**2.35%**	**1.08%**	**2.22%**	**7.80%**

	Revenue Deficiency/(Surplus), $ millions					
	2014	**2015**	**2016**	**2017**	**2018**	**Total**
Evidentiary Update July 16th, 2013	$ 6.069	$ 7.425	$ 11.218	$ 5.622	$ 16.938	$ 47.272
Increase (Decrease)	$ 2.851	$ (0.949)	$ 0.101	$ 0.088	$ 0.110	$ 2.201
Evidentiary Update September 6th, 2013	$ 8.920	$ 6.476	$ 11.319	$ 5.710	$ 17.048	$ 49.473
Increase (Decrease)	$ (5.210)	$ 3.447	$ 3.926	$ 1.654	$ (2.006)	$ 1.811
Evidentiary Update February 21, 2014	**$ 3.710**	**$ 9.923**	**$ 15.245**	**$ 7.364**	**$ 15.042**	**$ 51.284**

FEI has updated some of the tables and wording in the Application and the Appendices (original filed under Exhibit B-1 and B-1-1 respectively, and as may have been updated by Exhibit B-1-3 in the July 16, 2013 Evidentiary Update and Exhibit B-15 in the September 6, 2013 Evidentiary Update) and included them in Attachment 4 of this filing. Sections B1 through B8 have been reproduced in their entirety to facilitate referencing during the oral hearing. Attachment 4 includes the following:

Description	Revised Pages
Application, Section A	Pages 6 - 10
Application, Section B	Pages 26-84
Application, Section C	Key tables only, please see Attachment 5
Application, Section D	Key tables only, please see Attachment 5
Application, Section E Financial Schedules	All Pages
Appendix G1 – FEI 2015-2018 Formula Financial Schedules	All Pages
Appendix G2 – FEI 2014-2018 Forecast Financial Schedules	All Pages
Appendix H – Natural Gas for Transportation	All Pages
Appendix J – Draft Order	All Pages

For ease of identification of the revisions made, FEI has provided all revised pages from Volume 1 (Application) and Appendix J blacklined for ease of reference. Updated financial schedules provided in Section E, Appendix G1 and Appendix G2 as well as revised version of Appendix H are also provided.

The pages have been printed single-sided to facilitate insertion into the binder volumes, and can be inserted sequentially, keeping the current page in place and marking it with a stroke through to indicate it has been replaced. The financial schedules in Section E and Appendices G1 and G2, and Appendices H and J can be replaced in their entirety in the binder volumes.

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

Yours very truly,

on behalf of FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Attachment 1

JANUARY 30, 2014 GGRR CLARIFICATION LETTER

Diane Roy
Director, Regulatory Affairs

FortisBC Energy
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

January 30, 2014

Via Email
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI or the Company)

British Columbia Utilities Commission Order G-56-13 and Letter L-40-13 in the matter of an Application by FEI for Approval of Rate Treatment of Expenditures under the Greenhouse Gas Reductions (Clean Energy) Regulation; and

Orders C-6-12 and G-150-12 in the matter of an Application by FEI for a Certificate of Public Convenience and Necessity for Constructing and Operating a Compressed Natural Gas Refueling Station at BFI Canada Inc. (BFI)

Request for Clarification and For Transfer to the Natural Gas Class of Service

---

INTRODUCTION

In November 2013, two pieces of provincial legislation came into effect: (1) BC Regulation 235/2013, amending the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR) (the Amended GGRR); and (2) BC Regulation 245/2013, Special Direction No. 5 to the British Columbia Utilities Commission (Commission) regarding FEI's (and other FortisBC Energy Utilities'[1]) Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) services (Direction No. 5) (collectively the New Regulations). These New Regulations mandate changes to the way in which the Commission currently regulates FEI's CNG and LNG fueling station services as reflected in existing orders, such as Order G-56-13 and Letter L-40-13. Both New Regulations are attached as Appendix A and B for reference.

1 Consisting of FEI, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

FEI is seeking the following from the Commission to conform to these New Regulations:

1) Clarification that any revenue shortfalls from non-guaranteed volumes and un-recovered capital costs for CNG/LNG fueling stations undertaken under the GGRR remain in FEI's natural gas rate base and are fully recoverable in the rates of FEI's customers that are not under a fixed rate[2];

2) An order transferring the CNG fueling station services provided to BFI from the CNG class of service to the natural gas class of service;[3] and,

3) An order transferring the existing CNG and LNG fueling stations undertaken under the GGRR from the separate classes of service for such CNG and LNG fueling stations to the natural gas class of service.

Each request will be further explained below.

REQUEST FOR CLARIFICATION FOR RECOVERY ENDING PERIOD

The original GGRR came into effect on May 15, 2012 and, by its terms, was to be repealed on April 1, 2017. It established three types of Prescribed Undertakings that can be undertaken by a public utility; broadly these are incentives for eligible vehicles, CNG fueling station services and LNG fueling station services. It further set out a number of requirements, including spending categories and limits, for each of the Prescribed Undertakings. The original GGRR also set forth the minimum 80 percent take-or-pay requirement and the requirement for the minimum contract term of five years. The original GGRR did not, however, provide a definition of "expenditures."

On November 28, 2013, the GGRR was amended by BC Reg. 235/2013. In addition to increasing a public utility's spending limits for the average CNG/LNG fueling station capital cost (without increasing the aggregate CNG/LNG station spending limits), the Amended GGRR also includes the following amendments:

- Clarification that construction or purchase of a CNG or LNG fueling station qualifies as a Prescribed Undertaking if the public utility enters into a binding commitment before April 1, 2017;

- Addition of a definition of "expenditure" to clarify that "expenditures" include binding commitments to incur expenditures in the future; and

- Removal of the provision that repeals the GGRR on April 1, 2017.

[2] Fixed rate is used as defined in Special Direction No. 5, where it means a charge for natural gas service not subject to adjustment based on changes to the revenue requirements of a utility.

[3] FEI notes that the fueling station services provided to Waste Management Canada Corporation and to Vedder Transport Ltd. were approved within the existing traditional natural gas for distribution class of service.

The Amended GGRR made no change to the minimum 80 percent take-or-pay requirement or to the requirement for the minimum contract term.

By the above listed amendments, the Amended GGRR clarifies what is intended to be covered as Prescribed Undertakings under the GGRR:

- Expenditures under the GGRR include binding commitments to incur expenditures in the future;
- For CNG/LNG fueling station services, the binding commitments are qualified as Prescribed Undertakings if the commitments are made before April 1, 2017; and,
- Actual costs pursuant to the binding commitments can still be eligible to be treated as Prescribed Undertakings even if they are incurred after April 1, 2017. This is made clear by removing the original GGRR expiry date of April 1, 2017. That is, the April 1, 2017 date is not intended as the end of the expenditure period or as a temporal limit on recovery of costs to those incurred before April 1, 2017.

As mentioned above, the Amended GGRR did not alter the take-or-pay requirement or the requirement for minimum contract term. Thus, the Amended GGRR continues to recognize that there may be a revenue shortage from volumes not subject to customer agreements (up to 20 percent) and unrecovered fueling station capital costs from the CNG/LNG station customers due to the contracted volume differences after the end of the initial term of a contract and until the useful life of the asset is reached. As clarified by the Amended GGRR and consistent with established accounting and rate treatment, the unrecovered station capital costs and revenue shortfalls should continue to be recovered in rates of natural gas customers beyond March 31, 2017 and until fully recovered.

The previous Commission determinations with respect to expenditures under the original GGRR, such as the one made in Order G-56-13 and clarified in L-40-13 that "all expenditures must be made by the end of the expenditure period" and "revenue shortfall treatment ends at the later of March 31, 2017," are no longer consistent with the Amended GGRR. FEI does not believe that a formal variance is required because the GGRR trumps decisions and statements of the Commission. However, as long as those orders/letters remain outstanding they can give rise to uncertainty. Certainty is important for the successful implementation of the program as recognized by the Commission in Order G-56-13. Hence, FEI respectfully submits that the Commission should further clarify that its Letter L-40-13 is no longer effective given the amendments to the GGRR.

REQUEST TO TRANSFER SERVICE TO BFI AND SMITHRITE TO NATURAL GAS CLASS OF SERVICE

Pursuant to Commission Order C-6-12, as varied by Order G-150-12 (collectively the BFI Decision), FEI established a new class of service for CNG services on an interim basis pending the outcome of the Commission's Inquiry Into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiative (AES Inquiry). On December 27, 2012, the Commission issued the AES Inquiry Report (the Report). In the Report, the

FORTIS BC™

Commission directed that CNG and LNG fueling stations undertaken as Prescribed Undertakings are to be accounted for in respective separate classes of service. Further, the Commission acknowledged that the BFI CNG station was ordered to be in a separate class of service, and did not direct any change to the BFI Decision. As a result, FEI reclassified its existing CNG and LNG stations into four classes of service. The four classes of service include:

1. Non-GGRR CNG Stations
2. Non-GGRR LNG Stations
3. GGRR CNG Stations
4. GGRR LNG Stations

Currently, the fueling station service provided to BFI is the only service in the Non-GGRR CNG Stations class of service, and the fueling station service to Smithrite Disposal Ltd. (Smithrite), rate approved (with required modifications) by Order G-113-13, is the only service in the GGRR CNG Stations class of service.[4]

On November 28, 2013, the Province of British Columbia, under the authority of the *Utilities Commission Act* (the Act) issued Direction No. 5 to the Commission relating to FEI's LNG and CNG services. Specifically, Direction No. 5 states:

> 3 In setting rates under the Act for a utility, the commission must do all of the following:
>
> (a) treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service;
>
> (b) allocate all costs and revenues related to CNG service and LNG service to all applicable customers;
>
> (c) allow recovery of costs of purchasing LNG under the agreement referred to in section 5 (1) (b) of this direction.

Direction No. 5 defines CNG and LNG services in a manner that includes all CNG and LNG fueling station services, irrespective of whether they have been undertaken as a Prescribed Undertaking under the GGRR or pursued outside the GGRR. That is, all CNG and LNG fueling station services are to be included in the traditional natural gas class of service with cost recovery from natural gas customers other than fixed rate customers.

To align the way in which BFI and Smithrite are regulated with Direction No. 5 in future years, FEI requires the following:

1) Transferring the fueling station service to BFI from the Non-GGRR CNG Stations class of service to the natural gas class of service; and,

---

4 FEI has a pending application before the Commission, seeking rate approval for the LNG fueling station service to Denwill Enterprises Inc.

2) Transferring the fueling station service to Smithrite from the GGRR CNG Stations class of service to the natural gas class of service.

CONCLUSION

The Amended GGRR and Direction No. 5 to the Commission relating to treatment of FEI's LNG and CNG services provide directions as to how to operate and treat NGT-related business and expenditures. To ensure that the initiatives are regulated according to the New Regulations on a prospective basis, FEI respectfully requests that the Commission:

1) confirm that, despite Letter L-40-13, FEI can recover GGRR CNG/LNG fueling station revenue shortfalls from CNG/LNG volumes not subject to the customer agreements and unrecovered GGRR CNG/LNG fueling station capital costs that cannot be recovered from the respective CNG/LNG station customers from all natural gas ratepayers who are not under a fixed rate until the GGRR fueling stations capital costs are fully recovered;

2) approve the transfer of the service provided to BFI from the Non-GGRR CNG Stations class of service to the natural gas class of service; and

3) approve the transfer of the service provided to Smithrite from the GGRR CNG Stations class of service to the natural gas class of service.

Going forward, and consistent with Direction No. 5, the Company will record all costs and revenues related to the CNG and LNG services in FEI's natural gas class of service and, with Commission approval, will recover the net costs and revenues from FEI's customers who are not under a fixed rate.

If you require further information or have any questions regarding this submission, please contact Shawn Hill at (604) 592-7840.

Sincerely,

FORTISBC ENERGY INC.

Original signed by: Shawn Hill

For: Diane Roy

cc (email only): Registered Parties to the following proceedings:

- FEI CNG-LNG Service Application
- FEU 2012-2013 RRA
- FEI EEC NGV Incentive Review
- AES Inquiry

Appendix A

BC REGULATION 235/2013 AMENDED GGRR

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

Order in Council No. 556 , *Approved and Ordered* November 27, 2013

Lieutenant Governor

Executive Council Chambers, Victoria

On the recommendation of the undersigned, the Lieutenant Governor, by and with the advice and consent of the Executive Council, orders that the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, is amended as set out in the attached Schedule.

DEPOSITED

November 28, 2013

B.C. REG. 235/2013

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

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

Authority under which Order is made:

Act and section: *Clean Energy Act*, S.B.C. 2010, c. 22, s. 35

Other: OIC 295/2012

October 31, 2013 R/541/2013/27

SCHEDULE

1 *Section 1 of the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012, is amended in the definition of* "eligible vehicle" *by striking out* "and" *at the end of paragraph (a), by adding* "," *at the end of paragraph (b), and by adding the following paragraphs:*

(c) a mine haul truck, and

(d) a locomotive.

2 *Section 2 is amended*

(a) in subsection (1) (b) by adding "an expenditure on" *before* "a grant or zero-interest loan",

(b) in subsection ((1) (c) (ii) (B) by striking out "$4 million" *and substituting* "$6 million",

(c) by adding the following subsection:

(1.1) Despite the reference in subsection (1) (a) to an open and competitive application process, a public utility may, in carrying out the undertaking described in subsection (1), give priority to a person in British Columbia who fuels an eligible vehicle using natural gas delivered through the public utility's pipeline system.,

(d) by repealing subsection (2) (a) and substituting the following:

(a) the public utility, before April 1, 2017, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

one or more compressed natural gas fuelling stations, including storage, compression and dispensing equipment and facilities, within the service territory of the public utility for the purposes of providing compressed natural gas fuel and fuelling services to owners of vehicles that operate on compressed natural gas;,

(e) in subsection (2) (b) (i) by striking out "$1.1 million" *and substituting* "$2 million",

(f) in subsection (2) (c) by striking out "during the undertaking period",

(g) by repealing subsection (3) (a) and substituting the following:

(a) the public utility, before April 1, 2017, enters into a binding commitment to

(i) construct and operate, or

(ii) purchase and operate

one or more tanker truck load-outs, liquefied natural gas tank trailers or liquefied natural gas fuelling stations for the purposes of providing within British Columbia liquefied natural gas fuel and fuelling services to owners of vehicles that operate on liquefied natural gas;, *(h) in subsection (3) (b) (ii) by striking out* "$4 million" *and substituting* "$5.5 million",

(i) in subsection (3) (c) by striking out "during the undertaking period", *and*

(j) by adding the following subsection:

(4) In subsections (1) to (3), **"expenditures"** includes, except with respect to expenditures on administration and marketing, binding commitments to incur expenditures in the future.

3 *Section 3 is repealed.*

Appendix B

SPECIAL DIRECTION NO. 5 - CNG/LNG SERVICES

PROVINCE OF BRITISH COLUMBIA

ORDER OF THE LIEUTENANT GOVERNOR IN COUNCIL

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

Lieutenant Governor

Executive Council Chambers, Victoria

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

DEPOSITED
November 28, 2013
B.C. REG. 245/2013

Minister of Energy and Mines and Minister Responsible for Core Review

Presiding Member of the Executive Council

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

Authority under which Order is made:

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

Other:

November 4, 2013 R/589/2013/27

SCHEDULE

DIRECTION NO. 5 TO THE BRITISH COLUMBIA UTILITIES COMMISSION

Contents

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

APPENDIX 1

APPENDIX 2

Definitions

1 In this direction:

"Act" means the *Utilities Commission Act*;

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

(a) under a fixed rate, or

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

"CNG" means compressed natural gas;

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

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

(b) transporting CNG using specialized trailers or equipment;

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

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

"LNG" means liquefied natural gas;

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

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

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

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

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

(b) procurement of LNG;

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

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

(e) storage of LNG;

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

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

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

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

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

"utility" means

(a) FortisBC Energy Inc.

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

(c) FortisBC Energy (Whistler) Inc.,

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

Application

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

CNG services and LNG services

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

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

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

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

Expansion facilities

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

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

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

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

(ii) $400 million;

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

LNG rate schedule and LNG purchase agreement

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

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

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

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

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

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

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

APPENDIX 1

FORTISBC ENERGY INC.

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

TABLE OF CONTENTS

Section		Page
1	DEFINITIONS	1
	1.1 Definitions	1
2	APPLICABILITY	4
	2.1 Applicability	4
	2.2 Amendment of Rate Schedule	4
3	CONDITIONS OF LNG SERVICE	4
	3.1 Availability of LNG Service	4
	3.2 Limitation on Short-Term LNG Service	4
	3.3 LNG Service Priority Where There Are Competing Requests for LNG Service	5
	3.4 Spot LNG Service Availability	5
	3.5 LNG Service Subject to Curtailment	5
4	PURCHASE OF LNG	5
	4.1 Determination of Contract Demand	5
	4.2 Allocation of Contract Demand	5
	4.3 Purchase of LNG	5
	4.4 Purchase Over Contract Demand	6
5	DISPENSING OF LNG	6
	5.1 Dispensing of LNG	6
	5.2 Curtailment of Dispensing Service	6
	5.3 Notice of Curtailment	6
	5.4 Title Transfer	7
6	TRANSPORTATION OF LNG	7
	6.1 Transportation of LNG	7
	6.2 Availability of LNG Transportation Service	7
	6.3 Charges for LNG Transportation Service	7
7	RIGHTS AND RESPONSIBILITIES	7
	7.1 Responsibility for Compliance	7
	7.2 Right to Refuse	8
	7.3 Responsibility for Emergency Response	8
	7.4 Customer's Responsibility	8
	7.5 Required Insurance	8
8	TERMS OF PAYMENT	8
	8.1 LNG Service Charges	8
	8.2 LNG Transportation Service Charges	10
	8.3 Currency	10

9 DAILY LOADING AND SCHEDULING 10

9.1 Requested Quantity and Loading Schedule 10
9.2 Adjustment of Loading Schedule 10

10 TERM OF LNG AGREEMENT 10

10.1 Renewal 10
10.2 Early Termination by FortisBC Energy 11
10.3 Survival of Covenants 11

11 STATEMENTS AND PAYMENTS 11

11.1 Statements to be Provided 11
11.2 Payment and Late Payment Charge 11
11.3 Examination of Records 11
11.4 Security 11

12 MEASUREMENT 12

12.1 Unit of Measurement 12
12.2 Determination of Quantity 12
12.3 Conversion to Energy Units 12

13 DEFAULT OR BANKRUPTCY 13

13.1 Default by the Customer 13
13.2 Bankruptcy or Insolvency of the Customer 13
13.3 Obligations of Customer upon Suspension or Termination 13

14 NOTICE 14

14.1 Notice 14
14.2 Specific Notices 14

15 INDEMNITY AND LIMITATION ON LIABILITY 15

15.1 Limitation on Liability 15
15.2 Customer Indemnity 15

16 FORCE MAJEURE 15

16.1 Force Majeure 15
16.2 Curtailment Notice 16
16.3 Exceptions 16
16.4 Notice to Resume 16
16.5 Settlement of Labour Disputes 16
16.6 No Exemption for Payments 16
16.7 Periodic Repair by FortisBC Energy 16

17 DISPUTES 17

17.1 Mediation 17
17.2 Arbitration 17

17.3 Award 17
17.4 Costs 17
17.5 Obligations Continue 17

18 INTERPRETATION 18

18.1 Interpretation 18

19 MISCELLANEOUS 18

19.1 Waiver 18
19.2 Enurement 18
19.3 Assignment 18
19.4 Law 19
19.5 Time is of Essence 19
19.6 Subject to Legislation 19
19.7 Further Assurances 19
19.8 Form of Payments 19

TABLE OF CHARGES FOR LNG TRANSPORTATION SERVICE 20

TABLE OF CHARGES FOR LNG SERVICE 21

LIQUEFIED NATURAL GAS SALES AND DISPENSING SERVICE AGREEMENT SA-46.1

LNG TRANSPORTATION SERVICE AGREEMENT TA-46.1

1 Definitions

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

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

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

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

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

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

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

(g) **Delivery Charge** – means the sum of:

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

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

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

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

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

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

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

(m) **LNG** – means liquefied natural gas.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2 Applicability

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

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

3 Conditions of LNG Service

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

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

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

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

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

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

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

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

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

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

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

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

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

4 Purchase of LNG

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

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

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

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

5 Dispensing of LNG

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

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

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

(a) Spot LNG Service will be curtailed first.

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

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

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

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

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

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

6 Transportation of LNG

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

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

(a) FortisBC Energy has Tankers;

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

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

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

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

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

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

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

7 Rights and Responsibilities

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

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

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

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

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

8 Terms of Payment

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

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

(A) A charge calculated as the greater of

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

or

ii. the Minimum Monthly Charge; plus

(B) A Commodity Charge calculated by multiplying

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

by

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

and by

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

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

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

by

ii. the selected percentage of Biomethane

and by

iii. the BERC.

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

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

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

by

ii. the LNG Spot Charge.

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

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

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

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

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

9 Daily Loading and Scheduling

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

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

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

(b) accommodate multiple Customers; or

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

10 Term of LNG Agreement

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

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

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

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

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

will survive such termination.

11 Statements and Payments

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

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

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

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

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

12 Measurement

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

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

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

Converting Weight of LNG to Gigajoules

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

13 Default or Bankruptcy

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

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

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

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

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

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

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

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

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

14 Notice

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

If to FortisBC Energy	FORTISBC ENERGY INC.
MAILING ADDRESS:	16705 Fraser Highway Surrey, B.C. V4N 0E8
BILLING AND PAYMENT:	Attention: Industrial Billing Telephone: 1-855-873-8773 Fax: 1-888-224-2720 Email industrial.billing@fortisbc.com
CUSTOMER RELATIONS:	Attention: Business Development Telephone : (778) 571-3296 (604) 592-7840 Email : LNG@fortisbc.com
LEGAL AND OTHER:	Attention: Director, Legal and Governance Services Telephone: (604) 443-6512 Fax: (604) 443-6540

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

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

15 Indemnity and Limitation on Liability

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

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

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

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

16 Force Majeure

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

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

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

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

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

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

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

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

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

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

17 Disputes

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

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

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

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

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

(c) specific performance; and

(d) permanent relief.

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

18 Interpretation

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

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

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

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

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

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

19 Miscellaneous

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

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

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

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

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

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

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

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

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

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

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

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

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

Table of Charges
for LNG Transportation Service

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

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

Table of Charges

for LNG Service

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

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

Notes:

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

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

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

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

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

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

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

LNG Facility Charge	$ 2.66/GJ
Electricity Surcharge	$ 0.87/GJ
LNG Spot Charge	$ 4.20/GJ

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

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

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

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

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

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

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

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

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

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

LIQUEFIED NATURAL GAS SALES AND DISPENSING SERVICE AGREEMENT

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

WHEREAS:

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

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

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

1. Specific Information

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

2. Incorporation of Rate Schedule

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

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

3 General

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

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

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

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

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

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

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

LNG TRANSPORTATION SERVICE AGREEMENT

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

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

1. Incorporation by Rate Schedule

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

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

2. Additional Definitions

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

3. Term

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

4. LNG Transportation Service

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

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

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

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

5. Request for LNG Transportation Service

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

6. Subcontracting

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

7. Ownership of the Tanker and Rental of Tanker

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

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

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

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

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

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

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

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

8. LNG Tanker and Tanker Hauling Charges

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

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

9. Access to the Customer Location

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

10. Permits and Approvals

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

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

11. Termination

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

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

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

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

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

12. Additional Insurance Requirements

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

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

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

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

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

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

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

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

13. Environmental Covenant

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

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

14. Limitation of Liability and Indemnity

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

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

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

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

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

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

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

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

15. Force Majeure

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

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

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

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

(c) disruption in third party hauling services.

16. Survival

16.1 Upon the termination of this Agreement:

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

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

will survive such termination.

17. General

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

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

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

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

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

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

FORTISBC ENERGY INC.
by its authorized signatory:

____

____

THE CUSTOMER: ________________
by its authorized signatory:

____

____

APPENDIX 2

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

Between

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

and

FORTISBC ENERGY INC.

GAS LIQUEFACTION, STORAGE AND DISPENSING SERVICE AGREEMENT

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

BETWEEN:

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

AND:

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

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

WHEREAS:

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

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

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

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

1. DEFINITIONS

In this Agreement:

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

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

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

"**FEVI System**" means the FEVI transmission system;

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

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

"**LNG**" means liquefied natural gas;

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

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

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

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

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

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

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

2. TERM

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

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

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

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

3. LNG SERVICE

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

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

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

4. **CONTRACT LEVELS**

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

5. **PERFORMANCE OBLIGATIONS**

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

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

6. **FORCE MAJEURE**

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

7. **SERVICE CHARGE**

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

8. BILLING

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

9. NOTICES

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

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

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

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

10. GOVERNING LAW

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

11. EFFECT OF WAIVER OR CONSENT

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

12. HEADINGS

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

13. SEVERABILITY

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

14. ASSIGNMENT

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

15. RESPONSIBILITY FOR DAMAGE

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

16. INDEMNITY

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

17. TERMINATION

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

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

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

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

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

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

18. WAIVER OF CERTAIN DAMAGES

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

19. DISPUTE RESOLUTION

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

20. ENTIRE AGREEMENT

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

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

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

BY:____________________________
(Signature)

____
(Name – Please Print)

____
(Title)

FORTISBC ENERGY INC.

BY:____________________________
(Signature)

____
(Name – Please Print)

____
(Title)

Attachment 2

REVISED RESPONSE TO BCUC IR 1.188.2

188.0 Reference: ACCOUNTING POLICIES FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS

Exhibit B-1, Application, Tab C, Section 3.1.2, p. 122; Exhibit B-1-1, Appendix F6; BCUC Uniform System of Accounts (USoA) Report, BCUC 1.1, 1.6

BCUC UNIFORM SYSTEM OF ACCOUNTS

188.1 Please provide an electronic copy of the latest FEI code of accounts.

Response:

Please refer to Attachment 188.1 for the latest FEI code of accounts.

In the response to BCUC 1.1 FEI states: "the publication of notices for regulatory applications and proceedings is not recorded as an O&M expense. These costs are instead recorded in the various deferral accounts relevant to the application(s) in question. However, FEU is able to report on how much is spent on these costs through separate tracking within the deferral accounts as requested." (USoA Report, BCUC 1.1)

188.2 For 2007-2013, please provide the annual costs for the cost elements listed below:

63303 Communications, Public Relations
63304 Communications Employees
63401 Advertising Media
63402 Advertising Printed Matter
63403 Miscellaneous Advertising

Response:

Below is a summary of annual costs for the above mentioned cost elements.

Annual Costs for Communications and Advertising ($ thousands)

Cost Element	Description	2007	2008	2009	2010	2011	2012	2013
63303	Communications, Public Relations	1,097	205	146	193	42	44	188
63304	Communications, Employees	7	26	53	68	19	1	2
63401	Advertising Media	3,800	3,605	1,273	2,261	2,361	4,324	3,829
63402	Advertising Printed Matter	1,472	536	381	491	549	856	759
63403	Miscellaneous Advertising	264	530	811	1,918	1,968	1,146	945
Total		6,640	4,902	2,665	4,931	4,939	6,372	5,724

Note: the annual costs are total costs incurred for each cost element including O&M, capital, deferral, and recoveries.

Please note that these costs may include O&M, capital, and deferral items. Since the FEU do not have individual settlement accounts at the lowest level, the O&M portion of the above items is not separately available. Please refer to the response to BCUC IR 1.1.8 that was provided in the review of the FEU's filing of the BCUC Uniform System of Accounts (USoA) Report where this is described further.

Increases to advertising costs for years 2010 to 2012 are mainly attributed to increased safety awareness spending and EEC market awareness.

In the 2010-2011 RRA, the FEU requested and received approval for $1 million in safety awareness spending, primarily to increase the public's awareness of how to identify and respond to a gas leak. Additional funding of $750 thousand in 2012 and $850 thousand in 2013 was approved in BCUC Order No. G-44-12 for the 2012-2013 RRA.

In the 2010-2011 RRA, the FEU also requested and received approval for the continuation of the residential and commercial EEC program and new funding for the interruptible industrial programs and innovative technologies.

188.2.1 Please provide the cost for "the publication of notices for regulatory applications and proceedings" for 2007-2013.

Response:

Provided below is a summary of costs for publication of notices for regulatory applications and proceedings from 2007-2013. The costs will vary for each year depending on the number of applications filed, the number of service territories involved, and the publications used as directed by the Commission. In all instances, FEI seeks to minimize the amount of costs while conforming with the Commission's directives.

Attachment 3

REVISED RESPONSE TO CEC IR 3.15.2

requirements and customer rates before January 1. Variances, in either direction, between actual and forecast inflationary assumptions are normal forecasting occurrences that are created by external economic factors beyond the Companies' control.

15.2 For each inflation factor estimation source FEI and FBC plan to use please provide a 10 year history of the source's forecasts and the subsequent actual results for the inflation indices they were forecasting, such that the forecasting record is evident. Please provide this in a tabular format in a working spreadsheet.

Response:

Table has been provided below, and Attachment 15.2 is the working Excel spreadsheet.

Note that FEI provided a forecasted 2003 BC CPI figure that was not explicitly linked to a publication source in its revenue requirement application. Additionally both FEI and FBC did not include forecasts of BC Average Weekly Earnings (BC AWE) explicitly in revenue requirements applications for the last ten years and therefore such forecasts have not been provided and designated as not available (NA).

Similarly, FBC provided a forecasted 2005 BC CPI figure that was not explicitly linked to a publication source in its revenue requirement application, and did not forecast CPI in its 2006 application.

	FortisBC Energy Inc.							
	BC Consumer Price Index (CPI)						BC Average Weekly Earnings (AWE)	
	Forecast					Actual	Forecast	Actual
	Conference Board Canada	BC Ministry of Finance	RBC	TD	**Average BC CPI**	**Stat Can BC CPI**	**Average BC AWE**	**Stat Can BC AWE**
2003	NA	NA	NA	NA	**1.90%**	**2.20%**	**NA**	**2.2%**
2004	1.70%	2.20%	1.50%	1.50%	**1.70%**	**2.00%**	**NA**	**1.7%**
2005	2.10%	1.90%	2.00%	2.00%	**2.00%**	**2.00%**	**NA**	**3.7%**
2006	2.00%	2.00%	2.90%	1.90%	**2.20%**	**1.70%**	**NA**	**2.9%**
2007	1.90%	2.10%	2.30%	1.80%	**2.00%**	**1.80%**	**NA**	**3.4%**
2008	1.90%	2.00%	2.30%	2.00%	**2.10%**	**2.10%**	**NA**	**2.6%**
2009	2.50%	2.00%	1.50%	1.70%	**1.90%**	**0.00%**	**NA**	**0.8%**
2010	2.27%	2.20%	1.50%	1.60%	**1.90%**	**1.30%**	**NA**	**3.0%**
2011	2.05%	2.10%	1.80%	2.00%	**2.00%**	**2.40%**	**NA**	**2.8%**
2012	2.16%	2.00%	1.80%	2.00%	**2.00%**	**1.10%**	**NA**	**2.9%**

	FortisBC Inc.							
	BC Consumer Price Index (CPI)						BC Average Weekly Earnings (AWE)	
	Forecast					Actual	Forecast	Actual
	Conference Board Canada	BC Ministry of Finance	RBC/BMO	TD	**Average BC CPI**	**Stat Can BC CPI**	**Average BC AWE**	**Stat Can BC AWE**
2003	NA	NA	NA	NA	**NA**	**2.20%**	**NA**	**2.2%**
2004	NA	NA	NA	NA	**NA**	**2.00%**	**NA**	**1.7%**
2005	NA	NA	NA	NA	**NA**	**2.00%**	**NA**	**3.7%**
2006	NA	NA	NA	NA	**NA**	**1.70%**	**NA**	**2.9%**
2007	1.90%	2.10%	2.30%	1.70%	**2.00%**	**1.80%**	**NA**	**3.4%**
2008	2.00%	2.00%	2.10%	2.00%	**2.00%**	**2.10%**	**NA**	**2.6%**
2009	2.50%	2.10%	1.50%	1.70%	**2.00%**	**0.00%**	**NA**	**0.8%**
2010	2.60%	2.10%	NA	1.50%	**2.10%**	**1.30%**	**NA**	**3.0%**
2011	2.80%	2.30%	2.00%	2.10%	**2.30%**	**2.40%**	**NA**	**2.8%**
2012	2.20%	2.10%	2.10%	1.70%	**2.00%**	**1.10%**	**NA**	**2.9%**

Attachment 4

APPLICATION AND APPENDICES UPDATES, FEBRUARY 21, 2014

2. APPROVALS SOUGHT

In this Application, FEI is seeking an Order of the Commission granting approvals required to implement a five-year PBR Plan. The approvals sought are described in terms of their main categories below.

PBR Plan

1. Approval pursuant to sections 59 to 61 of the Act of the PBR mechanisms set out in Section B of this Application for setting delivery rates for the years 2014-2018.

Delivery Rates

2. Approval pursuant to sections 59 to 61 of the Act of permanent delivery rates for all non-bypass customers effective January 1, 2014, resulting in an increase of 0.6 per cent compared to 2013 delivery rates, with the increase to be applied to the delivery charge, holding the basic charge at 2013 levels.

Deleted: 1.4

3. Approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23 effective January 1, 2014 of a credit amount of $0.120/GJ as set out in Section E Schedule 63 of the Application (Exhibit B-1).

Deferral Accounts

4. Approval pursuant to sections 59 to 61 of the Act of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, for FEI as set out in Section D4 and Appendices F4 and F5 of the Application and summarized in the following table.

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change - New or Modified	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014

Type Of Change	Account	Company	Reference
	Depreciation Variance	FEI	Section D4.4.1; 1 year amortization period, commencing January 1, 2014
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEI EEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	Generic Cost of Capital Application Costs	FEI	Section D4.2.8; amortization period of 2 years commencing January 1, 2014
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.9; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.10; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	Fuelling Stations Variance Account	FEI	Appendix H, 3 year amortization period commencing January 1, 2014 with discontinuance of this account effective January 1, 2017.
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuance of this account effective January 1, 2016

Deleted: CNG and LNG Recoveries

Deleted: FEI

Deleted: Section D4.4.4; discontinuation of this account effective January 1, 2015

Deleted: Section D4.4.4

Deleted: BFI Costs and Recoveries

Deleted: FEI

Deleted: Section D4.4.5; discontinuation of this account effective January 1, 2014

Type Of Change	Account	Company	Reference
	RS 16 Application Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2016
	RS 16 Costs and Recoveries	FEI	Section D4.4.8; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	NGV for Transportation Application	FEI	Section D4.4.9; discontinuation of this account effective January 1, 2016
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	IFRS Implementation Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2014

Accounting Policies

5. 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 effective January 1, 2014:

(a) Modification to the approved Lead Lag days with the removal of the HST lead days and the insertion of GST and PST lead days as set out in Section D3.2 of the Application.

(b) Inclusion of the retiree portion of pension and OPEB expenses in benefit loadings for O&M and capital as set in Section D3.1 of the Application.

(c) Capitalization of the annual software costs paid to vendors in support of upgrade capability as set out in Section D3.1 of the Application.

(d) Depreciation to commence January 1 of the year following when the asset is placed into service as set out in Section D3.3 of the Application.

(e) A depreciation rate of 12.5% for asset class 484 Vehicles as set out in Section D3.1 of the Application.

(f) Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application.

(g) Approval to allocate Executive costs between FEI and FBC effective January 1, 2014 by way of applying the Massachusetts Formula as described in Section D3.6.5 of the Application.

6. 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 2014-2018 PBR Period as set out in Section C2.3 of the Application.

7. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and FEI and for Shared Services as between FEI and FEVI, and between FEI and FEW, as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Section D3.6 of the Application.

Deleted: Approval of these cost allocations is subject to FEVI and FEW receiving regulatory approval for the same allocation in their next RRA filings.

Energy Efficiency and Conservation (EEC) As Set out in Appendix I of the Application

In this Application, the FEU are also seeking approvals to continue their EEC programs for the next five years. The approvals sought by the FEU together are as follows:

8. Acceptance pursuant to section 44.2(a) of the Act of the following EEC expenditure schedules for the FEU to be spent on the EEC program areas described in Appendix I of the Application: Up to $34.353 million for 2014 (inclusive of the $15 million accepted by Order G-230-13), $37.303 million for 2015, $37.358 million for 2016, $37.664 million for 2017, and $38.982 million for 2018.

9. Continuation of the EEC framework approved by the Commission, with the following changes:
    a. Approval of the administration by a neutral third party of EEC funds provided to projects with a third party thermal energy component.
    b. Approval of the incorporation of spillover effects and the attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, for the purpose of reporting on cost effectiveness in the EEC Annual Report pursuant to section 43 of the Act.
    c. Approval for the FEU to transfer funds within a program area to a new program without prior Commission approval, provided that the new program is in accordance with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

FEI's proposed regulatory process for this Application is set out in Section A7 below. FEI has provided a Table of Concordance with past directives in Appendix C1 and a Draft form of Order sought in Appendix J. In the following three sections, FEI discuss the productivity and customer focus as well as its organizational performance and monitoring.

B: MULTI-YEAR PERFORMANCE-BASED RATE-MAKING MECHANISM

1. INTRODUCTION

This section of the Application sets out FEI's proposal for a Performance-Based Ratemaking plan for a five-year period commencing in 2014 (the PBR Plan or the 2014 Plan), and provides other background information with respect to PBR. The material in this section, along with information contained in Appendices D1 through D9, provides FEI's response to the Commission letter dated April 18, 2013, which requested that the FortisBC Energy Utilities and FortisBC Inc. include a PBR proposal with their next revenue requirements application and provide a review and comparison of PBR regimes in effect in other jurisdictions with the proposed PBR plan.

FEI has had two successful PBR plans in the past (1998-2001 and 2004-2009) that further aligned the interests of customers and the Company. In FEI's 2012-2013 RRA the Commission examined the results of FEI's 2004-2009 PBR plan (the 2004 PBR Plan) and concluded that significant benefits were achieved for both ratepayers and shareholders:

> *"In British Columbia, PBR, combined with the Negotiated Settlement Process has played a role within the rate setting process of FEI. Starting in 2004 and lasting through 2009 FEI operated in a PBR environment. During this period FEI was very successful as targets were met and the Companies note that shared earnings benefits flowing to customers and shareholders totalled $67.5 million each over the six years.*
>
> *The Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements."*[5]
>
> *"As noted in section 4.2, the Commission recognizes that during the PBR period FEI was able to find significant cost savings to the benefit of customers and the shareholder. During this six-year period $67.5 million in benefits flowed to customers, while an equal amount flowed to the shareholder."*[6]

The proposed 2014–2018 PBR Plan builds on FEI's successful 2004–2009 PBR Plan. The new PBR Plan focuses the performance incentives on the main areas of controllable costs, operating and maintenance (O&M) expenses and capital expenditures, consistent with the 2004 PBR Plan. The formulas to be applied to O&M and capital expenditures over the PBR term have the

[5] Commission Order G-44-12, Reasons for Decision, page 22
[6] Commission Order G-44-12, Reasons for Decision, page 34

same structure as in the 2004 PBR Plan, and employ the same or similar cost drivers, an inflation factor and a productivity improvement factor; however, some refinements to the formula parameters are proposed.

The success of FEI's 2004 PBR Plan provides a strong basis for going forward with a similar model for the proposed PBR. The model approved for use by FEI between 2004 and 2009 provided a flexible framework of incentives that allowed FEI to capture efficiencies for the long-term benefit of customers. Although the opportunities and potential results may be different in 2014 to 2018 than they were in 2004 to 2009, the Commission should have confidence that the incentive framework in the proposed PBR Plan will lead to a similar response from FEI this time.

FEI's PBR experts, B&V, have studied the available PBR methodologies and provided their recommendations on FEI's proposed PBR Plan model in Appendix D1 Comparison of Recent Performance Based Regulation for Distribution Utilities in Canada (the PBR Report). They conclude that there is no one "right" PBR model, and that the framework adopted for FEI should be in keeping with FEI's specific circumstances. B&V also identified some theoretical and practical issues with aspects of the plans developed in other jurisdictions that do not exist with the model being proposed by FEI. FEI's proposed PBR incorporates a more aggressive "stretch" productivity factor than is suggested by B&V's research of other North American utilities. (B&V Total Factor Productivity (TFP) for Gas Utilities Report – referred to as "TFP Report" or TFP Study", Appendix D2) FEI's model produces lower rate increases over the five year period than either cost of service regulation or a revenue cap model of the type approved by the Alberta Utilities Commission.

Overall, FEI believes that the proposed PBR Plan is an appropriate model that will encourage FEI to seek efficiencies in its operations over the term of the PBR for the benefit of both customers and the Company, while maintaining safe, reliable and customer-oriented utility service. B&V, who have provided input in the preparation of both the PBR Plan and this chapter of the Application,[7] endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate productivity factor as being approximately zero, based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package.

The section is organized as follows:

- Section B2 – PBR Overview – discusses the effectiveness of PBR, its benefits and challenges;

[7] B&V has provided input in the preparation of this chapter of the Application, and has also contributed sections providing their commentary on certain elements of the proposed PBR Plan. FEI has endeavoured to expressly attribute the portions that reflect B&V's commentary.

- Section B3 – PBR Variations – discussion of price cap and revenue cap variations on the PBR model;
- Section B4 – FEI Experience with PBR - a historical review of FEI's prior PBR plans;
- Section B5 – Jurisdictional Comparison – a review of the most recent PBR plans employed in Canada;
- Section B6 – FEI 2014 Proposed PBR - a full description of the proposed PBR for 2014-2018;
- Section B7 – Delivery Revenue Forecasts Under PBR - a comparison of customer delivery rates under the proposed PBR with rates under a cost of service regulatory approach and under a revenue cap model; and
- Section B8 – Conclusion.

2. PBR OVERVIEW

This section, which was prepared with input from B&V, addresses the benefits and challenges of PBR. PBR can provide additional incentives to the utility beyond those incentives inherent in cost of service regulation to undertake additional steps to reduce costs. The mechanism thus further aligns the interests of both customers and the utility shareholder. The concerns typically cited regarding PBR are, in some cases, overstated. In other cases, the concerns can be addressed by appropriate PBR design.

2.1 *PBR BENEFITS*

The two most commonly cited benefits of a PBR plan are its effectiveness in incenting the utility to capture efficiencies, and regulatory efficiency.

A PBR plan (also known as incentive regulation) uses a formula-based approach to adjust the prices or rates during the PBR term and decouples the utility's revenues and earnings from its costs. This approach encourages the regulated utility to adopt proactive efficiency plans that reduce costs. Customers also benefit from these efficiency plans, as an indexing formula ensures that the anticipated productivity gains, such as those expected on an industry wide basis, are provided to customers through lower rates. In other words, pure PBR regulation operates more like a fixed price contract in the sense that for a pre-specified period, the utility cannot pass on its additional controllable costs[8] to customers and takes on most of the risk for these costs. PBR can also improve the dynamic efficiency of the utility if the PBR term is long enough to encourage the cost-reducing innovations and investments that bring long-term efficiency gains.

PBR provides a longer term framework in which the utility can operate without frequent, costly and time consuming revenue requirement applications. Hence, a PBR mechanism can decrease the amount of regulatory process required for rate setting, particularly for utilities with regular cost of service rate cases, such as FEI's RRAs in 2010-2011 and 2012-2013. However, the extent of regulatory efficiencies achieved depends, for instance, on the frequency and scope of the review process adopted as a component of the PBR plan. As discussed later, FEI's proposed PBR Plan seeks to balance the anticipated desire on the part of some stakeholders for periodic review with the objective of capturing regulatory efficiency.

2.2 *POTENTIAL PBR CHALLENGES*

The arguments typically raised in opposition to PBR relate to the potential for "windfall" profits or losses for the regulated utility or customers, service issues, and challenges relating to the timing of capital expenditures. These challenges are discussed below. B&V concurs that the

[8] The utility can only pass on the costs implicit in the PBR formulas that determine the rate adjustments. If the PBR includes an earnings sharing mechanism some additional costs or cost savings may be passed on indirectly.

challenges can be managed through the design of a PBR Plan, and that there are provisions in FEI's proposed PBR Plan that appropriately address these challenges.

B&V observe that the potential for the utility to achieve higher earnings is inherent in a PBR and is one of the key reasons why it works. The issue is typically one of degree, with the potential for very significant losses or gains to be perceived by some stakeholders as being contrary to the "just and reasonable" rate principle. B&V also addresses this issue, for instance, in its TFP Report (refer to Appendix D2, page 7), stating:

> *"The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level. Customers actually benefit even in the absence of an earnings sharing mechanism by a reset of the cost basis of rates at the start of a new regulatory control period as the efficiency gains become entrenched in the utility's revenue requirements on a going forward basis."*

Earnings sharing mechanisms and mechanisms that allow the utility or customer to re-open the PBR (sometimes referred to as "re-opener" provisions) can be incorporated into the design of an overall PBR plan to temper the potential for profits or losses for the regulated utility.

A concern under PBR is that efficiencies not be achieved at the expense of service quality. B&V observe that, for this reason, PBR plans typically include provisions relating to service quality. FEI's 2004 PBR Plan, for instance, included a variety of Service Quality Indicators that FEI was required to report on in the Annual Reviews. Service Quality Indicators (SQIs) are proposed in the current FEI proposal as well.

B&V identify capital investment lumpiness in the utility industry as being another industry-specific problem for pure formula-based PBR plans. The formula's cost drivers used to forecast the capital investments may not be able to capture all of the significant, inconsistent and unusual investments that are common in the utility industry. The current recognition across many jurisdictions that much of the existing utility infrastructure is ageing and in need of replacement or major refurbishment is an example of a capital investment issue that formula-based PBR models may not adequately capture. B&V observe that it is particularly important to recognize that infrastructure replacement programs have significant and negative impacts on productivity and thus change the dynamics of the price or revenue cap requirements (this impact of infrastructure replacement on productivity is the subject of considerable discussion in B&V's TFP Report). This legitimate concern is ordinarily dealt with through the use of special cost recovery mechanisms that fund certain capital expenditures outside the PBR formula and within separate regulatory proceedings[9]. These are sometimes referred to as "capital trackers", a concept akin to excluding CPCN projects from the operation of the PBR formula.

Concerns are sometimes expressed that a utility under PBR may defer capital or O&M costs to outside the PBR term, or adopt other cost shifting strategies that do not produce true efficiency gains in order to obtain benefits under the PBR. These issues are not a function of PBR; rather, they relate to how the utility manages its costs within a defined rate setting period that could be either PBR or a forward test year under cost of service ratemaking. Nevertheless, FEI has addressed these concerns in Appendix D4, as some customer groups raised a concern that they perceived FEI had deferred expenditures to outside the 2004 PBR Plan period in a way that was detrimental to customer interests. In summary, FEI has shown in Appendix D4 that cost deferrals were very minor, and that deferrals of capital tend to produce a positive net present value in any event. Appendix D4 also explains how proposed changes in this PBR Plan should eliminate or minimize any further concern in this area.

In practice, the majority of PBR models are of a hybrid form, reflecting elements of both PBR and cost of service and regulators use various policy tools to overcome the above mentioned challenges.

9 According to American Gas Association report (June 2012), 47 utilities in 22 states serving 24 million residential natural gas customers are using full or limited special rate mechanisms to recover their infrastructure investments.

3. PBR VARIATIONS

The most common PBR approaches use formulas that employ an inflator and a productivity offset factor (referred to as (I – X) mechanisms). These approaches fall into two broad categories: price caps and revenue caps. The technical discussion below was prepared in consultation with B&V.

Under a price cap formula, the current prices or rates are a function of the previous year's rates, inflation (the "I factor") and an efficiency factor (known as the "X-Factor") where current rates are determined by adjusting the previous year's rates based on the difference between the inflation and efficiency factors:

$$P_{t,m} = P_{t-1,m} * (1 + (I-X)) +/- Z$$

Where: $P_{t,m}$ = rates for customer class m in time t
I = inflation factor
X = efficiency factor
Z = adjustments for unforeseen events beyond management's control

Under a revenue cap approach, the company's authorized revenue is subject to a cap. The cap might fix the base-rate revenues or it might allow some adjustments for increases in direct proportion to a growth adjustment factor (usually the number of customers). A variant of this approach is a revenue per customer cap, where the growth adjustment factor includes average revenues per customer and annual change in number of customers.

The revenue cap formula is similar to price cap; however, instead of customer rates, it is the allowed revenue which is adjusted by the (I – X) formula and is presented as:

$$R_t = (R_{t-1} + RGAF) * (1 + (I-X)) +/- Z$$

Where: R_t = allowed revenues for in time t
$RGAF$ = revenue growth adjustment factor
I = inflation factor
X = efficiency factor
Z = adjustments for unforeseen events beyond management's control

Both cap approaches create incentives to reduce costs and increase efficiency. However, there is a significant difference between price cap and revenue cap models in terms of the way they treat energy demand and incremental sales volumes. In the price cap model, a utility bears the risk for demand variations and is encouraged to maximize sales volumes up to the point where marginal revenue is equal to marginal costs. This is beneficial to utilities with a stable and growing demand trend. Demand variations can be problematic and unfair under a price cap model for utilities where, due to exogenous factors, there is a continuing decline in sales per customer (such as the case with current and forecast trend in natural gas use rates in BC). On the other hand, similar to revenue-decoupling mechanisms used for demand-side management regulation, the revenue cap model decouples the allowed revenue from demand and protects the utility against possible demand variations.

PBR plans (both price cap and revenue cap) are typically further categorized into two subgroups based on their rate base assessment methodology and the role of (I–X) mechanism in forecasting their costs. These are termed the “building-block” approach and the “total expenditure” approach.

Under a building-block approach, the O&M expenditures (Opex) and capital expenditures (Capex) are assessed separately, and in some cases the Capex expenditures are treated outside the (I – X) mechanism and the efficiency factor is only applied to the Opex. Under the total expenditure approach (also known as Totex), Opex and Capex are summed up and regulated under one efficiency factor (ordinarily total factor productivity). Totex and the building-block approaches lead to equal results if the productivity improvement factor and the expenditures covered under the formula are the same, other things being equal. However, due to the lumpy nature of utilities’ forecast investments, the majority of PBR plans end up as hybrid systems where a part of the capital expenditures (such as significant sustainment capital) is treated outside the PBR formulas and the rest of capital expenditures and O&M expenditures are determined under the indexing formula and the productivity factor. By removing sustainment capital from the formula, the large negative impact on TFP from infrastructure replacement is reduced or even eliminated resulting in a TFP that would otherwise be negative moving closer to zero.

PBR design is an exercise in balancing utility flexibility to seek out efficiencies and the need for a regulatory review process that ensures just and reasonable rates and the safe and reliable provision of services to customers. B&V’s view is that there is no single “correct” type of PBR design, and pure revenue and price cap PBR designs are unlikely to be practical. FEI’s proposed PBR plan, discussed later in this chapter, is a building block model within the revenue cap category. It has been designed with reference to past experience and the particular context relevant to the utility. B&V endorses the proposed PBR Plan, with the caveat regarding the proposed productivity factor should be closer to zero rather than FEI’s more challenging and aggressive proposal of 0.5 percent.

4. FEI EXPERIENCE WITH PBR

The Commission letter dated April 18, 2013, titled “Productivity Improvements in a Performance Based Rate Setting Environment” requested that FEI’s examination of PBR methodologies include discussion of the most recent PBR plans employed by FEI. FEI has had two successful PBR plans in the past (1998-2001 and 2004-2009). FEI’s proposed PBR Plan builds on that success, incorporating a number of similar elements, with adjustments where appropriate. This section outlines FEI’s past PBR plans. Further discussion regarding FEI’s most recent PBR Plan is included in B&V’s PBR Report (Appendix D1).

4.1 *FEI PRE-2004 PBR EXPERIENCE*

A formula-based approach to setting O&M was first adopted in FEI’s 1994-1995 settlement and refined in the 1996-1997 settlement. The PBR plan originally approved for 1998-2000, subsequently extended to 2001, was a further step forward. In comparison to the alternative of annual revenue requirement filings, the longer term focus better enabled the Company to invest in efficiency initiatives with multi-year paybacks; there was time to realize incentive gains before the multi-year term ended. During the 1998-2001 PBR, the Company undertook restructuring, and the break-even point on this restructuring “investment” was achieved by the fourth year. In addition to a focus on pursuing operating and maintenance cost efficiencies, the 1998-2001 PBR plan included a limited capital incentive mechanism and a series of SQIs that were tracked to confirm that service quality was being maintained throughout the term.

4.2 *FEI 2004 PBR EXPERIENCE*

FEI’s next PBR plan, which is the subject of this section, commenced in 2004 pursuant to an approved Negotiated Settlement Agreement and remained in effect (after an approved two-year extension) until 2009. It was based on the previous PBR Plan in key aspects. For instance, base O&M expenses and capital expenditures were escalated by a formula that incorporated forecast inflation and productivity factors. It included a 50/50 earnings sharing mechanism between customers and shareholders, and retained most of the same deferral accounts and exogenous factors as the 1998 PBR. The 2004 PBR Plan did however incorporate some enhancements over the prior plan, including (i) a longer term, (ii) a stronger capital incentive, (iii) service quality indicators that were more results oriented, and (iv) a proposed Efficiency Carry-over Mechanism (ECM) designed to encourage the Company to continue to pursue efficiency gains throughout the PBR term. Approved components of the 2004 PBR Plan remain appropriate for the 2014 Plan, with some enhancements.

Term

FEI proposed a five year term for the 2004 PBR Plan, from 2004 to 2008. A four-year term from 2004 to 2007 was approved, and later extended for two years, ending in 2009.

O&M Expenses

The approved 2003 O&M was used as the base, and then escalated by inflation, a productivity factor and a customer growth factor. Customer growth was expressed as the change in the average number of customers from one year to the next. Although O&M was not rebased to actual spending levels during the PBR term, there was a provision to true-up the formula amounts going forward based on actual customer growth. Pension and insurance costs were forecast each year, with the variance deferred for flow-through amortization.

Capital Expenditures

Similar to O&M, the capital expenditures approved in the 2003 RRA were used as the base, and then escalated for inflation and a productivity factor. Each year, the capital expenditure forecasts were developed using the customer additions forecast for growth capital and the forecast average number of customers for all other base capital. The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth.

CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes.

Inflation Rate

An average annual forecast inflation rate was determined based on the following sources for BC Consumer Price Index (CPI):

- Conference Board of Canada
- BC Ministry of Finance
- RBC Financial Group
- Toronto-Dominion Bank

During the Annual Review, an updated inflation forecast for the upcoming year was provided.

Productivity Factor

The parties involved in the NSP agreed that linking the productivity factor to BC-CPI would be beneficial for both ratepayers and FEI since the productivity opportunities would increase as inflation increased, and conversely FEI would have more limited opportunities for productivity improvements if the rate of inflation decreased. The productivity factor agreed to was 50 percent of CPI for 2004 and 2005, and 66 percent of CPI from 2006 to 2009.

Customer Growth

Each year at the Annual Review, an update of the actual number of customers at the start of the year as well as a revised forecast for customer additions for the upcoming year was provided.

Earnings Sharing Mechanism

The variance between the allowed and actual return on equity was shared equally between customers and shareholders. Over the term of the PBR, customers and shareholders each received a benefit of $67.5 million, indicating that the PBR successfully reduced costs and resulted in material savings.

Service Quality Indicators

FEI established a number of SQIs to ensure that the Company continued to maintain a high level of service quality, and that cost reductions did not come at the expense of service and system standards. Each year, FEI's SQI results were compared to the established benchmarks and presented at the Annual Review. FEI consistently performed within the range for the SQIs.

Efficiency Carry-Over Mechanism (ECM)

FEI had proposed an ECM, referred to as the Full Term Efficiency Incentive. The proposed ECM was designed to provide incentives for the company to pursue efficiencies throughout the PBR term, even in the later years when the time remaining to generate benefits was limited. FEI's proposal incorporated a rolling five year period over which to recover the initial investment and generate further benefits.

The 2004 NSP resulted in a variation of the proposed ECM which was a phase-out of capital benefits only. It involved determining the difference between the formulaic and actual capital expenditures over the term of the PBR, and then, rather than full rebasing right away, the Company received 2/3 of its 50 percent share in the first year following the expiry of the plan, and 1/3 of its 50 percent share in the next year. The net benefit of the ECM in the 2004 PBR Plan was approximately $11 million, resulting in significant benefits for both customers and shareholders.

The rate base benefit factor was a factor to be applied to the capital expenditures savings to determine the amounts for the end-of-term phase-out. The agreed upon factor of 14 percent was representative of the average avoided revenue requirement (expressed as a percentage) related to capital expenditures being below the formula amounts.

Annual and Mid-Term Assessment Review

At its Annual Reviews, FEI presented its actual results from the previous year, projections for the current year and updated forecasts for the coming year. The Annual Reviews informed parties of past performance and also kept them apprised of any potential challenges facing the Company in the future.

The Mid-Term Assessment Review was held prior to the end of the third year of the 2004 PBR Plan, or 2006. The purpose of the review was to ensure that the PBR did not result in unintended outcomes, or lead to a deterioration in FEI's quality of service.

Results

As noted above, the Commission acknowledged that the 2004 PBR Plan was successful in achieving significant savings and benefits for both customers and the Company. These benefits were achieved in three ways – through the productivity improvement factor, through the O&M savings, and through the capital savings. Each of these is discussed below.

PRODUCTIVITY IMPROVEMENT FACTOR

In total the productivity improvement requirements over the six year period represented a 7.5 percent decrease in gross O&M or a cumulative benefit of approximately $45 million over the PBR term. This was a material benefit to customers even before any incremental earnings above the approved ROE could be achieved and shared. It was only with major restructuring that produced material sustainable savings that FEI was able to meet and exceed these targets. This was primarily the Utilities Strategy Project in 2003 and 2004 which brought FEI and FEVI under common management and produced lasting efficiencies for both utilities. The lasting benefit to customers from these efficiencies was that FEI had a lower O&M as the base level to move into the cost of service period, the 2010-2011 RRA that followed.

In addition, the efficiencies attained during the six year PBR period (both to meet and exceed the productivity improvement targets) were achieved without degradation in the quality of service provided to natural gas customers. FEI consistently performed within the range for the SQIs throughout the term. FEI also met other requirements in the PBR to be open and transparent in conducting its business. This included conducting Annual Reviews and Customer Advisory Council meetings as set out in the PBR, and responding to the issues and concerns raised by customers and Interveners in those settings.

O&M SAVINGS

During the PBR period, FEI found efficiencies to meet the productivity improvement requirements in the PBR formula and exceed the O&M targets by an aggregate amount of $87 million over the six years. Customers received 50 percent of this or $43.5 million back via the earnings sharing mechanism. O&M savings during the PBR Period benefit customers in two ways:

1. Through reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Through rebasing of the savings into opening O&M as the starting point for setting future rates after the PBR has ended.

CAPITAL SAVINGS

There were significant capital savings achieved over the term of the PBR period. Capital savings over the PBR period benefits customers in two ways:

1. Through reduced rates during the term of the PBR via the earnings sharing mechanism; and
2. Through rebasing of the savings in the opening rate base and future rates after the PBR has ended.

During the 2004 PBR, FEI's actual base capital expenditures for the six-year period were $490.2 million. This was $80.1 million, or about 14 percent on average, below the formula-allowed capital expenditures of $570.3 million for the period. The year-to-year amounts of the formula-based and actual capital expenditures are provided in Attachment 2 to Appendix D4 which is a copy of Exhibit B1-48 from the 2012 Generic Cost of Capital proceeding. FEI's actual capital spending was under the formula-based number in each year except 2009 where the actual spending was approximately $1 million above the formula-based amount.

The capital spending reductions relative to the formula-based spending allowances generated earnings benefits throughout the PBR term that were shared with customers through the earnings sharing mechanism. These earnings differences pertained to the differences in rate base return, depreciation expense and taxes between the formula-based plant balances and the plant balances from the actual expenditures. The earnings differences grew from year to year as FEI continued to contain its capital spending below formula allowed levels. The aggregate benefit over the six years that arose from these capital efficiencies was in the range of $50 million and customers received half of this back through the earnings sharing mechanism.

The second benefit to customers was that the opening rate base going into the next revenue requirement application was lower by approximately $80 million (less the corresponding accumulated depreciation on the $80 million during the PBR period). This rate base reduction produces sustained revenue requirement reductions in the order of $10 to $12 million per year.

A detailed description of PBR components for FEI's approved 2004 PBR Plan is included in the PBR Commission Decisions in Appendix D9. Continuing with that evolutionary approach, key elements of the 2004 PBR Plan are incorporated into the proposed Plan.

5. JURISDICTIONAL COMPARISON

The Commission letter dated April 18, 2013 requested that FEI's evaluation include the most recent PBR plans employed by FortisBC Inc. and PBR methodologies approved by other jurisdictions in Canada. B&V was retained to assist FEI in compiling and consolidating the information requested by the Commission and to provide its own expert assessment as to the merits of other PBR plans. In this section, FEI summarizes the elements of PBR plans employed in other Canadian jurisdictions. B&V's report, which is included in Appendix D1 to this section, contains further analysis. FEI's proposed PBR Plan shares many common features with other plans, with the overall package tailored to fit the circumstances of a BC utility with past experience in PBR.

In the last decade, various Canadian regulators (at provincial and federal levels) have employed PBR plans in the regulation of public utilities and pipeline companies within their jurisdiction. Currently, Alberta and Ontario are the only jurisdictions with PBR plans for major local distribution companies. Gaz Metro, a Quebec utility, recently emerged from PBR. FEI has provided information in this section about PBR plans from all three jurisdictions. B&V was asked to focus its analysis on the current plans (i.e. those in place in Ontario and Alberta), and the past plans from BC. In addition to being the most current, Alberta and Ontario are the largest jurisdictions in terms of the number of utilities and the background information required for B&V's assessment is readily available in English.

A summary of PBR plans applied to natural gas and electric utilities in these three jurisdictions is presented in the table below.

1 **Table B5-1: Jurisdictional Comparison**

	Alberta Electricity and Natural Gas	Union Gas (2008-2012)	Enbridge Gas (2008-2012)	OEB 4th Generation IR (Electricity)[10]	Gaz Metro (2007-2012)
Regulatory proceedings	Multi-utility oral hearing, AUC's initiative	Negotiated settlement	Negotiated Settlement	Multi utility hearing, OEB's initiative	Negotiated Settlement
Type	Revenue per customer (NG) and price cap (Power)	Hybrid Price cap (Cap adjusted based on Average Use)	Revenue per customer	Price cap	Hybrid (Cost of service, revenue cap and price cap)
Term	5 years				
Coverage	Includes both O&M expenditures and Capital expenditures				
Inflation	Composite (AWE,CPI)	GDP IPI FDD[11]	GDP IPI FDD	Composite index	Quebec CPI
X-factor methodology	TFP study	Negotiated. Not based on any specific report.	Different percentage of inflation	TFP Study	Negotiated. Reflective of the historical rate increases and inflation
Stretch-factor	0.2%	Implicit in the X-Factor	Implicit in the X-Factor	Three cohorts (0.2%, 0.4%, 0.6%)	Implicit in the X-Factor
Earnings sharing mechanism	No earnings sharing	If actual ROE is 300 bp above approved ROE; 90% of excess earnings is shared with customers	Weather normalized actual ROE is 100 bp above approved ROE; excess earnings is shared a 50/50 basis.	No earnings sharing	Yes, 100 percent after 375 bp. For less than 375 bp varied between 50% to 75% (for customers)
Off-ramps / re-openers	+/-300 bp weather normalized ROE for two consecutive years or +/- 500 bp in one year	No off-ramps (The initial settlement included an off-ramp).	+/- 300 bp normalized ROE for one year	+/- 300 bp weather normalized ROE for one year	3 consecutive years with no earned incentive return Cumulative excesses or shortfalls exceeding 1.5

[10] For the determined elements of the OEB's Fourth Generation Incentive Rate Setting (productivity factor, SQIs, and efficiency carry-over mechanism), the Third Generation Incentive Rate Making data is used.
[11] GDP IPI FDD is the Gross Domestic Product Implicit Price Index times Final Domestic Demand

	Alberta Electricity and Natural Gas	Union Gas (2008-2012)	Enbridge Gas (2008-2012)	OEB 4th Generation IR (Electricity)[10]	Gaz Metro (2007-2012)
					percent of rate base 2 consecutive years with inflation that is greater than 5%
Efficiency carry-over mechanism	Yes, ROE Bonus	None	None	None	Yes, It incorporates previous productivity gains based on a moving 5-year average
Rebasing	COS rebasing at the end of the PBR period (No annual re-calibrating or true-up)				Yes, it includes annual cost of service application
SQIs	Yes (No penalty/reward mechanism attached to SQIs in the PBR plan)				Yes, linked to financial incentives
K-factor	Capital trackers	None	None	Incremental capital module (ICM)	Not applicable
Y-factor	Included in all plans				
Z-Factor	Included in all plans				

1

The following high-level conclusions can be derived from the above table:

1. The appropriate choice for regulatory proceeding (negotiated settlement or litigation) is highly dependent on the number of utilities that are part of the proceeding. For major gas local distribution companies (LDCs) such as Gaz Metro, Union Gas and Enbridge Gas, separate proceedings were initiated and negotiated settlement was used to address the unique circumstances of each utility. The Alberta Utilities Commission (AUC) PBR initiative as well as the Ontario Energy Board (OEB) renewed regulatory framework for power distributors, which were applicable to a number of utilities, were resolved by hearing.
2. All the utilities have a 5 year price control period (i.e. PBR term) and all plans cover both O&M expenditures and capital expenditures.
3. The measure of the inflation factor is evolving and the use of a composite factor (labour and non-labour inflators) and industry specific indices are on the rise. Both the AUC's recent initiative and the OEB's 4th generation Incentive Regulation (IR) for power distributors adopt a composite inflator.
4. There is no single approach to estimating the X-Factor. The X-Factor in OEB's 3rd generation IR and AUC's PBR initiative are based on exact productivity percentages that were calculated from a specific TFP study. On the other hand, Union Gas' and Gaz Metro's final X-Factors were a product of a negotiated settlement rather than any specific TFP study (in the case of Union Gas, TFP studies were used as a guide but not as an ultimate number). The Enbridge Gas X-Factor estimation was also based on a negotiated settlement and, similar to FEI's 2004 final X-Factor settlement, based on various percentages of the inflation factor.
5. There is no particular pattern with regard to the use of earnings sharing mechanism, stretch factors, off ramps, re-openers and efficiency carry-over mechanism. The use and design of these regulatory tools are mainly based on the overall design of the PBR and/or negotiations between the Companies and interveners. In addition, the design of these items is inter-connected. For instance, the trigger point in an off-ramp provision may be higher for PBR plans without a sharing mechanism. Another example is the stretch factor. Stretch factors are ordinarily a substitute for an Earnings Sharing Mechanism (ESM) and the amount of stretch factor is mainly subjective.
6. Annual capital re-basing is deemed as inappropriate in both Alberta and Ontario jurisdictions and cost of service re-basing is limited to the end of the PBR term. The Gaz Metro hybrid incentive plan included annual cost of service applications, which reduced the strength of the incentive.
7. In Alberta and Ontario the SQIs are monitored during the PBR plan however there is no direct reward or penalty mechanism attached to SQIs. Gaz Metro is the only utility among those reviewed that has had SQIs with financial penalties or rewards.

6. FEI 2014 PROPOSED PBR

6.1 *PBR PRINCIPLES*

In developing the PBR Plan, FEI applied the principles and objectives articulated below. B&V's view is that these principles and objectives are appropriate. There are many ways to articulate principles and objectives, and B&V is aware that various jurisdictions do articulate them differently. However, there are common threads or themes in the principles articulated by most jurisdictions, and the principles and objectives articulated by FEI are consistent.

The guiding principles are, in no particular order:

> **Principle 1:** The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.
>
> **Principle 2:** The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.
>
> **Principle 4:** The PBR plan should maintain the utility's focus on maintaining, safe, reliable natural gas service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.
>
> **Principle 5:** The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

6.2 *PROPOSAL*

In this section, FEI outlines the key elements of the proposed PBR Plan. FEI's proposal builds on the 2004 PBR Plan, with some adjustments to enhance a customer focus and further promote FEI's productivity improvement culture. The proposed PBR shares common elements with plans in other jurisdictions, but FEI has preferred continuity with the past experience in circumstances where there are no obvious benefits, and possibly disadvantages, associated with adopting a new approach employed in the plans in other jurisdictions.

The material in this section should be read in conjunction with the reports prepared by B&V, included in Appendices D1 and D2, in which B&V provides its expert assessment of individual elements of FEI's past plan as well as PBR Plans in place elsewhere. As indicated previously, B&V endorses the overall proposed PBR Plan as being reasonable in the circumstances of FEI, with the exception that they regard the "stretch" productivity factor as being more aggressive than is warranted. B&V regard the appropriate X-Factor as being approximately zero based on the TFP study they conducted and the specific elements of the proposed PBR Plan. In other words, FEI's proposal is more favourable to customers than they would recommend. FEI is nonetheless comfortable with the proposal as part of an overall package.

Table B6-1 summarizes the items of FEI's proposed PBR Plan. Each item is discussed separately in the sections below.

Table B6-1: Summary of 2014 PBR Plan Proposal

Item	2014 PBR Application
Term	A five-year term from 2014-2018 is proposed.
Inflation Factor (I-Factor)	A weighted average of BC Average Weekly Earnings (AWE) for labour costs and BC-CPI for other O&M costs will be used to determine the I-factor, which will be reforecast annually.
Productivity Improvement Factor (X-Factor)	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M is proposed. 2013 approved O&M expenditures (with adjustments) are adopted as the base O&M The O&M formula will adjust the prior year's formula O&M by forecast customer growth and (I-X). O&M will not be rebased during the PBR term but will be subject to true-up for actual customer growth.
Controllable Expenses - Capital	A formula based approach for Capital is proposed using 2013 approved capital expenditures (with adjustments) as the base. Two formulas will be applied. Growth Capital is tied to forecast service line additions and other regular capital is tied to forecast growth in average customers. The (I-X) escalation factor is also applied to both formulas. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%. Formula amounts will be subject to true-up for actual cost driver results (i.e. service line additions or average customers).
Flow Through Expenses and Revenues	Revenues and non-controllable costs are forecast each year and flowed through in rates each year in the Annual Review Process.
Exogenous Factors	Cost increases or decreases for items such as legislative changes, catastrophic events, accounting changes and Commission decisions will be flowed through in rates.
Earnings Sharing Mechanism	The PBR includes a 50/50 earnings sharing mechanism for returns above or below the approved return on equity
Efficiency Carry-Over Mechanism	An expanded Efficiency Carry-over Mechanism is proposed based on a rolling 5-year benefit calculation derived from O&M and capital efficiencies achieved each year.
Service Quality Indicators	10 SQIs (7 SQIs with a target benchmark and 3 informational measures) are proposed that deal with emergency response, customer service (telephone service, billing), employee safety and meter exchanges.
Mid-Term Review and Off Ramps	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	Annual reviews are also proposed for this PBR.

6.2.1 Term

FEI proposes a five-year term for the PBR, effective 2014 to 2018. Five years is a commonly adopted PBR term in North America, and similar in term to previous plans in BC. The proposed term is one year less than FEI's 2004 PBR Plan, which became six years in duration after an approved two-year extension was added to the initial four-year term. There are two key advantages to the proposed term, relative to a shorter term.

First, the five-year term addresses a key objective regarding regulatory efficiency as the term minimizes the frequency of comprehensive revenue requirement applications.

Second, this five year period provides an adequate amount of time for FEI to attain cost savings from capital investments and other efficiency initiatives. These types of investments generally require a few years for the benefits to be realized. An example of this can be seen in FEI's experience (noted above) in the 1998-2001 PBR where break-even on the efficiency investment did not occur until the fourth and last year of the plan. In addition, the proposed Efficiency Carry-over Mechanism (discussed below) will provide incentive for FEI to continue pursuing efficiency gains throughout the PBR term for the long term benefit of customers.

The perceived challenges associated with a longer PBR term relate to risk to customers and the utility, as well as regulatory transparency. The potential risks of a longer term PBR for either the utility or its customers are typically mitigated through other plan provisions such as exogenous factors, re-openers or off-ramps. There are checks and balances implicit in the proposed PBR Plan, discussed below, which mitigate risk to either customers or the Company in the context of a five-year term. Moreover, FEI proposes an annual review (and mid-term review) of Company performance as a means of maintaining transparency. The achieved efficiencies, service quality measure results, earnings sharing results, and the off-ramp mechanism (if necessary) will be reviewed in that context and will provide regular opportunities during the term to assess the success of the PBR Plan.

B&V has commented on the considerations that go into the selection of a PBR term in its PBR Report (Appendix D1), where it discusses the five-year terms adopted by the AUC and the OEB. B&V highlights that the determination of the length of term should only be made in conjunction with other elements of a PBR plan. It states, for instance at p.36:

> *"While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans*

have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable."

B&V's view is that 5 years is a reasonable plan term for FEI's PBR Plan, having regard to the other elements of FEI's proposal.

6.2.2 PBR Inflation and Productivity Factors

6.2.2.1 Inflation Factor (I – Factor) Proposal

The use of an inflation or I-factor in a PBR plan is to provide recognition that utility costs are subject to the general inflationary pressures occurring in the economy, although the specific pressures or weightings of the various inflationary influences may be different than for the economy in general. This is one area where FEI is proposing a change from the 2004 PBR Plan. FEI's previous PBRs calculated an average inflation rate for British Columbia using a combination of sources for CPI forecasts. These forecasts were collectively referred to as the BC-CPI. FEI proposes to use instead a weighted composite I-Factor, consisting of the following inflation indexes: labour indexed to BC All Weekly Earnings (BC-AWE) and non-labour indexed to BC-CPI. FEI believes it is more appropriate to use a composite labour and non-labour inflation index in determining the I-Factor since this is more reflective of Company costs, which consist of both labour and non-labour components, than an economy-wide inflation measure such as CPI.

Two recent PBR initiatives (the AUC's generic PBR initiative and the OEB's 4th Generation PBR for Electricity Distributors) have adopted a weighted composite I-factor. This change away from the prior approach of using BC-CPI alone is endorsed by B&V. B&V discusses the precedent and rationale for the use of the weighted composite I-factor in Appendix D1 PBR Report at pages 35 and 46. B&V states at p.46, for instance: *"It is instructive to note that the evolution of PBR Plans for FEI includes a newly proposed change to a composite measure of inflation more reflective of the cost drivers for FEI. Since FEI is proposing both a general measure of inflation and a labor measure, this is a better reflection of price changes*."

In selecting the appropriate inflation indices, FEI considered whether or not the indexes were:

1. Indicative of the change in inflationary pressures that the Company expects to experience over the term of the PBR plan;
2. Published by a reputable, independent agency and made readily available on at least an annual basis;
3. Transparent, simple to calculate and easy to understand; and
4. Reasonably stable.

These selection criteria and the use of a composite I-Factor for the PBR are consistent with the model adopted in Alberta as approved by AUC Decision 2012-237[12]. FEI believes the BC-AWE and BC-CPI indexes satisfy each of the aforementioned criteria, as the indexes used are publicly available data that is published by the federal and provincial governments, as well as by three of Canada's largest financial institutions.

With respect to determining the composite factor weightings, FEI believes the weighting should reflect the Company's proportion of labour and non-labour costs.

An analysis of FEI's 2012 Actual O&M costs indicates that 55 percent percent of costs are labour-related while 45 percent of costs are non-labour related[13]. For that reason, FEI proposes the following I-Factor determination for the PBR period:

$$I_{t+1} = 55\%\ BC - AWE_{t+1} + 45\%\ BC - CPI_{t+1}$$

Where: *I=Inflation Factor*
BC-AWE = labour index
BC-CPI = non-labour index
t = current year

Consistent with the methodology employed in FEI's previous PBRs, FEI has calculated an average BC-CPI forecast from the sources listed in the following table[14]:

Table B6-2: BC-CPI Forecasts for the PBR Period[15]

BC CPI Forecast	2014	2015	2016	2017	2018
Toronto Dominion Bank	2.00%				
Royal Bank of Canada	1.60%				
Bank of Montreal	1.70%	2.00%	2.00%	2.00%	2.00%
Canadian Imperial Bank of Commerce	1.80%				
Conference Board of Canada	1.90%	2.10%	2.00%	2.10%	2.10%
BC Ministy Of Finance	2.00%	2.10%	2.10%	2.10%	
AVERAGE	**1.83%**	**2.07%**	**2.03%**	**2.07%**	**2.05%**

In addition, in November 2012 the Conference Board of Canada published the following forecast of annual changes in average weekly earnings data for British Columbia:

[12] Appendix D9 AUC Decision 2012-237 Rate Regulation Incentive Distribution Performance Based Regulation
[13] Section E, Schedule 15, Line 6, Column 2 Labour costs of $122,164 compared to Section E, Schedule 15, Line 17, column 2 Non-Labour costs of $97,540.
[14] Backup for the referenced sources of BC-CPI and BC AWE is found in Appendix E1. All referenced sources for BC-CPI do not provide five-year forecasts. For the rate setting process each year during the PBR term the average of all six sources for the coming year will be used.
[15] Refer to Appendix F1 for source information.

Table B6-3: BC AWE Forecasts for the PBR Period[16]

BC Average Weekly Earnings Forecast	2014	2015	2016	2017	2018
AVERAGE	2.70%	2.70%	2.60%	2.60%	2.50%

Based on these tables, the 2014 BC-CPI and BC-AWE rates are forecasted to be 1.83 percent and 2.70 percent respectively. As such, FEI proposes to use an I-Factor of 2.31 percent (calculated as (45% x 1.83%) + (55% x 2.70%)) for 2014.

As part of the PBR Annual Reviews, FEI will update both the BC-AWE and BC-CPI rates (using the same sources referenced above) to determine the value of the I-Factor for the 2015 through 2018 years. FEI proposes that the composite's weighting remain constant throughout the PBR Period.

6.2.2.2 X – Factor Estimation

The X-Factor (also known as efficiency factor or productivity offset) is a fundamental element of performance-based regulation. It represents the amount by which a company is expected to outperform the industry and economy-wide productivity gains. The X-Factor can be described as part of a forward-looking benefit sharing mechanism in which the company allocates the expected X-Factor productivity gains to customers, regardless of the firm's realized productivity. FEI proposes a fixed X-Factor of 0.5 per cent (inclusive of any stretch factor) for its 2014 PBR.

FEI commissioned B&V to perform a detailed analysis of industry-wide TFP growth and provide a survey of measured TFPs among natural gas utilities in other North American jurisdictions. FEI has also considered the business conditions expected to affect BC's natural gas utility industry during the PBR term as well as the analysis of proposed X-Factor rate impacts relative to forecast rate changes using the high level cost of service capital and O&M inputs discussed in Sections C3 and C4 to derive a reasonable and fair X-Factor. FEI has already embedded a great deal of efficiency into its operations. The proposed 0.5 percent expected productivity gain exceeds the measured industry productivity levels and represents a real challenge to the Company to seek additional efficiency and continue with its productivity improvement culture.

The following sections provide a discussion and explanation of the general literature on X-Factor estimation approaches as well as the rationale for FEI's proposed 0.5 per cent X-Factor, and were prepared with the assistance of B&V, reflecting B&V's views except where attributed to FEI.

[16] Refer to Appendix F1 for source information.

Approaches to X-Factor Estimation

Different approaches can be used to set the X-Factor. These can be classified into two major groups: "Pure TFP approach" and "Hybrid Judgement-based approach".

Under a "pure" TFP approach, the X-Factor is derived from rigorous mathematical models that calculate the growth of total factor productivity. In this approach the X-Factor is ordinarily defined as the measured industry TFP growth, plus an adjustment for any difference between the inflation index used in the PBR index formula and the rate of input price inflation for the regulated sector. The measured TFP growth is influenced by the following elements:

- TFP growth estimation methodology: Parametric (econometric modelling) and non-parametric (Index-based approaches) models are two major techniques used for the calculation of industry-wide TFP growth. The econometric models are statistically more robust; however, their complexity and extensive assumptions about items such as companies' production and cost functions have been criticized and limited their application. The non-parametric approaches on the other hand are well-established and relatively easy to understand as they do not impose any functional form on the relationship between inputs and outputs. However they are also based on assumptions that might not always hold. For instance, an index-based TFP may not yield a reliable estimate of future productivity gains if business conditions in the future differ from the past.
- The sample of companies: The first step in estimation of industry-wide TFP growth is to select companies from the applicable industry for which data is available. A broad sample is useful. Given that it is impossible to have exactly comparable firms, it becomes important to take the results of the analysis and consider them in light of the circumstances of the specific utility in question and the overall elements of its proposed PBR Plan.
- The measurement period: The TFP growth result is sensitive to the length of measurement period. In general it makes sense to use the most recent data, unless the recent past exhibits anomalous events that are not expected to continue during the PBR term. The evidence from other North American jurisdictions where PBR design has considered TFP analysis, demonstrates that the length of the study period for calculation of TFP varies between 5 to 20 years. This wide range may be partially explained by the choice of the measure of output in the TFP calculation. For example, an output measure based on customers or capacity is relatively stable so a shorter study period is adequate. However using throughput as a TFP output measure requires a longer study period to accommodate such factors as weather variations and impacts of the business cycle.
- Choice of Output measures: Output measures are representative of a regulated firm's cost drivers. Ideally a comprehensive set of cost drivers should be used to best capture the scale of the utility activities and services that the company undertakes. According to the research conducted by B&V, costs for natural gas distribution companies are mainly

Deleted: index-based

caused by a combination of customers, density, the age of assets and design day capacity served by the utility system. Some jurisdictions have used volumetric output measures such as throughput in TFP analysis; however B&V notes that a change in the level of throughput for a natural gas LDC does not change the level of fixed costs for the utility delivery function, and therefore volumetric output measures mislead the TFP results. B&V also concludes that the anomalies in the TFP results from external factors such as weather variations or economic conditions mean that the volumetric approach requires longer study periods. (However, using a longer study period does not overcome the other shortcomings noted in Appendix D2 of using throughput as a TFP output measure).

- Choice of Input measures: The input measures represent the operating and capital costs associated with the utility delivery function. Inclusion or exclusion of particular cost items may add to the bias of TFP estimates. For instance, the B&V report indicates that in the AUC decision 2012-237, general plant was excluded from the capital component of the costs and therefore the AUC-adopted TFP study fails to recognize the capital costs associated with maintenance of the distribution system (such as costs related to line trucks and other vehicles).

The result of a TFP growth study is thus dependent on expert judgement in a number of areas, such as the definition and choice of an appropriate set of companies, the data source, the input and output indices as well as the measurement period. In practice, the X-Factor values estimated through the pure TFP approaches are often adjusted to reflect circumstances of a specific company and by a judgement-based stretch factor. The B&V TFP Study demonstrates that in some cases, the subjective stretch factors are much greater than the measured TFP. Both the AUC and OEB final X-Factor values include stretch factor values and therefore represent some degree of subjectivity (ranging between 0.2 and 0.6 percent).

Under a hybrid judgement approach, the mathematical derivations of the X-Factor, such as TFP studies, are still used as guidance for the determination of X; however, practical matters such as the actual effects of X on the company's bottom line and expected business conditions during the PBR term are also considered to determine a final measure. Researchers such as Crew and Kleindorfer (1996)[17] support the hybrid judgment-based approach and suggest that mathematical models are based on assumptions that may not always hold and therefore justify some level of judgement to adjust the results and choose a reasonable value for X. In other research, Stephen Littlechild[18] (a principal originator of the price cap regulation) indicates that the initial level of X should be "set as part of a whole package of measures, whose parameters affect the costs, revenues and risks of the regulated company". These parameters include items such as the PBR term, cost items subject to flow-through in customers' rates, the implementation of other sharing models such as earnings sharing mechanisms, the use of

[17] Appendix D8-2, Crew 1996 Incentive Regulation in the UK
[18] Appendix D8-3, Beesley, M.E. and Littlechild, S.C., The Regulation of Privatized Monopolies in the United Kingdom, Rand Journal of Economics, Autumn 1989.

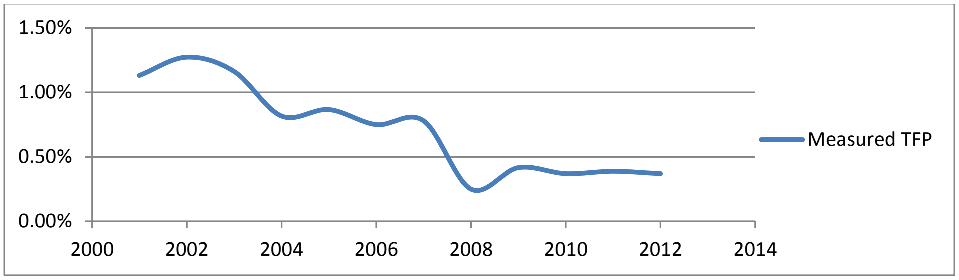
historical or expected performance as basis for X-Factor estimation, etc. For instance, it can be argued that the X-Factor for a PBR plan with an earnings sharing mechanism is less significant than under a plan with no earning sharing mechanism.

B&V TFP Report

Due to the high complexity of TFP estimation methodologies and in order to provide an independent expert analysis of TFP results, FEI retained the services of B&V to prepare a TFP study of the utility industry and to assess and benchmark the results of the TFP studies in other jurisdictions. The B&V TFP Report is found in Appendix D2.

The B&V survey of TFP studies used in the determination of North American electric and natural gas distributors' X-Factor values indicates a clear downward trend for TFP values in recent years. The graph below displays this downward trend for the 2001-2012 period.

Figure B6-1: The Historic Trend of Approved TFP Values in a Sample of North American Jurisdictions



This declining trend can also be seen as a pattern in individual jurisdictions. For example, Ontario's 3rd Generation Incentive Regulation (2009-2013) which was based on a TFP study conducted by the OEB's consultant was estimated at 0.72 per cent, while the most recent study prepared by the same consultant for the 4th Generation IR (2014-2018) indicates a negative TFP growth of -0.05 to -0.03 per cent. B&V concludes that the downward trend of TFP growth is mainly caused by capital intensive infrastructure replacement programs in both natural gas and electric utilities, which drive up input costs without increasing output. B&V expects that this trend will continue during FEI's proposed five year PBR term.

In addition to the survey analysis, B&V prepared its own TFP growth calculation. The analysis is based on three different output measures and the TFP results range between -3.1 to -4.9 per cent. The following is a summary of the main elements of B&V's analysis:

- X-Factor and TFP estimation approach: The B&V study confirms that the hybrid judgement-based approach is preferred. According to B&V, the estimated TFP value is one component of the X-Factor estimation process and that the measured TFP value should be considered along with other elements of the proposed plan to determine a reasonable X-Factor. In addition, the B&V TFP estimation methodology is based on a non-parametric approach. This will help with the transparency and ease of understanding of the processes and results.

Deleted: index-based

- The choice of companies: Given the lack of a centralized database of Canadian utilities and the different reporting requirements among Canadian jurisdictions, B&V compiled TFP data on 95 US-based natural gas LDCs operating in 30 states. U.S. data has been used in other Canadian jurisdictions as well. It is appropriate because of the operating similarities. For instance, the North American Energy Standards Board includes gas utilities in both Canada and the United States, assuring a consistent approach to a variety of operating and other activities between the two countries.
- The measurement period: The B&V study is based on a five year measurement period (2007-2011). The five year measurement period is considered appropriate due to the relative stability of selected output measures (customers and capacity), and the fact that the measured TFP uses a period where the business conditions are similar to those expected during the PBR term.
- Choice of Output Measures: To investigate the sensitivity of TFP analysis to different utility delivery function cost drivers, the analysis provides three different output measures based on the critical variables of customers served and system capacity, and a density-weighted composite factor of these two variables.
- Choice of Input Measures: The input measure includes a capital component and a composite component that reflects labour, materials, services, and rents. The capital component is designed based on the "Kahn" methodology (developed by noted regulatory economist Alfred Kahn) and is measured as Operating Revenue excluding gas costs and all other operating and maintenance expenses. The resulting revenue represents the cost of capital including return, depreciation, and taxes. The measure of all other costs is a direct composite measure as reported in the financial reports of each company.

The measured negative TFP growth is reflective of the business conditions faced by the natural gas utilities in Canada and BC. The following section addresses the need to consider the results of the measured TFP value in the context of the specific utility and PBR proposal.

Hybrid Judgement Approach and Derivation of Proposed X-Factor

FEI is proposing a TFP of 0.5 percent, which is well above the range specified in the B&V TFP Report. FEI's decision to adopt a more challenging X-Factor than that suggested by B&V's TFP Report for the natural gas industry is intended to account for FEI's specific circumstances and the overall design of the proposed PBR plan.

B&V and FEI are in agreement that B&V's TFP Report produces a more negative TFP number than would be applicable to FEI by virtue of how TFP data has been provided for the sample companies in TFP Report. The capital component in B&V's study is measured as the difference between operating revenue (excluding gas costs) and all other O&M expenditures, and which therefore includes all capital costs, whether pertaining to base capital or growth spending, as well as the infrastructure replacement programs that have been more prevalent in recent years. In contrast, in FEI's proposed PBR Plan, large capital projects approved as CPCNs are excluded from the (I-X) mechanism and are treated under a separate regulatory approval process. Due to limitations in the data used in the TFP Study, the revenue earned by the surveyed companies from these types of infrastructure projects or other particular categories of capital cannot be separated from the capital component as a whole. Therefore, a certain degree of educated judgement is required to adjust the TFP value for the companies in the study. The effect of FEI's proposal to exclude CPCN type projects from capital expenditures subject to the I-X mechanism is to moderate the measured negative TFP value applicable to the industry as a whole.

The reasonableness of FEI's proposed X-Factor can be assessed by comparing the impact of the proposed X-Factor on forecast rate changes under a formula relative to forecasted rate changes under the cost of service model. As FEI explains in Section B7 of this Application, the rates arising from PBR formulas (the combination of proposed 0.5 per cent X-Factor and the proposed composite inflator) will lead to average delivery revenues that are 2.0 percent lower than the average rates under the cost of service model which indicates that the proposed X-Factor is an ambitious estimate of expected productivity gains and represents a considerable challenge to the Company. FEI considers that this conclusion is further supported by the review of the most recent X-Factors approved or recommended in other North American jurisdictions, the declining trend of measured TFP values across North America and the negative measured TFP value of the B&V TFP Study. In addition, FEI's proposed PBR Plan includes an earnings sharing mechanism with no deadband which will further reduce the earnings of the Company in comparison with other jurisdictions.

All things considered, FEI considers that a 0.5 per cent X-Factor is an appropriate and reasoned value in the context of FEI and the overall PBR Plan that ensures the continuation of a productivity improvement culture. However, as indicated previously, this is the one area where B&V and FEI part company. B&V are of the view that even accounting for the above factors, the X-Factor should be no higher than approximately zero in order to be theoretically justifiable within the context of FEI's PBR Plan. B&V's evidence is an indication of the real challenge that the Company has set for itself in the proposed PBR Plan.

6.2.3 Determination of FEI Rates

The 2014 PBR Plan applies only to the delivery portion of customers' rates. The commodity and midstream components of customer rates are set through separate flow-through regulatory processes. Delivery costs include the costs incurred to build, maintain, finance and operate the infrastructure necessary to deliver natural gas and provide service to customers.

The proposed PBR formulas and flow-through cost components will affect the delivery rates, exclusive of rate riders and applicable taxes. In general, rate riders pertain to an established mechanism, approved in a previous Commission process and order, for recovering or refunding specific cost or revenue variances. Rate riders will continue in the approved fashion throughout the PBR term.

From 2014 onwards, the controllable expenditures will be adjusted annually by the PBR formula as outlined in Sections B6.2.4 and B6.2.5 which follow. Other items will be re-forecast annually as part of the Annual Review process. At that time, the delivery rates for the following year will be determined. Section B6.9 describes the Annual Review process.

Operating and maintenance expenses and capital expenditures are the two main types of controllable expenses that present an opportunity for FEI to identify and achieve cost savings. As discussed in the respective sections below, a formula is applied to the base year O&M and capital expenditures (2013 Approved amounts as adjusted to form the 2013 Base, discussed below) that will determine the amount of expenditures from 2014 to 2018 that will be included in the delivery rates. FEI will attempt to meet and ideally incur expenses below those amounts in each year, with net savings to be shared according to the proposed Earnings Sharing Mechanism as discussed further in Section B6.5.

6.2.4 O&M under PBR

2013 O&M expenditures are now at a level that reflects substantial productivity savings relative to previous years, yet still ensures that safety standards and other service requirements continue to be met.

For the PBR Period, actual O&M expenditures will not flow through to rates. Instead, each year the component of rates designed to recover O&M expenses will adjust the previous years' amount by the formula which includes a productivity factor. This will incent the pursuit of further efficiencies in O&M expenditures in the context of meeting SQIs and providing reliable service.

6.2.4.1 2013 Base O&M

Recognizing that the O&M Base for the 2014-2018 formula should be an O&M number that has undergone a full review in a public hearing, FEI has used the 2013 Approved O&M as the starting point for the O&M formula. A number of adjustments are then made to this amount to arrive at the "2013 Base". The adjustments are of three types:

1. An adjustment to recognize the sustainable savings that were realized in 2012 and 2013 that should be carried forward to future years;
2. Adjustments to include actual incurred 2013 "non-controllable" O&M that is held in deferral accounts in 2013; and
3. Accounting changes that reclassify items from O&M to capital.

The goal of these adjustments is to determine the appropriate starting point for O&M expenses in the upcoming PBR Period. B&V considers this approach is reasonable given the fact that the current rates were set based on a fully litigated hearing that occurred recently. It is common to use approved rates in circumstances where the revenue requirements were recently assessed, and making known and measurable adjustments is also appropriate.

Under the above methodology, the 2013 Base is calculated as follows:

Table B6-4: 2013 Base O&M

		($ thousands)
2013 Decision		**236,003**
Sustainable Savings & Other Adjustments		(16,167)
2013 Deferrals:		
PST (full year impact)	762	
BCUC Fees & Insurance	1,016	
Pension (O&M portion)	10,605	12,383
Accounting Changes:		
Allocation of retiree pension/OPEBs	(930)	
Capitalization of annual software costs	(1,800)	(2,730)
2013 Base		**229,489**

Sustainable Savings:

The total sustainable savings that are being embedded in the 2013 Base O&M for the future benefit of customers is $16.17 million[19]. A breakdown of this total sustainable savings by department is shown in Table C3-2. Further description of the nature of these savings is provided in the departmental narrative that follows within Section C3.

Deleted: 14.67

2013 Deferrals:

The 2013 deferral adjustments reflect the re-basing of 2013 Approved to 2013 expected Actual amounts for those items that are considered non-controllable, and for which the variance is captured in a deferral account. In 2013, FEI will record the following amounts in O&M related deferral accounts:

1. $571 thousand[20] in the Tax Variance deferral account related to PST for 9 months of 2013 (equivalent to the $762 thousand shown above for the full year). In addition,

[19] Of this amount, $13.234 million in savings achieved in the Customer Service department in 2013 and deferred to the Customer Service Variance deferral account (Section E Financial Schedules Schedule 47, Line 27 Column 4)

[20] Appendix F7, 2013 FEI Summary of PST Expenditures for 2013 Revenue Requirements Lines 1, 6, 10, 11

Deleted: 10.285

Deleted: 6

$1.664 million[21] was included relating to PST on capital in the calculation of the amount to be included in the Tax Variance deferral account. Grossed up for a full year, the $1.664 million becomes $2.219 million, of which $1.999 million[22] is related to capital expenditures and has been adjusted in the Base Capital below, and the remaining $220 thousand relates to removal costs (captured in another deferral account).

2. $923 thousand in the BCUC Levies Variance deferral account[23], representing the difference between the actual amounts that will be paid in 2013 and the amounts approved in rates.
3. $93 thousand in the Insurance Variance deferral account[24], representing the difference between the actual insurance that will be paid in 2013 and the amounts approved in rates;
4. A total of $12.607 million to the Pension and OPEB Variance deferral account[25]. Of this amount, $10.605 million is related to O&M, $1.311 million is related to capital expenditures and has been adjusted in the Base Capital below, and the remaining $691 thousand relates to removal costs (captured in another deferral account).

Accounting Changes:

The two accounting changes (allocation of retiree pensions/OPEBs and capitalization of annual software costs) are described in further detail Section D3.1 and serve to reallocate costs from O&M to capital.

6.2.4.2 2014 - 2018 O&M

The 2013 Base O&M is then escalated using the formula approach. Excluded from the O&M formula approach are pensions and OPEBs, insurance and also the O&M related to NGT stations, Rate Schedules 16 and 46, and Biomethane. The pensions, OPEBs and insurance were also excluded from the formula in the last PBR and were considered "flow through" items in recognition of their uncontrollable nature. The Rate Schedule 16 and 46 O&M has been excluded because these costs are directly tied to incremental revenue that is not part of the formula approach. The Biomethane O&M is not recovered through the delivery rate, but rather through a separate rate setting process.

As in the 2004 PBR Plan, the PBR formula FEI proposes to apply to the O&M is tied to the average number of customers. FEI will reforecast the average number of customers for the upcoming year in the Annual Review. The following formula illustrates the formula applied to O&M:

---

[21] Appendix F7, 2013 FEI Summary of PST Expenditures for 2013 Revenue Requirements Lines 2 and 3
[22] $17 thousand relates to PST on Biomethane Interconnect costs and has been removed from the Base calculation in Table B6-6 below.
[23] Section E financial schedules Schedule 47, Line 23, Column 4
[24] Section E Financial Schedules Schedule 47, Line 21, Column 4
[25] Section E Financial Schedules; Schedule 47, Line 22, Column 4.

Deleted: 2
Deleted: 0
Deleted: 1

$$OM_t = OM_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *OM=Operating and Maintenance Expense subject to formula*
AC=Average Customers
t *= Upcoming year*
I *= Inflation Factor*
X *= Productivity Factor*

The inputs used for calculating the O&M under the PBR Plan, include:

1. The 2013 O&M Base;
2. The 2013 base and forecasted number of average customers, including its year to year per cent change;
3. The composite I-Factor values; and
4. The Productivity X-Factor.

B&V consider that linking O&M to the number of customers is appropriate. B&V has noted in its PBR Report and TFP Report that customers and capacity are the principle drivers for costs. For O&M, a number of the specific costs are driven by number of customers. Other costs are driven by capacity. The influence of the capacity component on O&M costs is not easily measured and would lack transparency if that measure were used. As a result, B&V believes it is appropriate to use customers since system capacity is also related to the number of customers and customer count becomes a reasonable proxy for the capacity variable in the formula. It effectively adds an estimate of additional O&M expense associated with system growth to the plan's revenue adjustment.

The O&M allowed under the PBR Plan is shown in Table B6-5. As indicated above, the O&M allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted number of customers and the re-forecasted composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

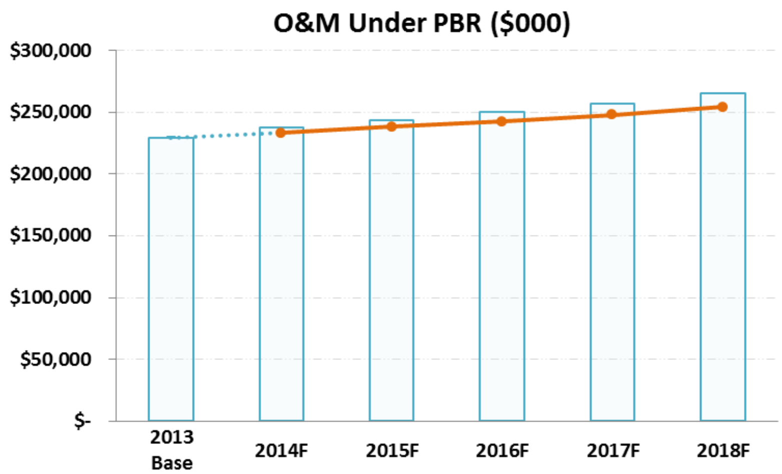
Table B6-5: Forecast O&M Formula Results[26]

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
2013 Base O&M ($000)	$ 229,489					
LESS O&M Tracked Outside PBR Formula:						
Pension / OPEB ($000) (O&M Portion)	$ (25,312)					
Insurance ($000)	$ (4,710)					
Bio-Methane O&M ($000)	$ (410)					
NGT Stations O&M ($000)	$ (289)					
RS 16/46 O&M ($000)	$ -					
O&M Applicable to PBR Formula:	$ 198,768					
Average Number of Customers	840,721	845,495	850,620	856,001	861,402	866,681
% Change in Customer Additions		**0.57%**	**0.61%**	**0.63%**	**0.63%**	**0.61%**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Gross O&M Under PBR ($000)		$ 203,515	$ 208,680	$ 213,864	$ 219,216	$ 224,530
ADD: O&M Tracked Outside of the Formula						
Pension / OPEB ($000) (O&M Portion)		24,113	22,426	21,340	20,520	20,973
Insurance ($000)		4,990	5,290	5,610	5,945	6,300
Bio-Methane O&M ($000)		590	686	689	710	739
NGT Stations O&M ($000)		433	629	760	949	1,211
RS 16/46 O&M ($000)		376	1,089	1,089	1,089	1,089
Tilbury 2 LNG O&M ($000)						
Total Gross O&M	**$ 229,489**	**$ 234,017**	**$ 238,799**	**$ 243,352**	**$ 248,429**	**$ 254,840**
Less: O&M transferred to BVA		(570)	(620)	(612)	(633)	(662)
Total Delivery Rate Gross O&M		**$ 233,447**	**$ 238,179**	**$ 242,740**	**$ 247,796**	**$ 254,179**

Based on the results from Table B6-5 above and O&M forecasts provided in Section C3, Figure B6-2 below illustrates the comparison between the 5-year O&M forecasts, and the O&M calculated under the PBR Plan.

[26] Refer to Attachment 1 to Appendix E1 for the forecast of average customers.

Figure B6-2: Comparison of PBR O&M vs. Forecast ($000s)



	2013 Base	2014F	2015F	2016F	2017F	2018F
O&M Forecast	229,489	237,830	243,566	250,216	257,024	265,545
O&M Under PBR	229,489	233,447	238,179	242,740	247,796	254,179

As Figure B6-2 indicates, the O&M expense allowed under PBR falls below the forecasted O&M expense throughout the PBR Term. FEI believes this level of O&M expenditure allowed under PBR provides a strong incentive for FEI to find efficiencies for O&M spending.

6.2.5 Capital Expenditures under PBR

The formula–based capital portion of the PBR Plan pertains to the categories of capital expenditures over which the Company and its employees have some control. The other components of rate base such as working capital and deferred charge balances are largely beyond management control. The PBR formulas recognize this distinction and are thus applied to controllable capital expenditures and leave non-controllable rate base components for the annual forecasting process.

Capital expenditures include both regular capital expenditures and projects approved as CPCNs. FEI proposes the same treatment in the 2014 PBR Plan for regular capital expenditures and CPCN expenditures as was approved in the 2004 PBR Plan. Regular capital expenditures will be determined by formula and CPCN expenditures will be excluded from the formula and will continue to be subject to the minimum $5 million cost threshold. CPCN expenditures will only be included in rate base after receiving CPCN approval from the Commission and being placed into service. B&V considers that the exclusion of CPCN capital is an appropriate means of addressing capital under a PBR Plan. It is akin to the adoption of a "capital tracker", which is incorporated in PBR plans elsewhere. B&V describe the purpose of such mechanisms as follows in the PBR Report:

> *"Given the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system."* (Appendix D1, p.37)

There are three categories of regular capital expenditures which FEI has included in its PBR formula – growth, sustainment and other capital. A description of the types of capital included in each of these categories is included in Section C4.

Similar to O&M expenses, actual regular capital expenditures (i.e. actual plant additions) will not be flowed through in rates. The formula-based capital expenditures will be added to rate base and carried through the PBR term, however similar to the 2004 PBR, the formula-based capital expenditures, which use customer counts as a cost driver, will be trued up each year for actual customer counts.

6.2.5.1 2013 Base Capital

FEI has used the approved capital expenditures for 2013 from the 2012-2013 RRA Decision as the starting point for the capital formula. Similar to the methodology used to arrive at the 2013 O&M Base for PBR, adjustments are made to the 2013 Approved capital to arrive at the "2013 Capital Base". These include:

1. Adjustments to include the capital portion of 2013 actual "non-controllable" items that are held in deferral accounts in 2013 (PST and Pension amounts); and
2. Accounting changes that reclassify items from O&M to capital.

The goal of these adjustments is to determine the appropriate starting point or base for capital expenditures in the upcoming PBR period.

Under the above methodology, the 2013 Base Capital is calculated as follows:

Table B6-6: 2013 Base Capital ($ thousands)

	2013 Approved	2013 Adjustments					2013 Base
		PST	Pension Deferral Amount	Pension Accounting Change	Vehicles	IT Cap	
Growth Capital	$ 21,515	$ 367	$ 333	$ 236	$ -	$ -	$ 22,451
Sustainment Capital	$ 75,114	$ 1,280	$ 978	$ 694	$ -	$ -	$ 78,065
Other Capital	$ 25,054	$ 427	$ -	$ -	$ 2,860	$ 1,800	$ 30,141
Total Gross Capital	$ 121,683	$ 2,074	$ 1,311	$ 930	$ 2,860	$ 1,800	$ 130,657
(Contribution in Aid of Construction)	$ (5,400)	$ (92)	$ -	$ -	$ -	$ -	$ (5,492)
Total Net Capital	$ 116,283	$ 1,982	$ 1,311	$ 930	$ 2,860	$ 1,800	**$ 125,165**

All of the adjustments have been described above in Section B6.2.4.1 Base O&M with the exception of the Vehicles adjustment. The 2013 Capital Base has been restated to show vehicle purchases that will start in 2013, at the 2013 Approved amount for vehicle lease additions of $2.860 million. This adjustment is simply a reclassification of what was considered a capital addition (the vehicle capital lease) to a capital expenditure (an upfront payment for the purchase of a vehicle) and therefore does not affect total capital additions at all. This adjustment is described further in Section D3 Accounting Policies.

For capital, there is no need to adjust the 2013 Approved for savings realized in 2012. This is because amounts that were not spent in 2012 are not considered sustainable, since they have been carried forward to the 2013 Projection. As described in Section C4 on Capital Expenditures, the total of the 2012 Actual and 2013 Projection amounts are very close to the 2012-2013 RRA Approved amounts (approximately $2 million less). Further, 2013 actual capital expenditures were $6.4 million higher than the 2013 Projection, after removing the Biomethane interconnect facilities. Overall, the combined 2012 and 2013 Actual spending was $5.3 million above the 2012 and 2013 Approved. Excluded from the capital expenditures subject to the formula are biomethane upgraders and future interconnect costs, CNG and LNG fuelling stations, future Tilbury expansion costs and CPCNs. Bio-methane upgraders and interconnect costs are not recovered through the delivery rate, but rather through a separate rate setting process, NGT capital costs are associated with incremental NGT revenues that is tracked outside the formula, and CPCNs are subject to separate regulatory processes. These separate processes are analogous to the capital tracker mechanisms adopted in other jurisdictions, in that the capital expenditures in these categories are outside the PBR formula just as the capital expenditures in capital tracker applications are outside the formulas in those jurisdictions. Consistent with past practice, the impact of CPCNs will not be included in rates until FEI has received Commission approval for such projects through separate processes.

Consistent with O&M, the capital portion of the annual pension/OPEB expense is flowed through outside of the formula.

Deleted: and in fact the 2013 Projection is $6.5 million higher than the 2013 Approved amount that is being used as a base for the PBR capital formula

6.2.5.2 2014 - 2018 Capital

Consistent with the 2004 PBR plan, FEI proposes to apply two capital formulas under the proposed PBR in determining total annual capital. B&V believes that using two separate formulas for capital results in a better estimate of overall capital than would result from a single formula. These formulas are described below.

Growth Capital under PBR

Of the three categories of regular capital expenditures that FEI has included in its PBR formula, Growth Capital differs from Sustainment and Other capital in that it is primarily driven by customer additions. In particular, Growth Capital is driven by service line additions (which are calculated as a percentage of gross customer additions) that arise from providing service for new customers. For that reason, the PBR formula FEI proposes to apply to Growth Capital is tied to the forecasted service line additions for the upcoming year. FEI will re-forecast the level of service line additions for upcoming years (driven off of the gross customer additions) in the PBR Annual Reviews.

In determining the Growth Capital allowed under PBR, an Average Growth Capital Cost[27] per Service Line Addition is calculated by dividing the current year's total Growth Capital by the current years' service line additions. This Average Growth Capital Cost per Service Line Addition is then escalated by the I-X mechanism and then multiplied by the forecasted level of service line additions for the upcoming year. FEI will recalculate the Average Growth Capital Cost per Service Line Addition yearly in the PBR Annual Review, based on the forecasted gross customer additions and resulting number of service line additions over the same period. The following formula illustrates the formula applied to Growth Capital:

$$GC_t = \frac{GC_{t-1}}{SLA_{t-1}} \times [1 + (I - X)] \times SLA_t$$

Where: $GC = Growth\ Capital$
$SLA = Service\ Line\ Additions$
$t = Upcoming\ year$
$I = Inflation\ Factor$
$X = Productivity\ Factor$

The inputs used for calculating the Growth Capital under PBR include:

1. The Growth Capital 2013 base;
2. The 2013 Base and forecasted level of service line additions.
3. The composite I-Factor values; and

[27] Average Growth Capital Cost per Service Line Addition includes the average cost of a new service line as well the meter, regulator and average main extension costs.

4. The Productivity X-Factor.

The Average Growth Capital Cost per Service Line Addition allowed under the PBR Plan is shown in Table B6-7. As indicated above, the Average Growth Capital Cost per Service Line Addition allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecasted level of service line additions and the re-forecasted composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

Table B6-7: PBR Growth Capital Expenditures Formula Results

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Growth Capital ($000)	$ 22,450					
LESS: Capital Tracked Outside of the Formula:						
Pension & OPEB ($000)	$ (569)					
Growth Capital Applicable to PBR Formula	**$ 21,881**					
Service Line Additions *	7,989	8,051	8,407	8,555	8,444	8,270
Average Growth in Capital Cost per Service Line Addition	**$ 2,739**	**$ 2,788**	**$ 2,842**	**$ 2,894**	**$ 2,948**	**$ 3,001**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Gross Growth Capital Under PBR ($000)		$ 22,450	$ 23,893	$ 24,761	$ 24,894	$ 24,820
ADD: Capital Tracked Outside of the Formula						
Pension & OPEB ($000)		$ 525	$ 473	$ 447	$ 433	$ 513
Total Growth Capital Under PBR ($000)	**$ 22,450**	**$ 22,974**	**$ 24,366**	**$ 25,208**	**$ 25,327**	**$ 25,333**

In B&V's view, the use of a new service line to measure the added costs for growth capital is significant because it represents adding a previously unserved premise[28] to the system. For a new premise, the costs include all the distribution facilities to interconnect the customer to the system. For growth capital, the formula essentially estimates the incremental capital for the new customer.

Sustainment and Other Capital under PBR

The PBR formula that FEI proposes to apply to Sustainment Capital and Other Capital is tied to the average number of customers. B&V notes that in actual fact, sustainment and other capital costs are driven by both customers and capacity. However, as in the case of O&M, there is no convenient measure of capacity. By using the change in average customers as part of the formula, the impact of both customers and capacity is reflected in the determination of the expected change in capital costs. Customers become a proxy for capacity since the addition of mains to serve customers adds new capacity to the system.

[28] In FEI's case new service lines are also installed where an older dwelling that previously had gas service has been torn down and replaced by a new dwelling.

FEI will reforecast the average number of customers for the upcoming year in the Annual Review. The following formula illustrates the formula applied to Sustainment and Other capital:

$$RC_t = RC_{t-1} \times [1 + (I - X)] \times \left(\frac{AC_t}{AC_{t-1}}\right)$$

Where: *RC=Remaining Capital: Total of Sustainment & Other Capital*
AC=Average Customers
t = Upcoming year
I = Inflation Factor
X = Productivity Factor

The inputs used for calculating the Sustainment and Other Capital under the PBR Plan include:

1. The total of Sustainment and Other Capital 2013 base;
2. The 2013 base and forecasted number of average customers, including its corresponding yearly growth percentage;
3. The composite I-Factor values; and
4. The Productivity X-Factor.

The Sustainment and Other Capital allowed under the PBR Plan is included below in Table B6-8. As indicated above, the Sustainment and Other Capital allowed under PBR will be revised yearly in the PBR Annual Review, recalculated based on both the re-forecast number of customers and the re-forecast composite inflation rate for the upcoming year. The X-Factor, however, remains constant throughout the PBR Period.

Table B6-8: PBR Sustainment and Other Capital Expenditures Formula Results[29]

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Total Sustainment & Other Capital ($000)	$ 102,714					
LESS: Capital Tracked Outside of the Formula:						
Pension & OPEB ($000)	$ (1,672)					
Sustainment and Other Capital Applicable to PBR Formula	**$ 101,042**					
Average Number of Customers	840,721	845,495	850,620	856,001	861,402	866,681
% Change in Customer Additions		**0.57%**	**0.61%**	**0.63%**	**0.63%**	**0.61%**
Composite I-Factor		2.31%	2.42%	2.34%	2.36%	2.30%
Productivity X-Factor		0.50%	0.50%	0.50%	0.50%	0.50%
I-X Mechanism (1+I-X)		**101.81%**	**101.92%**	**101.84%**	**101.86%**	**101.80%**
Sustainment and Other Capital Under PBR ($000)		$ 103,455	$ 106,081	$ 108,716	$ 111,437	$ 114,138
ADD: Capital Tracked Outside of the Formula						
Pension & OPEB ($000)		$ 1,543	$ 1,390	$ 1,313	$ 1,271	$ 1,508
Bio-Methane Upgraders ($000)		$ 1,468	$ -	$ -	$ -	$ -
Bio-Methane Interconnect ($000)		$ 3,700	$ 1,434	$ 1,864	$ 1,864	$ 1,864
NGT Assets ($000)		$ 3,356	$ 2,251	$ 2,050	$ 5,500	$ 6,750
Tilbury 2 Assets ($000)		$ -	$ -	$ -	$ -	$ -
Total Sustainment and Other Capital ($000)	**$ 102,714**	**$ 113,522**	**$ 111,155**	**$ 113,943**	**$ 120,072**	**$ 124,260**
Less: Bio-Methane Upgraders costs transferred to BVA		(1,468)	-	-	-	-
Less: Bio-Methane Interconnect costs (on new projects) transferred to BVA				(1,864)	(1,864)	(1,864)
Total Delivery Rate Sustainment and Other Capital ($000)		**$ 112,054**	**$ 111,155**	**$ 112,079**	**$ 118,208**	**$ 122,396**

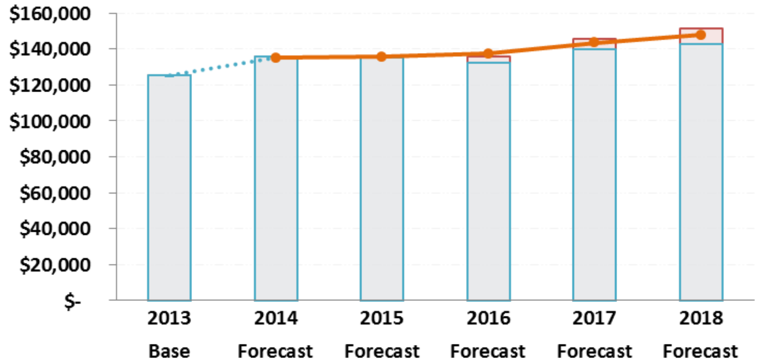
Total Capital Under PBR

Figure B6-3 provides a comparison of total capital under the PBR formula and the total capital forecasts over the PBR term.

With respect to the total capital forecasts, FEI presents two scenarios: a high construction cost forecast and a low construction cost forecast. The potential for a high construction cost forecast is driven by both an anticipated boom in pipeline projects projected in the later years and the related trend in higher construction costs. Both factors could considerably inflate construction costs particularly related to transmission system reinforcement projects and CPCN projects that require steel pipe and significant contract and engineering resources. As such, for the high construction cost forecast, FEI is projecting a potential 20 percent annual inflation rate in the last three years of the PBR Period as applied to transmission system reinforcement projects only. For the low construction cost forecast, FEI is projecting a 2 percent per year inflation rate (refer to Section C4.3.3 for further discussion).

[29] Refer to Attachment 1 to Appendix E1 for the forecast of average customers.

Figure B6-3: Comparison of PBR Total Capital Expenditures vs Total Capital Expenditures (TC) Forecasts ($000s)



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
TC High Contruction Cost forecast	$125,165	$135,910	$135,138	$135,540	$145,554	$151,298
TC Low Construction Cost forecast	$125,165	$135,910	$135,138	$132,432	$139,866	$142,719
TC Under PBR	$125,165	$135,029	$135,521	$137,287	$143,535	$147,729

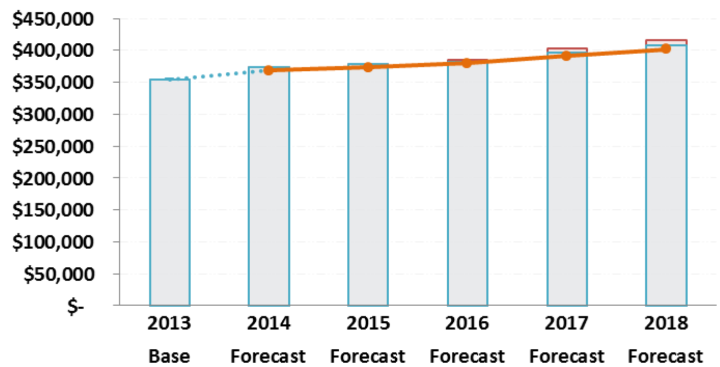
As Figure B6-3 indicates, the total allowed capital under PBR tracks closely with forecasted amounts. FEI believes this level of capital expenditure allowed under PBR provides a suitable incentive for FEI to find efficiencies for capital expenditures under both scenarios without raising concerns of compromising safe, reliable natural gas service or service quality.

6.2.5.3 Total O&M and Capital Under PBR

When the O&M and Capital allowed under PBR are examined separately, it is clear that the allowed expenditures under the PBR formula tracks more closely for capital than it does for O&M. While the capital allowed under the PBR formula is lower than the High Construction Cost Forecast in most years, it is also higher in some years than that forecasted when compared to the low construction cost scenarios. However, for O&M the allowed expenditure under the PBR formula falls significantly below what has been forecasted over the PBR Period.

When the O&M and Capital allowed under the PBR formula are examined together, the total is lower than what has been forecasted by FEI under both scenarios in every year of the PBR term. In other words, customers will benefit under the proposed PBR Plan since the resulting costs for customers under PBR are less than what FEI is forecasting they would be if rates were set under a Cost of Service model using the O&M and capital forecast in Sections C3 and C4 (see Section 7 below for further discussion on rate forecasts under PBR). Figure B6-4 provides a comparison of the total Capital and O&M allowed under the PBR formula and the total Capital and O&M Forecasts over the PBR term.

Figure B6-4: Comparison of Total O&M and Capital Expenditures Under PBR vs Total Forecast O&M and Capital Expenditures



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
O&M and TC High Contruction Cost forecast	$354,654	$373,740	$378,705	$385,756	$402,578	$416,843
O&M and TC Low Construction Cost forecast	$354,654	$373,740	$378,705	$382,648	$396,890	$408,264
O&M and TC Under PBR	$354,654	$368,476	$373,701	$380,027	$391,331	$401,908

As Figure B6-4 indicates, total allowed expenditures under the PBR formula fall below the Low Construction Cost Forecast in every year of the PBR term. FEI believes that the proposed PBR Plan provides a strong incentive for FEI to find efficiencies for all expenditures throughout the PBR term.

6.3 *FLOW-THROUGH ITEMS AND EXOGENOUS FACTORS*

At various points in this section of the Application, FEI has made reference to elements in the proposed PBR Plan that will be flowed through in rates each year through the Annual Review process. This type of mechanism is used on non-controllable costs and revenues to ensure that customers pay actual costs in circumstances where the Utility does not control the level of expenditures or revenues. The rationale for addressing uncontrollable costs and revenues outside the PBR formula is addressed below with a discussion of the types of expenses and revenues that are beyond the control of the Company. The treatment of these items in the annual rate-setting process is the same as they were treated in the 2004 PBR Plan.

6.3.1 Addressing Uncontrollable Costs/Revenues Outside Formula

It is typical in the context of PBRs to treat uncontrollable factors outside of the PBR formula. As B&V states in its PBR Report:

"Since Z-Factors are beyond the control of management, it is typical to include a specific list of events that trigger the Z-Factor particularly where the cost changes represent cost changes that would be passed through as part of a cost of service proceeding. The standard list includes changes in taxes such as payroll or income tax changes, regulations that require increased capital or expenses associated with environmental or other regulatory decisions and specific events that may occur beyond the control of the utility." (p.36)

B&V considers that the rationale for this treatment is sound. Including non-controllable costs within the formula can result in a windfall to either customers or the Company. Similarly, it is important to allow full recovery of these costs under a PBR plan, as the costs - being outside the control of management - are by definition prudently incurred costs of providing utility service that should be recovered from customers in the normal course.

B&V refers to all non-controllable factors as "Z-Factors", but the nomenclature differs from jurisdiction to jurisdiction. The AUC, for instance, adopts the term "Y-factors" for foreseeable uncontrollable expenditures, and uses the term "Z-Factors" only to describe those uncontrollable factors that are also unforeseen. FEI has similarly differentiated between factors that are foreseen and those that are not foreseen, although it does not generally use the term "Y-factors" when describing foreseen uncontrollable costs and revenues. There is no requirement to follow a specific terminology. Regardless of how the factors are characterized, the common element is that there is recognition that uncontrollable expenditures and revenues should not be subject to the PBR formula, otherwise it could result in windfalls for customers or the shareholder.

B&V agrees with FEI that the items identified below as flow through items and exogenous factors should be excluded from the proposed formula.

6.3.2 Flow-Through Expenses

A brief summary of the flow-through revenue and expense items is provided below.

Interest Expense

At the Annual Reviews a forecast of interest expense for the following year will be provided, and customers' rates for that following year will be determined on the basis of the forecast. The existing deferral account will record variances in long-term and short-term interest costs in accordance with the Commission-approved method for the account. Projected deferral account balances and forecasts of short term and long term interest rates and costs will be provided each year during the Annual Review process.

Return on Equity

With regard to the allowed ROE, the Commission approves both the ROE and the equity component within the capital structure. FEI will flow through any Commission-approved changes to the ROE and capital structure in the Annual Review process each year.

Taxes

Variances in property tax expenses, income tax rates, and other tax items are captured in deferral accounts. Projected deferral account balances and forecasts of tax expenses will be provided each year during the Annual Review process.

Pension and OPEB Expenses and Insurance Costs

These items are subject to deferral account treatment. Pension and OPEB expenses, and insurance expenses will be re-forecast at each Annual Review based on the most recent information provided by actuaries and FEI's insurance provider. Projected year-end deferral account balances will also be provided at the Annual Reviews.

Revenues

Revenues include amounts received from customers for the sale and delivery of natural gas, the provision of transportation service, revenues received under tariff supplements, and various other sources of revenue which are detailed in Sections C1 and C2. Natural gas usage rates are not under the control of FEI and customers make changes in the amount of natural gas they consume for various reasons.

Revenues will be forecast each year at the Annual Review and these revenues will be included in the determination of the revenue requirement and rates for the forecast year. Throughput-related revenue variations relating to residential and commercial customers (Rate Schedules 1, 2 and 3/23) will continue to be subject to the RSAM mechanism.

Depreciation and Amortization

As discussed in section B6.2.5, the 2014 Plan proposes to derive the annual regular capital expenditures by means of formulas. Similar to the treatment in the 2004 PBR Plan, the formula-based capital expenditures are carried forward in the rate base throughout the PBR term without adjusting the amounts to the actual spending levels (unless total capital expenditure spending deviates in any year by more than 10 percent from the formula amounts, as described in Appendix D4). Annual depreciation expense will be based on the approved depreciation rates and the opening plant account balances which include the formula-based capital expenditures as plant additions. The incentive power of the formula-based capital elements of the PBR Plan relates to finding ways to be more efficient in capital activities so that actual spending is less than the formula-derived amount. The accumulating differences between formula and actual spending give rise to variations in rate base carrying costs (i.e., return on rate base, depreciation expense and taxes).

Amortization of deferrals will be re-forecast at each Annual Review and actual amortization expense each year will equal the approved amount.

Rate Base other than Gas Plant in Service (from Capital Expenditures)

Section B6.2.5 describes how, as far as capital expenditures are concerned, the use of formula-based calculations will be limited to the regular capital expenditures. Larger projects developed as CPCNs will have their own BCUC approval process and will be added into rate base after they are approved and complete.

There are several other smaller components of rate base such as working capital and deferred charge balances other than those described above that are proposed to be forecast each year in the Annual Review process. These items include natural gas in storage and deferral account balances such as the MCRA, CCRA and RSAM (among others). These items cannot be reliably reduced to a formula and are strongly dependent on external factors such as commodity pricing and weather. Therefore FEI proposes to re-forecast the rate base balances each year in the Annual Review process.

6.3.3 Exogenous Factors

In the nomenclature of PBR, non-controllable and unforeseeable costs that flow-through to rates are referred to as Z-Factors. These factors were referred to in the 2004 PBR Plan as "exogenous factors". Consistent with the 2004 PBR Plan, FEI proposes that during the term of the proposed PBR Plan, customers' rates will be adjusted for the following exogenous factors that are beyond the control of the Company:

- Judicial, legislative or administrative changes, orders or directions;
- Catastrophic events;
- Bypass or similar events;
- Major seismic incident;
- Acts of war, terrorism or violence;
- Changes in GAAP, standards or policies; and
- Changes in revenue requirements due to Commission decisions (examples include rate design issues, depreciation rate changes, changes to cost of capital).

Exogenous or Z-Factor treatment of the above costs will ensure that customers pay only for the actual costs in circumstances where FEI does not control the level of expenditures. For further discussion of the rationale for exogenous factor treatment, please refer to the B&V PBR Report (Appendix D1), p.7.

6.4 *EARNINGS SHARING MECHANISM*

FEI is proposing to include an ESM as a component of the PBR Plan. The rationale for ESMs generally, and FEI's proposal to adopt an ESM design based on the 2004 PBR Plan, are addressed below.

6.4.1 Rationale for ESM

Sharing mechanisms are regulatory tools in a PBR that are designed to enhance the alignment between customer and company interests and share the risks and benefits of the PBR plan. They are also put in place to mitigate against unintended results of a new PBR plan such as excessive utility gains or losses. An earnings sharing mechanism is typically a backward-looking sharing mechanism in which a rate adjustment is provided if the actual earnings fall below or exceed a certain threshold (in some cases, the threshold equals the allowed ROE).

In general, two schools of thought exist in the regulatory economics literature regarding the use of an ESM. At one end of the spectrum is the assertion that ESM is contrary to the principles of incentive regulation as it decreases the incentive power of the PBR plan and imposes additional regulatory burdens and costs. The experts in the second group counter these claims by indicating that an ESM can allow for a utility's rates to better track realized costs which, along with other regulatory safeguards, mitigates the concern about excessive profits or losses, and that it is a fair approach for sharing the benefits of a PBR plan. In other words, an ESM amends some of the links between rates and costs that are decoupled under a PBR plan and helps to improve the allocative efficiency[30] of the plan[31]. The schools of thought also assert that ordinarily regulatory burden and costs related to ESM are minimal.

B&V is supportive of an ESM in the context of FEI's proposed PBR Plan. The B&V PBR Report articulates B&V's rationale for supporting the ESM:

> *"The concept of earnings sharing is based on assuring that an acceptable level of benefits are shared with consumers during the regulatory control period and that the utility is protected from unreasonably low returns in the event of unforeseen plan outcomes. The earnings sharing mechanism benefits both parties and does so without an overtly heavy hand of regulation."* (p.37)

6.4.2 Proposal for ESM

FEI is proposing to adopt an ESM based on the 2004 PBR Plan.

FEI's 2004 PBR Plan included an earnings sharing mechanism on a 50:50 basis between customers and the Company for earnings above and below the allowed ROE, as established each year by the Commission. As indicated in FEI's 2012-2013 RRA, the PBR Plan resulted in $135 million in gross savings ($67.5 million for the ratepayers and $67.5 million for the Company) during the 6 years of the PBR term over and above the embedded productivity factors. This significant amount of savings demonstrates that the 50:50 ESM design, along with other features of FEI's 2004 PBR Plan, provided incentives that were sufficiently powerful for

[30] Allocative efficiency is concerned with the optimal mix of goods and services and getting the most from scarce resources. Allocative efficiency is achieved when prices for goods and services are equal to marginal cost of production.

[31] Appendix D8-4 Lyon, Thomas P, 1996. "A Model of Sliding-Scale Regulation," Journal of Regulatory Economics, Springer, vol. 9(3), pages 227-247, May.

the Company to pursue substantial reductions in its costs. FEI's earnings sharing mechanism experience also indicates that the regulatory costs associated with its ESM have been generally minimal.

Based on the feedback received from various stakeholders and the positive experience with the previous earnings sharing mechanism, FEI believes that an earnings sharing mechanism continues to be beneficial and proposes an ESM similar to the 2004 PBR Plan with a 50:50 basis sharing between customers and the Company for earnings above and below the allowed ROE established for each year by the Commission.

Also, as in the 2004 PBR Plan, the amount of earnings to be shared will be projected at the Annual Review in the fall of each year and the customers' portion will be refunded or charged to customers by way of a rate rider. The actual earnings amount for sharing will be finally determined after the year end, with any differences between the projected and actual amount included in the calculation of the earnings sharing rider for the following year.

B&V supports FEI's decision to incorporate a similar ESM design to that employed in the 2004 PBR Plan. B&V's PBR Report states in that regard:

> *"The FEI plan included an earnings sharing mechanism that provided symmetric protection for all stakeholders. As a matter of regulatory policy, this reduces the risk of unfavorable outcomes for both FEI and stakeholders. Particularly, the ESM provided customers with real time benefits if FEI earned above the authorized return and assured customers that FEI would not be permitted to deteriorate financially such that system service, safety and reliability would not be compromised."* (p.46)

6.5 *EFFICIENCY CARRY-OVER MECHANISM*

FEI is proposing an efficiency carry-over mechanism (ECM) that incorporates some improvements from the ECM employed as part of the 2004 PBR Plan. The rationale for ECMs generally, and FEI's proposal to adopt an ECM, are addressed below.

6.5.1 Rationale for an ECM

The logic of incorporating an ECM is straightforward. For utilities operating under a fixed-term PBR, the value of the stream of savings to provide a payback of the Company's investments in efficiency improvements can only include those savings realized prior to the end of the term of the PBR. Therefore, the motivational power of incentives is highly dependent on the timing of the efficiency improvement gains. The reward for a utility is greatest when the efficiency savings are made in the first year of the PBR plan. The utility's incentive to pursue efficiency gains declines over the PBR term as the amount of time remaining to achieve a payback and return on efficiency investments becomes successively shorter. An ECM is a means of strengthening the incentive to pursue efficiency initiatives throughout the PBR term. The ECM does this by ensuring that the benefits of the efficiency gains are retained for a reasonable period after the PBR term. The benefit to customers of an ECM is that the greater efficiencies achieved throughout the PBR term become incorporated into rates going forward. A well-designed ECM decouples the link between the timing of efficiency gains and the PBR incentives and ensures that the stream of savings resulting from an investment in efficiencies will be allocated to help repay the investment regardless of how close the investment is to the end of the term of the PBR plan.

B&V's discussion on the rationale for an ECM is included in the PBR Report. B&V states, for instance, that "ECMs are an important factor in assuring that the efficiency incentive is not weakened as the end of the Regulatory Control Period approaches." (p.48) B&V further states:

> *"Using direct measures of capital and O&M efficiency gains and permitting those to carryover beyond the PBR period provides incentives for the utility to reduce costs based on an expected payback for the period of the carryover. The longer the period for carryover implies a lower required return for payback of the investment in efficiency while still being reasonably above the cost of capital so that customers also benefit beyond the reset of the regulatory control period."* (p.38)

As such, B&V supports the inclusion of an ECM in the PBR Plan, particularly with the enhancements discussed below.

6.5.2 Enhancing the Effectiveness of the 2004 PBR Plan ECM

FEI is proposing to include an ECM based on the 2004 PBR Plan, but with significant enhancements.

The 2004 PBR Plan included an ECM under which the accumulated capital benefits at the end of the term were phased-out by declining factors of 2/3 in the first year after the plan expiry and 1/3 in the second year after. B&V and FEI are of the view that the objective behind this mechanism was sound. B&V states in its PBR Report, for instance:

> *"While not approving the original FEI proposal [for the 2004 PBR Plan], the BCUC correctly recognized the need for an incentive to continue beyond the end of the plan and approved a mechanism to reflect the continuing benefit from such improvements. The logic behind this incentive is quite simple. When capital and other costs are rebased at the end of the control period all of the benefits from capital and savings on O&M immediately flow through to customers in lower rates. This means that investments in efficiency that have a longer payback period than the remaining time under the PBR plan would be discouraged because the utility could not expect a full payback on the investment before the savings were appropriated for customers. Unlike FEI, the FBC Plan did not include an ECM. Since capital was not included in the PBR, the annual review required by the exclusion would no longer be a necessity.*

Nevertheless, the ECM is a critical component of a PBR plan if the goal is to maximize efficiency during the pendency of the Plan." (p.47)

While the FEI 2004 PBR Plan mechanism increased the overall incentive power of the plan, it did not provide the optimal balance of incentive power between O&M and capital efficiencies over the whole term of the PBR. Under the approved capital-only approach, the incentive power in the first and early years of the PBR was higher than the later years of the PBR plan. In addition, the 2004 PBR ECM did not recognize the permanent efficiency gains that were achieved in O&M expenditures.

The effectiveness of the 2004 PBR Plan ECM can be enhanced in two ways:

1. by using a rolling carry-over approach; and
2. by including the O&M savings in the carried-over efficiencies.

Under a rolling ECM, efficiency gains are carried over for a specific number of years (5 years in the case of FEI's proposed term) following the year in which they occurred. The major advantage of a rolling ECM over other efficiency carry-over approaches is that it eliminates the timing issue from the decision making process of efficiency improvement investments. That is, the incentive power of PBR will remain the same for the entire PBR term. Also the addition of O&M savings is an essential part of an ECM model in order to maintain the incentive balance between capital and O&M expenditures. The equal treatment of cost savings between capital and O&M expenditures encourages the utility to seek the most efficient combination of these expenditure types throughout the PBR term.

Further, for O&M expenditures, the total efficiency gains are measured as the variance between actual expenditures and formula-based forecasts on a year-to-year incremental basis to avoid rolling forward of temporary savings. Capital expenditure savings however tend to be more discrete between the years and savings in one year implies a reduction in the costs of financing and other carrying costs rather than a permanent reduction in future capital spending. Therefore only a specific percentage of capital savings representing the avoided capital financing and carrying costs should be included in the ECM model. Similar to the 2004 PBR Plan, this percentage is identified as the "rate base benefit factor" in FEI's ECM model and is applied to the capital savings to account for average avoided financing and carrying costs (cost of capital, taxes and depreciation) in annual revenue requirements associated with the cost of service incurred by plant additions added to rate base.

Based on the above-mentioned principles, FEI proposes to balance the PBR incentives and improve the effectiveness of the 2004 PBR Plan ECM, by implementing a 5 year rolling-forward of the incremental O&M and capital savings calculated as the sum of:

1. Variance of current year formula-based O&M and actual O&M less cumulative O&M savings from prior years of the PBR Plan; and
2. Current year plant additions savings relative to current year allowed plant additions derived from the PBR capital formula multiplied by a rate base benefit factor of 15 percent.

The rate base benefit factor is representative of the avoided revenue requirements from reduced capital expenditures, which on average equal approximately 15 percent of the amount of the capital cost saving. The components that make up the avoided revenue requirements are the return on rate base, depreciation expense and associated taxes, sometimes referred to as rate base carrying costs. The calculations supporting the proposed 15 percent rate base benefit factor as well as an illustrative example of the proposed rolling ECM are provided in Appendix D6.

The effect of the 50/50 Earnings Sharing Mechanism extends beyond the PBR Plan term in the calculation of the ECM benefits that go to the customers through rate rebasing and the other half that is available to the Company through the rolling efficiency carry-over mechanism. This means the ECM phase-out of savings has the same 50:50 earnings sharing effect as the ESM does for the O&M and capital efficiencies during the PBR term.

B&V supports the proposed ECM because it permits the utility to maintain a continuous improvement culture rather than be concerned about the inability to earn the required return on investments made in efficiency and productivity occurring in the later years of the PBR Plan. By permitting a carryover to match the initial period of the plan, the utility invests in measures throughout the plan period and there is no disincentive as the PBR Plan comes to an end.

6.6 *SERVICE QUALITY INDICATORS*

Service Quality Indicators (SQIs) are used in the context of PBR to ensure that the utility is encouraged to pursue efficiencies that do not sacrifice service quality. B&V's discussion of SQIs appears at p.11 of its PBR Report (Appendix D1). SQIs were a key component of the 2004 PBR and FEI proposes to continue with this feature, with appropriate updates to the SQIs themselves.

The SQIs' design and targets have been unchanged since 2004 and FEI believes that based on an evaluation of the feedback received during the last 10 years it is appropriate to review and update the SQI elements. The 2014 Plan proposed SQIs include a number of new additions and replacement of some indicators with more relevant ones. The table below summarizes the proposed SQIs.

Table B6-9: Proposed 2014 PBR Improved SQIs

Performance measure	Indicator	Benchmark
Emergency response time	Percent of calls responded to within one hour	95%
Meter exchange appointment	Percent of appointments met for meter exchanges	95%
Telephone service factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	95%
Telephone service factor (Non Emergency)	Percent of non-emergency calls answered within 30 seconds or less	70%
First contact resolution	Percent of customers who achieved call resolution in one call	78%
Billing index	Measure of customer bills produced meeting performance criteria	5
Meter reading accuracy	Number of scheduled meters that were read	95%
All injury frequency rate	Informational indicator - 3 year rolling average of lost time injuries plus medical treatment injuries per 200,000 hours worked	---
Public contact with pipelines	Informational indicator - 3 year rolling average of number of line damages per 1,000 BC One Calls received	---
Customer satisfaction index	Informational indicator	---

FEI will report to the Commission and stakeholders at the Annual Review to allow a comparison of the performance of the Company against the targets set for each of the SQIs. A full discussion of the improved SQIs is included in Appendix D7 to this Application.

6.7 *MID-TERM REVIEW AND OFF RAMPS*

B&V has confirmed that the majority of PBR plans include provisions that protect the customers and the utility against the potential unintended or unexpected outcomes that may occur during the plan's term. These regulatory provisions may vary from modification of a particular element of the PBR design (regulatory review, also known as re-opener) to complete regulatory review or termination of the plan (also known as off-ramps). Similar to the 2004 PBR, FEI proposes a Mid-term Assessment Review of the PBR Plan and an off-ramp provision as the PBR's safeguard mechanisms. A discussion of each of the mentioned items follows.

6.7.1 Mid-term Assessment Review

A PBR Mid-term Assessment Review provides an opportunity for all the stakeholders to review the outcomes of the PBR and suggest adjustment to certain plan parameters (if required). The Mid-term review as part of the third Annual Review is intended to be a "checkpoint" to permit stakeholders to review the performance over the first three years and to address specific and discrete flaws with an otherwise workable plan. This limitation is important. Off-ramps exist for more fundamental flaws with the PBR Plan as a whole, and short of triggering those off-ramps, the PBR Plan should be allowed to play out unless there is consensus that an element of the plan is capable of being improved for the mutual benefit of stakeholders.

The proposed Mid-term Assessment Review will be held prior to the end of the third year (2016) of the term as part of the third Annual Review. Similar to the 2004 PBR Plan, the terms of reference of the Mid-term Assessment Review will be two fold:

1. If any one (or more) particular element of the PBR Plan appears to be inducing unintended outcomes or results in continuous material changes to service quality, then stakeholders will work to identify a change that can address that element and put it forward to the Commission.
2. If the results of operating under the PBR Plan have caused financial distress and, if so, to implement a change (an example might be significant inflationary pressures on sustainment capital expenditures that are not reflected in the province-wide CPI or AWE measures).

6.7.2 Off-ramp Provision

Whereas the Mid-term review is intended to be a "checkpoint" to permit stakeholders to address specific and discrete flaws with an otherwise workable plan, an "off-ramp provision" is a term of a PBR Plan that contemplates a complete regulatory review of the PBR Plan in particular limited circumstances. FEI is proposing both financial and non-financial triggers for the off-ramp provision. B&V considers that the inclusion of automatic quantitative re-openers or off ramp provisions is an improvement over the past FEI and FBC PBR plans:

> *"Both FEI's and FBC's Plans did not include any quantitative reopener[32] or off-ramp provisions. Under the annual review provision, FEI and FBC retained the right to request a change or termination of the Plan if there were unacceptable outcomes associated with the Plan. This provision does not represent the best approach to addressing serious issues with a PBR plan."* (p.46)

The proposed financial and non-financial triggers are discussed below.

6.7.2.1 Financial Trigger

Earnings-based trigger mechanisms, which are triggered if the actual ROE of the utility differs significantly from its approved ROE, is the most common form of off-ramp provisions. FEI is proposing that the PBR Plan be reviewed if the post-sharing achieved ROE of the Company exceeds or drops below the allowed ROE by 200 basis points in any single year of the PBR term.

[32] B&V is referring to an automatic reopener.

Finding the right balance between maintaining the PBR incentives and safeguarding the ratepayers and the Company is essential in design of the earnings-based off-ramps. The trigger point (the variance between earned and approved ROE) should be substantial enough to ensure that PBR's incentive powers are maintained (this is particularly important for a single year trigger point) and at the same time small enough to safeguard against potential excessive profits or losses. FEI believes that its proposed 200 basis point trigger achieves the appropriate balance[33]. B&V has discussed the considerations that go into the selection of an off-ramp in its PBR Report at p.9.

6.7.2.2 Non-Financial Triggers

In addition to the earnings based off-ramp provision, FEI proposes a number of non-financial SQIs to assist with the review and analysis of annual performance. The SQIs will provide a framework for determining whether there is a need for a complete regulatory review of the PBR Plan during the mid-term assessment review. Failure to meet one (or more) SQI benchmarks does not necessarily constitute unacceptable performance. Reasons provided by the Company as to why certain service quality indicator benchmarks were not met will be taken into account, recognizing that variances in performance may occur due to random events or events beyond the full control of FEI. Triggering of the off-ramp provision would be warranted only if there is sustained serious degradation of the SQIs.

6.8 *ANNUAL REVIEW*

The 2004 PBR Plan included an Annual Review which provided the Commission, interveners and interested parties an opportunity to review the Company's performance during the prior year. The Annual Review also provided these parties with forecasts and determined the delivery rates for the upcoming year. The Annual Review was a successful tool in communicating the Company's performance and activities, and also for understanding the issues and challenges facing the Company.

Based on the effectiveness of the past annual reviews, the FEI proposes to continue the Annual Review process for this PBR Plan. Each year, the Annual Review will present the current year's projections and the upcoming year's forecasts for a number of key measures, including:

1. Customer growth, volumes and revenues;
2. Year-end and average customers, and other cost driver information including inflation;
3. Expenses (determined by the PBR formula plus flow through items);
4. Capital expenditures (as determined by the PBR formula plus flow through items);

[33] The 2004 PBR Plan had a trigger mechanism of 150 basis points (after earnings sharing) above or below the allowed ROE that was not an automatic off-ramp. It was open for parties to request a Commission review of the 2004 PBR Plan if this threshold was exceeded but the 150 basis point threshold was not exceeded in the six-year term.

5. Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates;
6. Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year
7. Service Quality Indicator results; and
8. Any proposals for funding of incremental resources in support of customer service and load growth initiatives.

FEI expects that the Annual Review regulatory process will generally include a workshop, one round of IRs from the Commission and Interveners, letters of comment and a Commission determination of rates.

What follows is Table B6-10, a summary comparison of FEI's current PBR Plan proposal and the 2004 Plan.

1 **Table B6-10: FEI PBR Plans Comparison**

Item	2004 PBR Application	2014 PBR Application
Term	Five year term proposed. A four year term from 2004-2007 was approved after NSP, Two year extension to 2009 approved later.	A five year term from 2014-2018 is proposed
Inflation Factor (I-Factor)	A forecast of BC-CPI was used as the I-factor.	A weighted average of BC-CPI as well as Average Weekly Earnings will be used to determine inflation forecasts.
Productivity Improvement Factor (X-Factor)	Approved adjustment factors (i.e. X-Factors): 50% of CPI 2004 and 2005, 66% from 2006 to 2009.	A fixed X-Factor of 0.5% is proposed
Controllable Expenses - O&M	A formula based approach for O&M was approved. 2003 approved O&M used as a base, escalated each year by customer growth and inflation less the adjustment factor (i.e. I-X). No O&M rebasing during the PBR term; however formula amounts were trued-up going forward for actual customer growth.	Same O&M formula structure & annual O&M escalation proposed as in 2004 PBR. 2013 approved O&M expenditures (with adjustments) proposed as the base. No rebasing but same customer true-up as in 2004 PBR.
Controllable Expenses – Capital	Base capital expenditures in each year were based on forecast net customer additions for growth capital and forecast average number of customers for other base capital. Capital costs were also escalated annually by BC-CPI less the adjustment factor. CPCNs (>$5 million) were outside the formula. No capital rebasing during the term however formula amounts were subject to true-up going forward for actual customer growth.	Same capital formula structure and escalation as in 2004 PBR. Cost driver for growth capital changed to service line additions. Same treatment for CPCNs and customer count true-up as in 2004. Limited rebasing of capital will occur if annual capital expenditures are above or below the formula-based amount by more than 10%.
Controllable Expenses - Other Revenue	FEVI Wheeling Agreement and SCP third party revenues forecast each year at the Annual Review. The Late Payment revenue was adjusted by inflation less the adjustment factor.	All Other Revenue items to be reforecast annually.
Exogenous Factors	These factors included judicial, legislative or administrative changes, orders or directions, catastrophic events, bypass or similar events, major seismic incidents, acts of war, terrorism or violence, changes in accounting principles, standards or policies, and changes in revenue requirements due to Commission directions.	Same exogenous factors as in the 2004 Plan.
Flow Through Expenses & Revenues	Revenues and non-controllable expenses (such as property taxes, interest costs, return on equity, pension/OPEB costs, insurance costs, depreciation rate changes, amortization of deferral accounts and others) were reforecast annually and flowed through in rates in the Annual Review process.	Same flow-through expense items and treatment as in 2004 PBR. Rate Schedule 16 O&M is a new item for annual reforecasting and flow-through treatment.

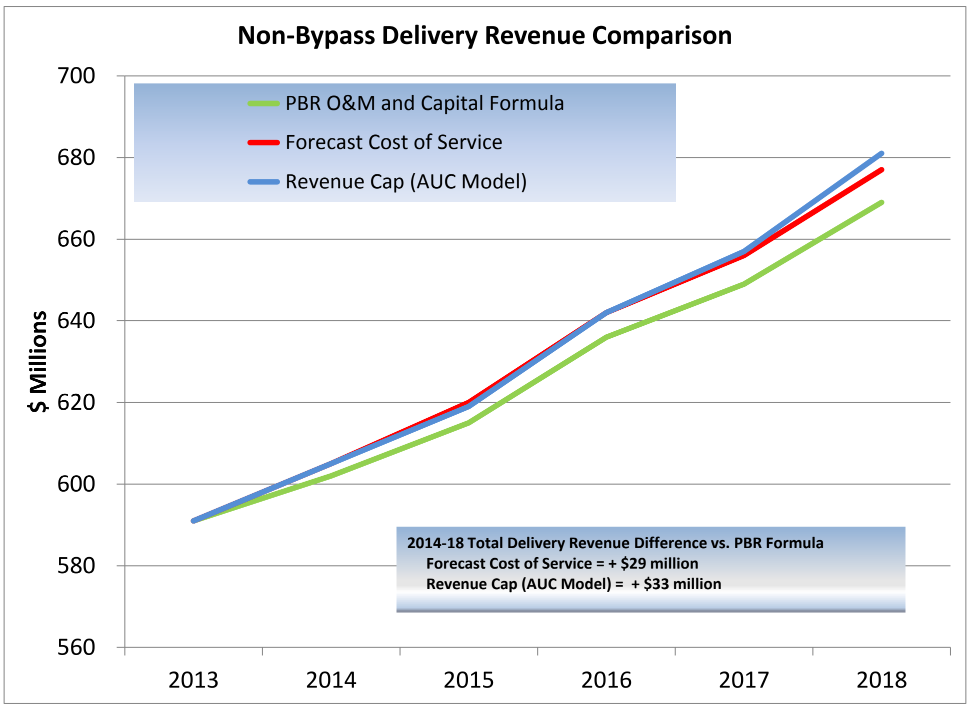
Item	2004 PBR Application	2014 PBR Application
Earnings Sharing Mechanism	A 50/50 earnings sharing mechanism was applied during this PBR. The difference between the allowed and actual ROE was shared equally between customers and shareholders.	Earnings sharing will be the same as in 2004 PBR at 50/50 earnings sharing above and below the approved ROE.
End of Term Efficiency (Efficiency Carry-Over Mechanism)	At the end of the PBR term, cumulative capital savings were returned to customers over a two year period, with one third being refunded in the first year and two thirds refunded in the second year.	An enhanced ECM is proposed that considers capital and O&M benefits on a rolling five year basis.
Service Quality Indicators	A set of 10 SQIs and 2 directional indicators. 3 of the 10 SQIs were recognized as being susceptible to external influences beyond the Company's control and were to be given less weight.	An improved set of 10 SQIs is proposed dealing with emergency response, customer service (telephone service, billing), employee safety and meter exchanges. 3 of the 10 SQIs are considered to be informational indicators.
Mid-term Review and Off Ramps	A midterm assessment review was held prior to the end of the third year of the PBR (2006). Any party could request a Commission review of the PBR Plan if the achieved ROE (after earnings sharing) was more than 150 basis points above or below the allowed ROE.	A midterm assessment review is proposed prior to the end of the third year of the PBR (2016). A review of the PBR Plan may be triggered by either a 200 basis point ROE variance above or below the allowed ROE, or sustained serious degradation of service quality as measured by the SQIs
Periodic Review	An annual review was conducted at the end of each year to provide a report on company performance.	An annual review is also proposed for this PBR.

7. DELIVERY REVENUE FORECASTS UNDER PBR

FEI has looked at three delivery revenue[34] scenarios for the years 2014 through 2018. They are:

- FEI's PBR Plan Proposal (green line in the graph below);
- Cost of Service using the O&M and capital forecasts included in Sections C3 and C4 using forecast inflation (red line)
- A delivery revenue cap per customer scenario using the same assumptions as the PBR Plan Proposal (blue line).

Figure B-5: Non-Bypass Delivery Margin Comparison



The differences in required revenues in the graph above reflect the customer benefit of the proposed PBR formula as compared to either the cost-based approach of setting rates or a delivery revenue cap per customer approach. FEI's PBR Plan results in non-bypass delivery

[34] The chart compares non-bypass delivery revenues under the various scenarios, which comprise more than 90% of FEI's total delivery revenues. The analysis adopts non-bypass delivery revenues as the basis of comparison since these represent the customer classes that receive rate adjustments through revenue requirement applications. Bypass and special contract revenues are excluded as they do not receive RRA rate increases or decreases.

revenues that are lower by an estimated $29 million over the five-year period than the Cost of Service scenario using the forecast O&M and capital expenditures included in this Application. In 2018, the fifth year of the PBR Plan, the non-bypass delivery revenues under the PBR are approximately 1.2 percent lower than those under the forecast Cost of Service scenario. The PBR Plan also produces delivery revenues that are lower by $33 million over the five-year period than a revenue cap model (similar to the type approved by the AUC in its Decision 2012-237).

In addition, the PBR Proposal offers both regulatory efficiencies and the opportunity for lower rates for customers through the ESM as compared to the Cost of Service approach. The PBR Proposal offers greater flexibility in addressing uncontrollable matters as compared to the delivery revenue per customer approach.

Deleted: 34

Deleted: 2

Deleted: 35

8. CONCLUSION

B&V and FEI regard FEI's proposed PBR Plan as capturing the best elements of the past plans, while improving upon some of the aspects that could work better. B&V's conclusion in its PBR Report sums up this view:

> *"FEI's and FBC's past PBR Plans provide valuable perspectives in the evolution to its currently proposed Plan. It is reasonable to conclude that no plan will be perfect in all respects (and thus the importance of settlement in satisfying the public interest). Subsequent plans should improve on the elements of the plan that were deficient and continue those elements that were successful. In particular, FEI and FBC should change the basis for determining the I-Factor and the ECM method. In addition, retaining the successful elements of the plan such as the ESM and the transparency created by the annual review are examples where the prior Plan benefited stakeholders. Further, by recognizing deficiencies of other plans as discussed above FEI and FBC will avoid implementing a Plan that does not represent the best interest of stakeholders. Neither excess earnings nor deficient earnings benefit stakeholders. The Plan should meet the goals of providing just and reasonable rates and a reasonable opportunity to earn the allowed return. If those goals are met all stakeholders benefit from a financially sound utility that provides reasonably priced services and does so with a safe, efficient and reliable system".* (p.47)

Summary of Rate Change Evidentiary Update - February 21, 2014

Section E
FORMULA
Schedule 1

Line No.	Particulars	2014 ($ Millions)		Cross Reference
1	(1)	(2)		(3)
2	Volume/Revenue Related			
3	Customer Growth and Use Rates	(7.2)		
4	Change in Other Revenue	0.2	(7.0)	
5				
6	O&M Changes			
7	Gross O&M Increases	(2.6)		
8	Less: Capitalized Overhead	0.3	(2.3)	
9				
10	Depreciation Expense			
11	Change in Depreciation Rates	(0.2)		
12	Tax Expense Impact of Depreciation Changes	0.3		
13	Depreciation from Net Additions	1.0	1.1	
14				
15	Amortization Expense			
16	CIAC	(0.0)		
17	Deferral Accounts	3.7	3.7	
18				
19	Other			
20	Property and Other Taxes	(2.4)		
21	Income Tax Rate Change	1.9		
22	Other Income Tax Changes	11.1		
23	Financing Rate Changes	(2.9)		
24	Financing Changes	0.2		
25	Rate Base Growth	0.3	8.2	
26				
27	**Revenue Deficiency (Surplus)**		**3.7**	- Section E-FORMULA, Sch 2
28				

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Non-Bypass Sales	2014 Non-Bypass Transportation	2014 Bypass and Special Rates	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,113,989	$ 1,011,096	$ 83,059	$ 11,524	$ 1,105,679	$ (8,310)	- Section E-FORMULA, Sch 8
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,237	-	-	18,138	18,138	(99)	- Section E-FORMULA, Sch 13
8								
9	Total Revenue	1,132,226	1,011,096	83,059	29,662	1,123,817	(8,409)	
10								
11	Less - Cost of Gas	(505,614)	(494,561)	(250)	(248)	(495,059)	10,555	- Section E-FORMULA, Sch 9
12								
13	Gross Margin	$ 626,612	$ 516,535	$ 82,809	$ 29,414	$ 628,758	$ 2,146	
14								
15	Revenue Deficiency (Surplus)	$ -	$ 3,197	$ 513	$ -	**$ 3,710**	$ 3,710	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	0.62%	0.62%	0.00%	0.59%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	0.32%	0.62%	0.00%	0.33%		
20								

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Section E
FORMULA
Schedule 3

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	ENERGY VOLUMES (TJ)					
2	Sales	113,621	112,327	113,914	1,587	- Section E-FORMULA, Sch 5
3	Transportation	86,767	94,833	97,837	3,004	- Section E-FORMULA, Sch 5
4		200,388	207,160	211,751	4,591	
5						
6	Average Rate per GJ					
7	Sales	$ 9.106	$ 10.426	$ 8.943	$ (1.483)	
8	Transportation	$ 1.039	$ 0.946	$ 0.974	$ 0.028	
9	Average	$ 5.616	$ 6.086	$ 5.226	$ (0.860)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 1,034,629	$ 1,171,155	$ 1,018,733	$ (152,422)	- Section E-FORMULA, Sch 7
13	- Increase / (Decrease)	-	-	-	-	
14	RSAM Revenue	472	-	(7,323)	(7,323)	
15	Transportation - Existing Rates	90,183	89,704	95,257	5,553	- Section E-FORMULA, Sch 7
16	- Increase / (Decrease)	-	-	-	-	
17						
18	**Total Revenue**	1,125,284	1,260,859	1,106,667	(154,192)	
19						
20	Cost of Gas Sold (Including Gas Lost)	539,821	658,568	505,614	(152,954)	- Section E-FORMULA, Sch 9
21						
22	**Gross Margin**	585,463	602,291	601,053	(1,238)	
23						
24	Operation and Maintenance	187,925	202,963	196,170	(6,793)	- Section E-FORMULA, Sch 15
25	Property and Sundry Taxes	49,656	51,239	51,239	-	- Section E-FORMULA, Sch 19
26	Depreciation and Amortization	123,928	142,912	142,909	(3)	- Section E-FORMULA, Sch 21
27	Other Operating Revenue	(24,501)	(24,789)	(24,165)	624	- Section E-FORMULA, Sch 12
28	Sub-total	337,008	372,325	366,153	(6,172)	
29	Utility Income Before Income Taxes	248,454	229,966	234,900	4,934	
30						
31	Income Taxes	26,880	24,066	25,325	1,259	- Section E-FORMULA, Sch 23
32						
33	**EARNED RETURN**	$ 221,574	$ 205,900	209,576	$ 3,676	- Section E-FORMULA, Sch 59
34						
35						
36	**UTILITY RATE BASE**	$ 2,692,824	$ 2,767,651	$ 2,688,936	$ (78,715)	- Section E-FORMULA, Sch 29
37						
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.23%	7.44%	7.79%	0.35%	- Section E-FORMULA, Sch 59

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	113,914	114,087	-	114,087	173	- Section E-FORMULA, Sch 6
3	Transportation	97,837	98,330	-	98,330	493	- Section E-FORMULA, Sch 6
4		211,751	212,417	-	212,417	666	
5							
6	Average Rate per GJ						
7	Sales	$ 8.943	$ 8.862	$ -	$ 8.891	$ (0.052)	
8	Transportation	$ 0.974	$ 0.962	$ -	$ 0.967	$ (0.007)	
9	Average	$ 5.226	$ 5.205	$ -	$ 5.223	$ (0.003)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,018,733	$ 1,011,096	$ -	$ 1,011,096	$ (7,637)	- Section E-FORMULA, Sch 8
13	- Increase / (Decrease)	-	-	3,196	3,196	3,196	- Section E-FORMULA, Sch 10
14	RSAM Revenue	(7,323)				7,323	
15	Transportation - Existing Rates	95,257	94,582	-	94,582	(675)	- Section E-FORMULA, Sch 8
16	- Increase / (Decrease)	-		514	514	514	- Section E-FORMULA, Sch 10
17							
18	**Total Revenue**	1,106,667	1,105,678	3,710	1,109,388	2,721	
19							
20	Cost of Gas Sold (Including Gas Lost)	505,614	496,151	-	496,151	(9,463)	- Section E-FORMULA, Sch 9
21							
22	**Gross Margin**	601,053	609,527	3,710	613,237	12,184	
23							
24	Operation and Maintenance	196,170	200,684	-	200,684	4,514	- Section E-FORMULA, Sch 15
25	Property and Sundry Taxes	51,239	48,797	-	48,797	(2,442)	- Section E-FORMULA, Sch 20
26	Depreciation and Amortization	142,909	147,446	-	147,446	4,537	- Section E-FORMULA, Sch 22
27	Other Operating Revenue	(24,165)	(24,567)	-	(24,567)	(402)	- Section E-FORMULA, Sch 13
28	Sub-total	366,153	372,360	-	372,360	6,207	
29	Utility Income Before Income Taxes	234,900	237,167	3,710	240,877	5,977	
30							
31	Income Taxes	25,325	36,398	964	37,362	12,037	- Section E-FORMULA, Sch 24
32							
33	**EARNED RETURN**	$ 209,576	$ 200,769	$ 2,746	$ 203,515	$ (6,061)	- Section E-FORMULA, Sch 60
34							
35							
36	**UTILITY RATE BASE**	$ 2,688,936	$ 2,777,435	$ 277	$ 2,777,712	$ 88,776	- Section E-FORMULA, Sch 30
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.79%	7.23%		7.33%	-0.47%	- Section E-FORMULA, Sch 60

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Projected Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	69,753.0	69,816.4	69,644.2	-	69,644.2	(172.2)	
3	Schedule 2 - Small Commercial	24,319.0	23,331.9	24,087.6		24,087.6	755.7	
4	Schedule 3 - Large Commercial	16,744.0	16,514.8	17,354.8		17,354.8	840.0	
5								
6	Schedules 1, 2 and 3	110,816.0	109,663.1	111,086.6	-	111,086.6	1,423.5	
7								
8	Schedule 4 - Seasonal	169.0	185.2	169.1		169.1	(16.1)	
9	Schedule 5 - General Firm	2,315.0	2,407.7	2,315.3		2,315.3	(92.4)	
10								
11	Industrials							
12	Schedule 7 - Interruptible	87.0	14.2	86.7		86.7	72.5	
13								
14	Schedule 6 - N G V Fuel - Stations	62.0	56.4	61.4		61.4	5.0	
15	Schedule 16 - Liquefied Natural Gas (LNG)	172.0	-	194.7		194.7	194.7	
16	Schedule 46 - Liquefied Natural Gas (LNG)			-		-	-	
17								
18	Total Sales	113,621.0	112,326.6	113,913.8	-	113,913.8	1,587.2	- Section E-FORMULA, Sch 3
19								
20	**TRANSPORTATION SERVICE**							
21	Schedule 22 - Firm Service	18,884.0	17,089.5	13,208.0	6,874.9	20,082.9	2,993.4	
22	- Interruptible Service	18,760.0	12,302.6	15,940.9	-	15,940.9	3,638.3	
23	Byron Creek (aka Fording Coal Mountain)	393.0	227.4		179.1	179.1	(48.3)	
24	Burrard Thermal - Firm	482.0	1,372.0		482.5	482.5	(889.5)	
25	FEVI - Firm	21,244.0	37,080.0		33,553.2	33,553.2	(3,526.8)	
26	Schedule 23 - Large Commercial	7,803.0	7,485.3	8,168.1		8,168.1	682.8	
27	Schedule 25 - Firm Service	12,829.0	13,471.3	12,268.5	837.3	13,105.8	(365.5)	
28	Schedule 27 - Interruptible Service	6,372.0	5,804.8	6,324.5		6,324.5	519.7	
29								
30	Total Transportation Service	86,767.0	94,832.9	55,910.0	41,927.0	97,837.0	3,004.1	- Section E-FORMULA, Sch 3
31								
32	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,388.0	207,160.0	169,823.8	41,927.0	211,750.8	4,591.3	- Section E-FORMULA, Sch 3
33								

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2014

Line No.	Particulars	2013 PROJECTED	2014 Forecast Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	69,644.2	69,511.7	-	69,511.7	(132.5)	
3	Schedule 2 - Small Commercial	24,087.6	24,246.8		24,246.8	159.2	
4	Schedule 3 - Large Commercial	17,354.8	17,253.0		17,253.0	(101.8)	
5							
6	Schedules 1, 2 and 3	111,086.6	111,011.5	-	111,011.5	(75.1)	
7							
8	Schedule 4 - Seasonal	169.1	169.1		169.1	-	
9	Schedule 5 - General Firm	2,315.3	2,315.3		2,315.3	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	86.7	86.7		86.7	-	
13							
14	Schedule 6 - N G V Fuel - Stations	61.4	61.4		61.4	-	
15	Schedule 16 - Liquefied Natural Gas (LNG)	194.7	165.0		165.0	(29.7)	
16	Schedule 46 - Liquefied Natural Gas (LNG)	-	277.7		277.7	277.7	
17							
18	Total Sales	113,913.8	114,086.7	-	114,086.7	172.9	- Section E-FORMULA, Sch 4
19							
20	**TRANSPORTATION SERVICE**						
21	Schedule 22 - Firm Service	20,082.9	13,188.4	6,553.2	19,741.6	(341.3)	
22	- Interruptible Service	15,940.9	15,822.0	-	15,822.0	(118.9)	
23	Byron Creek (aka Fording Coal Mountain)	179.1		176.6	176.6	(2.5)	
24	Burrard Thermal - Firm	482.5		482.5	482.5	-	
25	FEVI - Firm	33,553.2		33,720.0	33,720.0	166.8	
26	Schedule 23 - Large Commercial	8,168.1	8,721.3		8,721.3	553.2	
27	Schedule 25 - Firm Service	13,105.8	12,352.3	837.3	13,189.6	83.8	
28	Schedule 27 - Interruptible Service	6,324.5	6,476.3		6,476.3	151.8	
29							
30	Total Transportation Service	97,837.0	56,560.3	41,769.6	98,329.9	492.9	- Section E-FORMULA, Sch 4
31							
32	**TOTAL SALES AND TRANSPORTATION SERVICES**	211,750.8	170,647.0	41,769.6	212,416.6	665.8	- Section E-FORMULA, Sch 4
33							- Section E-FORMULA, Sch 11

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	$ 684,879	$ 777,332	$ 672,249	$ -	$ 672,249	$ (105,083)	
3	Schedule 2 - Small Commercial	207,547	229,774	204,217		204,217	(25,557)	
4	Schedule 3 - Large Commercial	123,547	142,700	124,396		124,396	(18,304)	
5	Schedules 1, 2 and 3	1,015,973	1,149,806	1,000,862	-	1,000,862	(148,944)	
6								
7	Schedule 4 - Seasonal	945	1,285	939	-	939	(346)	
8	Schedule 5 - General Firm	15,405	19,409	14,522		14,522	(4,887)	
9		16,350	20,694	15,461	-	15,461	(5,233)	
10	Industrials							
11	Schedule 7 - Interruptible	489	137	456	-	456	319	
12								
13	Schedule 6 - N G V Fuel - Stations	480	518	461		461	(57)	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,337	-	1,493		1,493	1,493	
15	Schedule 46 - Liquefied Natural Gas (LNG)			-		-	-	
16	Total Sales	1,034,629	1,171,155	1,018,733	-	1,018,733	(152,422)	- Section E-FORMULA, Sch 3
17								
18	**Transportation Service**							
19	Schedule 22 - Firm Service	7,173	9,459	10,523	823	11,346	1,887	
20	- Interruptible Service	17,350	11,987	14,721	-	14,721	2,734	
21	Byron Creek (aka Fording Coal Mountain)	78	55		32	32	(23)	
22	Burrard Thermal - Firm	9,965	9,996		9,965	9,965	(31)	
23	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch12)	-	-		-	-	-	
24	Schedule 23 - Large Commercial	22,810	22,845	24,566	-	24,566	1,721	
25	Schedule 25 - Firm Service	24,484	27,382	25,399	704	26,103	(1,279)	
26	Schedule 27 - Interruptible Service	8,323	7,980	8,524	-	8,524	544	
27	Total Transportation Service	90,183	89,704	83,733	11,524	95,257	5,553	- Section E-FORMULA, Sch 3
28								
29	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,124,812	$ 1,260,859	$ 1,102,466	$ 11,524	$ 1,113,990	$ (146,869)	- Section E-FORMULA, Sch 3

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 672,249	$ 667,279	$ -	$ 667,279	$ (4,970)	
3	Schedule 2 - Small Commercial	204,217	201,875		201,875	(2,342)	
4	Schedule 3 - Large Commercial	124,396	121,939		121,939	(2,457)	
5	Schedules 1, 2 and 3	1,000,862	991,093	-	991,093	(9,769)	
6							
7	Schedule 4 - Seasonal	939	939	-	939	-	
8	Schedule 5 - General Firm	14,522	14,522		14,522	-	
9		15,461	15,461	-	15,461	-	
10	Industrials						
11	Schedule 7 - Interruptible	456	456	-	456	-	
12							
13	Schedule 6 - N G V Fuel - Stations	461	461		461	-	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,493	1,325		1,325	(168)	
15	Schedule 46 - Liquefied Natural Gas (LNG)	-	2,300		2,300	2,300	
16	Total Sales	1,018,733	1,011,096	-	1,011,096	(7,637)	- Section E-FORMULA, Sch 4
17							
18	**Transportation Service**						
19	Schedule 22 - Firm Service	11,346	8,397	823	9,220	(2,126)	
20	- Interruptible Service	14,721	14,379	-	14,379	(342)	
21	Byron Creek (aka Fording Coal Mountain)	32		32	32	-	
22	Burrard Thermal - Firm	9,965		9,965	9,965	-	
23	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch13)	-		-	-	-	
24	Schedule 23 - Large Commercial	24,566	26,120	-	26,120	1,554	
25	Schedule 25 - Firm Service	26,103	25,460	704	26,164	61	
26	Schedule 27 - Interruptible Service	8,524	8,702	-	8,702	178	
27	Total Transportation Service	95,257	83,058	11,524	94,582	(675)	- Section E-FORMULA, Sch 4
28							
29	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,113,990	$ 1,094,154	$ 11,524	$ 1,105,678	$ (8,312)	- Section E-FORMULA, Sch 4 - Section E-FORMULA, Sch 11

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Projected Gas Costs Non-Bypass Sales & Transp	2013 Projected Gas Costs Bypass and Special Rates	2013 Projected Gas Costs Total	2014 Forecast Gas Costs Non-Bypass Sales & Transp	2014 Forecast Gas Costs Bypass and Special Rates	2014 Forecast Gas Costs Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	310,537	$ -	$ 310,537	$ 305,432	$ -	$ 305,432
3	Schedule 2 - Small Commercial	110,811		110,811	107,890		107,890
4	Schedule 3 - Large Commercial	72,872		72,872	70,770		70,770
5							
6	Schedules 1, 2 and 3	494,220	-	494,220	484,092	-	484,092
7							
8	Schedule 4 - Seasonal	629		629	629		629
9	Schedule 5 - General Firm	8,660		8,660	8,660		8,660
10							
11	Schedules 4 and 5	9,289	-	9,289	9,289	-	9,289
12							
13	Industrials						
14	Schedule 7 - Interruptible	323		323	323		323
15							
16	Schedule 6 - N G V Fuel - Stations	208		208	208		208
17	Schedule 16 - Liquefied Natural Gas (LNG)	697		697	649		649
18	Schedule 46 - Liquefied Natural Gas (LNG)	-		-	1,092		1,092
19							
20	Total Sales	504,737	-	504,737	495,653	-	495,653
21							
22	**TRANSPORTATION SERVICE**						
23	Schedule 22 - Firm Service	268	58	326	44	31	75
24	- Interruptible Service	58	-	58	73	-	73
25	Byron Creek (aka Fording Coal Mountain)		7	7		-	-
26	Burrard Thermal - Firm		5	5		3	3
27	FEVI - Firm		324	324		210	210
28	Schedule 23 - Large Commercial	41	-	41	43	-	43
29	Schedule 25 - Firm Service	71	6	77	59	4	63
30	Schedule 27 - Interruptible Service	39	-	39	31	-	31
31							
32	Total Transportation Service	477	400	877	250	248	498
33							
34	TOTAL SALES AND TRANSPORTATION SERVICES	$ 505,214	$ 400	$ 505,614	$ 495,903	$ 248	$ 496,151
35							
36	Cross Reference			- Section E-FORMULA, Sch 3			- Section E-FORMULA, Sch 4

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			Revenue		Gross Margin		Effective Increase / (Decrease)			Revenue	
			-- At Existing 2013 Rates --		-- At Existing 2013 Rates --		0.62%	of Margin			
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000s)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000s)	Average Number of Customers	Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,511.7	$ 9.600	$ 667,279	$ 5.206	$ 361,847	$ 0.032	$ 2,244	765,842	$ 9.632	$ 669,523
4	Schedule 2 - Small Commercial	24,246.8	8.326	201,875	3.876	93,986	0.024	582	72,614	8.350	202,457
5	Schedule 3 - Large Commercial	17,253.0	7.068	121,939	2.966	51,168	0.018	318	4,577	7.086	122,257
6	Schedules 1, 2 and 3	111,011.5		991,093		507,001		3,144	843,033		994,237
7											
8	Schedule 4 - Seasonal	169.1	5.553	939	1.833	310	0.012	2	26	5.565	941
9	Schedule 5 - General Firm	2,315.3	6.272	14,522	2.532	5,863	0.016	36	216	6.288	14,558
10											
11	Industrials										
12	Schedule 7 - Interruptible	86.7	5.260	456	1.546	134	0.012	1	3	5.272	457
13											
14	Schedule 6 - N G V Fuel - Stations	61.4	7.508	461	4.137	254	0.033	2	14	7.541	463
15	Schedule 16 - Liquefied Natural Gas (LNG)	165.0	8.030	1,325	4.103	677	0.024	4	2	8.054	1,329
16	Schedule 46 - Liquefied Natural Gas (LNG)	277.7	8.282	2,300	4.350	1,208	0.025	7	3	8.307	2,307
17	Total Sales	114,086.7		1,011,096		515,447		3,196	843,297		1,014,292
18											
19	TRANSPORTATION SERVICE										
20	Schedule 22 - Firm Service	13,188.4	0.637	8,397	0.633	8,353	0.004	52	14	0.641	8,449
21	- Interruptible Service	15,822.0	0.909	14,380	0.904	14,307	0.006	89	25	0.915	14,469
22	Schedule 23 - Large Commercial	8,721.3	2.995	26,120	2.990	26,078	0.018	161	1,560	3.013	26,281
23	Schedule 25 - Firm Service	12,352.3	2.061	25,460	2.056	25,401	0.013	158	487	2.074	25,618
24	Schedule 27 - Interruptible Service	6,476.3	1.344	8,702	1.339	8,671	0.008	54	95	1.352	8,756
25											
26	Total Transportation Service	56,560.3		83,059		82,810		514	2,181		83,573
27											
28	Total Non-Bypass Sales & Transportation Service	170,647.0		$ 1,094,155		$ 598,257		$ 3,710	845,478		$ 1,097,865
29											
30	Cross Reference	ection E-FORMULA, Sch 6	- Section E-FORMULA, Sch 8				- Section E-FORMULA, Sch 2				

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2013 Rates -- Average $/GJ	Revenue -- At Existing 2013 Rates -- Revenue ($000)	Gross Margin -- At Existing 2013 Rates -- Average $/GJ	Gross Margin -- At Existing 2013 Rates -- Margin ($000s)	Increase / (Decrease) 0.62% of Margin $/GJ	Increase / (Decrease) 0.62% of Margin Revenue ($000)	Average Number of Customers	Revenue Average $/GJ	Revenue Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,553.2	$ 0.126	$ 823	$ 0.121	$ 791	$ -	$ -	5	$ 0.126	$ 823
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	176.6	0.181	32	0.181	32	-	-	1	0.181	32
6	Burrard Thermal - Firm	482.5	20.653	9,965	20.647	9,962	-	-	1	20.653	9,965
7	FEVI - Firm (Revenue/Margin in Other Revenue - Sch13)	33,720.0	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
9	Schedule 25 - Firm Service	837.3	0.841	704	0.836	700	-	-	6	0.841	704
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	41,769.6		11,524		11,485		-	15		11,524
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	212,416.6		$ 1,105,679		$ 609,742		$ 3,710	845,493		$ 1,109,389
15											
16	Cross Reference	ection E-FORMULA, Sch 6	- Section E-FORMULA, Sch 8				- Section E-FORMULA, Sch 2				

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 2,402	$ 2,333	$ 2,109	$ (224)	- Section E-FORMULA, Sch 56
4						
5	Connection Charge	2,390	2,685	2,622	(63)	- Section E-FORMULA, Sch 56
6						
7	NSF Returned Cheque Charges	110	79	79	-	- Section E-FORMULA, Sch 56
8						
9	Other Recoveries	237	126	284	158	- Section E-FORMULA, Sch 56
10						
11	Total Other Utility Revenue	5,139	5,223	5,094	(129)	
12						
13	**Miscellaneous Revenue**					
14						
15	FEVI Wheeling Charge	3,353	3,464	3,464	-	
16						
17	SCP Third Party Revenue	15,272	14,827	14,773	(54)	
18						
19	FEVI SAP Lease Income	17	-	-	-	- Section E-FORMULA, Sch 56
20						
21	NGT Overhead and Marketing Recovery	-	-	-	-	- Section E-FORMULA, Sch 56
22						
23	Biomethane Other Revenue	-	(29)	(97)	(68)	- Section E-FORMULA, Sch 56
24						
25	CNG & LNG Service Revenues	720	1,304	931	(373)	- Section E-FORMULA, Sch 56
26						
27						
28	Total Miscellaneous	19,362	19,566	19,071	(495)	
29						
30	**Total Other Operating Revenue**	$ 24,501	$ 24,789	$ 24,165	$ (624)	- Section E-FORMULA, Sch 3

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,109	$ 2,089	$ (20)	- Section E-FORMULA, Sch 56
4					
5	Connection Charge	2,622	2,636	14	- Section E-FORMULA, Sch 56
6					
7	NSF Returned Cheque Charges	79	79	-	- Section E-FORMULA, Sch 56
8					
9	Other Recoveries	284	284	-	- Section E-FORMULA, Sch 56
10					
11	Total Other Utility Revenue	5,094	5,088	(6)	
12					
13	**Miscellaneous Revenue**				
14					
15	FEVI Wheeling Charge	3,464	3,365	(99)	- Section E-FORMULA, Sch 2
16					
17	SCP Third Party Revenue	14,773	14,773	-	- Section E-FORMULA, Sch 2
18					
19	FEVI SAP Lease Income	-	-	-	- Section E-FORMULA, Sch 56
20					
21	NGT Overhead and Marketing Recovery	-	180	180	- Section E-FORMULA, Sch 56
22					
23	Biomethane Other Revenue	(97)	(198)	(101)	- Section E-FORMULA, Sch 56
24					
25	CNG & LNG Service Revenues	931	1,359	428	- Section E-FORMULA, Sch 56
26					
27					
28	Total Miscellaneous	19,071	19,479	408	
29					
30	**Total Other Operating Revenue**	$ 24,165	$ 24,567	$ 402	- Section E-FORMULA, Sch 4

FORMULA GROSS OPERATING & MAINTENANCE EXPENSE
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

Line No.	Particulars (1)		(2)	2013 Base (3)	2014 Formula (4)	Cross Reference (5)
1						
2						
3	**Cost Drivers for Formulaic O&M**					
4	CPI				1.83%	
5	AWE				2.70%	
6	Labour Split					
7		Non Labour			45.00%	
8		Labour			55.00%	
9	CPI/AWE		(line 4 * line 7) + (line 5 * line 8)		2.31%	
10	Productivity Factor				-0.50%	
11	Customer Growth				0.57%	
12	Net Inflation Factor		(1 + line 9 + line 10) * (1 + line 11)		**102.39%**	
13						
14	**2013 Base O&M**			$ 229,488		
15	Remove O&M tracked outside of Formula					
16		Pension/OPEB (O&M portion)		(25,312)		
17		Insurance		(4,710)		
18		Bio-Methane O&M		(410)		
19		NGT Stations O&M		(289)		
20		Tilbury 2 O&M				
21		RS 16 O&M				
22	**O&M Subject to Formula**		(prior year * line 12)	198,768	203,514	
23	O&M tracked outside of Formula					
24		Pension/OPEB (O&M portion)		25,312	24,113	
25		Insurance		4,710	4,990	
26		Bio-Methane O&M		410	590	
27		NGT Stations O&M		289	433	
28		Tilbury 2 O&M		-		
29		RS 16 O&M		-	376	
30						
31	**Formulaic O&M**			229,488	234,016	- Section E-FORMULA, Sch 15
32	Cross Reference			- Table C3-2 in Application		- Section E-FORMULA, Sch 18
33						

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	M&E Costs	$ 50,708	$ 59,097	$ 52,770		
2	COPE Costs	32,450	37,183	31,426		
3	COPE Customer Services Costs	11,825	11,144	10,977		
4	IBEW Costs	27,180	27,640	25,156		
5						
6	**Labour Costs**	**122,164**	**135,064**	**120,330**		
7						
8	Vehicle Costs	3,807	3,685	4,134		
9	Employee Expenses	5,898	5,716	5,744		
10	Materials and Supplies	7,903	7,019	8,764		
11	Computer Costs	14,570	14,769	16,397		
12	Fees and Administration Costs	38,611	37,905	37,790		
13	Contractor Costs	31,955	38,335	42,961		
14	Facilities	15,486	14,284	14,305		
15	Recoveries & Revenue	(20,689)	(20,774)	(21,211)		
16						
17	**Non-Labour Costs**	**97,540**	**100,939**	**108,884**		
18						
19						
20	**Total Gross O&M Expenses**	**219,704**	**236,003**	**229,214**	**234,016**	
21						
22	Less: O&M Transferred to Biomethane BVA	-	-	(4)	(570)	
23	Less: Capitalized Overhead	(31,779)	(33,040)	(33,040)	(32,762)	
24						
25	**Total O&M Expenses**	**$ 187,925**	**$ 202,963**	**$ 196,170**	**$ 200,684**	
26						
27	Cross Reference			- Section E-FORMULA, Sch 3		
28					- Section E-FORMULA, Sch 4	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 10,578	$ 11,026	$ 10,994		
2	Distribution Supervision Total	110-10	10,578	11,026	10,994		
3							
4	Operation Centre - Distribution	110-21	10,112	11,074	9,815		
5	Preventative Maintenance - Distribution	110-22	2,644	2,990	2,417		
6	Operations - Distribution	110-23	5,538	5,904	6,321		
7	Emergency Management - Distribution	110-24	5,405	5,077	5,434		
8	Field Training - Distribution	110-25	1,746	4,088	3,242		
9	Meter Exchange - Distribution	110-26	2,397	2,231	2,419		
10	Distribution Operations Total	110-20	27,842	31,363	29,647		
11							
12	Corrective - Distribution	110-31	5,564	4,643	6,061		
13	Distribution Maintenance Total	110-30	5,564	4,643	6,061		
14							
15	Account Services - Distribution	110-41	1,111	1,004	1,110		
16	Bad Debt Management - Distribution	110-42	585	599	661		
17	Distribution Meter to Cash Total	110-40	1,697	1,603	1,771		
18							
19	**Distribution Total**	**110**	**45,680**	**48,635**	**48,473**		
20							
21	Transmission Supervision	120-11	535	482	482		
22	Transmission Supervision Total	120-10	535	482	482		
23							
24	Pipeline / Right of Way Operations	120-21	7,287	6,096	7,541		
25	Compression Operations	120-22	1,827	2,112	2,074		
26	Measurement Control Operations	120-23	103	-	97		
27	Transmission Operations Total	120-20	9,217	8,208	9,712		
28							
29	Pipeline / Right of Way - Maintenance	120-31	1,830	2,707	2,504		
30	Compression - Maintenance	120-32	554	1,147	713		
31	Measurement Control Operations	120-33	117	119	119		
32	Transmission Maintenance Total	120-30	2,501	3,973	3,335		
33							
34	**Transmission Total**	**120**	**12,253**	**12,663**	**13,529**		
35							
36	LNG Operations	130-11	1,601	1,617	1,956		
37	LNG Operations Total	130-10	1,601	1,617	1,956		
38							
39	LNG Plant Maintenance	130-21	272	274	268		
40	LNG Plant Maintenance Total	130-20	272	274	268		
41							
42	**LNG Plant Total**	**130**	**1,873**	**1,891**	**2,224**		
43							
44	**Operations Total**	**100**	**59,806**	**63,189**	**64,226**		
45							
46	Customer Service Supervision	210-11	482	566	491		
47	Customer Assistance	210-12	11,513	11,493	10,874		
48	Customer Billing	210-13	18,586	14,494	23,701		
49	Meter Reading	210-14	12,178	19,696	10,148		
50	Credit & Collections	210-15	3,028	3,851	2,641		
51	Customer Operations	210-16	2,385	2,353	2,075		
52	Customer Service Total	210-10	48,172	52,452	49,931		
53							
54	**Customer Service Total**	**210**	**48,172**	**52,452**	**49,931**		
55							
56	**Customer Service Total**	**200**	**48,172**	**52,452**	**49,931**		

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervisi	310-11	614	796	$ 1,014		
2	Energy Solutions	310-12	5,134	4,991	5,076		
3	Energy Efficiency	310-13	117	120	151		
4	Corporate Communications and External Relatio	310-14	7,212	6,155	6,823		
5	Forecasting, Market & Business Development	310-15	4,998	6,119	5,957		
6	Energy Solutions & External Relations Total	310-10	18,075	18,181	19,022		
7							
8	**Energy Solutions & External Relations Total**	**310**	**18,075**	**18,181**	**19,022**		
9							
10	**Energy Solutions & External Relations Total**	**300**	**18,075**	**18,181**	**19,022**		
11							
12	Energy Supply & Resource Development	410-11	1,937	2,136	2,375		
13	Gas Control	410-12	1,551	1,602	1,562		
14	Energy Supply & Resource Development Tot	410-10	3,488	3,738	3,937		
15							
16	**Energy Supply & Resource Development Tot**	**410**	**3,488**	**3,738**	**3,937**		
17							
18	Information Technology Supervision	420-11	4,172	4,577	4,185		
19	Application Management	420-12	11,251	12,083	12,647		
20	Infrastructure Management	420-13	8,018	8,719	7,418		
21	Information Technology Total	420-10	23,442	25,379	24,249		
22							
23	**Information Technology Total**	**420**	**23,442**	**25,379**	**24,249**		
24							
25	System Planning	430-11	5,672	8,394	7,485		
26	Engineering	430-12	6,803	7,027	6,799		
27	Project Management	430-13	1,125	1,535	1,014		
28	Engineering Services & Project Management	430-10	13,599	16,956	15,297		
29							
30	**Engineering Services & Project Management**	**430**	**13,599**	**16,956**	**15,297**		
31							
32	Supply Chain	440-11	4,420	4,884	4,424		
33	Measurement	440-12	5,548	6,688	6,091		
34	Property Services	440-13	1,070	1,418	1,204		
35	Operations Support Total	440-10	11,038	12,990	11,718		
36							
37	**Operations Support Total**	**440**	**11,038**	**12,990**	**11,718**		
38							
39	Facilities Management	450-11	9,563	9,259	9,230		
40	Facilities Total	450-10	9,563	9,259	9,230		
41							
42	**Facilities Total**	**450**	**9,563**	**9,259**	**9,230**		
43							
44	Environment Health & Safety	460-11	2,481	2,999	2,680		
45	Environment Health & Safety Total	460-10	2,481	2,999	2,680		
46							
47	**Environment Health & Safety Total**	**460**	**2,481**	**2,999**	**2,680**		
48							
49							
50	**Business Services Total**	**400**	**63,611**	**71,321**	**67,111**		

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Financial & Regulatory Services	510-11	12,149	14,184	12,872		
2	Financial & Regulatory Services Total	510-10	12,149	14,184	12,872		
3							
4	**Financial & Regulatory Services Total**	**510**	**12,149**	**14,184**	**12,872**		
5							
6	Human Resources	520-11	8,610	8,511	8,305		
7	Human Resources Total	520-10	8,610	8,511	8,305		
8							
9	**Human Resources Total**	**520**	**8,610**	**8,511**	**8,305**		
10							
11	Legal	530-11	1,917	2,282	2,342		
12	Internal Audit	530-12	695	755	755		
13	Risk Management/Insurance	530-13	4,754	4,898	4,898		
14	Governance	530-10	7,366	7,935	7,995		
15							
16	**Governance Total**	**530**	**7,366**	**7,935**	**7,995**		
17							
18	Administration & General	540-11	226	(46)	262		
19	Shared Services Agreement	540-12	(5,984)	(5,581)	(6,366)		
20	Retiree Benefits	540-16	7,673	5,857	5,857		
21	Corporate Total	540-10	1,915	230	(247)		
22							
23	**Corporate Total**	**540**	**1,915**	**230**	**(247)**		
24							
25	**Corporate Services Total**	**500**	**30,041**	**30,860**	**28,924**		
26							
27	**Total Gross O&M Expenses**		**219,704**	**236,003**	**229,214**	**234,016**	
28	Less: O&M Transferred to Biomethane BVA		-	-	(4)	(570)	
29	Less: Capitalized Overhead		(31,779)	(33,040)	(33,040)	(32,762)	
30							
31	**Total O&M Expenses**		**$ 187,925**	**$ 202,963**	**$ 196,170**	**$ 200,684**	
32							
33	Cross Reference				- Section E-FORMULA, Sch 3		
34						- Section E-FORMULA, Sch 4	

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Total Expenses	2013 PROJECTED 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 13,283	$ 13,728	$ 12,151	$ 12,151	$ (1,577)	
4							
5	General, School and Other	34,132	37,511	35,547	35,547	(1,964)	
6							
7		47,415	51,239	47,698	47,698	(3,541)	
8							
9	Add / Less: Deferred Property Taxes	2,241	-	3,541	3,541	3,541	
10							
11	Total	$ 49,656	$ 51,239	$ 51,239	$ 51,239	$ -	- Section E-FORMULA, Sch 3

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Total Expenses	2014 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 12,151	$ 12,032	$ 12,032	$ (119)	
4						
5	General, School and Other	35,547	36,765	36,765	1,218	
6						
7		47,698	48,797	48,797	1,099	
8						
9	Add / Less: Deferred Property Taxes	3,541	-	-	(3,541)	
10						
11	Total	$ 51,239	$ 48,797	$ 48,797	$ (2,442)	- Section E-FORMULA, Sch 4

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 118,639	$ 123,842	$ 123,839	$ (3)	- Section E-FORMULA, Sch 41
4						
5	Less: Amortization of Contributions in Aid of Construction	(6,558)	(6,499)	(6,499)	-	- Section E-FORMULA, Sch 45
6		112,081	117,343	117,340	(3)	- Section E-FORMULA, Sch 25
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ 11,847	$ 25,569	$ 25,569	$ -	- Section E-FORMULA, Sch 48
11						
12	TOTAL	123,928	142,912	142,909	$ (3)	- Section E-FORMULA, Sch 3

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 123,839	$ 124,667	$ 828	- Section E-FORMULA, Sch 44
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,499)	(6,505)	(6)	- Section E-FORMULA, Sch 46
6		117,340	118,162	822	- Section E-FORMULA, Sch 26
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 25,569	$ 29,284	$ 3,715	- Section E-FORMULA, Sch 50
11					
12	TOTAL	$ 142,909	147,446	$ 4,537	- Section E-FORMULA, Sch 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing Rates	2013 PROJECTED Revised Revenue	2013 PROJECTED Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 221,574	$ 205,900	$ 209,576	$ -	$ 209,575	$ 3,675	- Section E-FORMULA, Sch 3
3	Deduct - Interest on Debt	(108,979)	(112,665)	(110,971)	-	(110,971)	1,694	- Section E-FORMULA, Sch 59
4	Net Additions (Deductions)	(31,957)	(21,038)	(22,631)	-	(22,631)	(1,593)	- Section E-FORMULA, Sch 25
5	Accounting Income After Tax	$ 80,638	$ 72,197	$ 75,974	$ -	$ 75,973	$ 3,776	
6								
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	75.00%	0.00%	
9								
10	Taxable Income	$ 107,518	$ 96,263	$ 101,299	$ -	$ 101,297	$ 5,034	
11								
12								
13	Income Tax - Current	$ 26,880	$ 24,066	$ 25,325	$ -	$ 25,324	$ 1,258	
14	Previous Year Adjustment	-	-		-		-	
15								
16	**Total Income Tax**	$ 26,880	$ 24,066	$ 25,325	$ -	$ 25,324	$ 1,258	- Section E-FORMULA, Sch 3

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Existing Rates	2014 Revised Revenue	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 209,575	$ 200,769	$ 2,746	$ 203,515	$ (6,060)	- Section E-FORMULA, Sch 4
3	Deduct - Interest on Debt	(110,971)	(109,938)	(3)	(109,941)	1,030	- Section E-FORMULA, Sch 60
4	Net Additions (Deductions)	(22,631)	12,763	-	12,763	35,394	- Section E-FORMULA, Sch 26
5	Accounting Income After Tax	75,973	$ 103,594	$ 2,743	$ 106,337	$ 30,364	
6							
7	Current Income Tax Rate	25.00%	26.00%	26.00%	26.00%	1.00%	
8	1 - Current Income Tax Rate	75.00%	74.00%	74.00%	74.00%	-1.00%	
9							
10	Taxable Income	101,297	$ 139,992	$ 3,707	$ 143,699	$ 42,402	
11							
12							
13	Income Tax - Current	$ 25,324	$ 36,398	$ 964	$ 37,362	$ 12,038	
14	Previous Year Adjustment	-		-		-	
15							
16	**Total Income Tax**	$ 25,324	$ 36,398	$ 964	$ 37,362	$ 12,038	- Section E-FORMULA, Sch 4

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 677	$ 700	700	$ -	
3	Depreciation	112,081	117,343	117,340	(3)	- Section E-FORMULA, Sch 21
4	Amortization of Debt Issue Expenses	537	622	577	(45)	
5	Vehicles: Interest & Capitalized Depreciation	1,898	2,187	1,688	(499)	
6	Pension Expense	14,097	12,530	12,530	-	
7	OPEB Expense	4,765	4,902	4,902	-	
8	Olympic Cauldron (50% NBV)	1,445	-	-	-	
9	Bad Debt Provision	726	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	11,847	25,569	25,569	-	- Section E-FORMULA, Sch 21
13	Capital Cost Allowance	(129,279)	(136,232)	(136,232)	-	- Section E-FORMULA, Sch 27
14	Cumulative Eligible Capital Allowance	(907)	(857)	(846)	11	
15	Debt Issue Costs	(834)	(411)	(385)	26	
16	Vehicle Lease Payment	(3,432)	(4,613)	(3,316)	1,297	
17	Pension Contributions	(13,920)	(12,006)	(12,666)	(660)	
18	OPEB Contributions	(1,667)	(2,367)	(2,407)	(40)	
19	Overheads Capitalized Expensed for Tax Purposes	(13,620)	(14,160)	(14,160)	-	
20	Removal Costs	(14,766)	(12,932)	(13,398)	(466)	
21	Discounts on Debt Issue and Other	-	-	-	-	
22	Major Inspection Costs	(1,606)	(1,342)	(2,624)	(1,282)	
23	SCP Landscaping Deduction	-	-	-	-	
24	Biomethane Other Revenue	-	29	97	68	
25	TOTAL	(31,957)	(21,038)	$ (22,631)	$ (1,593)	- Section E-FORMULA, Sch 23

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Section E
FORMULA
Schedule 26

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	800	$ 100	
3	Depreciation	117,340	118,162	822	- Section E-FORMULA, Sch 22
4	Amortization of Debt Issue Expenses	577	734	157	
5	Vehicles: Interest & Capitalized Depreciation	1,688	1,386	(302)	
6	Pension Expense	12,530	20,004	7,474	
7	OPEB Expense	4,902	8,662	3,760	
8	Olympic Cauldron (50% NBV)	-	-	-	
9	Bad Debt Provision	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	25,569	29,284	3,715	- Section E-FORMULA, Sch 22
13	Capital Cost Allowance	(136,232)	(115,464)	20,768	- Section E-FORMULA, Sch 28
14	Cumulative Eligible Capital Allowance	(846)	(787)	59	
15	Debt Issue Costs	(385)	(202)	183	
16	Vehicle Lease Payment	(3,316)	(3,006)	310	
17	Pension Contributions	(12,666)	(16,114)	(3,448)	
18	OPEB Contributions	(2,407)	(2,631)	(224)	
19	Overheads Capitalized Expensed for Tax Purposes	(14,160)	(14,041)	119	
20	Removal Costs	(13,398)	(12,486)	912	
21	Discounts on Debt Issue and Other	-	-	-	
22	Major Inspection Costs	(2,624)	(1,736)	888	
23	SCP Landscaping Deduction	-	-	-	
24	Biomethane Other Revenue	97	198	101	
25	TOTAL	$ (22,631)	$ 12,763	$ 35,394	- Section E-FORMULA, Sch 24

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

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,044,769	$ -	$ 208	$ (41,795)	$ 1,003,182
2	1(b)	6%	27,756	-	8,451	(1,919)	34,288
3	2	6%	136,353	-	-	(8,181)	128,172
4	3	5%	2,423	-	-	(121)	2,302
5	6	10%	150	-	-	(15)	135
6	7	15%	5,442	-	1,180	(905)	5,717
7	8	20%	23,402	(1,412)	8,301	(5,228)	25,063
8	10	30%	1,680	-	323	(553)	1,450
9	12	100%	26,830	-	13,083	(33,372)	6,541
10	13	manual	3,517	-	180	(687)	3,010
11	14	manual	-	-	-	-	-
12	17	8%	174	-	-	(14)	160
13	38	30%	511	-	72	(164)	419
14	39	25%	-	-	-	-	-
15	45	45%	202	-	-	(91)	111
16	47	8%	5,496	-	25	(441)	5,080
17	49	8%	77,300	-	3,989	(6,344)	74,945
18	50	55%	7,461	-	9,481	(6,711)	10,231
19	51	6%	336,347	-	98,039	(23,122)	411,264
20	43.2	50%	-	-	2,369	(592)	1,777
21		Total	$ 1,699,813	$ (1,412)	$ 145,701	$ (130,255)	$ 1,713,847
22							
23	Add: Depreciation variance adjustment					(5,977)	
24	Approved CCA					(136,232)	
25							
26	Cross Reference					- Section E-FORMULA, Sch 25	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Class	CCA Rate	12/31/2013 UCC Balance	Adjustments	2014 Net Additions	2014 CCA	12/31/2014 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,003,182	$ -	$ 272	$ (40,133)	$ 963,321
2	1(b)	6%	34,288	-	6,762	(2,260)	38,790
3	2	6%	128,172	-	-	(7,690)	120,482
4	3	5%	2,302	-	-	(115)	2,187
5	6	10%	135	-	-	(14)	121
6	7	15%	5,717	-	2,265	(1,027)	6,955
7	8	20%	25,063	-	10,314	(6,044)	29,333
8	10	30%	1,450	-	2,441	(801)	3,090
9	12	100%	6,541	-	11,885	(12,484)	5,942
10	13	manual	3,010	-	178	(303)	2,885
11	14	manual	-	-	-	-	-
12	17	8%	160	-	-	(13)	147
13	38	30%	419	-	-	(126)	293
14	39	25%	-	-	-	-	-
15	45	45%	111	-	-	(50)	61
16	47	8%	5,080	-	2,011	(487)	6,604
17	49	8%	74,945	-	5,977	(6,235)	74,687
18	50	55%	10,231	-	8,585	(7,988)	10,828
19	51	6%	411,264	-	100,777	(27,699)	484,342
20	43.2	50%	1,777	-	4,426	(1,995)	4,208
21		Total	$ 1,713,847	$ -	$ 155,893	$ (115,464)	$ 1,754,276
22							
23							
24							
25							
26	Cross Reference						- Section E-FORMULA, Sch 26

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	Adjustments	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	Gas Plant in Service, Beginning	$ 3,545,030	$ 3,774,425	$ 3,726,853	$ -	$ 3,726,853	$ (47,572)	- Section E-FORMULA, Sch 35
2	Opening Balance Adjustment	(3,890)	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,726,853	3,905,299	3,870,810	-	3,870,810	(34,489)	- Section E-FORMULA, Sch 35
4								
5	Accumulated Depreciation Beginning - Plant	$ (922,011)	$ (1,012,343)	$ (1,011,180)	$ -	$ (1,011,180)	$ 1,163	- Section E-FORMULA, Sch 41
6	Opening Balance Adjustment	4,463	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,011,179)	(1,104,066)	(1,102,885)	-	(1,102,885)	1,181	- Section E-FORMULA, Sch 41
8								
9	CIAC, Beginning	$ (180,038)	$ (191,772)	$ (185,545)	$ -	$ (185,545)	$ 6,227	- Section E-FORMULA, Sch 45
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	CIAC, Ending	(185,545)	(198,468)	(200,601)	-	(200,601)	(2,133)	- Section E-FORMULA, Sch 45
12								
13	Accumulated Amortization Beginning - CIAC	$ 49,620	$ 51,072	$ 51,143	$ -	$ 51,143	$ 71	- Section E-FORMULA, Sch 45
14	Opening Balance Adjustment	(5)	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	51,143	57,367	57,280	-	57,280	(87)	- Section E-FORMULA, Sch 45
16								
17	Net Plant in Service, Mid-Year	$ 2,537,220	$ 2,640,757	$ 2,602,938	$ -	$ 2,602,938	$ (37,819)	
18								
19	Adjustment to 13-Month Average	30,786	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	20,803	26,120	-	26,120	5,317	
21	Unamortized Deferred Charges	497	8,249	(20,190)	-	(20,190)	(28,439)	- Section E-FORMULA, Sch 48
22	Cash Working Capital	(1,899)	(2,630)	(1,903)	-	(1,903)	727	- Section E-FORMULA, Sch 53
23	Other Working Capital	101,416	101,622	83,121	-	83,121	(18,501)	- Section E-FORMULA, Sch 53
24	Deferred Income Taxes Regulatory Asset	281,929	282,359	284,958	-	284,958	2,599	- Section E-FORMULA, Sch 58
25	Deferred Income Taxes Regulatory Liability	(281,929)	(282,359)	(284,958)	-	(284,958)	(2,599)	- Section E-FORMULA, Sch 58
26	LILO Benefit	(1,316)	(1,150)	(1,150)	-	(1,150)	-	
27	**Utility Rate Base**	$ 2,692,824	$ 2,767,651	$ 2,688,936	$ -	$ 2,688,936	$ (78,715)	- Section E-FORMULA, Sch 59
28								- Section E-FORMULA, Sch 3

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			2014 FORECAST				
Line No.	Particulars	2013 PROJECTED	Existing 2013 Rates	Adjustments	2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,726,853	$ 3,870,810	$ -	$ 3,870,810	$ 143,957	- Section E-FORMULA, Sch 38
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,870,810	4,019,425	-	4,019,425	148,615	- Section E-FORMULA, Sch 38
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,011,180)	$ (1,102,885)	$ -	$ (1,102,885)	$ (91,705)	- Section E-FORMULA, Sch 44
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,102,885)	(1,203,723)	-	(1,203,723)	(100,838)	- Section E-FORMULA, Sch 44
8							
9	CIAC, Beginning	$ (185,545)	$ (200,601)	$ -	$ (200,601)	$ (15,056)	- Section E-FORMULA, Sch 46
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(200,601)	(202,456)	-	(202,456)	(1,855)	- Section E-FORMULA, Sch 46
12							
13	Accumulated Amortization Beginning - CIAC	$ 51,143	$ 57,280	$ -	$ 57,280	$ 6,137	- Section E-FORMULA, Sch 46
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	57,280	60,017	-	60,017	2,737	- Section E-FORMULA, Sch 46
16							
17	Net Plant in Service, Mid-Year	$ 2,602,938	$ 2,648,934	$ -	$ 2,648,934	$ 45,996	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	(20,190)	24,937	-	24,937	45,127	- Section E-FORMULA, Sch 50
22	Cash Working Capital	(1,903)	(612)	277	(335)	1,568	- Section E-FORMULA, Sch 54
23	Other Working Capital	83,121	79,039	-	79,039	(4,082)	- Section E-FORMULA, Sch 54
24	Deferred Income Taxes Regulatory Asset	284,958	288,453	-	288,453	3,495	- Section E-FORMULA, Sch 58
25	Deferred Income Taxes Regulatory Liability	(284,958)	(288,453)	-	(288,453)	(3,495)	- Section E-FORMULA, Sch 58
26	LILO Benefit	(1,150)	(983)	-	(983)	167	
27	**Utility Rate Base**	$ 2,688,936	$ 2,777,435	$ 277	$ 2,777,712	$ 88,776	- Section E-FORMULA, Sch 60
28							- Section E-FORMULA, Sch 4

FORMULA CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

Line No.	Particulars		2013 Base	2014 Formula	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1					
2					
3	**Cost Drivers for Formulaic Capital**				
4	CPI			1.83%	
5	AWE			2.70%	
6	Labour Split				
7	Non Labour			45.00%	
8	Labour			55.00%	
9	CPI/AWE	(line 4 * line 7) + (line 5 * line 8)		2.31%	
10	Productivity Factor			-0.50%	
11	Net Inflation Factor			**1.81%**	
12					
13	Forecast Service Line Additions		7,989	8,051	
14	Average Growth Capital per Service Line Addition	(prior year * line 11)	$ 2,738.92	$ 2,788.50	
15					
16	Forecast Customer Growth			0.57%	
17					
18	**2013 Base Capital Expenditures**				
19	Growth Capital	(Line 13 * Line 14)	21,881	22,450	
20	Sustainment Capital	(prior year * (1 + Line 11) * (1 + Line 16)	70,902	72,595	
21	Other Capital	(prior year * (1 + Line 11) * (1 + Line 16)	30,141	30,861	
22	**Capital Subject to Formula**		122,924	125,906	
23	**Add: Capital Tracked Outside of the Formula**				
24	Insurance & OPEB		2,241	2,068	
25	Bio-Methane Upgraders			1,468	
26	Bio-Methane Interconnect			3,700	
27	NGT Assets			3,356	
28	Tilbury 2				
29	**Formulaic Capital**		125,165	136,498	- Section E-FORMULA, Sch 38 -
30	Cross Reference		- Table C4-2 in Application		- Section E-FORMULA, Sch 46
31					

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2013 Projected	2014 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 138,204	$ 133,597	
6	Gateway Project	4,139	-	
7	Biomethane Assets	3,436	5,168	
8	Total Regular Capital Expenditures	$ 145,779	$ 138,765	
9				
10	Special Projects - CPCN's			
11	Fraser River Crossing Seismic Upg	42	-	
12	Kootenay River Crossing	755	-	
13	Tilbury Expansion Project (Q-477)	2,656	-	
14	NGT Assets	4,233	3,356	
15	Tilbury Land Property Purchase	(406)	-	
16	Total CPCN's	$ 7,279	$ 3,356	
17				
18				
19				
20	TOTAL CAPITAL EXPENDITURES	$ 153,058	$ 142,121	
21				
22				
23	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
24				
25	Regular Capital			
26	Regular Capital Expenditures	$ 145,779	$ 138,765	
27	Add - Opening WIP	43,661	48,168	
28	Less - Adjustments	777	-	
29	Less - Closing WIP	(48,168)	(45,420)	
30	Capital Spares Inventory	727	-	
31	Capital Vehicle Lease	2,577	-	
32	Add - AFUDC	1,749	1,642	
33	Add - Overhead Capitalized	33,040	32,762	
34				
35	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 180,141	$ 175,917	
36				
37	Special Projects - CPCN's			
38	CPCN Expenditures	$ 7,279	$ 3,356	
39	Add - Opening WIP	(158)	5,098	
40	Less - Closing WIP	(5,098)	(4,654)	
41	Add: Projects transferred from Deferral Accounts	-	-	
42	Less: Projects settling to Deferral Accounts	406	-	
43	Less: Adjustments	(4)	-	
44	Less: Removal Costs	-	-	
44	Add - AFUDC	52	-	
45				
46	TOTAL CPCN ADDITIONS	$ 2,477	$ 3,800	
47				
48	TOTAL PLANT ADDITIONS	$ 182,618	$ 179,717	
49				
50	Cross Reference	- Section E-FORMULA, Sch 35		
51			- Section E-FORMULA, Sch 38	

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

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,529	12	34	-	-	-	1	44,576	44,553
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	4	1,213	1,211
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,471	-	9,173	208	-	(5,985)	(427)	88,440	86,956
17	402-02 Application Software - 20%	18,723	-	3,245	34	-	(2,982)	(94)	18,926	18,825
18	TOTAL INTANGIBLE	152,412	12	12,452	242	-	(8,967)	(516)	155,635	154,024
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	965	-	25	-	9	-	-	999	982
24	433-00 Manufact'd Gas - Equipment	448	-	8	-	3	-	-	459	454
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	65	-	23	-	-	2,940	2,896
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	8	-	3	-	-	366	361
27	437-00 Manufact'd Gas - Measuring & Regulating Equipme	735	-	100	4	36	-	-	875	805
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
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)	25,014	-	21	-	7	-	-	25,042	25,028
36	TOTAL MANUFACTURED	67,023	-	227	4	81	-	-	67,335	67,179

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

Line No.	Particulars	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	$ 7,402	$ -	$ 27	$ -	$ -	$ -	$ -	$ 7,429	$ 7,416
3	461-00 Transmission Land Rights	-	-	-	-	-	-	1	1	1
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	29	-	10	-	-	16,338	16,319
6	463-00 Measuring Structures	5,511	-	596	62	228	(5)	-	6,392	5,952
7	464-00 Other Structures & Improvements	6,023	-	246	-	85	-	1	6,355	6,189
8	465-00 Mains	799,512	102	14,202	596	5,171	(441)	(340)	818,802	809,157
9	465-00 Mains - INSPECTION	5,803	-	2,624	87	941	-	-	9,455	7,629
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	111,811	-	981	34	352	(1,329)	-	111,849	111,830
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,249	-	1,423	54	513	(121)	445	32,563	31,406
17	467-10 Telemetering	9,293	-	643	52	241	(38)	(31)	10,160	9,727
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	995,547	102	20,771	885	7,541	(1,934)	76	1,022,988	1,009,268
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,219	-	651	18	232	(92)	8	19,036	18,628
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	758,346	-	25,999	-	9,020	(4,250)	(7)	789,108	773,727
29	474-00 House Regulators & Meter Installations	174,943	-	-	-	-	(265)	67	174,745	174,844
30	477-00 Meters/Regulators Installations	18,871	-	18,798	7	6,526	-	-	44,202	31,537
31	475-00 Mains	947,273	-	21,502	87	7,492	(1,702)	112	974,764	961,019
32	476-00 Compressor Equipment	1,450	-	-	-	-	-	(340)	1,110	1,110
33	477-00 Measuring & Regulating Equipment	88,594	-	4,503	230	1,643	(393)	79	94,656	91,625
34	477-00 Telemetering	7,102	-	1,022	24	363	(10)	31	8,532	7,817
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
36	478-10 Meters	207,016	-	11,514	-	-	(8,249)	4	210,285	208,651
37	478-20 Instruments	11,889	-	55	-	-	-	-	11,944	11,917
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,237,368	-	84,044	366	25,276	(14,961)	(46)	2,332,047	2,284,538
40										
41	**BIO GAS**									
42	472-00 Bio Gas Struct. & Improvements	137	-	36	-	12	-	-	185	161
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
44	475-20 Bio Gas Mains – Private Land	41	-	-	-	-	-	-	41	41
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	-	2,369	-	-	-	-	2,369	1,185
47	477-10 Bio Gas Reg & Meter Equipment	280	-	374	-	130	-	-	784	532
48	478-30 Bio Gas Meters	7	-	3	-	-	-	-	10	9
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
50	TOTAL BIO-GAS	567	-	2,782	-	142	-	-	3,491	2,029

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

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,554	$ 1,051	$ (12)	$ 12	$ -	$ -	$ 340	$ 3,945	$ 3,420
3	476-20 NG Transportation LNG Dispensing Equipment	47	923	1,443	4	-	-	-	2,417	1,232
4	476-30 NG Transportation CNG Foundations	471	175	(1)	1	-	-	-	646	559
5	476-40 NG Transportation LNG Foundations	4	119	432	-	-	-	-	555	280
6	476-50 NG Transportation LNG Pumps	-	20	43	-	-	-	-	63	32
7	476-60 NG Transportation CNG Dehydrator	119	75	(1)	1	-	-	-	194	157
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	3,195	2,363	1,904	18	-	-	340	7,820	5,678
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,329	-	(112)	-	-	-	-	22,217	22,273
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	380	-	-	-	10	11,160	10,965
16	- Masonry Buildings	92,527	-	5,062	-	-	-	-	97,589	95,058
17	- Leasehold Improvement	3,822	-	180	-	-	(151)	-	3,851	3,837
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,479	-	376	-	-	(301)	17	3,571	3,525
20	483-40 GP Furniture	21,395	-	1,176	2	-	(1,954)	-	20,619	21,007
21	483-10 GP Computer Hardware	29,627	-	9,481	216	-	(6,424)	-	32,900	31,264
22	483-20 GP Computer Software	3,405	-	1,076	16	-	(190)	110	4,417	3,911
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	323	-	-	(30)	11	2,512	2,360
26	484-00 Vehicles - Leased	28,385	-	2,577	-	-	(1,783)	-	29,179	28,782
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	(418)	246	455
28	485-20 Heavy Mobile Equipment	838	-	72	-	-	(80)	421	1,251	1,045
29	486-00 Small Tools & Equipment	38,733	-	2,435	-	-	(963)	10	40,215	39,474
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,679	-	-	-	-	(905)	239	7,013	7,346
34	- Radio	4,856	-	145	1	-	(33)	(239)	4,730	4,793
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	270,741	-	23,171	235	-	(12,814)	161	281,494	276,118
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,726,853	$ 2,477	$ 145,351	$ 1,750	$ 33,040	$ (38,676)	$ 15	$ 3,870,810	$ 3,798,832
43										
44	Cross Reference	- Section E-FORMULA, Sch 29		- Section E-FORMULA, Sch 32					- Section E-FORMULA, Sch 29	
45			- Section E-FORMULA, Sch 32			- Section E-FORMULA, Sch 32				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year 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	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,576	-	429	-	-	-	-	45,005	44,791
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,213	-	-	-	-	-	-	1,213	1,213
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	88,440	-	6,314	184	-	(3,738)	-	91,200	89,820
17	402-02 Application Software - 20%	18,926	-	5,572	111	-	(2,317)	-	22,292	20,609
18	TOTAL INTANGIBLE	155,635	-	12,315	295	-	(6,055)	-	162,190	158,913
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	999	-	-	-	-	-	-	999	999
24	433-00 Manufact'd Gas - Equipment	459	-	229	-	81	-	-	769	614
25	434-00 Manufact'd Gas - Gas Holders	2,940	-	-	-	-	-	-	2,940	2,940
26	436-00 Manufact'd Gas - Compressor Equipment	366	-	-	-	-	-	-	366	366
27	437-00 Manufact'd Gas - Measuring & Regulating Equipme	875	-	-	-	-	-	-	875	875
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
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)	25,042	-	1,692	65	600	-	-	27,399	26,221
36	TOTAL MANUFACTURED	67,335	-	1,921	65	681	-	-	70,002	68,669

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,429	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,429	$ 7,429
3	461-00 Transmission Land Rights	1	-	-	-	-	-	-	1	1
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,338	-	-	-	-	-	-	16,338	16,338
6	463-00 Measuring Structures	6,392	-	-	-	-	(21)	-	6,371	6,382
7	464-00 Other Structures & Improvements	6,355	-	-	-	-	-	-	6,355	6,355
8	465-00 Mains	818,802	-	10,016	412	3,552	(374)	-	832,408	825,605
9	465-00 Mains - INSPECTION	9,455	-	1,736	-	615	(368)	-	11,438	10,447
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	111,849	-	1,906	88	676	(372)	-	114,147	112,998
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	32,563	-	-	-	-	(131)	-	32,432	32,498
17	467-10 Telemetering	10,160	-	240	10	85	(24)	-	10,471	10,316
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	1,022,988	-	13,898	510	4,928	(1,290)	-	1,041,034	1,032,011
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	19,036	-	-	-	-	(21)	-	19,015	19,026
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	789,108	-	25,318	-	8,974	(3,185)	-	820,215	804,662
29	474-00 House Regulators & Meter Installations	174,745	-	-	-	-	(6)	-	174,739	174,742
30	477-00 Meters/Regulators Installations	44,202	-	18,461	129	6,544	-	-	69,336	56,769
31	475-00 Mains	974,764	-	18,843	102	6,677	(1,049)	-	999,337	987,051
32	476-00 Compressor Equipment	1,110	-	-	-	-	-	-	1,110	1,110
33	477-00 Measuring & Regulating Equipment	94,656	-	6,279	303	2,226	(598)	-	102,866	98,761
34	477-00 Telemetering	8,532	-	703	6	249	(6)	-	9,484	9,008
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
36	478-10 Meters	210,285	-	12,359	-	-	(6,672)	-	215,972	213,129
37	478-20 Instruments	11,944	-	-	-	-	-	-	11,944	11,944
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,332,047	-	81,963	540	24,670	(11,537)	-	2,427,683	2,379,865
40										
41	**BIO GAS**									
42	472-00 Bio Gas Struct. & Improvements	185	-	259	-	-	-	-	444	315
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
44	475-20 Bio Gas Mains – Private Land	41	-	1,495	-	530	-	-	2,066	1,054
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	2,369	-	4,426	-	-	-	-	6,795	4,582
47	477-10 Bio Gas Reg & Meter Equipment	784	-	1,710	-	606	-	-	3,100	1,942
48	478-30 Bio Gas Meters	10	-	26	-	-	-	-	36	23
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
50	TOTAL BIO-GAS	3,491	-	7,916	-	1,136	-	-	12,543	8,017

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,945	$ 915	$ -	$ -	$ 324	$ -	$ -	$ 5,184	$ 4,565
3	476-20 NG Transportation LNG Dispensing Equipment	2,417	2,550	-	-	904	-	-	5,871	4,144
4	476-30 NG Transportation CNG Foundations	646	301	-	-	107	-	-	1,054	850
5	476-40 NG Transportation LNG Foundations	555	-	-	-	-	-	-	555	555
6	476-50 NG Transportation LNG Pumps	63	-	-	-	-	-	-	63	63
7	476-60 NG Transportation CNG Dehydrator	194	34	-	-	12	-	-	240	217
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	7,820	3,800	-	-	1,347	-	-	12,967	10,394
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,217	-	350	-	-	-	-	22,567	22,392
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	11,160	-	-	-	-	-	-	11,160	11,160
16	- Masonry Buildings	97,589	-	5,431	-	-	-	-	103,020	100,305
17	- Leasehold Improvement	3,851	-	178	-	-	(40)	-	3,989	3,920
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,571	-	522	-	-	(92)	-	4,001	3,786
20	483-40 GP Furniture	20,619	-	1,761	-	-	(3,123)	-	19,257	19,938
21	483-10 GP Computer Hardware	32,900	-	8,585	233	-	(3,708)	-	38,010	35,455
22	483-20 GP Computer Software	4,417	-	-	-	-	(44)	-	4,373	4,395
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,512	-	2,441	-	-	-	-	4,953	3,733
26	484-00 Vehicles - Leased	29,179	-	-	-	-	(1,536)	-	27,643	28,411
27	485-10 Heavy Work Equipment	246	-	-	-	-	-	-	246	246
28	485-20 Heavy Mobile Equipment	1,251	-	-	-	-	-	-	1,251	1,251
29	486-00 Small Tools & Equipment	40,215	-	3,117	-	-	(2,003)	-	41,329	40,772
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,013	-	-	-	-	(1,460)	-	5,553	6,283
34	- Radio	4,730	-	1,114	-	-	(214)	-	5,630	5,180
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	281,494	-	23,499	233	-	(12,220)	-	293,006	287,250
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,870,810	$ 3,800	$ 141,512	$ 1,643	$ 32,762	$ (31,102)	$ -	$ 4,019,425	$ 3,945,118
43										
44	Cross Reference	- Section E-FORMULA, Sch 3(		- Section E-FORMULA, Sch 32				- Section E-FORMULA, Sch 30		
45			- Section E-FORMULA, Sch 32			- Section E-FORMULA, Sch 32				

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	9	-	-	548	557
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	-	-	-	-	-
5	178-00 Organization Expense	728	1.00%	7	2	-	391	400
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	1	-	98	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	21	-	-	227	248
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,553	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	86,956	12.50%	10,665	(118)	(5,985)	23,581	28,143
17	402-02 Application Software - 20%	18,825	20.00%	3,785	(36)	(2,982)	7,243	8,010
18	TOTAL INTANGIBLE	154,024		14,487	(151)	(8,967)	32,839	38,208
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	982	3.38%	33	10	-	143	186
24	433-00 Manufact'd Gas - Equipment	454	6.63%	30	-	-	88	118
25	434-00 Manufact'd Gas - Gas Holders	2,896	2.35%	67	-	-	238	305
26	436-00 Manufact'd Gas - Compressor Equipment	361	5.16%	19	-	-	38	57
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	805	15.89%	127	-	-	363	490
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,789	2,966
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,028	4.24%	1,061	-	-	10,901	11,962
36	TOTAL MANUFACTURED	67,179		1,832	10	-	25,282	27,124

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	2013 DEPRECIATION Adjust-ments	2013 DEPRECIATION Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,416	0.00%	$ -	$ 102	$ -	$ 401	$ 503
3	461-00 Transmission Land Rights	1	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,319	3.74%	610	-	-	6,790	7,400
6	463-00 Measuring Structures	5,952	3.80%	217	-	(3)	1,936	2,150
7	464-00 Other Structures & Improvements	6,189	2.83%	174	(2)	-	1,891	2,063
8	465-00 Mains	809,157	1.44%	11,601	(224)	(211)	214,894	226,060
9	465-00 Mains - INSPECTION	7,629	14.87%	974	-	-	1,851	2,825
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	49	-	937	1,035
13	466-00 Compressor Equipment	111,830	2.87%	3,207	-	(719)	44,521	47,009
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	298	400
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	31,406	4.27%	1,323	(26)	(59)	10,440	11,678
17	467-10 Telemetering	9,727	0.31%	29	(26)	(66)	6,316	6,253
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	7	-	3	10
20	468-00 Communication Structures & Equipment	346	4.37%	15	(9)	-	328	334
21	TOTAL TRANSMISSION	1,009,268		18,301	(129)	(1,058)	290,606	307,720
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	(35)	-	26	(9)
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,628	3.33%	612	-	(19)	4,852	5,445
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	32	37
28	473-00 Services	773,727	2.53%	19,248	6	(1,579)	142,028	159,703
29	474-00 House Regulators & Meter Installations	174,844	7.62%	12,409	47	(208)	18,625	30,873
30	477-00 Meters/Regulators Installations	31,537	4.55%	1,202	-	-	206	1,408
31	475-00 Mains	961,019	1.59%	15,365	2	(642)	299,353	314,078
32	476-00 Compressor Equipment	1,110	26.54%	295	(272)	-	1,235	1,258
33	477-00 Measuring & Regulating Equipment	91,625	4.75%	4,257	(2)	(220)	25,902	29,937
34	477-00 Telemetering	7,817	0.25%	19	(8)	(1)	6,063	6,073
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	4	-	-	212	216
36	478-10 Meters	208,651	8.05%	16,266	425	(4,960)	75,361	87,092
37	478-20 Instruments	11,917	3.15%	375	-	-	1,299	1,674
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,284,538		70,057	163	(7,629)	575,194	637,785
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	161	3.60%	6	-	-	11	17
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	4	5
44	475-20 Bio Gas Mains – Private Land	41	1.48%	1	-	-	1	2
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	1,185	6.67%	105	-	-	-	105
47	477-10 Bio Gas Reg & Meter Equipment	532	4.75%	25	-	-	28	53
48	478-30 Bio Gas Meters	9	8.05%	1	-	-	1	2
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	1	-	-	2	3
50	TOTAL BIO-GAS	2,029		140	-	-	47	187

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,420	5.00%	$ 148	$ 175	$ -	135	$ 458
3	476-20 NG Transportation LNG Dispensing Equipment	1,232	5.00%	81	-	-	4	85
4	476-30 NG Transportation CNG Foundations	559	5.00%	24	(60)	-	80	44
5	476-40 NG Transportation LNG Foundations	280	5.00%	22	-	-	2	24
6	476-50 NG Transportation LNG Pumps	32	10.00%	6	-	-	-	6
7	476-60 NG Transportation CNG Dehydrator	157	5.00%	6	-	-	6	12
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,678		287	115	-	227	629
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,273	0.00%	-	(13)	-	30	17
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,965	4.82%	524	(26)	-	2,912	3,410
16	- Masonry Buildings	95,058	2.23%	2,099	85	-	15,696	17,880
17	- Leasehold Improvement	3,837	10.00%	408	(50)	(151)	565	772
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,525	6.67%	232	1,943	(243)	1,554	3,486
20	483-40 GP Furniture	21,007	5.00%	1,075	(1,937)	(1,954)	12,884	10,068
21	483-10 GP Computer Hardware	31,264	20.00%	5,768	143	(6,424)	12,281	11,768
22	483-20 GP Computer Software	3,911	12.50%	460	-	(190)	1,146	1,416
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,360	5.16%	113	(143)	(24)	601	547
26	484-00 Vehicles - Leased	28,782	0.00%	2,978	-	(1,600)	14,556	15,934
27	485-10 Heavy Work Equipment	455	8.96%	22	280	-	(175)	127
28	485-20 Heavy Mobile Equipment	1,045	18.06%	222	(332)	(63)	753	580
29	486-00 Small Tools & Equipment	39,474	5.00%	1,979	-	(963)	17,124	18,140
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	12	14
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,346	6.67%	523	253	(795)	4,368	4,349
34	- Radio	4,793	6.67%	311	(232)	(33)	2,678	2,724
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	276,118		16,716	(29)	(12,440)	86,985	91,232
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,798,832		$ 121,820	$ (21)	$ (30,094)	$ 1,011,180	$ 1,102,885
43	Less: Depreciation & Amortization transferred to biomethane BVA			(105)				
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,350)				
45	Add: Depreciation variance adjustment			3,474				
46	**Net Depreciation Expense**			$ 123,839				
47								
48	Cross Reference	- Section E-FORMULA, Sch 35		- Section E-FORMULA, Sch 21			- Section E-FORMULA, Sch 29	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	557	558
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	78
5	178-00 Organization Expense	728	1.00%	7	-	-	400	407
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	248	264
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,576	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,213	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	88,440	12.50%	11,055	-	(3,738)	28,143	35,460
17	402-02 Application Software - 20%	18,926	20.00%	3,785	-	(2,317)	8,010	9,478
18	TOTAL INTANGIBLE	155,635		14,942	-	(6,055)	38,208	47,095
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	999	3.38%	34	-	-	186	220
24	433-00 Manufact'd Gas - Equipment	459	6.63%	30	-	-	118	148
25	434-00 Manufact'd Gas - Gas Holders	2,940	2.35%	69	-	-	305	374
26	436-00 Manufact'd Gas - Compressor Equipment	366	5.16%	19	-	-	57	76
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	875	15.89%	139	-	-	490	629
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,966	3,143
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	11,039	11,357
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,042	4.24%	1,062	-	-	11,962	13,024
36	TOTAL MANUFACTURED	67,335		1,848	-	-	27,124	28,972

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,429	0.00%	$ -	$ -	$ -	$ 503	$ 503
3	461-00 Transmission Land Rights	1	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,338	3.74%	611	-	-	7,400	8,011
6	463-00 Measuring Structures	6,392	3.80%	243	-	(17)	2,150	2,376
7	464-00 Other Structures & Improvements	6,355	2.83%	180	-	-	2,063	2,243
8	465-00 Mains	818,802	1.44%	11,791	-	(372)	226,060	237,479
9	465-00 Mains - INSPECTION	9,455	14.87%	1,406	-	(368)	2,825	3,863
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	1,035	1,084
13	466-00 Compressor Equipment	111,849	2.87%	3,210	-	(372)	47,009	49,847
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	400	502
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	32,563	4.27%	1,390	-	(108)	11,678	12,960
17	467-10 Telemetering	10,160	0.31%	31	-	(24)	6,253	6,260
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	10	10
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	334	349
21	TOTAL TRANSMISSION	1,022,988		19,028	-	(1,261)	307,720	325,487
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	(9)	(9)
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	19,036	3.33%	634	-	(13)	5,445	6,066
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	37	42
28	473-00 Services	789,108	2.53%	19,712	-	(1,132)	159,703	178,283
29	474-00 House Regulators & Meter Installations	174,745	7.62%	12,411	-	(4)	30,873	43,280
30	477-00 Meters/Regulators Installations	44,202	4.55%	2,011	-	-	1,408	3,419
31	475-00 Mains	974,764	1.59%	15,655	-	(501)	314,078	329,232
32	476-00 Compressor Equipment	1,110	26.54%	295	-	-	1,258	1,553
33	477-00 Measuring & Regulating Equipment	94,656	4.75%	4,496	-	(436)	29,937	33,997
34	477-00 Telemetering	8,532	0.25%	21	-	(2)	6,073	6,092
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	216	216
36	478-10 Meters	210,285	8.05%	16,313	-	(3,667)	87,092	99,738
37	478-20 Instruments	11,944	3.15%	376	-	-	1,674	2,050
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,332,047		71,929	-	(5,755)	637,785	703,959
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	185	3.60%	7	-	-	17	24
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	5	6
44	475-20 Bio Gas Mains – Private Land	41	1.48%	1	-	-	2	3
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	2,369	6.67%	158	-	-	105	263
47	477-10 Bio Gas Reg & Meter Equipment	784	4.75%	37	-	-	53	90
48	478-30 Bio Gas Meters	10	8.05%	1	-	-	2	3
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	3	3
50	TOTAL BIO-GAS	3,491		205	-	-	187	392

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,945	5.00%	$ 197	$ -	$ -	$ 458	$ 655
3	476-20 NG Transportation LNG Dispensing Equipment	2,417	5.00%	121	-	-	85	206
4	476-30 NG Transportation CNG Foundations	646	5.00%	32	-	-	44	76
5	476-40 NG Transportation LNG Foundations	555	5.00%	28	-	-	24	52
6	476-50 NG Transportation LNG Pumps	63	10.00%	6	-	-	6	12
7	476-60 NG Transportation CNG Dehydrator	194	5.00%	10	-	-	12	22
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	7,820		394	-	-	629	1,023
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,217	0.00%	-	-	-	17	17
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	11,160	4.82%	538	-	-	3,410	3,948
16	- Masonry Buildings	97,589	2.23%	2,176	-	-	17,880	20,056
17	- Leasehold Improvement	3,851	10.00%	385	-	(40)	772	1,117
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,571	6.67%	238	-	(69)	3,486	3,655
20	483-40 GP Furniture	20,619	5.00%	1,031	-	(3,123)	10,068	7,976
21	483-10 GP Computer Hardware	32,900	20.00%	6,580	-	(3,708)	11,768	14,640
22	483-20 GP Computer Software	4,417	12.50%	552	-	(44)	1,416	1,924
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,512	12.50%	314	-	-	547	861
26	484-00 Vehicles - Leased	29,179	0.00%	2,755	-	(1,536)	15,934	17,153
27	485-10 Heavy Work Equipment	246	8.96%	22	-	-	127	149
28	485-20 Heavy Mobile Equipment	1,251	18.06%	226	-	-	580	806
29	486-00 Small Tools & Equipment	40,215	5.00%	2,011	-	(2,003)	18,140	18,148
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	14	16
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,013	6.67%	468	-	(1,314)	4,349	3,503
34	- Radio	4,730	6.67%	316	-	(214)	2,724	2,826
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	281,494		17,614	-	(12,051)	91,232	96,795
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,870,810		$ 125,960	$ -	$ (25,122)	$ 1,102,885	$ 1,203,723
43	Less: Depreciation & Amortization transferred to biomethane BVA			(158)				
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,135)				
45	Add: Depreciation variance adjustment							
46	**Net Depreciation Expense**			$ 124,667				
47								
48	Cross Reference	- Section E-FORMULA, Sch 38		- Section E-FORMULA, Sch 22			- Section E-FORMULA, Sch 30	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Section E FORMULA Schedule 45

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

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 PROJECTED Additions	2013 PROJECTED Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 145,014	$ (645)	$ 13,054	$ -	$ 157,423	
4							
5	Transmission Contributions	29,058	(110)	2,302	-	31,250	
6							
7	Others	714	-	113	-	827	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	(204)	10,555	
11							
12	Biomethane	-	-	546	-	546	
13							
14	TOTAL Contributions	185,545	(755)	16,015	(204)	200,601	- Section E-FORMULA, Sch 29
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(42,313)	(1)	(4,325)	-	(46,639)	
21							
22	Transmission Contributions	(2,335)	1	(522)	-	(2,856)	
23							
24	Others	(97)	-	(128)	-	(225)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(6,398)	-	(1,345)	204	(7,539)	
28							
29	Biomethane	-	-	(21)	-	(21)	
30							
31	TOTAL CIAC Amortization	(51,143)	-	(6,341)	204	(57,280)	- Section E-FORMULA, Sch 29
32							
33	**NET CONTRIBUTIONS**	$ 134,402	$ (755)	$ 9,674	$ -	$ 143,321	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,341)			
37	Add: Depreciation variance adjustment			(158)			
38	**Net Amortization Expense**			$ (6,499)			
39				- Section E-FORMULA, Sch 21			
40							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	Adjustment	2014 FORECAST Additions	2014 FORECAST Retirements	Balance 12/31/2014	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 157,423	$ -	$ 5,227	$ -	$ 162,650	
4							
5	Transmission Contributions	31,250	-	396	-	31,646	
6							
7	Others	827	-	-	-	827	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,555	-	-	(3,768)	6,787	
11							
12	Biomethane	546	-	-	-	546	
13							
14	TOTAL Contributions	200,601	-	5,623	(3,768)	202,456	- Section E-FORMULA, Sch 30
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(46,639)	-	(4,548)	-	(51,187)	
21							
22	Transmission Contributions	(2,856)	-	(524)	-	(3,380)	
23							
24	Others	(225)	-	(114)	-	(339)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(7,539)	-	(1,319)	3,768	(5,090)	
28							
29	Biomethane	(21)	-	-	-	(21)	
30							
31	TOTAL CIAC Amortization	(57,280)	-	(6,505)	3,768	(60,017)	- Section E-FORMULA, Sch 30
32							
33	**NET CONTRIBUTIONS**	$ 143,321	$ -	$ (882)	$ -	$ 142,439	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,505)			
37							
38	**Net Amortization Expense**			$ (6,505)			
39				- Section E-FORMULA, Sch 22			
40							

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

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,042)	$ -	$ (289)	$ 74	$ (214)	$ -	$ -	$ -	$ (10,256)	$ (10,149)
3	Midstream Cost Reconciliation Account (MCRA)	(17,800)	-	(3,731)	961	(2,770)	-	8,914	(2,295)	(13,951)	(15,876)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(24,583)	-	(7,323)	1,886	(5,437)	-	11,582	(2,982)	(21,420)	(23,002)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,125)	-	(1,077)	278	(799)	(10)	159	(41)	(4,816)	(4,471)
6	Revelstoke Propane Cost Deferral Account	(348)	-	499	(128)	371	-	-	-	23	(163)
7	SCP Mitigation Revenues Variance Account	(4,154)	-	431	(111)	320	2,926	-	-	(908)	(2,531)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	22,698	-	10,827	(2,788)	8,039	(3,152)	-	-	27,585	25,142
11	NGV Conversion Grants	37	-	18	(5)	13	(28)	-	-	22	30
12	Emmissions Regulations	-	-	4	(1)	3	-	-	-	3	1
13	Biomethane Program Costs	324	-	328	(85)	244	(172)	-	-	396	360
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	-	-	-	-	-	-	-	-	-
16	CNG and LNG Recoveries	(11)	-	(69)	18	(51)	-	-	-	(62)	(37)
17	Rate Schedule 16 Cost & Recoveries	-	-	(27)	7	(20)	-	-	-	(20)	(10)
18											
19	Non-Controllable Items Deferral Accounts										
20	Property Tax Deferral	(2,868)	-	(3,541)	912	(2,629)	594	-	-	(4,903)	(3,886)
21	Insurance Variance	45	-	93	(24)	69	-	-	-	114	80
22	Pension & OPEB Variance	15,807	-	12,607	-	12,607	(3,205)	-	-	25,209	20,508
23	BCUC Levies Variance	449	-	923	(238)	685	-	-	-	1,134	792
24	Interest Variance	(5,699)	-	(734)	189	(545)	2,600	-	-	(3,644)	(4,671)
25	Interest Variance - Funding benefits via Customer Deposits	834	-	160	(41)	119	(309)	-	-	644	739
26	Tax Variance Account	597	-	2,150	(351)	1,799	-	-	-	2,396	1,497
27	Customer Service Variance Account	(5,548)	-	(13,234)	3,408	(9,826)	-	-	-	(15,374)	(10,461)
28	Pension & OPEB Funding	(171,550)	3,050	(13,171)	-	(13,171)	-	-	-	(181,671)	(175,086)
29	US GAAP Pension & OPEB Funded Status	139,153	(3,050)	-	-	-	-	-	-	136,103	136,103

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

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	NGV for Transportation Application	140	(113)	73	(19)	54	(46)	-	-	36	32
4	Long Term Resource Plan Application	-	-	-	-	-	(90)	-	-	(90)	(45)
5	AES Inquiry Cost	619	-	(21)	5	(16)	(85)	-	-	518	569
6	Generic Cost of Capital Application	-	-	-	-	-	-	-	-	-	-
7	Amalgamation and Rate Design Application Costs	-	-	-	-	-	-	-	-	-	-
8	Rate Schedule 16 Application Cost	-	-	-	-	-	-	-	-	-	-
9											
10	Other Deferral Accounts										
11	2010-2011 Customer Service O&M and COS	21,613	-	-	-	-	(2,807)	-	-	18,806	20,210
12	Gas Asset Records Project	(60)	-	744	(192)	552	(567)	-	-	(75)	(68)
13	BC OneCall Project	(69)	-	777	(200)	577	(334)	-	-	174	53
14	Gains and Losses on Asset Disposition	27,090	-	8,389	-	8,389	(730)	-	-	34,749	30,920
15	Negative Salvage Provision/Cost	(5,965)	-	13,398	-	13,398	(16,933)	-	-	(9,500)	(7,732)
16	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
17											
18	Residual Deferred Accounts										
19	Depreciation Variance	(1,281)	-	(1,012)	-	(1,012)	-	-	-	(2,293)	(1,787)
20	SCP Tax Reassessment	(32)	-	-	-	-	-	-	-	(32)	(32)
21	BFI Costs and Recoveries	147	-	(250)	64	(186)	-	-	-	(39)	54
22	Fuelling Stations Variance Account	-	-	-	-	-	-	-	-	-	-
23	2011 CNG and LNG Service Costs and Recoveries	(69)	-	-	-	-	35	-	-	(34)	(51)
24	Olympics Security Costs Deferral	188	-	-	-	-	(188)	-	-	-	94
25	IFRS Conversion Costs	238	-	-	-	-	(238)	-	-	-	119
26	2009 ROE & Cost of Capital Application	496	-	-	-	-	(168)	-	-	328	412
27	2012-2013 Revenue Requirement Application	614	-	0	(0)	0	(409)	-	-	205	410
28	CCE CPCN Application	150	-	-	-	-	(56)	-	-	94	122
29	Deferred Removal Costs	2,223	-	-	-	-	(2,354)	-	-	(131)	1,046
30	US GAAP Conversion Costs	(62)	-	-	-	-	(791)	-	-	(853)	(458)
31	US GAAP Transitional Costs	477	-	-	-	-	948	-	-	1,425	951
32	Earnings Sharing Mechanism	84	-	-	-	-	-	-	-	84	84
33	OH&M Recoveries from NGT	-	-	-	-	-	-	-	-	-	-
34	Tilbury Property Purchase (Subdividable Land)	-	-	-	-	-	-	-	-	-	-
35	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	-
36											
37	Total Deferred Charges for Rate Base	$ (20,243)	$ (113)	$ 6,945	$ 3,619	$ 10,564	$ (25,569)	$ 20,655	$ (5,319)	$ (20,025)	$ (20,190)
38											
39	Cross Reference						- Section E-FORMULA, Sch 21			- Section E-FORMULA, Sch 29	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2014	Mid-Year Average 2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,256)	$ -	$ 13,860	$ (3,604)	$ 10,256	$ -	$ -	$ -	$ 0	$ (5,128)
3	Midstream Cost Reconciliation Account (MCRA)	(13,951)	-	-	-	-	-	9,085	(2,362)	(7,228)	(10,590)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(21,420)	-	-	-	-	-	14,160	(3,682)	(10,942)	(16,181)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,816)	-	1,530	(397)	1,133	388	165	(43)	(3,174)	(3,995)
6	Revelstoke Propane Cost Deferral Account	23	-	(30)	8	(23)	-	-	-	(0)	11
7	SCP Mitigation Revenues Variance Account	(908)	-	-	-	-	684	-	-	(224)	(566)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	27,585	16,752	13,350	(3,471)	9,879	(5,278)	-	-	48,938	46,638
11	NGV Conversion Grants	22	-	15	(4)	11	(13)	-	-	20	21
12	Emmissions Regulations	3	-	-	-	-	-	-	-	3	3
13	Biomethane Program Costs	396	-	-	-	-	(396)	-	-	(0)	198
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	6,564	9,336	(2,427)	6,909	(1,347)	-	-	12,125	9,345
16	CNG and LNG Recoveries	(62)	-	-	-	-	62	-	-	0	(31)
17	Rate Schedule 16 Cost & Recoveries	(20)	-	-	-	-	20	-	-	0	(10)
18											
19	Non-Controllable Items Deferral Accounts										
20	Property Tax Deferral	(4,903)	-	-	-	-	2,030	-	-	(2,873)	(3,888)
21	Insurance Variance	114	-	-	-	-	(114)	-	-	(0)	57
22	Pension & OPEB Variance	25,209	-	-	-	-	(5,039)	-	-	20,170	22,690
23	BCUC Levies Variance	1,134	-	-	-	-	(1,134)	-	-	(0)	567
24	Interest Variance	(3,644)	-	-	-	-	2,829	-	-	(815)	(2,229)
25	Interest Variance - Funding benefits via Customer Deposits	644	-	-	-	-	(302)	-	-	342	493
26	Tax Variance Account	2,396	-	-	-	-	(2,396)	-	-	0	1,198
27	Customer Service Variance Account	(15,374)	-	-	-	-	3,075	-	-	(12,299)	(13,837)
28	Pension & OPEB Funding	(181,671)	-	9,636	-	9,636	-	-	-	(172,035)	(176,853)
29	US GAAP Pension & OPEB Funded Status	136,103	-	(9,300)	-	(9,300)	-	-	-	126,803	131,453

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2014	Mid-Year Average 2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ 438	$ 1,000	$ (260)	$ 740	$ (236)	$ -	$ -	$ 942	$ 690
3	NGV for Transportation Application	36	-	-	-	-	(36)	-	-	(0)	18
4	Long Term Resource Plan Application	(90)	-	36	(9)	26	76	-	-	12	(39)
5	AES Inquiry Cost	518	-	-	-	-	(132)	-	-	387	453
6	Generic Cost of Capital Application	-	1,354	-	-	-	(677)	-	-	677	1,016
7	Amalgamation and Rate Design Application Costs	-	1,219	-	-	-	(407)	-	-	812	1,016
8	Rate Schedule 16 Application Cost	-	126	-	-	-	(126)	-	-	-	63
9											
10	Other Deferral Accounts										
11	2010-2011 Customer Service O&M and COS	18,806	-	-	-	-	(2,877)	-	-	15,930	17,368
12	Gas Asset Records Project	(75)	-	1,277	(332)	945	(152)	-	-	718	322
13	BC OneCall Project	174	-	712	(185)	527	(135)	-	-	566	370
14	Gains and Losses on Asset Disposition	34,749	-	5,981	-	5,981	(1,806)	-	-	38,924	36,837
15	Negative Salvage Provision/Cost	(9,500)	-	12,486	-	12,486	(17,313)	-	-	(14,326)	(11,913)
16	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
17											
18	Residual Deferred Accounts										
19	Depreciation Variance	(2,293)	-	-	-	-	2,293	-	-	-	(1,147)
20	SCP Tax Reassessment	(32)	-	-	-	-	32	-	-	-	(16)
21	BFI Costs and Recoveries	(39)	39	-	-	-	-	-	-	-	-
22	Fuelling Stations Variance Account	-	159	-	-	-	(53)	-	-	106	133
23	2011 CNG and LNG Service Costs and Recoveries	(34)	-	-	-	-	34	-	-	-	(17)
24	Olympics Security Costs Deferral	-	-	-	-	-	-	-	-	-	-
25	IFRS Conversion Costs	-	-	-	-	-	-	-	-	-	-
26	2009 ROE & Cost of Capital Application	328	-	-	-	-	(328)	-	-	-	164
27	2012-2013 Revenue Requirement Application	205	-	-	-	-	(205)	-	-	(0)	103
28	CCE CPCN Application	94	-	-	-	-	(94)	-	-	-	47
29	Deferred Removal Costs	(131)	-	-	-	-	131	-	-	-	(66)
30	US GAAP Conversion Costs	(853)	-	-	-	-	853	-	-	-	(427)
31	US GAAP Transitional Costs	1,425	-	-	-	-	(1,425)	-	-	-	713
32	Earnings Sharing Mechanism	84	(84)	-	-	-	-	-	-	-	-
33	OH&M Recoveries from NGT	-	(70)	-	-	-	70	-	-	-	(35)
34	Tilbury Property Purchase (Subdividable Land)	-	(220)	-	-	-	220	-	-	-	(110)
35	Residual Delivery Rate Riders	-	61	-	-	-	(61)	-	-	-	31
36											
37	Total Deferred Charges for Rate Base	$ (20,025)	$ 26,339	$ 59,888	$ (10,681)	$ 49,207	$ (29,284)	$ 23,410	$ (6,087)	$ 43,561	$ 24,937
38											
39	Cross Reference						- Section E-FORMULA, Sch 22			- Section E-FORMULA, Sch 30	

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ -	$ 18
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	25,028	0.37%	99	-	(2)	-	-	97
5	TOTAL MANUFACTURED	46,487		183	-	(2)	-	-	181
5									
6	**TRANSMISSION PLANT**								
7	462-00 Compressor Structures	16,319	0.18%	27	-	(1)	-	-	26
8	463-00 Measuring Structures	5,952	0.18%	10	-	-	-	-	10
9	464-00 Other Structures & Improvements	6,189	0.14%	8	-	(15)	-	-	(7)
10	465-00 Mains	809,157	0.14%	1,175	-	(122)	-	-	1,053
11	466-00 Compressor Equipment	111,830	0.28%	333	-	(2)	-	-	331
12	467-00 Measuring & Regulating Equipment	31,406	0.18%	51	-	(103)	-	-	(52)
13	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	-	3
14	TOTAL TRANSMISSION	981,198		1,607	-	(243)	-	-	1,364
15									
16	**DISTRIBUTION PLANT**								
17	472-00 Structures & Improvements	18,628	0.16%	27	-	(2)	-	-	25
18	473-00 Services	773,727	1.24%	8,982	-	(9,753)	-	-	(771)
19	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
20	474-00 House Regulators & Meter Installations	174,844	0.75%	1,188	-	(3,009)	-	-	(1,821)
21	477-00 Meters/Regulators Installations	31,537	0.75%	173	-	-	-	-	173
22	475-00 Mains	961,019	0.33%	3,107	-	(497)	-	-	2,610
23	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
24	476-00 Compressor Equipment	1,110	11.43%	165	-	-	-	-	165
25	477-00 Measuring & Regulating Equipment	91,625	0.52%	468	-	(48)	-	-	420
26	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	208,651	0.50%	1,031	-	169	-	-	1,200
28	TOTAL DISTRIBUTION	2,261,302		15,141	-	(13,152)	-	-	1,989
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	41	0.33%	1	-	-	-	-	1
32	478-30 Bio Gas Meters	9	0.50%	-	-	-	-	-	-
33	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
34	TOTAL BIO-GAS	72		2	-	-	-	-	2
35									
36	TOTALS	$ 3,289,059		$ 16,933	$ -	$ (13,398)	$ -	$ -	$ 3,535
37									
38	Cross Reference	-FORMULA, Sch 35							- Section E-FORMULA, Sch 48

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2014 DEPRECIATION Provision (Cr.)	Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2013	Ending 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 18	$ 36
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	25,042	0.37%	93	-	-	-	97	190
5	TOTAL MANUFACTURED	46,501		177	-	-	-	181	358
5									
6	**TRANSMISSION PLANT**								
7	462-00 Compressor Structures	16,338	0.18%	29	-	-	-	26	55
8	463-00 Measuring Structures	6,392	0.18%	12	-	-	-	10	22
9	464-00 Other Structures & Improvements	6,355	0.14%	9	-	-	-	(7)	2
10	465-00 Mains	818,802	0.14%	1,146	-	-	-	1,053	2,199
11	466-00 Compressor Equipment	111,849	0.28%	313	-	-	-	331	644
12	467-00 Measuring & Regulating Equipment	32,563	0.18%	59	-	-	-	(52)	7
13	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
14	TOTAL TRANSMISSION	992,645		1,571	-	-	-	1,364	2,935
15									
16	**DISTRIBUTION PLANT**								
17	472-00 Structures & Improvements	19,036	0.16%	30	-	-	-	25	55
18	473-00 Services	789,108	1.24%	9,289	-	(8,928)	-	(771)	(410)
19	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
20	474-00 House Regulators & Meter Installations	174,745	0.75%	1,190	-	(2,713)	-	(1,821)	(3,344)
21	477-00 Meters/Regulators Installations	44,202	0.75%	332	-	-	-	173	505
22	475-00 Mains	974,764	0.33%	3,104	-	(845)	-	2,610	4,869
23	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
24	476-00 Compressor Equipment	1,110	11.43%	127	-	-	-	165	292
25	477-00 Measuring & Regulating Equipment	94,656	0.52%	492	-	-	-	420	912
26	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
27	478-10 Meters	210,285	0.50%	1,001	-	-	-	1,200	2,201
28	TOTAL DISTRIBUTION	2,308,069		15,565	-	(12,486)	-	1,989	5,068
29									
30	**BIO GAS**								
31	475-20 Bio Gas Mains – Private Land	41	0.33%	-	-	-	-	1	1
32	478-30 Bio Gas Meters	10	0.50%	-	-	-	-	-	-
33	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
34	TOTAL BIO-GAS	73		-	-	-	-	2	2
35									
36	TOTALS	$ 3,347,288		$ 17,313	$ -	$ (12,486)	$ -	$ 3,535	$ 8,362
37									
38	Cross Reference	-FORMULA, Sch 38						- Section E-FORMULA, Sch 50	

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	2013 PROJECTED Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 9,202	$ 7,121	$ 8,216	$ 8,216	$ 1,095	- Section E-FORMULA, Sch 55
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(6,282)	(4,588)	(5,760)	(5,760)	(1,172)	
9							
10	Withholdings From Employees	(4,819)	(5,163)	(4,359)	(4,359)	804	
11							
12	Subtotal	(1,899)	(2,630)	(1,903)	(1,903)	727	- Section E-FORMULA, Sch 29
13							
14	**Other Working Capital Items**						
15	Construction Advances	(439)	(620)	-	-	620	
16	Transmission Line Pack Gas	3,924	3,566	2,846	2,846	(720)	
17	Gas in Storage	97,294	97,242	78,766	78,766	(18,476)	
18	Inventory - Materials & Supplies	637	1,434	1,509	1,509	75	
19							
20	Subtotal	101,416	101,622	83,121	83,121	(18,501)	- Section E-FORMULA, Sch 29
21							
22	Total	$ 99,517	$ 98,992	$ 81,218	$ 81,218	$ (17,774)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Existing 2013 Rates	2014 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 8,216	$ 9,336	$ 9,613	$ 1,397	- Section E-FORMULA, Sch 55
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(5,760)	(5,459)	(5,459)	301	
9						
10	Withholdings From Employees	(4,359)	(4,489)	(4,489)	(130)	
11						
12	Subtotal	(1,903)	(612)	(335)	1,568	- Section E-FORMULA, Sch 30
13						
14	**Other Working Capital Items**					
15	Construction Advances	-	-	-	-	
16	Transmission Line Pack Gas	2,846	2,662	2,662	(184)	
17	Gas in Storage	78,766	74,841	74,841	(3,925)	
18	Inventory - Materials & Supplies	1,509	1,536	1,536	27	
19						
20	Subtotal	83,121	79,039	79,039	(4,082)	- Section E-FORMULA, Sch 30
21						
22	Total	$ 81,218	$ 78,427	$ 78,704	$ (2,514)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Days	2013 Expenses	2013 Cash Working Capital	2014 Days	2014 Expenses	2014 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASH WORKING CAPITAL**							
2								
3	Revenue Lag Days	39.0			39.0			- Section E-FORMULA, Sch 56
4	Expense Lead Days	35.9			35.5			- Section E-FORMULA, Sch 57
5								
6	Net Lead/(Lag) Days	3.1	$ 967,311	$ 8,216	3.5	$ 973,594	$ 9,336	- Section E-FORMULA, Sch 53
7								- Section E-FORMULA, Sch 54
8								
9								
10	**CASH WORKING CAPITAL, REVISED RATES**							
11								
12	Revenue Lag Days	39.0			39.0			- Section E-FORMULA, Sch 56
13	Expense Lead Days	35.9			35.4			- Section E-FORMULA, Sch 57
14								
15	Net Lead/(Lag) Days	3.1	$ 967,312	$ 8,216	3.6	$ 974,629	$ 9,613	- Section E-FORMULA, Sch 53
16								- Section E-FORMULA, Sch 54
17								
18								
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 277	
20								
21								
22								
23	Cash working capital = Col. 2 x Col. 3 / 365 days							

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Particulars	2013 Revenue At 2013 Rates	2013 Lag Days Service to Collection	2013 Dollar Days	2014 Revenue At 2013 Rates	2014 Lag Days Service to Collection	2014 Dollar Days	Cross Reference
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
REVENUE							
Gas Sales and Transportation Service Revenue							
Residential and Commercial	$ 1,000,861	38.3	$ 38,376,423	$ 991,092	38.3	$ 38,002,583	- Section E-FORMULA, Sch 10
Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	75,110	45.1	3,386,250	76,903	45.1	3,467,282	
NGV Fuel - Stations	461	41.7	19,233	461	41.7	19,233	
Rate 16, 46, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	55,792	42.9	2,390,757	55,359	42.7	2,364,396	
Total Gas Sales	1,132,225	39.0	44,172,663	1,123,815	39.0	43,853,494	
Other Revenues							
Late Payment Charges	2,109	38.3	80,767	2,089	38.3	79,993	- Section E-FORMULA, Sch 12-13
Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Section E-FORMULA, Sch 12-13
Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Section E-FORMULA, Sch 12-13
Other Utility Income	1,118	38.3	42,835	1,625	39.1	63,568	- Section E-FORMULA, Sch 12-13
Total Revenue	$ 1,138,153	39.0	$ 44,399,717	$ 1,130,244	39.0	$ 44,101,066	
REVENUE, REVISED RATES							
Gas Sales and Transportation Service Revenue							
Residential and Commercial	$ 1,000,861	38.3	$ 38,376,423	$ 994,237	38.3	$ 38,123,189	- Section E-FORMULA, Sch 10
Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	75,110	45.1	3,386,250	77,315	45.1	3,485,886	
NGV Fuel - Stations	461	41.7	19,233	463	41.7	19,316	
Rate 16, 46, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	55,792	42.9	2,390,757	55,511	42.7	2,371,228	
Total Gas Sales	1,132,225	39.0	44,172,663	1,127,526	39.0	43,999,619	
Other Revenues							
Late Payment Charges	2,109	38.3	80,767	2,089	38.3	79,993	- Section E-FORMULA, Sch 12-13
Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Section E-FORMULA, Sch 12-13
Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Section E-FORMULA, Sch 12-13
Other Utility Income	1,118	38.3	42,835	1,625	39.1	63,568	- Section E-FORMULA, Sch 12-13
Total Revenue	$ 1,138,153	39.0	$ 44,399,717	$ 1,133,955	39.0	$ 44,247,191	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	2014 Amount	2014 Lead Days Expense to Payment	2014 Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**							
2								
3	Operating And Maintenance							- Section E-FORMULA, Sch 3
4	Expenses	$ 196,170	25.5	$ 5,002,335	$ 200,684	25.5	$ 5,117,442	- Section E-FORMULA, Sch 4
5	Gas Purchases (excl Royalty Credits)	505,614	40.2	20,325,683	496,151	40.2	19,945,270	
6								
7	Taxes Other Than Income							- Section E-FORMULA, Sch 19
8	Property Taxes	47,698	2.0	95,396	48,797	2.0	97,594	- Section E-FORMULA, Sch 20
9	Franchise Fees	8,048	420.3	3,382,574	7,927	420.3	3,331,718	
10	Carbon Tax	169,709	29.1	4,938,525	169,966	29.1	4,946,021	
11	HST - Net *	6,565	38.8	254,735			-	
12	PST Component of HST (REC) *	(2,326)	33.8	(78,624)			-	
13	GST - Net **	7,257	38.8	281,553	9,604	38.8	372,650	
14	PST - Net **	3,252	37.1	120,641	4,067	37.1	150,869	
15	Income Tax	25,325	15.2	384,940	36,398	15.2	553,250	- Section E-FORMULA, Sch 23
16								- Section E-FORMULA, Sch 24
17	Total Expenses	$ 967,312	35.9	$ 34,707,758	$ 973,594	35.5	$ 34,514,814	
18								
19								
20	**EXPENSES, REVISED RATES**							
21								
22	Operating And Maintenance							- Section E-FORMULA, Sch 3
23	Expenses	$ 196,170	25.5	$ 5,002,335	$ 200,684	25.5	$ 5,117,442	- Section E-FORMULA, Sch 4
24	Gas Purchases (excl Royalty Credits)	505,614	40.2	20,325,683	496,151	40.2	19,945,270	
25								
26	Taxes Other Than Income							- Section E-FORMULA, Sch 19
27	Property Taxes	47,698	2.0	95,396	48,797	2.0	97,594	- Section E-FORMULA, Sch 20
28	Franchise Fees	8,048	420.3	3,382,574	7,954	420.3	3,343,067	
29	Carbon Tax	169,709	29.1	4,938,525	169,966	29.1	4,946,021	
30	HST - Net *	6,565	38.8	254,735			-	
31	PST Component of HST (REC) *	(2,326)	33.8	(78,624)			-	
32	GST - Net **	7,257	38.8	281,553	9,636	38.8	373,891	
33	PST - Net **	3,252	37.1	120,641	4,078	37.1	151,294	
34	Income Tax	25,324	15.2	384,925	37,362	15.2	567,902	- Section E-FORMULA, Sch 23
35								- Section E-FORMULA, Sch 24
36	Total Expenses	$ 967,311	35.9	$ 34,707,743	$ 974,629	35.4	$ 34,542,481	
37								

38 * January to March 2013 is computed at 25% of 2013 Approved cash outflows.
39 ** April to December 2013 is computed at 75% of 2013 Projected cash outflows.

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Section E FORMULA Schedule 58

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Total DIT Liability- After Tax	(210,925)	(215,501)	(216,513)	(216,167)	
2						
3	Tax Gross Up	(70,308)	(71,834)	(72,171)	(72,056)	
4						
5	DIT Liability/Asset - End of Year	(281,233)	(287,335)	(288,683)	(288,222)	
6						
7	DIT Liability/Asset - Opening Balance	(282,624)	(277,382)	(281,233)	(288,683)	
8						
9	DIT Liability/Asset - Mid Year	(281,929)	(282,359)	(284,958)	(288,453)	
10						
11	Cross Reference			- Section E-FORMULA, Sch 29		
12					- Section E-FORMULA, Sch 30	
13						
14	Note: * Excludes Land, Software CIAC, and WIP.					

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

Line No.	Particulars	-------- Capitalization -------- Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 RATES							
2	Long-Term Debt		$ 1,576,778	58.64%	6.87%	4.03%	$ 108,279	- Section E-FORMULA, Sch 61
3	Unfunded Debt		76,918	2.86%	3.50%	0.10%	2,692	
4	Common Equity		1,035,240	38.50%	9.52%	3.66%	98,605	
5								
6			$ 2,688,936	100.00%		7.79%	$ 209,575	- Section E-FORMULA, Sch 29
7								
8								
9								
10	2013 REVISED RATES - PROJECTED							
11	Long-Term Debt		$ 1,576,778	58.64%	6.87%	4.03%	$ 108,279	- Section E-FORMULA, Sch 61
12	Unfunded Debt	$ 76,918						
13	Adjustment, Revised Rates	-	76,918	2.86%	3.50%	0.10%	2,692	
14	Common Equity		1,035,240	38.50%	9.52%	3.66%	98,605	
15								- Section E-FORMULA, Sch 3
16			$ 2,688,936	100.00%		7.79%	$ 209,575	- Section E-FORMULA, Sch 29

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Capitalization Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2014 AT 2013 RATES							
2	Long-Term Debt		$ 1,575,067	56.71%	6.83%	3.87%	$ 107,610	- Section E-FORMULA, Sch 62
3	Unfunded Debt		133,056	4.79%	1.75%	0.08%	2,328	
4	Common Equity		1,069,312	38.50%	8.49%	3.28%	90,831	
5								
6			$ 2,777,435	100.00%		7.23%	$ 200,769	- Section E-FORMULA, Sch 30
7								
8								
9								
10	2014 REVISED RATES							
11	Long-Term Debt		$ 1,575,067	56.70%	6.83%	3.87%	$ 107,610	- Section E-FORMULA, Sch 62
12	Unfunded Debt	$ 133,056						
13	Adjustment, Revised Rates	170	133,226	4.80%	1.75%	0.08%	2,331	
14	Common Equity		1,069,419	38.50%	8.75%	3.37%	93,574	
15								- Section E-FORMULA, Sch 4
16			$ 2,777,712	100.00%		7.33%	$ 203,515	- Section E-FORMULA, Sch 30

FORTISBC ENERGY INC. G-44-12 (May 1, 2012) Section E FORMULA Schedule 61

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2013 *** APPROVED ***
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100 *	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,882 *	10.461%	158,110	16,540
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-Oct-2011	1-Oct-2021	4.500%	100,000	1,000	99,000	4.626%	100,000	4,626
13										
14	LILO Obligations - Kelowna							6.445%	21,892	1,411
15	LILO Obligations - Nelson							7.872%	3,519	277
16	LILO Obligations - Vernon							9.153%	10,466	958
17	LILO Obligations - Prince George							8.067%	27,085	2,185
18	LILO Obligations - Creston							7.218%	2,577	186
19										
20	Vehicle Lease Obligation							5.685%	13,510	768
21										
22	Sub-Total								$ 1,582,114	$ 108,645
23	Less: Fort Nelson Division Portion of Long Term Debt								5,336	366
24	Total								$ 1,576,778	$ 108,279
25										
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).								Average Embedded Cost	6.87%
27	**Includes adjustment of $836 for BC Hydro Premium (Series B).									
28	Cross Reference								- Section E-FORMULA, Sch 59	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	158,429	**	10.461%	160,657	16,806
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	1,234	98,766		6.645%	100,000	6,645
11	2011 Medium Term Debt Issue - Series 25	9-Dec-2011	9-Dec-2041	4.250%	100,000	1,410	98,590		4.334%	100,000	4,334
12											
13	LILO Obligations - Kelowna								6.469%	20,963	1,356
14	LILO Obligations - Nelson								7.983%	3,382	270
15	LILO Obligations - Vernon								9.276%	10,037	931
16	LILO Obligations - Prince George								8.182%	26,057	2,132
17	LILO Obligations - Creston								7.330%	2,483	182
18											
19	Vehicle Lease Obligation								2.115%	11,868	251
20											
21	Sub-Total									$ 1,580,402	$ 107,974
22	Less: Fort Nelson Division Portion of Long Term Debt									5,335	364
23	Total									$ 1,575,067	$ 107,610
24											
25	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.83%
26	**Includes adjustment of $3,383 for BC Hydro Premium (Series B).										
27	Cross Reference									- Section E-FORMULA, Sch 60	

Appendix G

SUMMARY FINANCIAL SCHEDULES
EVIDENTIARY UPDATE FEBRUARY 21, 2014

Summary of Rate Change

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 1

Line No.	Particulars	2014 ($ Millions)		2015 Incremental ($ Millions)		2015 Cumulative ($ Millions)		2016 Incremental ($ Millions)		2016 Cumulative ($ Millions)		2017 Incremental ($ Millions)		2017 Cumulative ($ Millions)		2018 Incremental ($ Millions)		2018 Cumulative ($ Millions)		Cross Reference
1	(1)	(2)		(3)		(4)		(5)		(6)		(7)		(8)		(9)		(10)		(11)
2	Volume/Revenue Related																			
3	Customer Growth and Use Rates	(7.2)		(3.1)		(10.3)		(5.9)		(16.2)		(5.4)		(21.6)		(5.0)		(26.7)		
4	Change in Other Revenue	0.2	(7.0)	(0.7)	(3.8)	(0.5)	(10.8)	(0.7)	(6.6)	(1.2)	(17.4)	(0.9)	(6.3)	(2.1)	(23.7)	(1.2)	(6.3)	(3.3)	(30.0)	
5																				
6	O&M Changes																			
7	Gross O&M Increases	(2.6)		4.7		2.2		4.6		6.7		5.1		11.8		6.4		18.2		
8	Less: Capitalized Overhead	0.3	(2.3)	(0.7)	4.1	(0.4)	1.8	(0.6)	3.9	(1.0)	5.7	(0.7)	4.3	(1.7)	10.1	(0.9)	5.5	(2.6)	15.5	
9																				
10	Depreciation Expense																			
11	Change in Depreciation Rates	(0.2)		1.7		1.5		1.7		3.2		0.1		3.4		0.9		4.3		
12	Tax Expense Impact of Depreciation Changes	0.3		2.1		2.4		2.2		4.6		1.5		6.1		1.9		8.0		
13	Depreciation from Net Additions	1.0	1.1	4.7	8.6	5.7	9.7	4.8	8.6	10.5	18.3	4.3	6.0	14.8	24.3	4.9	7.7	19.7	32.0	
14																				
15	Amortization Expense																			
16	CIAC	(0.0)		0.3		0.3		0.1		0.4		0.2		0.5		0.2		0.7		
17	Deferral Accounts	3.7	3.7	(1.6)	(1.3)	2.1	2.4	6.1	6.1	8.2	8.5	3.4	3.5	11.6	12.1	2.1	2.3	13.7	14.4	
18																				
19	Other																			
20	Property and Other Taxes	(2.4)		0.5		(1.9)		1.3		(0.6)		1.0		0.4		1.1		1.5		
21	Other (NSP Provision)	-		-		-		-		-		-		-		-		-		
22	Income Tax Rate Change	1.9		0.0		1.9		0.2		2.1		0.1		2.3		0.1		2.4		
23	Other Income Tax Changes	11.1		(2.0)		9.1		1.5		10.7		1.0		11.6		0.1		11.7		
24	Financing Rate Changes	(2.9)		(0.4)		(3.4)		(3.1)		(6.5)		(8.0)		(14.4)		(0.8)		(15.3)		
25	Financing Changes	0.2		1.5		1.7		1.3		3.0		4.2		7.3		4.1		11.4		
26	Rate Base Growth	0.3	8.2	2.7	2.3	3.0	10.5	2.0	3.2	5.0	13.7	1.5	(0.2)	6.5	13.6	1.2	5.8	7.7	19.4	
27																				
28	**Revenue Deficiency (Surplus)**		**3.7**				**13.6**				**28.9**				**36.2**				**51.3**	
29	Cross Reference						- Appendix G-1 FORMULA Sch 2				- Appendix G-1 FORMULA Sch 7				- Appendix G-1 FORMULA Sch 12				- Appendix G-1 FORMULA Sch 17	
30																				

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Non-Bypass Sales	2015 Non-Bypass Transportation	2015 Bypass and Special Rates	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,105,679	$ 1,008,157	$ 84,934	$ 11,524	$ 1,104,615	$ (1,064)	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,138	-	-	18,149	18,149	11	
8								
9	Total Revenue	1,123,817	1,008,157	84,934	29,673	1,122,764	(1,053)	
10								
11	Less - Cost of Gas	(495,059)	(489,657)	(253)	(249)	(490,159)	4,900	
12								
13	Gross Margin	$ 628,758	$ 518,500	$ 84,681	$ 29,424	$ 632,605	$ 3,847	
14								
15	Revenue Deficiency (Surplus)	$ 3,710	$ 11,719	$ 1,914	$ -	**$ 13,633**	$ 9,923	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.59%	2.26%	2.26%	0.00%	2.16%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.33%	1.16%	2.25%	0.00%	1.21%		
20								

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G-1 FORMULA Schedule 3

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,087	114,254	-	114,254	167	
3	Transportation	98,330	99,501	-	99,501	1,171	
4		212,417	213,755	-	213,755	1,338	
5							
6	Average Rate per GJ						
7	Sales	$8.891	$8.824	$0.000	$8.926	$0.035	
8	Transportation	$0.967	$0.969	$0.000	$0.989	$0.022	
9	Average	$5.223	$5.168	$0.000	$5.231	$0.008	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,011,096	$ 1,008,157	$ -	$ 1,008,157	$ (2,939)	
13	- Increase / (Decrease)	3,196	-	11,721	11,721	8,525	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	94,582	96,459	-	96,459	1,877	
16	- Increase / (Decrease)	514		1,912	1,912	1,398	
17							
18	**Total Revenue**	1,109,388	1,104,616	13,633	1,118,249	8,861	
19							
20	Cost of Gas Sold (Including Gas Lost)	496,151	492,036	-	492,036	(4,115)	
21							
22	**Gross Margin**	613,237	612,580	13,633	626,213	12,976	
23							
24	Operation and Maintenance	200,684	204,747	-	204,747	4,063	
25	Property and Sundry Taxes	48,797	49,335	-	49,335	538	
26	Depreciation and Amortization	147,446	152,604	-	152,604	5,158	
27	Other Operating Revenue	(24,567)	(25,293)	-	(25,293)	(726)	
28	Sub-total	372,360	381,393	-	381,393	9,033	
29	Utility Income Before Income Taxes	240,877	231,187	13,633	244,820	3,943	
30							
31	Income Taxes	37,362	34,006	3,544	37,550	188	
32							
33	**EARNED RETURN**	$ 203,515	$ 197,181	$ 10,089	$ 207,270	$ 3,755	- Appendix G-1 FORMULA Sch 6
34							
35							
36	**UTILITY RATE BASE**	$ 2,777,712	$ 2,856,688	$ 38	$ 2,856,726	$ 79,014	- Appendix G-1 FORMULA Sch 5
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	6.90%		7.26%	-0.07%	- Appendix G-1 FORMULA Sch 6

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G-1 FORMULA Schedule 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 203,515	$ 197,181	$ 10,089	$ 207,270	$ 3,755	- Appendix G-1 FORMULA Sch 3
3	Deduct - Interest on Debt	(109,941)	(111,033)	(1)	(111,034)	(1,093)	- Appendix G-1 FORMULA Sch 6
4	Add (Deduct) - Permanent & Timing Differences	12,763	10,638	-	10,638	(2,125)	
5	Adjusted Taxable Income After Tax	$ 106,337	96,786	10,088	$ 106,874	537	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 143,699	$ 130,792	$ 13,632	$ 144,424	$ 725	
11							
12							
13	Income Tax - Current	$ 37,362	$ 34,006	$ 3,544	$ 37,550	$ 188	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 37,362	$ 34,006	$ 3,544	$ 37,550	$ 188	- Appendix G-1 FORMULA Sch 3
17							

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G-1 FORMULA Schedule 5

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Adjustments	2015 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,870,810	$ 4,019,425	$ -	$ 4,019,425	$ 148,615	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,019,425	4,168,826	-	4,168,826	149,401	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,102,885)	$ (1,203,723)	$ -	$ (1,203,723)	$ (100,838)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,203,723)	(1,315,527)	-	(1,315,527)	(111,804)	
8							
9	CIAC, Beginning	$ (200,601)	$ (202,456)	$ -	$ (202,456)	$ (1,855)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(202,456)	(206,505)	-	(206,505)	(4,049)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 57,280	$ 60,017	$ -	$ 60,017	$ 2,737	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	60,017	64,491	-	64,491	4,474	
16							
17	Net Plant in Service, Mid-Year	$ 2,648,934	$ 2,692,274	$ -	$ 2,692,274	$ 43,341	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	24,937	58,785	-	58,785	33,848	
22	Cash Working Capital	(335)	(378)	38	(340)	(5)	
23	Other Working Capital	79,039	80,704	-	80,704	1,665	
24	Deferred Income Taxes Regulatory Asset	288,453	287,980	-	287,980	(473)	
25	Deferred Income Taxes Regulatory Liability	(288,453)	(287,980)	-	(287,980)	473	
26	LILO Benefit	(983)	(817)	-	(817)	166	
27	**Utility Rate Base**	$ 2,777,712	$ 2,856,688	$ 38	$ 2,856,726	$ 79,015	- Appendix G-1 FORMULA Sch 6

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2015 AT 2013 RATES							
2	Long-Term Debt		$ 1,573,226	55.07%	6.77%	3.73%		
3	Unfunded Debt		183,637	6.43%	2.50%	0.16%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,099,825	38.50%	7.83%	3.01%		
6								
7			$ 2,856,688	100.00%		6.90%		- Appendix G-1 FORMULA Sch 5
8								
9	2015 REVISED RATES							
10	Long-Term Debt		$ 1,573,226	55.07%	6.77%	3.73%	$ 106,442	
11	Unfunded Debt	$ 183,637						
12	Adjustment, Revised Rates	23	183,660	6.43%	2.50%	0.16%	4,592	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,099,840	38.50%	8.75%	3.37%	96,236	
15								- Appendix G-1 FORMULA Sch 3
16			$ 2,856,726	100.00%		7.26%	$ 207,270	- Appendix G-1 FORMULA Sch 5
17								
18	2014 REVISED RATES							
19	Long-Term Debt		$ 1,575,067	56.70%	6.83%	3.87%	$ 107,610	
20	Unfunded Debt	$ 133,056						
21	Adjustment, Revised Rates	170	133,226	4.80%	1.75%	0.08%	2,331	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,069,419	38.50%	8.75%	3.37%	93,574	
24								
25			$ 2,777,712	100.00%		7.33%	$ 203,515	
26								
27	CHANGE FROM 2014 REVISED RATES							
28	Long-Term Debt		$ (1,841)	-1.63%	-0.06%	-0.14%	$ (1,168)	
29	Unfunded Debt	$ 50,581						
30	Adjustment, Revised Rates	(147)	50,434	1.63%	0.75%	0.08%	2,261	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		30,421	0.00%	0.00%	0.00%	2,662	
33								
34			$ 79,014	0.00%		-0.06%	$ 3,755	

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Non-Bypass Sales	2016 Non-Bypass Transportation	2016 Bypass and Special Rates	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,104,615	$ 1,015,848	$ 86,825	$ 11,524	$ 1,114,197	$ 9,582	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,149	-	-	18,160	18,160	11	
8								
9	Total Revenue	1,122,764	1,015,848	86,825	29,684	1,132,357	9,593	
10								
11	Less - Cost of Gas	(490,159)	(490,321)	(255)	(252)	(490,828)	(669)	
12								
13	Gross Margin	$ 632,605	$ 525,527	$ 86,570	$ 29,432	$ 641,529	$ 8,924	
14								
15	Revenue Deficiency (Surplus)	$ 13,633	$ 24,794	$ 4,084	$ -	**$ 28,878**	$ 15,245	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	2.16%	4.72%	4.72%	0.00%	4.50%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.21%	2.44%	4.70%	0.00%	2.55%		
20								

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G-1 FORMULA Schedule 8

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,254	115,079	-	115,079	825	
3	Transportation	99,501	100,439	-	100,439	938	
4		213,755	215,518	-	215,518	1,763	
5							
6	Average Rate per GJ						
7	Sales	$8.926	$8.827	$0.000	$9.043	$0.117	
8	Transportation	$0.989	$0.979	$0.000	$1.020	$0.031	
9	Average	$5.231	$5.170	$0.000	$5.304	$0.073	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,008,157	$ 1,015,848	$ -	$ 1,015,848	$ 7,691	
13	- Increase / (Decrease)	11,721	-	24,794	24,794	13,073	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	96,459	98,349	-	98,349	1,890	
16	- Increase / (Decrease)	1,912		4,084	4,084	2,172	
17							
18	**Total Revenue**	1,118,249	1,114,197	28,878	1,143,075	24,826	
19							
20	Cost of Gas Sold (Including Gas Lost)	492,036	495,712	-	495,712	3,676	
21							
22	**Gross Margin**	626,213	618,485	28,878	647,363	21,150	
23							
24	Operation and Maintenance	204,747	208,670	-	208,670	3,923	
25	Property and Sundry Taxes	49,335	50,614	-	50,614	1,279	
26	Depreciation and Amortization	152,604	165,196	-	165,196	12,592	
27	Other Operating Revenue	(25,293)	(26,013)	-	(26,013)	(720)	
28	Sub-total	381,393	398,467	-	398,467	17,074	
29	Utility Income Before Income Taxes	244,820	220,018	28,878	248,896	4,076	
30							
31	Income Taxes	37,550	33,929	7,507	41,436	3,886	
32							
33	**EARNED RETURN**	$ 207,270	$ 186,089	$ 21,371	$ 207,460	$ 190	- Appendix G-1 FORMULA Sch 11
34							
35							
36	**UTILITY RATE BASE**	$ 2,856,726	$ 2,915,663	$ 352	$ 2,916,015	$ 59,289	- Appendix G-1 FORMULA Sch 10
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.26%	6.38%		7.11%	-0.14%	- Appendix G-1 FORMULA Sch 11

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

			2016				
Line No.	Particulars	2015 FORECAST	Existing 2013 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 207,270	$ 186,089	$ 21,371	$ 207,460	$ 190	- Appendix G-1 FORMULA Sch 8
3	Deduct - Interest on Debt	(111,034)	(109,220)	(7)	(109,227)	1,807	- Appendix G-1 FORMULA Sch 11
4	Add (Deduct) - Permanent & Timing Differences	10,638	19,699	-	19,699	9,061	
5	Adjusted Taxable Income After Tax	$ 106,874	96,568	21,364	$ 117,932	11,058	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 144,424	$ 130,497	$ 28,870	$ 159,368	$ 14,944	
11							
12							
13	Income Tax - Current	$ 37,550	$ 33,929	$ 7,506	$ 41,436	$ 3,886	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 37,550	$ 33,929	$ 7,506	$ 41,436	$ 3,886	- Appendix G-1 FORMULA Sch 8
17							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 10

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Adjustments	2016 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,019,425	$ 4,168,826	$ -	$ 4,168,826	$ 149,401	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,168,826	4,303,458	-	4,303,458	134,632	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,203,723)	$ (1,315,527)	$ -	$ (1,315,527)	$ (111,804)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,315,527)	(1,416,659)	-	(1,416,659)	(101,132)	
8							
9	CIAC, Beginning	$ (202,456)	$ (206,505)	$ -	$ (206,505)	$ (4,049)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(206,505)	(209,877)	-	(209,877)	(3,372)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 60,017	$ 64,491	$ -	$ 64,491	$ 4,474	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	64,491	68,093	-	68,093	3,602	
16							
17	Net Plant in Service, Mid-Year	$ 2,692,274	$ 2,728,150	$ -	$ 2,728,150	$ 35,876	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	58,785	77,342	-	77,342	18,557	
22	Cash Working Capital	(340)	43	352	395	735	
23	Other Working Capital	80,704	84,659	-	84,659	3,955	
24	Deferred Income Taxes Regulatory Asset	287,980	287,029	-	287,029	(951)	
25	Deferred Income Taxes Regulatory Liability	(287,980)	(287,029)	-	(287,029)	951	
26	LILO Benefit	(817)	(651)	-	(651)	166	
27	**Utility Rate Base**	$ 2,856,726	$ 2,915,663	$ 352	$ 2,916,015	$ 59,289	- Appendix G-1 FORMULA Sch 11

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2016 AT 2013 RATES							
2	Long-Term Debt		$ 1,571,383	53.89%	6.49%	3.50%		
3	Unfunded Debt		221,750	7.61%	3.25%	0.25%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,122,530	38.50%	6.85%	2.63%		
6								
7			$ 2,915,663	100.00%		6.38%		- Appendix G-1 FORMULA Sch 10
8								
9	2016 REVISED RATES							
10	Long-Term Debt		$ 1,571,383	53.89%	6.49%	3.50%	$ 102,013	
11	Unfunded Debt	$ 221,750						
12	Adjustment, Revised Rates	216	221,966	7.61%	3.25%	0.25%	7,214	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,122,666	38.50%	8.75%	3.37%	98,233	
15								- Appendix G-1 FORMULA Sch 8
16			$ 2,916,015	100.00%		7.11%	$ 207,460	- Appendix G-1 FORMULA Sch 10
17								
18	2015 REVISED RATES							
19	Long-Term Debt		$ 1,573,226	55.07%	6.77%	3.73%	$ 106,442	
20	Unfunded Debt	$ 183,637						
21	Adjustment, Revised Rates	23	183,660	6.43%	2.50%	0.16%	4,592	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,099,840	38.50%	8.75%	3.37%	96,236	
24								
25			$ 2,856,726	100.00%		7.26%	$ 207,270	- Appendix G-1 FORMULA Sch 6
26								
27	CHANGE FROM 2015 REVISED RATES							
28	Long-Term Debt		$ (1,843)	-1.18%	-0.28%	-0.23%	$ (4,429)	
29	Unfunded Debt	$ 38,113						
30	Adjustment, Revised Rates	193	38,306	1.18%	0.75%	0.09%	2,622	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		22,826	0.00%	0.00%	0.00%	1,997	
33								
34			$ 59,289	0.00%		-0.14%	$ 190	

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G-1
FORMULA
Schedule 12

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Non-Bypass Sales	2017 Non-Bypass Transportation	2017 Bypass and Special Rates	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,114,197	$ 1,022,967	$ 88,748	$ 11,525	$ 1,123,240	$ 9,043	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,160	-	-	18,159	18,159	(1)	
8								
9	Total Revenue	1,132,357	1,022,967	88,748	29,684	1,141,399	9,042	
10								
11	Less - Cost of Gas	(490,828)	(491,181)	(259)	(253)	(491,693)	(865)	
12								
13	Gross Margin	$ 641,529	$ 531,786	$ 88,489	$ 29,431	$ 649,706	$ 8,177	
14								
15	Revenue Deficiency (Surplus)	$ 28,878	$ 31,072	$ 5,170	$ -	**$ 36,242**	$ 7,364	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	4.50%	5.84%	5.84%	0.00%	5.58%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	2.55%	3.04%	5.83%	0.00%	3.18%		
20								

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G-1 FORMULA Schedule 13

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars (1)	2016 FORECAST (2)	2017 Existing 2013 Rates (3)	2017 Revised Revenue (4)	2017 Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,079	115,784	-	115,784	705	
3	Transportation	100,439	101,477	-	101,477	1,038	
4		215,518	217,261	-	217,261	1,743	
5							
6	Average Rate per GJ						
7	Sales	$9.043	$8.835	$0.000	$9.103	$0.060	
8	Transportation	$1.020	$0.988	$0.000	$1.039	$0.019	
9	Average	$5.304	$5.170	$0.000	$5.337	$0.033	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,015,848	$ 1,022,967	$ -	$ 1,022,967	$ 7,119	
13	- Increase / (Decrease)	24,794	-	31,071	31,071	6,277	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	98,349	100,273	-	100,273	1,924	
16	- Increase / (Decrease)	4,084		5,171	5,171	1,087	
17							
18	**Total Revenue**	1,143,075	1,123,240	36,242	1,159,482	16,407	
19							
20	Cost of Gas Sold (Including Gas Lost)	495,712	499,335	-	499,335	3,623	
21							
22	**Gross Margin**	647,363	623,905	36,242	660,147	12,784	
23							
24	Operation and Maintenance	208,670	213,016	-	213,016	4,346	
25	Property and Sundry Taxes	50,614	51,598	-	51,598	984	
26	Depreciation and Amortization	165,196	173,188	-	173,188	7,992	
27	Other Operating Revenue	(26,013)	(26,890)	-	(26,890)	(877)	
28	Sub-total	398,467	410,912	-	410,912	12,445	
29	Utility Income Before Income Taxes	248,896	212,993	36,242	249,235	339	
30							
31	Income Taxes	41,436	34,616	9,421	44,037	2,601	
32							
33	**EARNED RETURN**	$ 207,460	$ 178,377	$ 26,821	$ 205,198	$ (2,262)	- Appendix G-1 FORMULA Sch 16
34							
35							
36	**UTILITY RATE BASE**	$ 2,916,015	$ 2,959,295	$ 380	$ 2,959,675	$ 43,660	- Appendix G-1 FORMULA Sch 15
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.11%	6.03%		6.93%	-0.18%	- Appendix G-1 FORMULA Sch 16

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 14

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 207,460	$ 178,377	$ 26,821	$ 205,198	$ (2,262)	- Appendix G-1 FORMULA Sch 13
3	Deduct - Interest on Debt	(109,227)	(105,485)	(9)	(105,494)	3,733	- Appendix G-1 FORMULA Sch 16
4	Add (Deduct) - Permanent & Timing Differences	19,699	25,631	-	25,631	5,932	
5	Adjusted Taxable Income After Tax	$ 117,932	98,523	26,812	$ 125,335	7,403	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 159,368	$ 133,139	$ 36,232	$ 169,372	$ 10,004	
11							
12							
13	Income Tax - Current	$ 41,436	$ 34,616	$ 9,420	$ 44,037	$ 2,601	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 41,436	$ 34,616	$ 9,420	$ 44,037	$ 2,601	- Appendix G-1 FORMULA Sch 13
17							

FORTISBC ENERGY INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 15

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Adjustments	2017 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,168,826	$ 4,303,458	$ -	$ 4,303,458	$ 134,632	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,303,458	4,455,708	-	4,455,708	152,250	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,315,527)	$ (1,416,659)	$ -	$ (1,416,659)	$ (101,132)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,416,659)	(1,532,513)	-	(1,532,513)	(115,854)	
8							
9	CIAC, Beginning	$ (206,505)	$ (209,877)	$ -	$ (209,877)	$ (3,372)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(209,877)	(213,016)	-	(213,016)	(3,139)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 64,491	$ 68,093	$ -	$ 68,093	$ 3,602	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	68,093	71,163	-	71,163	3,070	
16							
17	Net Plant in Service, Mid-Year	$ 2,728,150	$ 2,763,179	$ -	$ 2,763,179	$ 35,029	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	77,342	79,702	-	79,702	2,360	
22	Cash Working Capital	395	268	380	648	253	
23	Other Working Capital	84,659	90,511	-	90,511	5,852	
24	Deferred Income Taxes Regulatory Asset	287,029	285,481	-	285,481	(1,548)	
25	Deferred Income Taxes Regulatory Liability	(287,029)	(285,481)	-	(285,481)	1,548	
26	LILO Benefit	(651)	(485)	-	(485)	166	
27	**Utility Rate Base**	$ 2,916,015	$ 2,959,295	$ 380	$ 2,959,675	$ 43,660	- Appendix G-1 FORMULA Sch 16

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 16

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2017 AT 2013 RATES							
2	Long-Term Debt		$ 1,670,471	56.45%	5.98%	3.38%		
3	Unfunded Debt		149,495	5.05%	3.75%	0.19%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,139,329	38.50%	6.40%	2.46%		
6								
7			$ 2,959,295	100.00%		6.03%		- Appendix G-1 FORMULA Sch 15
8								
9	2017 REVISED RATES							
10	Long-Term Debt		$ 1,670,471	56.44%	5.98%	3.38%	$ 99,879	
11	Unfunded Debt	$ 149,495						
12	Adjustment, Revised Rates	234	149,729	5.06%	3.75%	0.19%	5,615	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,139,475	38.50%	8.75%	3.37%	99,704	
15								- Appendix G-1 FORMULA Sch 13
16			$ 2,959,675	100.00%		6.93%	$ 205,198	- Appendix G-1 FORMULA Sch 15
17								
18	2016 REVISED RATES							
19	Long-Term Debt		$ 1,571,383	53.89%	6.49%	3.50%	$ 102,013	
20	Unfunded Debt	$ 221,750						
21	Adjustment, Revised Rates	216	221,966	7.61%	3.25%	0.25%	7,214	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,122,666	38.50%	8.75%	3.37%	98,233	
24								
25			$ 2,916,015	100.00%		7.11%	$ 207,460	- Appendix G-1 FORMULA Sch 11
26								
27	CHANGE FROM 2016 REVISED RATES							
28	Long-Term Debt		$ 99,088	2.55%	-0.51%	-0.12%	$ (2,134)	
29	Unfunded Debt	$ (72,255)						
30	Adjustment, Revised Rates	18	(72,237)	-2.55%	0.50%	-0.06%	(1,599)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		16,809	0.00%	0.00%	0.00%	1,471	
33								
34			$ 43,660	0.00%		-0.18%	$ (2,262)	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G-1

FORMULA

Schedule 17

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Non-Bypass Sales	2018 Non-Bypass Transportation	2018 Bypass and Special Rates	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,123,240	$ 1,029,249	$ 90,719	$ 11,525	$ 1,131,493	$ 8,253	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,159	-	-	18,159	18,159	-	
8								
9	Total Revenue	1,141,399	1,029,249	90,719	29,684	1,149,652	8,253	
10								
11	Less - Cost of Gas	(491,693)	(491,767)	(262)	(255)	(492,284)	(591)	
12								
13	Gross Margin	$ 649,706	$ 537,482	$ 90,457	$ 29,429	$ 657,368	$ 7,662	
14								
15	Revenue Deficiency (Surplus)	$ 36,242	$ 43,896	$ 7,388	$ -	**$ 51,284**	$ 15,042	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.58%	8.17%	8.17%	0.00%	7.80%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.18%	4.26%	8.14%	0.00%	4.46%		
20								

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 18

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,784	116,394	-	116,394	610	
3	Transportation	101,477	102,556	-	102,556	1,079	
4		217,261	218,950	-	218,950	1,689	
5							
6	Average Rate per GJ						
7	Sales	$9.103	$8.843	$0.000	$9.220	$0.117	
8	Transportation	$1.039	$0.997	$0.000	$1.069	$0.030	
9	Average	$5.337	$5.168	$0.000	$5.402	$0.065	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,022,967	$ 1,029,249	$ -	$ 1,029,249	$ 6,282	
13	- Increase / (Decrease)	31,071	-	43,896	43,896	12,825	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	100,273	102,244	-	102,244	1,971	
16	- Increase / (Decrease)	5,171		7,388	7,388	2,217	
17							
18	**Total Revenue**	1,159,482	1,131,493	51,284	1,182,777	23,295	
19							
20	Cost of Gas Sold (Including Gas Lost)	499,335	502,541	-	502,541	3,206	
21							
22	**Gross Margin**	660,147	628,952	51,284	680,236	20,089	
23							
24	Operation and Maintenance	213,016	218,501	-	218,501	5,485	
25	Property and Sundry Taxes	51,598	52,691	-	52,691	1,093	
26	Depreciation and Amortization	173,188	181,287	-	181,287	8,099	
27	Other Operating Revenue	(26,890)	(28,120)	-	(28,120)	(1,230)	
28	Sub-total	410,912	424,359	-	424,359	13,447	
29	Utility Income Before Income Taxes	249,235	204,593	51,284	255,877	6,642	
30							
31	Income Taxes	44,037	32,838	13,330	46,168	2,131	
32							
33	**EARNED RETURN**	$ 205,198	$ 171,755	$ 37,954	$ 209,709	$ 4,511	- Appendix G-1 FORMULA Sch 21
34							
35							
36	**UTILITY RATE BASE**	$ 2,959,675	$ 2,995,063	$ 461	$ 2,995,524	$ 35,849	- Appendix G-1 FORMULA Sch 20
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.93%	5.73%		7.00%	0.07%	- Appendix G-1 FORMULA Sch 21

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 205,198	$ 171,755	$ 37,954	$ 209,709	$ 4,511	- Appendix G-1 FORMULA Sch 18
3	Deduct - Interest on Debt	(105,494)	(108,783)	(14)	(108,797)	(3,303)	- Appendix G-1 FORMULA Sch 21
4	Add (Deduct) - Permanent & Timing Differences	25,631	30,490	-	30,490	4,859	
5	Adjusted Taxable Income After Tax	$ 125,335	93,462	37,940	$ 131,402	6,067	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 169,372	$ 126,300	$ 51,270	$ 177,570	$ 8,198	
11							
12							
13	Income Tax - Current	$ 44,037	$ 32,838	$ 13,330	$ 46,168	$ 2,131	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 44,037	$ 32,838	$ 13,330	$ 46,168	$ 2,131	- Appendix G-1 FORMULA Sch 18
17							

FORTISBC ENERGY INC.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Evidentiary Update - February 21, 2014

Appendix G-1
FORMULA
Schedule 20

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Adjustments	2018 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,303,458	$ 4,455,708	$ -	$ 4,455,708	$ 152,250	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,455,708	4,620,144	-	4,620,144	164,436	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,416,659)	$ (1,532,513)	$ -	$ (1,532,513)	$ (115,854)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,532,513)	(1,661,068)	-	(1,661,068)	(128,555)	
8							
9	CIAC, Beginning	$ (209,877)	$ (213,016)	$ -	$ (213,016)	$ (3,139)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(213,016)	(219,605)	-	(219,605)	(6,589)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 68,093	$ 71,163	$ -	$ 71,163	$ 3,070	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	71,163	77,341	-	77,341	6,178	
16							
17	Net Plant in Service, Mid-Year	$ 2,763,179	$ 2,799,077	$ -	$ 2,799,077	$ 35,899	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	79,702	73,335	-	73,335	(6,367)	
22	Cash Working Capital	648	169	461	630	(18)	
23	Other Working Capital	90,511	96,690	-	96,690	6,179	
24	Deferred Income Taxes Regulatory Asset	285,481	283,368	-	283,368	(2,113)	
25	Deferred Income Taxes Regulatory Liability	(285,481)	(283,368)	-	(283,368)	2,113	
26	LILO Benefit	(485)	(328)	-	(328)	157	
27	**Utility Rate Base**	$ 2,959,675	$ 2,995,063	$ 461	$ 2,995,524	$ 35,850	- Appendix G-1 FORMULA Sch 21

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2018 AT 2013 RATES							
2	Long-Term Debt		$ 1,768,209	59.04%	5.95%	3.51%		
3	Unfunded Debt		73,755	2.46%	4.75%	0.12%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,153,099	38.50%	5.46%	2.10%		
6								
7			$ 2,995,063	100.00%		5.73%		- Appendix G-1 FORMULA Sch 20
8								
9	2018 REVISED RATES							
10	Long-Term Debt		$ 1,768,209	59.03%	5.95%	3.51%	$ 105,280	
11	Unfunded Debt	$ 73,755						
12	Adjustment, Revised Rates	283	74,038	2.47%	4.75%	0.12%	3,517	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,153,277	38.50%	8.75%	3.37%	100,912	
15								- Appendix G-1 FORMULA Sch 18
16			$ 2,995,524	100.00%		7.00%	$ 209,709	- Appendix G-1 FORMULA Sch 20
17								
18	2017 REVISED RATES							
19	Long-Term Debt		$ 1,670,471	56.44%	5.98%	3.38%	$ 99,879	
20	Unfunded Debt	$ 149,495						
21	Adjustment, Revised Rates	234	149,729	5.06%	3.75%	0.19%	5,615	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,139,475	38.50%	8.75%	3.37%	99,704	
24								
25			$ 2,959,675	100.00%		6.93%	$ 205,198	- Appendix G-1 FORMULA Sch 16
26								
27	CHANGE FROM 2017 REVISED RATES							
28	Long-Term Debt		$ 97,738	2.59%	-0.03%	0.13%	$ 5,401	
29	Unfunded Debt	$ (75,740)						
30	Adjustment, Revised Rates	49	(75,691)	-2.59%	1.00%	-0.07%	(2,098)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		13,802	0.00%	0.00%	0.00%	1,208	
33								
34			$ 35,849	0.00%		0.06%	$ 4,511	

Summary of Rate Change

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 1

Line No.	Particulars	2014 ($ Millions)		Cross Reference
	(1)	(2)	(3)	(4)
1	Volume/Revenue Related			
2	Customer Growth and Use Rates	(7.2)		
3	Change in Other Revenue	0.2	(7.0)	
4				
5	O&M Changes			
6	Gross O&M Increases	1.8		
7	Less: Capitalized Overhead	(0.3)	1.5	
8				
9	Depreciation Expense			
10	Change in Depreciation Rates	(0.2)		
11	Tax Expense Impact of Depreciation Changes	0.3		
12	Depreciation from Net Additions	1.0	1.1	
13				
14	Amortization Expense			
15	CIAC	(0.0)		
16	Deferral Accounts	3.7	3.7	
17				
18	Property and Other Taxes	(2.4)		
19	Other (NSP Provision)	-		
20	Income Tax Rate Change	1.9		
21	Other Income Tax Changes	10.7		
22	Financing Rate Changes	(2.9)		
23	Financing Changes	0.2		
24	Rate Base Growth	0.4	7.8	
25				
26	**Revenue Deficiency (Surplus)**		**7.1**	- Appendix G2-FORECAST, Sch 2

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Non-Bypass Sales	2014 Non-Bypass Transportation	2014 Bypass and Special Rates	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,113,989	$ 1,011,096	$ 83,059	$ 11,524	$ 1,105,679	$ (8,310)	- Appendix G2-FORECAST, Sch 8
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,237	-	-	18,138	18,138	(99)	- Appendix G2-FORECAST, Sch 13
8								
9	Total Revenue	1,132,226	1,011,096	83,059	29,662	1,123,817	(8,409)	
10								
11	Less - Cost of Gas	(505,614)	(494,561)	(250)	(248)	(495,059)	10,555	- Appendix G2-FORECAST, Sch 9
12								
13	Gross Margin	$ 626,612	$ 516,535	$ 82,809	$ 29,414	$ 628,758	$ 2,146	
14								
15	Revenue Deficiency (Surplus)	$ -	$ 6,110	$ 979	$ -	**$ 7,089**	$ 7,089	- Appendix G2-FORECAST, Sch 1
16								- Appendix G2-FORECAST, Sch 61
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	1.18%	1.18%	0.00%	1.13%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	0.60%	1.18%	0.00%	0.63%		
20								

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 3

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

Line No.	Particulars (1)	2012 ACTUAL (2)	2013 APPROVED (3)	2013 PROJECTED (4)	Change (5) (Column (4) - Column (3))	Cross Reference (6)
1	ENERGY VOLUMES (TJ)					
2	Sales	113,621	112,327	113,914	1,587	- Appendix G2-FORECAST, Sch 5
3	Transportation	86,767	94,833	97,837	3,004	- Appendix G2-FORECAST, Sch 5
4		200,388	207,160	211,751	4,591	
5						
6	Average Rate per GJ					
7	Sales	$ 9.106	$ 10.426	$ 8.943	$ (1.483)	
8	Transportation	$ 1.039	$ 0.946	$ 0.974	$ 0.028	
9	Average	$ 5.616	$ 6.086	$ 5.226	$ (0.860)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 1,034,629	$ 1,171,155	$ 1,018,733	$ (152,422)	- Appendix G2-FORECAST, Sch 7
13	- Increase / (Decrease)	-	-	-	-	
14	RSAM Revenue	472	-	(7,323)	(7,323)	
15	Transportation - Existing Rates	90,183	89,704	95,257	5,553	- Appendix G2-FORECAST, Sch 7
16	- Increase / (Decrease)	-	-	-	-	
17						
18	**Total Revenue**	1,125,284	1,260,859	1,106,667	(154,192)	
19						
20	Cost of Gas Sold (Including Gas Lost)	539,821	658,568	505,614	(152,954)	- Appendix G2-FORECAST, Sch 9
21						
22	**Gross Margin**	585,463	602,291	601,053	(1,238)	
23						
24	Operation and Maintenance	187,925	202,963	196,170	(6,793)	- Appendix G2-FORECAST, Sch 14
25	Property and Sundry Taxes	49,656	51,239	51,239	-	- Appendix G2-FORECAST, Sch 18
26	Depreciation and Amortization	123,928	142,912	142,909	(3)	- Appendix G2-FORECAST, Sch 20
27	Other Operating Revenue	(24,501)	(24,789)	(24,165)	624	- Appendix G2-FORECAST, Sch 12
28	Sub-total	337,008	372,325	366,153	(6,172)	
29	Utility Income Before Income Taxes	248,454	229,966	234,900	4,934	
30						
31	Income Taxes	26,880	24,066	25,324	1,258	- Appendix G2-FORECAST, Sch 22
32						
33	**EARNED RETURN**	$ 221,574	$ 205,900	$ 209,575	$ 3,675	- Appendix G2-FORECAST, Sch 57
34				1		
35						
36	**UTILITY RATE BASE**	$ 2,692,824	$ 2,767,651	$ 2,688,936	$ (78,715)	- Appendix G2-FORECAST, Sch 28
37						
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.23%	7.44%	7.79%	0.35%	- Appendix G2-FORECAST, Sch 57

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	113,914	114,087	-	114,087	173	- Appendix G2-FORECAST, Sch 6
3	Transportation	97,837	98,330	-	98,330	493	- Appendix G2-FORECAST, Sch 6
4		211,751	212,417	-	212,417	666	
5							
6	Average Rate per GJ						
7	Sales	$ 8.943	$ 8.862	$ -	$ 8.916	$ (0.027)	
8	Transportation	$ 0.974	$ 0.962	$ -	$ 0.972	$ (0.002)	
9	Average	$ 5.226	$ 5.205	$ -	$ 5.239	$ 0.013	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,018,733	$ 1,011,096	$ -	$ 1,011,096	$ (7,637)	- Appendix G2-FORECAST, Sch 8
13	- Increase / (Decrease)	-	-	6,109	6,109	6,109	- Appendix G2-FORECAST, Sch 10
14	RSAM Revenue	(7,323)				7,323	
15	Transportation - Existing Rates	95,257	94,582	-	94,582	(675)	- Appendix G2-FORECAST, Sch 8
16	- Increase / (Decrease)	-		980	980	980	- Appendix G2-FORECAST, Sch 10
17							
18	**Total Revenue**	1,106,667	1,105,678	7,089	1,112,767	6,100	
19							
20	Cost of Gas Sold (Including Gas Lost)	505,614	496,151	-	496,151	(9,463)	- Appendix G2-FORECAST, Sch 9
21							
22	**Gross Margin**	601,053	609,527	7,089	616,616	15,563	
23							
24	Operation and Maintenance	196,170	204,454	-	204,454	8,284	- Appendix G2-FORECAST, Sch 14
25	Property and Sundry Taxes	51,239	48,797	-	48,797	(2,442)	- Appendix G2-FORECAST, Sch 19
26	Depreciation and Amortization	142,909	147,450	-	147,450	4,541	- Appendix G2-FORECAST, Sch 21
27	Other Operating Revenue	(24,165)	(24,567)	-	(24,567)	(402)	- Appendix G2-FORECAST, Sch 13
28	Sub-total	366,153	376,134	-	376,134	9,981	
29	Utility Income Before Income Taxes	234,900	233,393	7,089	240,482	5,582	
30							
31	Income Taxes	25,324	35,065	1,843	36,908	11,584	- Appendix G2-FORECAST, Sch 23
32							
33	**EARNED RETURN**	$ 209,575	$ 198,328	$ 5,246	$ 203,574	$ (6,001)	- Appendix G2-FORECAST, Sch 58
34							
35							
36	**UTILITY RATE BASE**	$ 2,688,936	$ 2,778,942	$ 19	$ 2,778,961	$ 90,025	- Appendix G2-FORECAST, Sch 29
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.79%	7.14%		7.33%	-0.47%	- Appendix G2-FORECAST, Sch 58

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 5

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Projected Terajoules: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	69,753.0	69,816.4	69,644.2	-	69,644.2	(172.2)	
3	Schedule 2 - Small Commercial	24,319.0	23,331.9	24,087.6		24,087.6	755.7	
4	Schedule 3 - Large Commercial	16,744.0	16,514.8	17,354.8		17,354.8	840.0	
5								
6	Schedules 1, 2 and 3	110,816.0	109,663.1	111,086.6	-	111,086.6	1,423.5	
7								
8	Schedule 4 - Seasonal	169.0	185.2	169.1		169.1	(16.1)	
9	Schedule 5 - General Firm	2,315.0	2,407.7	2,315.3		2,315.3	(92.4)	
10								
11	Industrials							
12	Schedule 7 - Interruptible	87.0	14.2	86.7		86.7	72.5	
13								
14	Schedule 6 - N G V Fuel - Stations	62.0	56.4	61.4		61.4	5.0	
15	Schedule 16 - Liquefied Natural Gas (LNG)	172.0	-	194.7		194.7	194.7	
16	Schedule 46 - Liquefied Natural Gas (LNG)			-		-	-	
17								
18	Total Sales	113,621.0	112,326.6	113,913.8	-	113,913.8	1,587.2	- Appendix G2-FORECAST, Sch 3
19								
20	**TRANSPORTATION SERVICE**							
21	Schedule 22 - Firm Service	18,884.0	17,089.5	13,208.0	6,874.9	20,082.9	2,993.4	
22	- Interruptible Service	18,760.0	12,302.6	15,940.9	-	15,940.9	3,638.3	
23	Byron Creek (aka Fording Coal Mountain)	393.0	227.4		179.1	179.1	(48.3)	
24	Burrard Thermal - Firm	482.0	1,372.0		482.5	482.5	(889.5)	
25	FEVI - Firm	21,244.0	37,080.0		33,553.2	33,553.2	(3,526.8)	
26	Schedule 23 - Large Commercial	7,803.0	7,485.3	8,168.1		8,168.1	682.8	
27	Schedule 25 - Firm Service	12,829.0	13,471.3	12,268.5	837.3	13,105.8	(365.5)	
28	Schedule 27 - Interruptible Service	6,372.0	5,804.8	6,324.5		6,324.5	519.7	
29								
30	Total Transportation Service	86,767.0	94,832.9	55,910.0	41,927.0	97,837.0	3,004.1	- Appendix G2-FORECAST, Sch 3
31								
32	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,388.0	207,160.0	169,823.8	41,927.0	211,750.8	4,591.3	- Appendix G2-FORECAST, Sch 3
33								

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2014

			2014 Forecast Terajoules				
Line No.	Particulars	2013 PROJECTED	Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	69,644.2	69,511.7	-	69,511.7	(132.5)	
3	Schedule 2 - Small Commercial	24,087.6	24,246.8		24,246.8	159.2	
4	Schedule 3 - Large Commercial	17,354.8	17,253.0		17,253.0	(101.8)	
5							
6	Schedules 1, 2 and 3	111,086.6	111,011.5	-	111,011.5	(75.1)	
7							
8	Schedule 4 - Seasonal	169.1	169.1		169.1	-	
9	Schedule 5 - General Firm	2,315.3	2,315.3		2,315.3	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	86.7	86.7		86.7	-	
13							
14	Schedule 6 - N G V Fuel - Stations	61.4	61.4		61.4	-	
15	Schedule 16 - Liquefied Natural Gas (LNG)	194.7	165.0		165.0	(29.7)	
16	Schedule 46 - Liquefied Natural Gas (LNG)	-	277.7		277.7	277.7	
17							
18	Total Sales	113,913.8	114,086.7	-	114,086.7	172.9	- Appendix G2-FORECAST, Sch 4
19							
20	**TRANSPORTATION SERVICE**						
21	Schedule 22 - Firm Service	20,082.9	13,188.4	6,553.2	19,741.6	(341.3)	
22	- Interruptible Service	15,940.9	15,822.0	-	15,822.0	(118.9)	
23	Byron Creek (aka Fording Coal Mountain)	179.1		176.6	176.6	(2.5)	
24	Burrard Thermal - Firm	482.5		482.5	482.5	-	
25	FEVI - Firm	33,553.2		33,720.0	33,720.0	166.8	
26	Schedule 23 - Large Commercial	8,168.1	8,721.3		8,721.3	553.2	
27	Schedule 25 - Firm Service	13,105.8	12,352.3	837.3	13,189.6	83.8	
28	Schedule 27 - Interruptible Service	6,324.5	6,476.3		6,476.3	151.8	
29							
30	Total Transportation Service	97,837.0	56,560.3	41,769.6	98,329.9	492.9	- Appendix G2-FORECAST, Sch 4
31							
32	**TOTAL SALES AND TRANSPORTATION SERVICES**	211,750.8	170,647.0	41,769.6	212,416.6	665.8	- Appendix G2-FORECAST, Sch 4
33							- Appendix G2-FORECAST, Sch 11

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	$ 684,879	$ 777,332	$ 672,249	$ -	$ 672,249	$ (105,083)	
3	Schedule 2 - Small Commercial	207,547	229,774	204,217		204,217	(25,557)	
4	Schedule 3 - Large Commercial	123,547	142,700	124,396		124,396	(18,304)	
5	Schedules 1, 2 and 3	1,015,973	1,149,806	1,000,862	-	1,000,862	(148,944)	
6								
7	Schedule 4 - Seasonal	945	1,285	939	-	939	(346)	
8	Schedule 5 - General Firm	15,405	19,409	14,522		14,522	(4,887)	
9		16,350	20,694	15,461	-	15,461	(5,233)	
10	Industrials							
11	Schedule 7 - Interruptible	489	137	456	-	456	319	
12								
13	Schedule 6 - N G V Fuel - Stations	480	518	461		461	(57)	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,337	-	1,493		1,493	1,493	
15	Schedule 46 - Liquefied Natural Gas (LNG)			-		-	-	
16	Total Sales	1,034,629	1,171,155	1,018,733	-	1,018,733	(152,422)	- Appendix G2-FORECAST, Sch 3
17								
18	**Transportation Service**							
19	Schedule 22 - Firm Service	7,173	9,459	10,523	823	11,346	1,887	
20	- Interruptible Service	17,350	11,987	14,721	-	14,721	2,734	
21	Byron Creek (aka Fording Coal Mountain)	78	55		32	32	(23)	
22	Burrard Thermal - Firm	9,965	9,996		9,965	9,965	(31)	
23	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch1:	-	-		-	-	-	
24	Schedule 23 - Large Commercial	22,810	22,845	24,566	-	24,566	1,721	
25	Schedule 25 - Firm Service	24,484	27,382	25,399	704	26,103	(1,279)	
26	Schedule 27 - Interruptible Service	8,323	7,980	8,524	-	8,524	544	
27	Total Transportation Service	90,183	89,704	83,733	11,524	95,257	5,553	- Appendix G2-FORECAST, Sch 3
28								
29	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,124,812	$ 1,260,859	$ 1,102,466	$ 11,524	$ 1,113,990	$ (146,869)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 8

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 672,249	$ 667,279	$ -	$ 667,279	$ (4,970)	
3	Schedule 2 - Small Commercial	204,217	201,875		201,875	(2,342)	
4	Schedule 3 - Large Commercial	124,396	121,939		121,939	(2,457)	
5	Schedules 1, 2 and 3	1,000,862	991,093	-	991,093	(9,769)	
6							
7	Schedule 4 - Seasonal	939	939	-	939	-	
8	Schedule 5 - General Firm	14,522	14,522		14,522	-	
9		15,461	15,461	-	15,461	-	
10	Industrials						
11	Schedule 7 - Interruptible	456	456	-	456	-	
12							
13	Schedule 6 - N G V Fuel - Stations	461	461		461	-	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,493	1,325		1,325	(168)	
15	Schedule 46 - Liquefied Natural Gas (LNG)	-	2,300		2,300	2,300	
16	Total Sales	1,018,733	1,011,096	-	1,011,096	(7,637)	- Appendix G2-FORECAST, Sch 4
17							
18	**Transportation Service**						
19	Schedule 22 - Firm Service	11,346	8,397	823	9,220	(2,126)	
20	- Interruptible Service	14,721	14,379	-	14,379	(342)	
21	Byron Creek (aka Fording Coal Mountain)	32		32	32	-	
22	Burrard Thermal - Firm	9,965		9,965	9,965	-	
23	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch13)	-		-	-	-	
24	Schedule 23 - Large Commercial	24,566	26,120	-	26,120	1,554	
25	Schedule 25 - Firm Service	26,103	25,460	704	26,164	61	
26	Schedule 27 - Interruptible Service	8,524	8,702	-	8,702	178	
27	Total Transportation Service	95,257	83,058	11,524	94,582	(675)	- Appendix G2-FORECAST, Sch 4
28							
29	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,113,990	$ 1,094,154	$ 11,524	$ 1,105,678	$ (8,312)	- Appendix G2-FORECAST, Sch 4 - Appendix G2-FORECAST, Sch 11

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 9

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Projected Gas Costs Non-Bypass Sales & Transp	2013 Projected Gas Costs Bypass and Special Rates	2013 Projected Gas Costs Total	2014 Forecast Gas Costs Non-Bypass Sales & Transp	2014 Forecast Gas Costs Bypass and Special Rates	2014 Forecast Gas Costs Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	310,537	$ -	$ 310,537	$ 305,432	$ -	$ 305,432
3	Schedule 2 - Small Commercial	110,811		110,811	107,890		107,890
4	Schedule 3 - Large Commercial	72,872		72,872	70,770		70,770
5							
6	Schedules 1, 2 and 3	494,220	-	494,220	484,092	-	484,092
7							
8	Schedule 4 - Seasonal	629		629	629		629
9	Schedule 5 - General Firm	8,660		8,660	8,660		8,660
10							
11	Schedules 4 and 5	9,289	-	9,289	9,289	-	9,289
12							
13	Industrials						
14	Schedule 7 - Interruptible	323		323	323		323
15							
16	Schedule 6 - N G V Fuel - Stations	208		208	208		208
17	Schedule 16 - Liquefied Natural Gas (LNG)	697		697	649		649
18	Schedule 46 - Liquefied Natural Gas (LNG)	-		-	1,092		1,092
19							
20	Total Sales	504,737	-	504,737	495,653	-	495,653
21							
22	**TRANSPORTATION SERVICE**						
23	Schedule 22 - Firm Service	268	58	326	44	31	75
24	- Interruptible Service	58	-	58	73	-	73
25	Byron Creek (aka Fording Coal Mountain)		7	7		-	-
26	Burrard Thermal - Firm		5	5		3	3
27	FEVI - Firm		324	324		210	210
28	Schedule 23 - Large Commercial	41	-	41	43	-	43
29	Schedule 25 - Firm Service	71	6	77	59	4	63
30	Schedule 27 - Interruptible Service	39	-	39	31	-	31
31							
32	Total Transportation Service	477	400	877	250	248	498
33							
34	TOTAL SALES AND TRANSPORTATION SERVICES	$ 505,214	$ 400	$ 505,614	$ 495,903	$ 248	$ 496,151
35							
36	Cross Reference			- Appendix G2-FORECAST, Sch 3			- Appendix G2-FORECAST, Sch 4

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2013 Rates -- Average $/GJ	Revenue -- At Existing 2013 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2013 Rates -- Average $/GJ	Gross Margin -- At Existing 2013 Rates -- Margin ($000s)	Effective Increase / (Decrease) 1.18% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000s)	Average Number of Customers	Revenue Average $/GJ	Revenue Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,511.7	$ 9.600	$ 667,279	$ 5.206	$ 361,847	$ 0.062	$ 4,289	765,842	$ 9.662	$ 671,568
4	Schedule 2 - Small Commercial	24,246.8	8.326	201,875	3.876	93,986	0.046	1,114	72,614	8.372	202,989
5	Schedule 3 - Large Commercial	17,253.0	7.068	121,939	2.966	51,168	0.035	606	4,577	7.103	122,545
6	Schedules 1, 2 and 3	111,011.5		991,093		507,001		6,009	843,033		997,102
7											
8	Schedule 4 - Seasonal	169.1	5.553	939	1.833	310	0.024	4	26	5.577	943
9	Schedule 5 - General Firm	2,315.3	6.272	14,522	2.532	5,863	0.030	69	216	6.302	14,591
10											
11	Industrials										
12	Schedule 7 - Interruptible	86.7	5.260	456	1.546	134	0.023	2	3	5.283	458
13											
14	Schedule 6 - N G V Fuel - Stations	61.4	7.508	461	4.137	254	0.049	3	14	7.557	464
15	Schedule 16 - Liquefied Natural Gas (LNG)	165.0	8.030	1,325	4.103	677	0.048	8	2	8.078	1,333
16	Schedule 46 - Liquefied Natural Gas (LNG)	277.7	8.282	2,300	4.350	1,208	0.050	14	3	8.332	2,314
17	Total Sales	114,086.7		1,011,096		515,447		6,109	843,297		1,017,205
18											
19	TRANSPORTATION SERVICE										
20	Schedule 22 - Firm Service	13,188.4	0.637	8,397	0.633	8,353	0.008	99	14	0.645	8,496
21	- Interruptible Service	15,822.0	0.909	14,380	0.904	14,307	0.011	170	25	0.920	14,550
22	Schedule 23 - Large Commercial	8,721.3	2.995	26,120	2.990	26,078	0.035	309	1,560	3.030	26,429
23	Schedule 25 - Firm Service	12,352.3	2.061	25,460	2.056	25,401	0.024	300	487	2.085	25,760
24	Schedule 27 - Interruptible Service	6,476.3	1.344	8,702	1.339	8,671	0.016	102	95	1.360	8,804
25											
26	Total Transportation Service	56,560.3		83,059		82,810		980	2,181		84,039
27											
28	Total Non-Bypass Sales & Transportation Service	170,647.0		$ 1,094,155		$ 598,257		$ 7,089	845,478		$ 1,101,244
29											
30	Cross Reference	- Appendix G2-FORECAST, Sch 6		- Appendix G2-FORECAST, Sch 8				- Appendix G2-FORECAST, Sch 4			

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 11

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2013 Rates -- Average $/GJ	Revenue ($000)	Gross Margin -- At Existing 2013 Rates -- Average $/GJ	Margin ($000s)	Increase / (Decrease) 1.18% of Margin $/GJ	Revenue ($000)	Average Number of Customers	Revenue Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,553.2	$ 0.126	$ 823	$ 0.121	$ 791	$ -	$ -	5	$ 0.126	$ 823
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	176.6	0.181	32	0.181	32	-	-	1	0.181	32
6	Burrard Thermal - Firm	482.5	20.653	9,965	20.647	9,962	-	-	1	20.653	9,965
7	FEVI - Firm (Revenue/Margin included in Other Revenue - Sc	33,720.0	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
9	Schedule 25 - Firm Service	837.3	0.841	704	0.836	700	-	-	6	0.841	704
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	41,769.6		11,524		11,485		-	15		11,524
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	212,416.6		$ 1,105,679		$ 609,742		$ 7,089	845,493		$ 1,112,768
15											
16	Cross Reference	- Appendix G2-FORECAST, Sch 6		- Appendix G2-FORECAST, Sch 8				- Appendix G2-FORECAST, Sch 2			

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 12

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 2,402	$ 2,333	$ 2,109	$ (224)	- Appendix G2-FORECAST, Sch 54
4						
5	Connection Charge	2,390	2,685	2,622	(63)	- Appendix G2-FORECAST, Sch 54
6						
7	NSF Returned Cheque Charges	110	79	79	-	- Appendix G2-FORECAST, Sch 54
8						
9	Other Recoveries	237	126	284	158	- Appendix G2-FORECAST, Sch 54
10						
11	Total Other Utility Revenue	5,139	5,223	5,094	(129)	
12						
13	**Miscellaneous Revenue**					
14						
15	FEVI Wheeling Charge	3,353	3,464	3,464	-	
16						
17	SCP Third Party Revenue	15,272	14,827	14,773	(54)	
18						
19	FEVI SAP Lease Income	17	-	-	-	- Appendix G2-FORECAST, Sch 54
20						
21	NGT Overhead and Marketing Recovery	-	-	-	-	- Appendix G2-FORECAST, Sch 54
22						
23	Surrey & Burnaby Operations CNG Pump Charges	-	-	-	-	- Appendix G2-FORECAST, Sch 54
24						
25	Biomethane Other Revenue	-	(29)	(97)	(68)	- Appendix G2-FORECAST, Sch 54
26						
27	CNG & LNG Service Revenues	720	1,304	931	(373)	- Appendix G2-FORECAST, Sch 54
28						
29						
30	Total Miscellaneous	19,362	19,566	19,071	(495)	
31						
32	**Total Other Operating Revenue**	$ 24,501	$ 24,789	$ 24,165	$ (624)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 13

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,109	$ 2,089	$ (20)	- Appendix G2-FORECAST, Sch 54
4					
5	Connection Charge	2,622	2,636	14	- Appendix G2-FORECAST, Sch 54
6					
7	NSF Returned Cheque Charges	79	79	-	- Appendix G2-FORECAST, Sch 54
8					
9	Other Recoveries	284	284	-	- Appendix G2-FORECAST, Sch 54
10					
11	Total Other Utility Revenue	5,094	5,088	(6)	
12					
13	**Miscellaneous Revenue**				
14					
15	FEVI Wheeling Charge	3,464	3,365	(99)	- Appendix G2-FORECAST, Sch 2
16					
17	SCP Third Party Revenue	14,773	14,773	-	- Appendix G2-FORECAST, Sch 2
18					
19	FEVI SAP Lease Income	-	-	-	- Appendix G2-FORECAST, Sch 54
20					
21	NGT Overhead and Marketing Recovery	-	180	180	- Appendix G2-FORECAST, Sch 54
22					
23	Surrey & Burnaby Operations CNG Pump Charges	-	-	-	- Appendix G2-FORECAST, Sch 54
24					
25	Biomethane Other Revenue	(97)	(198)	(101)	- Appendix G2-FORECAST, Sch 54
26					
27	CNG & LNG Service Revenues	931	1,359	428	- Appendix G2-FORECAST, Sch 54
28					
29					
30	Total Miscellaneous	19,071	19,479	408	
31					
32	**Total Other Operating Revenue**	$ 24,165	$ 24,567	$ 402	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 14

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	M&E Costs	$ 50,708	$ 59,097	$ 52,770	$ 61,022	
2	COPE Costs	32,450	37,183	31,426	35,329	
3	COPE Customer Services Costs	11,825	11,144	10,977	12,801	
4	IBEW Costs	27,180	27,640	25,156	29,723	
5						
6	**Labour Costs**	**122,164**	**135,064**	**120,330**	**138,874**	
7						
8	Vehicle Costs	3,807	3,685	4,134	4,149	
9	Employee Expenses	5,898	5,716	5,744	5,803	
10	Materials and Supplies	7,903	7,019	8,764	7,126	
11	Computer Costs	14,570	14,769	16,397	16,028	
12	Fees and Administration Costs	38,611	37,905	37,790	40,338	
13	Contractor Costs	31,955	38,335	42,961	30,898	
14	Facilities	15,486	14,284	14,305	14,484	
15	Recoveries & Revenue	(20,689)	(20,774)	(21,211)	(19,300)	
16						
17	**Non-Labour Costs**	**97,540**	**100,939**	**108,884**	**99,525**	
18						
19						
20	**Total Gross O&M Expenses**	**219,704**	**236,003**	**229,214**	**238,400**	
21						
22	Less: O&M Transferred to Biomethane BVA	-	-	(4)	(570)	
23	Less: Capitalized Overhead	(31,779)	(33,040)	(33,040)	(33,376)	
24						
25	**Total O&M Expenses**	**$ 187,925**	**$ 202,963**	**$ 196,170**	**$ 204,454**	
26						
27	Cross Reference			- Appendix G2-FORECAST, Sch 3		
28					- Appendix G2-FORECAST, Sch 4	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 10,578	$ 11,026	$ 10,994	$ 12,439	
2	Distribution Supervision Total	110-10	10,578	11,026	10,994	12,439	
3							
4	Operation Centre - Distribution	110-21	10,112	11,074	9,815	11,204	
5	Preventative Maintenance - Distribution	110-22	2,644	2,990	2,417	3,322	
6	Operations - Distribution	110-23	5,538	5,904	6,321	6,331	
7	Emergency Management - Distribution	110-24	5,405	5,077	5,434	6,479	
8	Field Training - Distribution	110-25	1,746	4,088	3,242	3,547	
9	Meter Exchange - Distribution	110-26	2,397	2,231	2,419	3,161	
10	Distribution Operations Total	110-20	27,842	31,363	29,647	34,045	
11							
12	Corrective - Distribution	110-31	5,564	4,643	6,061	5,978	
13	Distribution Maintenance Total	110-30	5,564	4,643	6,061	5,978	
14							
15	Account Services - Distribution	110-41	1,111	1,004	1,110	1,249	
16	Bad Debt Management - Distribution	110-42	585	599	661	569	
17	Distribution Meter to Cash Total	110-40	1,697	1,603	1,771	1,818	
18							
19	**Distribution Total**	**110**	**45,680**	**48,635**	**48,473**	**54,280**	
20							
21	Transmission Supervision	120-11	535	482	482	694	
22	Transmission Supervision Total	120-10	535	482	482	694	
23							
24	Pipeline / Right of Way Operations	120-21	7,287	6,096	7,541	6,979	
25	Compression Operations	120-22	1,827	2,112	2,074	2,024	
26	Measurement Control Operations	120-23	103	-	97	17	
27	Transmission Operations Total	120-20	9,217	8,208	9,712	9,020	
28							
29	Pipeline / Right of Way - Maintenance	120-31	1,830	2,707	2,504	3,263	
30	Compression - Maintenance	120-32	554	1,147	713	1,230	
31	Measurement Control Operations	120-33	117	119	119	204	
32	Transmission Maintenance Total	120-30	2,501	3,973	3,335	4,697	
33							
34	**Transmission Total**	**120**	**12,253**	**12,663**	**13,529**	**14,410**	
35							
36	LNG Operations	130-11	1,601	1,617	1,956	2,218	
37	LNG Operations Total	130-10	1,601	1,617	1,956	2,218	
38							
39	LNG Plant Maintenance	130-21	272	274	268	377	
40	LNG Plant Maintenance Total	130-20	272	274	268	377	
41							
42	**LNG Plant Total**	**130**	**1,873**	**1,891**	**2,224**	**2,595**	
43							
44	**Operations Total**	**100**	**59,806**	**63,189**	**64,226**	**71,285**	
45							
46	Customer Service Supervision	210-11	482	566	491	636	
47	Customer Assistance	210-12	11,513	11,493	10,874	13,830	
48	Customer Billing	210-13	18,586	14,494	23,701	12,604	
49	Meter Reading	210-14	12,178	19,696	10,148	10,722	
50	Credit & Collections	210-15	3,028	3,851	2,641	3,342	
51	Customer Operations	210-16	2,385	2,353	2,075	2,308	
52	Customer Service Total	210-10	48,172	52,452	49,931	43,442	
53							
54	**Customer Service Total**	**210**	**48,172**	**52,452**	**49,931**	**43,442**	
55							
56	**Customer Service Total**	**200**	**48,172**	**52,452**	**49,931**	**43,442**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervision	310-11	$ 614	$ 796	$ 1,014	$ 700	
2	Energy Solutions	310-12	5,134	4,991	5,076	6,009	
3	Energy Efficiency	310-13	117	120	151	308	
4	Corporate Communications and External Relations	310-14	7,212	6,155	6,823	8,609	
5	Forecasting, Market & Business Development	310-15	4,998	6,119	5,957	7,649	
6	Energy Solutions & External Relations Total	310-10	18,075	18,181	19,022	23,275	
7							
8	**Energy Solutions & External Relations Total**	**310**	**18,075**	**18,181**	**19,022**	**23,275**	
9							
10	**Energy Solutions & External Relations Total**	**300**	**18,075**	**18,181**	**19,022**	**23,275**	
11							
12	Energy Supply & Resource Development	410-11	1,937	2,136	2,375	2,938	
13	Gas Control	410-12	1,551	1,602	1,562	1,800	
14	Energy Supply & Resource Development Total	410-10	3,488	3,738	3,937	4,738	
15							
16	**Energy Supply & Resource Development Total**	**410**	**3,488**	**3,738**	**3,937**	**4,738**	
17							
18	Information Technology Supervision	420-11	4,172	4,577	4,185	4,276	
19	Application Management	420-12	11,251	12,083	12,647	11,101	
20	Infrastructure Management	420-13	8,018	8,719	7,418	9,014	
21	Information Technology Total	420-10	23,442	25,379	24,249	24,392	
22							
23	**Information Technology Total**	**420**	**23,442**	**25,379**	**24,249**	**24,392**	
24							
25	System Planning	430-11	5,672	8,394	7,485	8,859	
26	Engineering	430-12	6,803	7,027	6,799	7,657	
27	Project Management	430-13	1,125	1,535	1,014	1,220	
28	Engineering Services & Project Management Total	430-10	13,599	16,956	15,297	17,735	
29							
30	**Engineering Services & Project Management Total**	**430**	**13,599**	**16,956**	**15,297**	**17,735**	
31							
32	Supply Chain	440-11	4,420	4,884	4,424	5,234	
33	Measurement	440-12	5,548	6,688	6,091	6,983	
34	Property Services	440-13	1,070	1,418	1,204	1,481	
35	Operations Support Total	440-10	11,038	12,990	11,718	13,698	
36							
37	**Operations Support Total**	**440**	**11,038**	**12,990**	**11,718**	**13,698**	
38							
39	Facilities Management	450-11	9,563	9,259	9,230	10,299	
40	Facilities Total	450-10	9,563	9,259	9,230	10,299	
41							
42	**Facilities Total**	**450**	**9,563**	**9,259**	**9,230**	**10,299**	
43							
44	Environment Health & Safety	460-11	2,481	2,999	2,680	2,934	
45	Environment Health & Safety Total	460-10	2,481	2,999	2,680	2,934	
46							
47	**Environment Health & Safety Total**	**460**	**2,481**	**2,999**	**2,680**	**2,934**	
48							
49							
50	**Business Services Total**	**400**	**63,611**	**71,321**	**67,111**	**73,796**	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2
FORECAST
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued) Schedule 17
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Financial & Regulatory Services	510-11	12,149	$ 14,184	12,872	15,217	
2	Financial & Regulatory Services Total	510-10	12,149	14,184	12,872	15,217	
3							
4	**Financial & Regulatory Services Total**	**510**	**12,149**	**14,184**	**12,872**	**15,217**	
5							
6	Human Resources	520-11	8,610	8,511	8,305	9,398	
7	Human Resources Total	520-10	8,610	8,511	8,305	9,398	
8							
9	**Human Resources Total**	**520**	**8,610**	**8,511**	**8,305**	**9,398**	
10							
11	Legal	530-11	1,917	2,282	2,342	2,325	
12	Internal Audit	530-12	695	755	755	769	
13	Risk Management/Insurance	530-13	4,754	4,898	4,898	5,277	
14	Governance	530-10	7,366	7,935	7,995	8,371	
15							
16	**Governance Total**	**530**	**7,366**	**7,935**	**7,995**	**8,371**	
17							
18	Administration & General	540-11	226	(46)	262	575	
19	Shared Services Agreement	540-12	(5,984)	(5,581)	(6,366)	(6,958)	
20	Retiree Benefits	540-16	7,673	5,857	5,857	-	
21	Corporate Total	540-10	1,915	230	(247)	(6,384)	
22							
23	**Corporate Total**	**540**	**1,915**	**230**	**(247)**	**(6,384)**	
24							
25	**Corporate Services Total**	**500**	**30,041**	**30,860**	**28,924**	**26,603**	
26							
27	**Total Gross O&M Expenses**		**219,704**	**236,003**	**229,214**	**238,400**	
28	Less: O&M Transferred to Biomethane BVA		-	-	(4)	(570)	
29	Less: Capitalized Overhead		(31,779)	(33,040)	(33,040)	(33,376)	
30							
31	**Total O&M Expenses**		**$ 187,925**	**$ 202,963**	**$ 196,170**	**$ 204,454**	
32							
33	Cross Reference				- Appendix G2-FORECAST, Sch 3		
34						- Appendix G2-FORECAST, Sch 4	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 18

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Total Expenses	2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 13,283	$ 13,728	$ 12,151	$ 12,151	$ (1,577)	
4							
5	General, School and Other	34,132	37,511	35,547	35,547	(1,964)	
6							
7		47,415	51,239	47,698	47,698	(3,541)	
8							
9	Add / Less: Deferred Property Taxes	2,241	-	3,541	3,541	3,541	
10							
11	Total	$ 49,656	$ 51,239	$ 51,239	$ 51,239	$ -	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 19

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Total Expenses	2014 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 12,151	$ 12,032	$ 12,032	$ (119)	
4						
5	General, School and Other	35,547	36,765	36,765	1,218	
6						
7		47,698	48,797	48,797	1,099	
8						
9	Add / Less: Deferred Property Taxes	3,541	-	-	(3,541)	
10						
11	Total	$ 51,239	$ 48,797	$ 48,797	$ (2,442)	- Appendix G2-FORECAST, Sch 4

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 118,639	$ 123,842	$ 123,839	$ (3)	- Appendix G2-FORECAST, Sch 39
4						
5	Less: Amortization of Contributions in Aid of Construction	(6,558)	(6,499)	(6,499)	-	- Appendix G2-FORECAST, Sch 43
6		112,081	117,343	117,340	(3)	- Appendix G2-FORECAST, Sch 24
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ 11,847	$ 25,569	$ 25,569	$ -	- Appendix G2-FORECAST, Sch 46
11						
12	TOTAL	123,928	142,912	142,909	$ (3)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 123,839	$ 124,667	$ 828	- Appendix G2-FORECAST, Sch 42
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,499)	(6,505)	(6)	- Appendix G2-FORECAST, Sch 44
6		117,340	118,162	822	- Appendix G2-FORECAST, Sch 25
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 25,569	$ 29,288	$ 3,719	- Appendix G2-FORECAST, Sch 48
11					
12	TOTAL	$ 142,909	147,450	$ 4,541	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 22

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Existing Rates	2013 Revised Revenue	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 221,574	$ 205,900	$ 209,575	$ -	$ 209,576	$ 3,676	- Appendix G2-FORECAST, Sch 3
3	Deduct - Interest on Debt	(108,979)	(112,665)	(110,971)	-	(110,971)	1,694	- Appendix G2-FORECAST, Sch 57
4	Net Additions (Deductions)	(31,957)	(21,038)	(22,631)	-	(22,631)	(1,593)	- Appendix G2-FORECAST, Sch 24
5	Accounting Income After Tax	80,638	72,197	75,973	$ -	75,974	3,777	
6								
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	75.00%	0.00%	
9								
10	Taxable Income	$ 107,518	$ 96,263	$ 101,297	$ -	$ 101,299	$ 5,036	
11								
12								
13	Income Tax - Current	$ 26,880	$ 24,066	$ 25,324	$ -	$ 25,325	$ 1,259	
14								
15	**Total Income Tax**	$ 26,880	$ 24,066	$ 25,324	$ -	$ 25,325	$ 1,259	- Appendix G2-FORECAST, Sch 3

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Existing Rates	2014 Revised Revenue	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 209,576	$ 198,328	$ 5,246	$ 203,574	$ (6,002)	- Appendix G2-FORECAST, Sch 4
3	Deduct - Interest on Debt	(110,971)	(109,957)	(1)	(109,958)	1,013	- Appendix G2-FORECAST, Sch 58
4	Net Additions (Deductions)	(22,631)	11,429	-	11,429	34,060	- Appendix G2-FORECAST, Sch 25
5	Accounting Income After Tax	75,974	99,800	$ 5,245	105,045	29,071	
6							
7	Current Income Tax Rate	25.00%	26.00%	26.00%	26.00%	1.00%	
8	1 - Current Income Tax Rate	75.00%	74.00%	74.00%	74.00%	-1.00%	
9							
10	Taxable Income	101,299	$ 134,865	$ 7,088	$ 141,953	$ 40,654	
11							
12							
13	Income Tax - Current	$ 25,325	$ 35,065	$ 1,843	$ 36,908	$ 11,583	
14							
15	**Total Income Tax**	$ 25,325	$ 35,065	$ 1,843	$ 36,908	$ 11,583	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 24

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 677	$ 700	700	$ -	
3	Depreciation	112,081	117,343	117,340	(3)	- Appendix G2-FORECAST, Sch 20
4	Amortization of Debt Issue Expenses	537	622	577	(45)	
5	Vehicle: Interest & Capitialized Depreciation	1,898	2,187	1,688	(499)	
6	Pension Expense	14,097	12,530	12,530	-	
7	OPEB Expense	4,765	4,902	4,902	-	
8	Olympic Cauldron (50% NBV)	1,445	-	-	-	
9	Bad Debt Provision	726	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	11,847	25,569	25,569	-	- Appendix G2-FORECAST, Sch 20
13	Capital Cost Allowance	(129,279)	(136,232)	(136,232)	-	- Appendix G2-FORECAST, Sch 26
14	Cumulative Eligible Capital Allowance	(907)	(857)	(846)	11	
15	Debt Issue Costs	(834)	(411)	(385)	26	
16	Vehicle Lease Payment	(3,432)	(4,613)	(3,316)	1,297	
17	Pension Contributions	(13,920)	(12,006)	(12,666)	(660)	
18	OPEB Contributions	(1,667)	(2,367)	(2,407)	(40)	
19	Overheads Capitalized Expensed for Tax Purposes	(13,620)	(14,160)	(14,160)	-	
20	Removal Costs	(14,766)	(12,932)	(13,398)	(466)	
21	Discounts on Debt Issue and Other	-	-	-	-	
22	Major Inspection Costs	(1,606)	(1,342)	(2,624)	(1,282)	
23	Biomethane Other Revenue	-	29	97	68	
24						
25	TOTAL	(31,957)	(21,038)	$ (22,631)	$ (1,593)	- Appendix G2-FORECAST, Sch 22

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 25

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	800	$ 100	
3	Depreciation	117,340	118,162	822	- Appendix G2-FORECAST, Sch 21
4	Amortization of Debt Issue Expenses	577	734	157	
5	Vehicle: Interest & Capitialized Depreciation	1,688	1,386	(302)	
6	Pension Expense	12,530	20,004	7,474	
7	OPEB Expense	4,902	8,662	3,760	
8	Olympic Cauldron (50% NBV)	-	-	-	
9	Bad Debt Provision	-	-	-	
10					
11	Deductions:				
12	Amortization of Deferred Charges	25,569	29,288	3,719	- Appendix G2-FORECAST, Sch 21
13	Capital Cost Allowance	(136,232)	(115,336)	20,896	- Appendix G2-FORECAST, Sch 27
14	Cumulative Eligible Capital Allowance	(846)	(787)	59	
15	Debt Issue Costs	(385)	(202)	183	
16	Vehicle Lease Payment	(3,316)	(3,006)	310	
17	Pension Contributions	(12,666)	(16,114)	(3,448)	
18	OPEB Contributions	(2,407)	(2,631)	(224)	
19	Overheads Capitalized Expensed for Tax Purposes	(14,160)	(14,304)	(144)	
20	Removal Costs	(13,398)	(13,327)	71	
21	Discounts on Debt Issue and Other	-	-	-	
22	Major Inspection Costs	(2,624)	(2,098)	526	
23	Biomethane Other Revenue	97	198	101	
24					
25	TOTAL	$ (22,631)	$ 11,429	$ 34,060	- Appendix G2-FORECAST, Sch 23

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

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,044,769	$ -	$ 208	$ (41,795)	$ 1,003,182
2	1(b)	6%	27,756	-	8,451	(1,919)	34,288
3	2	6%	136,353	-	-	(8,181)	128,172
4	3	5%	2,423	-	-	(121)	2,302
5	6	10%	150	-	-	(15)	135
6	7	15%	5,442	-	1,180	(905)	5,717
7	8	20%	23,402	(1,412)	8,301	(5,228)	25,063
8	10	30%	1,680	-	323	(553)	1,450
9	12	100%	26,830	-	13,083	(33,372)	6,541
10	13	manual	3,517	-	180	(687)	3,010
11	17	8%	174	-	-	(14)	160
12	38	30%	511	-	72	(164)	419
13	45	45%	202	-	-	(91)	111
14	47	8%	5,496	-	25	(441)	5,080
15	49	8%	77,300	-	3,989	(6,344)	74,945
16	50	55%	7,461	-	9,481	(6,711)	10,231
17	51	6%	336,347	-	98,039	(23,122)	411,264
18	43.2	50%	-	-	2,369	(592)	1,777
19		Total	$ 1,699,813	$ (1,412)	$ 145,701	$ (130,255)	$ 1,713,847
20							
21	Add: Depreciation variance adjustment					(5,977)	
22	Approved CCA					$ (136,232)	
23							
24	Cross Reference					- Appendix G2-FORECAST, Sch 24	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Class	CCA Rate	12/31/2013 UCC Balance	Adjustments	2014 Net Additions	2014 CCA	12/31/2014 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,003,182	$ -	$ 124	$ (40,130)	$ 963,176
2	1(b)	6%	34,288	-	4,192	(2,183)	36,297
3	2	6%	128,172	-	-	(7,690)	120,482
4	3	5%	2,302	-	-	(115)	2,187
5	6	10%	135	-	-	(14)	121
6	7	15%	5,717	-	1,817	(994)	6,540
7	8	20%	25,063	-	8,315	(5,844)	27,534
8	10	30%	1,450	-	2,600	(825)	3,225
9	12	100%	6,541	-	12,067	(12,575)	6,033
10	13	manual	3,010	-	274	(313)	2,971
11	17	8%	160	-	-	(13)	147
12	38	30%	419	-	-	(126)	293
13	45	45%	111	-	-	(50)	61
14	47	8%	5,080	-	4,071	(569)	8,582
15	49	8%	74,945	-	4,463	(6,174)	73,234
16	50	55%	10,231	-	8,044	(7,839)	10,436
17	51	6%	411,264	-	107,042	(27,887)	490,419
18	43.2	50%	1,777	-	4,426	(1,995)	4,208
19		Total	$ 1,713,847	$ -	$ 157,435	$ (115,336)	$ 1,755,946
20							
21							
22							
23							
24	Cross Reference				- Appendix G2-FORECAST, Sch 25		

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 28

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	Gas Plant in Service, Beginning	$ 3,545,030	$ 3,774,425	$ 3,726,853	$ -	$ 3,726,853	$ (47,572)	- Appendix G2-FORECAST, Sch 33
2	Opening Balance Adjustment	(3,890)	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,726,853	3,905,299	3,870,810	-	3,870,810	(34,489)	- Appendix G2-FORECAST, Sch 33
4								
5	Accumulated Depreciation Beginning - Plant	$ (922,011)	$ (1,012,343)	$ (1,011,180)	$ -	$ (1,011,180)	$ 1,163	- Appendix G2-FORECAST, Sch 39
6	Opening Balance Adjustment	4,463	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,011,179)	(1,104,066)	(1,102,885)	-	(1,102,885)	1,181	- Appendix G2-FORECAST, Sch 39
8								
9	CIAC, Beginning	$ (180,038)	$ (191,772)	$ (185,545)	$ -	$ (185,545)	$ 6,227	- Appendix G2-FORECAST, Sch 43
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	CIAC, Ending	(185,545)	(198,468)	(200,601)	-	(200,601)	(2,133)	- Appendix G2-FORECAST, Sch 43
12								
13	Accumulated Amortization Beginning - CIAC	$ 49,620	$ 51,072	$ 51,143	$ -	$ 51,143	$ 71	- Appendix G2-FORECAST, Sch 43
14	Opening Balance Adjustment	(5)	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	51,143	57,367	57,281	-	57,281	(86)	- Appendix G2-FORECAST, Sch 43
16								
17	Net Plant in Service, Mid-Year	$ 2,537,220	$ 2,640,757	$ 2,602,938	$ -	$ 2,602,938	$ (37,819)	
18								
19	Adjustment to 13-Month Average	30,786	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	20,803	26,120	-	26,120	5,317	
21	Unamortized Deferred Charges	497	8,249	(20,190)	-	(20,190)	(28,439)	- Appendix G2-FORECAST, Sch 46
22	Cash Working Capital	(1,899)	(2,630)	(1,903)	-	(1,903)	727	- Appendix G2-FORECAST, Sch 51
23	Other Working Capital	101,416	101,622	83,121	-	83,121	(18,501)	- Appendix G2-FORECAST, Sch 51
24	Deferred Income Taxes Regulatory Asset	281,929	282,359	284,958	-	284,958	2,599	- Appendix G2-FORECAST, Sch 56
25	Deferred Income Taxes Regulatory Liability	(281,929)	(282,359)	(284,958)	-	(284,958)	(2,599)	- Appendix G2-FORECAST, Sch 56
26	LILO Benefit	(1,316)	(1,150)	(1,150)	-	(1,150)	-	
27	**Utility Rate Base**	$ 2,692,824	$ 2,767,651	$ 2,688,936	$ -	$ 2,688,936	$ (78,715)	- Appendix G2-FORECAST, Sch 57
28								- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 29

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,726,853	$ 3,870,810	$ -	$ 3,870,810	$ 143,957	- Appendix G2-FORECAST, Sch 36
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	3,870,810	4,021,274	-	4,021,274	150,464	- Appendix G2-FORECAST, Sch 36
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,011,180)	$ (1,102,885)	$ -	$ (1,102,885)	$ (91,705)	- Appendix G2-FORECAST, Sch 42
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,102,885)	(1,203,788)	-	(1,203,788)	(100,903)	- Appendix G2-FORECAST, Sch 42
8							
9	CIAC, Beginning	$ (185,545)	$ (200,601)	$ -	$ (200,601)	$ (15,056)	- Appendix G2-FORECAST, Sch 44
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(200,601)	(202,655)	-	(202,655)	(2,054)	- Appendix G2-FORECAST, Sch 44
12							
13	Accumulated Amortization Beginning - CIAC	$ 51,143	$ 57,281	$ -	$ 57,281	$ 6,138	- Appendix G2-FORECAST, Sch 44
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	57,281	60,018	-	60,018	2,737	- Appendix G2-FORECAST, Sch 44
16							
17	Net Plant in Service, Mid-Year	$ 2,602,938	$ 2,649,727	$ -	$ 2,649,727	$ 46,789	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	(20,190)	25,360	-	25,360	45,550	- Appendix G2-FORECAST, Sch 48
22	Cash Working Capital	(1,903)	(321)	19	(302)	1,601	- Appendix G2-FORECAST, Sch 52
23	Other Working Capital	83,121	79,039	-	79,039	(4,082)	- Appendix G2-FORECAST, Sch 52
24	Deferred Income Taxes Regulatory Asset	284,958	288,491	-	288,491	3,533	- Appendix G2-FORECAST, Sch 56
25	Deferred Income Taxes Regulatory Liability	(284,958)	(288,491)	-	(288,491)	(3,533)	- Appendix G2-FORECAST, Sch 56
26	LILO Benefit	(1,150)	(983)	-	(983)	167	
27	**Utility Rate Base**	$ 2,688,936	$ 2,778,942	$ 19	$ 2,778,961	$ 90,025	- Appendix G2-FORECAST, Sch 58
28							- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. / Update - February 21, 2014 Appendix G2

FORECAST

CAPITAL EXPENDITURES AND PLANT ADDITIONS Schedule 30

FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

($000)

Line No.	Particulars	2013 Projected	2014 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 138,204	$ 134,676	
6	Gateway Project	4,139	-	
7	Biomethane Assets	3,436	5,168	
8	Total Regular Capital Expenditures	$ 145,779	$ 139,844	
9				
10	Special Projects - CPCN's			
11	Fraser River Crossing Seismic Upg	42	-	
12	Kootenay River Crossing	755	-	
13	Tilbury Expansion Project (Q-477)	2,656	-	
14	NGT Assets	4,233	3,356	
15	Tilbury Land Property Purchase	(406)	-	
16	Total CPCN's	$ 7,279	$ 3,356	
17				
18	TOTAL CAPITAL EXPENDITURES	$ 153,058	$ 143,200	
19				
20				
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
22				
23	Regular Capital			
24	Regular Capital Expenditures	$ 145,779	$ 139,844	
25	Add - Opening WIP	43,661	48,168	
26	Less - Adjustments	777	-	
27	Less - Closing WIP	(48,168)	(45,419)	
28	Capital Spares Inventory	727	-	
29	Capital Vehicle Lease	2,577	-	
30	Add - AFUDC	1,749	1,732	
31	Add - Overhead Capitalized	33,040	33,376	
32				
33	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVI	$ 180,141	$ 177,701	
34				
35	Special Projects - CPCN's			
36	CPCN Expenditures	$ 7,279	$ 3,356	
37	Add - Opening WIP	(158)	5,098	
38	Less - Closing WIP	(5,098)	(4,654)	
39	Add: Projects transferred from Deferral Accounts	-	-	
40	Less: Projects settling to Deferral Accounts	406	-	
41	Less: Adjustments	(4)	-	
42	Less: Removal Costs	-	-	
42	Add - AFUDC	52	-	
43				
44	TOTAL CPCN ADDITIONS	$ 2,477	$ 3,800	
45				
46	TOTAL PLANT ADDITIONS	$ 182,618	$ 181,501	
47				
48	Cross Reference	- Appendix G2-FORECAST, Sch 33		
49			- Appendix G2-FORECAST, Sch 36	

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

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,529	12	34	-	-	-	1	44,576	44,553
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	4	1,213	1,211
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,471	-	9,173	208	-	(5,985)	(427)	88,440	86,956
17	402-02 Application Software - 20%	18,723	-	3,245	34	-	(2,982)	(94)	18,926	18,825
18	TOTAL INTANGIBLE	152,412	12	12,452	242	-	(8,967)	(516)	155,635	154,024
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	965	-	25	-	9	-	-	999	982
24	433-00 Manufact'd Gas - Equipment	448	-	8	-	3	-	-	459	454
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	65	-	23	-	-	2,940	2,896
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	8	-	3	-	-	366	361
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	735	-	100	4	36	-	-	875	805
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
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)	25,014	-	21	-	7	-	-	25,042	25,028
36	TOTAL MANUFACTURED	67,023	-	227	4	81	-	-	67,335	67,179

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

Line No.	Particulars	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	$ 7,402	$ -	$ 27	$ -	$ -	$ -	$ -	$ 7,429	$ 7,416
3	461-00 Transmission Land Rights	-	-	-	-	-	-	1	1	1
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	29	-	10	-	-	16,338	16,319
6	463-00 Measuring Structures	5,511	-	596	62	228	(5)	-	6,392	5,952
7	464-00 Other Structures & Improvements	6,023	-	246	-	85	-	1	6,355	6,189
8	465-00 Mains	799,512	102	14,202	596	5,171	(441)	(340)	818,802	809,157
9	465-00 Mains - INSPECTION	5,803	-	2,624	87	941	-	-	9,455	7,629
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	111,811	-	981	34	352	(1,329)	-	111,849	111,830
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,249	-	1,423	54	513	(121)	445	32,563	31,406
17	467-10 Telemetering	9,293	-	643	52	241	(38)	(31)	10,160	9,727
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	995,547	102	20,771	885	7,541	(1,934)	76	1,022,988	1,009,268
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,219	-	651	18	232	(92)	8	19,036	18,628
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	758,346	-	25,999	-	9,020	(4,250)	(7)	789,108	773,727
29	474-00 House Regulators & Meter Installations	174,943	-	-	-	-	(265)	67	174,745	174,844
30	477-00 Meters/Regulators Installations	18,871	-	18,798	7	6,526	-	-	44,202	31,537
31	475-00 Mains	947,273	-	21,502	87	7,492	(1,702)	112	974,764	961,019
32	476-00 Compressor Equipment	1,450	-	-	-	-	-	(340)	1,110	1,110
33	477-00 Measuring & Regulating Equipment	88,594	-	4,503	230	1,643	(393)	79	94,656	91,625
34	477-00 Telemetering	7,102	-	1,022	24	363	(10)	31	8,532	7,817
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
36	478-10 Meters	207,016	-	11,514	-	-	(8,249)	4	210,285	208,651
37	478-20 Instruments	11,889	-	55	-	-	-	-	11,944	11,917
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,237,368	-	84,044	366	25,276	(14,961)	(46)	2,332,047	2,284,538
40										
41	**BIO GAS**									
42	472-00 Bio Gas Struct. & Improvements	137	-	36	-	12	-	-	185	161
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
44	475-20 Bio Gas Mains – Private Land	41	-	-	-	-	-	-	41	41
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	-	-	2,369	-	-	-	-	2,369	1,185
47	477-10 Bio Gas Reg & Meter Equipment	280	-	374	-	130	-	-	784	532
48	478-30 Bio Gas Meters	7	-	3	-	-	-	-	10	9
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
50	TOTAL BIO-GAS	567	-	2,782	-	142	-	-	3,491	2,029

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 33

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

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,554	$ 1,051	$ (12)	$ 12	$ -	$ -	$ 340	$ 3,945	$ 3,420
3	476-20 NG Transportation LNG Dispensing Equipment	47	923	1,443	4	-	-	-	2,417	1,232
4	476-30 NG Transportation CNG Foundations	471	175	(1)	1	-	-	-	646	559
5	476-40 NG Transportation LNG Foundations	4	119	432	-	-	-	-	555	280
6	476-50 NG Transportation LNG Pumps	-	20	43	-	-	-	-	63	32
7	476-60 NG Transportation CNG Dehydrator	119	75	(1)	1	-	-	-	194	157
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	3,195	2,363	1,904	18	-	-	340	7,820	5,678
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,329	-	(112)	-	-	-	-	22,217	22,273
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	380	-	-	-	10	11,160	10,965
16	- Masonry Buildings	92,527	-	5,062	-	-	-	-	97,589	95,058
17	- Leasehold Improvement	3,822	-	180	-	-	(151)	-	3,851	3,837
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,479	-	376	-	-	(301)	17	3,571	3,525
20	483-40 GP Furniture	21,395	-	1,176	2	-	(1,954)	-	20,619	21,007
21	483-10 GP Computer Hardware	29,627	-	9,481	216	-	(6,424)	-	32,900	31,264
22	483-20 GP Computer Software	3,405	-	1,076	16	-	(190)	110	4,417	3,911
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	323	-	-	(30)	11	2,512	2,360
26	484-00 Vehicles - Leased	28,385	-	2,577	-	-	(1,783)	-	29,179	28,782
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	(418)	246	455
28	485-20 Heavy Mobile Equipment	838	-	72	-	-	(80)	421	1,251	1,045
29	486-00 Small Tools & Equipment	38,733	-	2,435	-	-	(963)	10	40,215	39,474
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,679	-	-	-	-	(905)	239	7,013	7,346
34	- Radio	4,856	-	145	1	-	(33)	(239)	4,730	4,793
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	270,741	-	23,171	235	-	(12,814)	161	281,494	276,118
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,726,853	$ 2,477	$ 145,351	$ 1,750	$ 33,040	$ (38,676)	$ 15	$ 3,870,810	$ 3,798,832
43		- Appendix G2-FORECAST, Sch 28								
44	Cross Reference			- Appendix G2-FORECAST, Sch 30					- Appendix G2-FORECAST, Sch 28	
45			- Appendix G2-FORECAST, Sch 30			- Appendix G2-FORECAST, Sch 30				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,576	-	109	-	-	-	-	44,685
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,213	-	-	-	-	-	-	1,213
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1
16	402-01 Application Software - 12.5%	88,440	-	6,033	176	-	(3,738)	-	90,911
17	402-02 Application Software - 20%	18,926	-	6,033	120	-	(2,317)	-	22,762
18	TOTAL INTANGIBLE	155,635	-	12,175	296	-	(6,055)	-	162,051
19									
20	**MANUFACTURED GAS / LOCAL STORAGE**								
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	999	-	-	-	-	-	-	999
24	433-00 Manufact'd Gas - Equipment	459	-	105	-	36	-	-	600
25	434-00 Manufact'd Gas - Gas Holders	2,940	-	-	-	-	-	-	2,940
26	436-00 Manufact'd Gas - Compressor Equipment	366	-	-	-	-	-	-	366
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	875	-	-	-	-	-	-	875
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499
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)	25,042	-	3,433	133	1,182	-	-	29,790
36	TOTAL MANUFACTURED	67,335	-	3,538	133	1,218	-	-	72,224

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	460-00 Land in Fee Simple	$ 7,429	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,429
3	461-00 Transmission Land Rights	1	-	-	-	-	-	-	1
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,338	-	-	-	-	-	-	16,338
6	463-00 Measuring Structures	6,392	-	-	-	-	(21)	-	6,371
7	464-00 Other Structures & Improvements	6,355	-	-	-	-	-	-	6,355
8	465-00 Mains	818,802	-	9,064	373	3,120	(374)	-	830,985
9	465-00 Mains - INSPECTION	9,455	-	2,098	-	722	(368)	-	11,907
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974
13	466-00 Compressor Equipment	111,849	-	1,532	70	527	(299)	-	113,679
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	32,563	-	-	-	-	(131)	-	32,432
17	467-10 Telemetering	10,160	-	319	13	110	(32)	-	10,570
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346
21	TOTAL TRANSMISSION	1,022,988	-	13,013	456	4,479	(1,225)	-	1,039,711
22									
23	**DISTRIBUTION PLANT**								
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	19,036	-	-	-	-	(21)	-	19,015
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107
28	473-00 Services	789,108	-	25,031	-	8,617	(3,185)	-	819,571
29	474-00 House Regulators & Meter Installations	174,745	-	-	-	-	(6)	-	174,739
30	477-00 Meters/Regulators Installations	44,202	-	13,844	97	4,766	-	-	62,909
31	475-00 Mains	974,764	-	26,178	141	9,010	(1,049)	-	1,009,044
32	476-00 Compressor Equipment	1,110	-	-	-	-	-	-	1,110
33	477-00 Measuring & Regulating Equipment	94,656	-	8,058	389	2,774	(598)	-	105,279
34	477-00 Telemetering	8,532	-	287	2	99	(6)	-	8,914
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163
36	478-10 Meters	210,285	-	13,844	-	-	(6,672)	-	217,457
37	478-20 Instruments	11,944	-	-	-	-	-	-	11,944
38	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,332,047	-	87,242	629	25,266	(11,537)	-	2,433,647
40									
41	**BIO GAS**								
42	472-00 Bio Gas Struct. & Improvements	185	-	259	-	-	-	-	444
43	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80
44	475-20 Bio Gas Mains – Private Land	41	-	1,495	-	515	-	-	2,051
45	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	2,369	-	4,426	-	-	-	-	6,795
47	477-10 Bio Gas Reg & Meter Equipment	784	-	1,710	-	589	-	-	3,083
48	478-30 Bio Gas Meters	10	-	26	-	-	-	-	36
49	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22
50	TOTAL BIO-GAS	3,491	-	7,916	-	1,104	-	-	12,511

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 36

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Natural Gas for Transportation**								
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,945	$ 915	$ -	$ -	$ 315	$ -	$ -	$ 5,175
3	476-20 NG Transportation LNG Dispensing Equipment	2,417	2,550	-	-	878	-	-	5,845
4	476-30 NG Transportation CNG Foundations	646	301	-	-	104	-	-	1,051
5	476-40 NG Transportation LNG Foundations	555	-	-	-	-	-	-	555
6	476-50 NG Transportation LNG Pumps	63	-	-	-	-	-	-	63
7	476-60 NG Transportation CNG Dehydrator	194	34	-	-	12	-	-	240
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	7,820	3,800	-	-	1,309	-	-	12,929
10									
11	**GENERAL PLANT & EQUIPMENT**								
12	480-00 Land in Fee Simple	22,217	-	-	-	-	-	-	22,217
13	481-00 Land Rights	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
15	- Frame Buildings	11,160	-	-	-	-	-	-	11,160
16	- Masonry Buildings	97,589	-	3,276	-	-	-	-	100,865
17	- Leasehold Improvement	3,851	-	274	-	-	(40)	-	4,085
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,571	-	51	-	-	(92)	-	3,530
20	483-40 GP Furniture	20,619	-	305	-	-	(3,123)	-	17,801
21	483-10 GP Computer Hardware	32,900	-	8,044	218	-	(3,708)	-	37,454
22	483-20 GP Computer Software	4,417	-	-	-	-	(44)	-	4,373
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,512	-	2,600	-	-	-	-	5,112
26	484-00 Vehicles - Leased	29,179	-	-	-	-	(1,536)	-	27,643
27	485-10 Heavy Work Equipment	246	-	-	-	-	-	-	246
28	485-20 Heavy Mobile Equipment	1,251	-	-	-	-	-	-	1,251
29	486-00 Small Tools & Equipment	40,215	-	2,915	-	-	(2,003)	-	41,127
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-
33	- Telephone	7,013	-	-	-	-	(1,460)	-	5,553
34	- Radio	4,730	-	1,244	-	-	(214)	-	5,760
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	281,494	-	18,709	218	-	(12,220)	-	288,201
37									
38	**UNCLASSIFIED PLANT**								
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-
41									
42	TOTAL CAPITAL	$ 3,870,810	$ 3,800	$ 142,593	$ 1,732	$ 33,376	$ (31,037)	$ -	$ 4,021,274
43		- Appendix G2-FORECAST, Sch 29							
44	Cross Reference			- Appendix G2-FORECAST, Sch 30					- Appendix G2-FORECAST, Sch 29
45			- Appendix G2-FORECAST, Sch 30				- Appendix G2-FORECAST, Sch 30		

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2

FORECAST

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE

FOR THE YEAR ENDING DECEMBER 31, 2013

($000s)

Schedule 37

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	9	-	-	548	557
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	-	-	-	-	-
5	178-00 Organization Expense	728	1.00%	7	2	-	391	400
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	1	-	98	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	21	-	-	227	248
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,553	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,211	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	86,956	12.50%	10,665	(118)	(5,985)	23,581	28,143
17	402-02 Application Software - 20%	18,825	20.00%	3,785	(36)	(2,982)	7,243	8,010
18	TOTAL INTANGIBLE	154,024		14,487	(151)	(8,967)	32,839	38,208
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	982	3.38%	33	10	-	143	186
24	433-00 Manufact'd Gas - Equipment	454	6.63%	30	-	-	88	118
25	434-00 Manufact'd Gas - Gas Holders	2,896	2.35%	67	-	-	238	305
26	436-00 Manufact'd Gas - Compressor Equipment	361	5.16%	19	-	-	38	57
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	805	15.89%	127	-	-	363	490
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,789	2,966
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,028	4.24%	1,061	-	-	10,901	11,962
36	TOTAL MANUFACTURED	67,179		1,832	10	-	25,282	27,124

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,416	0.00%	$ -	$ 102	$ -	$ 401	$ 503
3	461-00 Transmission Land Rights	1	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,319	3.74%	610	-	-	6,790	7,400
6	463-00 Measuring Structures	5,952	3.80%	217	-	(3)	1,936	2,150
7	464-00 Other Structures & Improvements	6,189	2.83%	174	(2)	-	1,891	2,063
8	465-00 Mains	809,157	1.44%	11,601	(224)	(211)	214,894	226,060
9	465-00 Mains - INSPECTION	7,629	14.87%	974	-	-	1,851	2,825
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	49	-	937	1,035
13	466-00 Compressor Equipment	111,830	2.87%	3,207	-	(719)	44,521	47,009
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	298	400
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	31,406	4.27%	1,323	(26)	(59)	10,440	11,678
17	467-10 Telemetering	9,727	0.31%	29	(26)	(66)	6,316	6,253
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	7	-	3	10
20	468-00 Communication Structures & Equipment	346	4.37%	15	(9)	-	328	334
21	TOTAL TRANSMISSION	1,009,268		18,301	(129)	(1,058)	290,606	307,720
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	(35)	-	26	(9)
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,628	3.33%	612	-	(19)	4,852	5,445
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	32	37
28	473-00 Services	773,727	2.53%	19,248	6	(1,579)	142,028	159,703
29	474-00 House Regulators & Meter Installations	174,844	7.62%	12,409	47	(208)	18,625	30,873
30	477-00 Meters/Regulators Installations	31,537	4.55%	1,202	-	-	206	1,408
31	475-00 Mains	961,019	1.59%	15,365	2	(642)	299,353	314,078
32	476-00 Compressor Equipment	1,110	26.54%	295	(272)	-	1,235	1,258
33	477-00 Measuring & Regulating Equipment	91,625	4.75%	4,257	(2)	(220)	25,902	29,937
34	477-00 Telemetering	7,817	0.25%	19	(8)	(1)	6,063	6,073
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	4	-	-	212	216
36	478-10 Meters	208,651	8.05%	16,266	425	(4,960)	75,361	87,092
37	478-20 Instruments	11,917	3.15%	375	-	-	1,299	1,674
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,284,538		70,057	163	(7,629)	575,194	637,785
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	161	3.60%	6	-	-	11	17
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	4	5
44	475-20 Bio Gas Mains – Private Land	41	1.48%	1	-	-	1	2
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	1,185	6.67%	105	-	-	-	105
47	477-10 Bio Gas Reg & Meter Equipment	532	4.75%	25	-	-	28	53
48	478-30 Bio Gas Meters	9	8.05%	1	-	-	1	2
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	1	-	-	2	3
50	TOTAL BIO-GAS	2,029		140	-	-	47	187

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 39

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,420	5.00%	$ 148	$ 175	$ -	135	$ 458
3	476-20 NG Transportation LNG Dispensing Equipment	1,232	5.00%	81	-	-	4	85
4	476-30 NG Transportation CNG Foundations	559	5.00%	24	(60)	-	80	44
5	476-40 NG Transportation LNG Foundations	280	5.00%	22	-	-	2	24
6	476-50 NG Transportation LNG Pumps	32	10.00%	6	-	-	-	6
7	476-60 NG Transportation CNG Dehydrator	157	5.00%	6	-	-	6	12
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	5,678		287	115	-	227	629
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,273	0.00%	-	(13)	-	30	17
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,965	4.82%	524	(26)	-	2,912	3,410
16	- Masonry Buildings	95,058	2.23%	2,099	85	-	15,696	17,880
17	- Leasehold Improvement	3,837	10.00%	408	(50)	(151)	565	772
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,525	6.67%	232	1,943	(243)	1,554	3,486
20	483-40 GP Furniture	21,007	5.00%	1,075	(1,937)	(1,954)	12,884	10,068
21	483-10 GP Computer Hardware	31,264	20.00%	5,768	143	(6,424)	12,281	11,768
22	483-20 GP Computer Software	3,911	12.50%	460	-	(190)	1,146	1,416
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,360	5.16%	113	(143)	(24)	601	547
26	484-00 Vehicles - Leased	28,782	0.00%	2,978	-	(1,600)	14,556	15,934
27	485-10 Heavy Work Equipment	455	8.96%	22	280	-	(175)	127
28	485-20 Heavy Mobile Equipment	1,045	18.06%	222	(332)	(63)	753	580
29	486-00 Small Tools & Equipment	39,474	5.00%	1,979	-	(963)	17,124	18,140
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	12	14
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,346	6.67%	523	253	(795)	4,368	4,349
34	- Radio	4,793	6.67%	311	(232)	(33)	2,678	2,724
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	276,118		16,716	(29)	(12,440)	86,985	91,232
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,798,832		$ 121,820	$ (21)	$ (30,094)	$ 1,011,180	$ 1,102,885
43	Less: Depreciation & Amortization transferred to Biomethane BVA			(105)				
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,350)				
45	Add: Depreciation variance adjustment			3,474				
46	**Net Depreciation Expense**			$ 123,839				
47		- Appendix G2-FORECAST, Sch 33						
48	Cross Reference			- Appendix G2-FORECAST, Sch 20			- Appendix G2-FORECAST, Sch 28	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	557	558
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	78
5	178-00 Organization Expense	728	1.00%	7	-	-	400	407
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	248	264
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,576	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,213	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	88,440	12.50%	11,055	-	(3,738)	28,143	35,460
17	402-02 Application Software - 20%	18,926	20.00%	3,785	-	(2,317)	8,010	9,478
18	TOTAL INTANGIBLE	155,635		14,942	-	(6,055)	38,208	47,095
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	999	3.38%	34	-	-	186	220
24	433-00 Manufact'd Gas - Equipment	459	6.63%	30	-	-	118	148
25	434-00 Manufact'd Gas - Gas Holders	2,940	2.35%	69	-	-	305	374
26	436-00 Manufact'd Gas - Compressor Equipment	366	5.16%	19	-	-	57	76
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	875	15.89%	139	-	-	490	629
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,966	3,143
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	11,039	11,357
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,042	4.24%	1,062	-	-	11,962	13,024
36	TOTAL MANUFACTURED	67,335		1,848	-	-	27,124	28,972

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust- ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,429	0.00%	$ -	$ -	$ -	$ 503	$ 503
3	461-00 Transmission Land Rights	1	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,338	3.74%	611	-	-	7,400	8,011
6	463-00 Measuring Structures	6,392	3.80%	243	-	(17)	2,150	2,376
7	464-00 Other Structures & Improvements	6,355	2.83%	180	-	-	2,063	2,243
8	465-00 Mains	818,802	1.44%	11,791	-	(372)	226,060	237,479
9	465-00 Mains - INSPECTION	9,455	14.87%	1,406	-	(368)	2,825	3,863
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	1,035	1,084
13	466-00 Compressor Equipment	111,849	2.87%	3,210	-	(299)	47,009	49,920
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	400	502
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	32,563	4.27%	1,390	-	(108)	11,678	12,960
17	467-10 Telemetering	10,160	0.31%	31	-	(32)	6,253	6,252
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	10	10
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	334	349
21	TOTAL TRANSMISSION	1,022,988		19,028	-	(1,196)	307,720	325,552
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	(9)	(9)
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	19,036	3.33%	634	-	(13)	5,445	6,066
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	37	42
28	473-00 Services	789,108	2.53%	19,712	-	(1,132)	159,703	178,283
29	474-00 House Regulators & Meter Installations	174,745	7.62%	12,411	-	(4)	30,873	43,280
30	477-00 Meters/Regulators Installations	44,202	4.55%	2,011	-	-	1,408	3,419
31	475-00 Mains	974,764	1.59%	15,655	-	(501)	314,078	329,232
32	476-00 Compressor Equipment	1,110	26.54%	295	-	-	1,258	1,553
33	477-00 Measuring & Regulating Equipment	94,656	4.75%	4,496	-	(436)	29,937	33,997
34	477-00 Telemetering	8,532	0.25%	21	-	(2)	6,073	6,092
35	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	216	216
36	478-10 Meters	210,285	8.05%	16,313	-	(3,667)	87,092	99,738
37	478-20 Instruments	11,944	3.15%	376	-	-	1,674	2,050
38	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
39	TOTAL DISTRIBUTION	2,332,047		71,929	-	(5,755)	637,785	703,959
40								
41	**BIO GAS**							
42	472-00 Bio Gas Struct. & Improvements	185	3.60%	7	-	-	17	24
43	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	5	6
44	475-20 Bio Gas Mains – Private Land	41	1.48%	1	-	-	2	3
45	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
46	418-20 Bio Gas Purification Upgrader	2,369	6.67%	158	-	-	105	263
47	477-10 Bio Gas Reg & Meter Equipment	784	4.75%	37	-	-	53	90
48	478-30 Bio Gas Meters	10	8.05%	1	-	-	2	3
49	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	3	3
50	TOTAL BIO-GAS	3,491		205	-	-	187	392

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 42

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ 3,945	5.00%	$ 197	$ -	$ -	$ 458	$ 655
3	476-20 NG Transportation LNG Dispensing Equipment	2,417	5.00%	121	-	-	85	206
4	476-30 NG Transportation CNG Foundations	646	5.00%	32	-	-	44	76
5	476-40 NG Transportation LNG Foundations	555	5.00%	28	-	-	24	52
6	476-50 NG Transportation LNG Pumps	63	10.00%	6	-	-	6	12
7	476-60 NG Transportation CNG Dehydrator	194	5.00%	10	-	-	12	22
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	7,820		394	-	-	629	1,023
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,217	0.00%	-	-	-	17	17
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	11,160	4.82%	538	-	-	3,410	3,948
16	- Masonry Buildings	97,589	2.23%	2,176	-	-	17,880	20,056
17	- Leasehold Improvement	3,851	10.00%	385	-	(40)	772	1,117
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,571	6.67%	238	-	(69)	3,486	3,655
20	483-40 GP Furniture	20,619	5.00%	1,031	-	(3,123)	10,068	7,976
21	483-10 GP Computer Hardware	32,900	20.00%	6,580	-	(3,708)	11,768	14,640
22	483-20 GP Computer Software	4,417	12.50%	552	-	(44)	1,416	1,924
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,512	12.50%	314	-	-	547	861
26	484-00 Vehicles - Leased	29,179	0.00%	2,755	-	(1,536)	15,934	17,153
27	485-10 Heavy Work Equipment	246	8.96%	22	-	-	127	149
28	485-20 Heavy Mobile Equipment	1,251	18.06%	226	-	-	580	806
29	486-00 Small Tools & Equipment	40,215	5.00%	2,011	-	(2,003)	18,140	18,148
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	14	16
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,013	6.67%	468	-	(1,314)	4,349	3,503
34	- Radio	4,730	6.67%	316	-	(214)	2,724	2,826
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	281,494		17,614	-	(12,051)	91,232	96,795
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,870,810		$ 125,960	$ -	$ (25,057)	$ 1,102,885	$ 1,203,788
43	Less: Depreciation & Amortization transferred to Biomethane BVA			(158)				
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,135)				
45								
46	**Net Depreciation Expense**			$ 124,667				
47		- Appendix G2-FORECAST, Sch 36						
48	Cross Reference			- Appendix G2-FORECAST, Sch 21			- Appendix G2-FORECAST, Sch 29	

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 43

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

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 PROJECTED Additions	2013 PROJECTED Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 145,014	$ (645)	$ 13,054	$ -	$ 157,423	
4							
5	Transmission Contributions	29,058	(110)	2,302	-	31,250	
6							
7	Others	714	-	113	-	827	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	(204)	10,555	
11							
12	Biomethane	-	-	546	-	546	
13							
14	TOTAL Contributions	185,545	(755)	16,015	(204)	200,601	- Appendix G2-FORECAST, Sch 28
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(42,313)	(1)	(4,331)	-	(46,645)	
21							
22	Transmission Contributions	(2,335)	1	(522)	-	(2,856)	
23							
24	Others	(97)	-	(123)	-	(220)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(6,398)	-	(1,345)	204	(7,539)	
28							
29	Biomethane	-	-	(21)	-	(21)	
30							
31	TOTAL CIAC Amortization	(51,143)	-	(6,342)	204	(57,281)	- Appendix G2-FORECAST, Sch 28
32							
33	**NET CONTRIBUTIONS**	$ 134,402	$ (755)	$ 9,673	$ -	$ 143,320	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,342)			
37	Add: Depreciation Variance Adjustment			(157)			
38	**Net Amortization Expense**			$ (6,499)			- Appendix G2-FORECAST, Sch 20
39							
40							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 44

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	Adjustment	2014 FORECAST Additions	2014 FORECAST Retirements	Balance 12/31/2014	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 157,423	$ -	$ 5,619	$ -	$ 163,042	
4							
5	Transmission Contributions	31,250	-	203	-	31,453	
6							
7	Others	827	-	-	-	827	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,555	-	-	(3,768)	6,787	
11							
12	Biomethane	546	-	-	-	546	
13							
14	TOTAL Contributions	200,601	-	5,822	(3,768)	202,655	- Appendix G2-FORECAST, Sch 29
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(46,645)	-	(4,548)	-	(51,193)	
21							
22	Transmission Contributions	(2,856)	-	(524)	-	(3,380)	
23							
24	Others	(220)	-	(114)	-	(334)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(7,539)	-	(1,319)	3,768	(5,090)	
28							
29	Biomethane	(21)	-	-	-	(21)	
30							
31	TOTAL CIAC Amortization	(57,281)	-	(6,505)	3,768	(60,018)	- Appendix G2-FORECAST, Sch 29
32							
33	**NET CONTRIBUTIONS**	$ 143,320	$ -	$ (683)	$ -	$ 142,637	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,505)			
37	Less: Depreciation & Amortization transferred to Biomethane BVA			-			
38	**Net Amortization Expense**			$ (6,505)			- Appendix G2-FORECAST, Sch 21
39							
40							

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

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,042)	$ -	$ (289)	$ 74	$ (214)	$ -	$ -	$ -	$ (10,256)	$ (10,149)
3	Midstream Cost Reconciliation Account (MCRA)	(17,800)	-	(3,731)	961	(2,770)	-	8,914	(2,295)	(13,951)	(15,876)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(24,583)	-	(7,323)	1,886	(5,437)	-	11,582	(2,982)	(21,420)	(23,002)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,125)	-	(1,077)	278	(799)	(10)	159	(41)	(4,816)	(4,471)
6	Revelstoke Propane Cost Deferral Account	(348)	-	499	(128)	371	-	-	-	23	(163)
7	SCP Mitigation Revenues Variance Account	(4,154)	-	431	(111)	320	2,926	-	-	(908)	(2,531)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	22,698	-	10,827	(2,788)	8,039	(3,152)	-	-	27,585	25,142
11	NGV Conversion Grants	37	-	18	(5)	13	(28)	-	-	22	30
12	Emmissions Regulations	-	-	4	(1)	3	-	-	-	3	1
13	Biomethane Program Costs	324	-	328	(85)	244	(172)	-	-	396	360
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	-	-	-	-	-	-	-	-	-
16	CNG and LNG Recoveries	(11)	-	(69)	18	(51)	-	-	-	(62)	(37)
17	Rate Schedule 16 Cost & Recoveries	-	-	(27)	7	(20)	-	-	-	(20)	(10)
18											
19	Non-Controllable Items Deferral Accounts										
20	Property Tax Deferral	(2,868)	-	(3,541)	912	(2,629)	594	-	-	(4,903)	(3,886)
21	Insurance Variance	45	-	93	(24)	69	-	-	-	114	80
22	Pension & OPEB Variance	15,807	-	12,607	-	12,607	(3,205)	-	-	25,209	20,508
23	BCUC Levies Variance	449	-	923	(238)	685	-	-	-	1,134	792
24	Interest Variance	(5,699)	-	(734)	189	(545)	2,600	-	-	(3,644)	(4,671)
25	Interest Variance - Funding benefits via Customer Deposits	834	-	160	(41)	119	(309)	-	-	644	739
26	Tax Variance Account	597	-	2,150	(351)	1,799	-	-	-	2,396	1,497
27	Customer Service Variance Account	(5,548)	-	(13,234)	3,408	(9,826)	-	-	-	(15,374)	(10,461)
28	Pension & OPEB Funding	(171,550)	3,050	(13,171)	-	(13,171)	-	-	-	(181,671)	(175,086)
29	US GAAP Pension & OPEB Funded Status	139,153	(3,050)	-	-	-	-	-	-	136,103	136,103

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 46

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

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	NGV for Transportation Application	140	(113)	73	(19)	54	(46)	-	-	36	32
4	Long Term Resource Plan Application	-	-	-	-	-	(90)	-	-	(90)	(45)
5	AES Inquiry Cost	619	-	(21)	5	(16)	(85)	-	-	518	569
6	Generic Cost of Capital Application	-	-	-	-	-	-	-	-	-	-
7	Amalgamation and Rate Design Application Costs	-	-	-	-	-	-	-	-	-	-
8	Rate Schedule 16 Application Cost	-	-	-	-	-	-	-	-	-	-
9											
10	Other Deferral Accounts										
11	2010-2011 Customer Service O&M and COS	21,613	-	-	-	-	(2,807)	-	-	18,806	20,210
12	Gas Asset Records Project	(60)	-	744	(192)	552	(567)	-	-	(75)	(68)
13	BC OneCall Project	(69)	-	777	(200)	577	(334)	-	-	174	53
14	Gains and Losses on Asset Disposition	27,090	-	8,389	-	8,389	(730)	-	-	34,749	30,920
15	Negative Salvage Provision/Cost	(5,965)	-	13,398	-	13,398	(16,933)	-	-	(9,500)	(7,732)
16	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
17											
18	Residual Deferred Accounts										
19	Depreciation Variance	(1,281)	-	(1,012)	-	(1,012)	-	-	-	(2,293)	(1,787)
20	SCP Tax Reassessment	(32)	-	-	-	-	-	-	-	(32)	(32)
21	BFI Costs and Recoveries	147	-	(250)	64	(186)	-	-	-	(39)	54
22	Fuelling Stations Variance Account	-	-	-	-	-	-	-	-	-	-
23	2011 CNG and LNG Service Costs and Recoveries	(69)	-	-	-	-	35	-	-	(34)	(51)
24	Olympics Security Costs Deferral	188	-	-	-	-	(188)	-	-	-	94
25	IFRS Conversion Costs	238	-	-	-	-	(238)	-	-	-	119
26	2009 ROE & Cost of Capital Application	496	-	-	-	-	(168)	-	-	328	412
27	2012-2013 Revenue Requirement Application	614	-	0	(0)	0	(409)	-	-	205	410
28	CCE CPCN Application	150	-	-	-	-	(56)	-	-	94	122
29	Deferred Removal Costs	2,223	-	-	-	-	(2,354)	-	-	(131)	1,046
30	US GAAP Conversion Costs	(62)	-	-	-	-	(791)	-	-	(853)	(458)
31	US GAAP Transitional Costs	477	-	-	-	-	948	-	-	1,425	951
32	Earnings Sharing Mechanism	84	-	-	-	-	-	-	-	84	84
33	OH&M Recoveries from NGT	-	-	-	-	-	-	-	-	-	-
34	Tilbury Property Purchase (Subdividable Land)	-	-	-	-	-	-	-	-	-	-
35	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	-
36											
37	Total Deferred Charges for Rate Base	$ (20,243)	$ (113)	$ 6,945	$ 3,619	$ 10,564	$ (25,569)	$ 20,655	$ (5,319)	$ (20,025)	$ (20,190)
38											
39	Cross Reference						- Appendix G2-FORECAST, Sch 20				- Appendix G2-FORECAST, Sch 28

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries		Balance 12/31/2014	Mid-Year Average 2014
								Rider	Tax on Rider		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,256)	$ -	$ 13,860	$ (3,604)	$ 10,256	$ -	$ -	$ -	$ 0	$ (5,128)
3	Midstream Cost Reconciliation Account (MCRA)	(13,951)	-	-	-	-	-	9,085	(2,362)	(7,228)	(10,590)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(21,420)	-	-	-	-	-	14,160	(3,682)	(10,942)	(16,181)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,816)	-	1,530	(397)	1,133	388	165	(43)	(3,174)	(3,995)
6	Revelstoke Propane Cost Deferral Account	23	-	(30)	8	(23)	-	-	-	(0)	11
7	SCP Mitigation Revenues Variance Account	(908)	-	-	-	-	684	-	-	(224)	(566)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	27,585	16,752	13,350	(3,471)	9,879	(5,278)	-	-	48,938	46,638
11	NGV Conversion Grants	22	-	15	(4)	11	(13)	-	-	20	21
12	Emmissions Regulations	3	-	-	-	-	-	-	-	3	3
13	Biomethane Program Costs	396	-	-	-	-	(396)	-	-	(0)	198
14	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
15	NGT Incentives	-	6,564	9,336	(2,427)	6,909	(1,347)	-	-	12,125	9,345
16	CNG and LNG Recoveries	(62)	-	-	-	-	62	-	-	0	(31)
17	Rate Schedule 16 Cost & Recoveries	(20)	-	-	-	-	20	-	-	0	(10)
18											
19	Non-Controllable Items Deferral Accounts										
20	Property Tax Deferral	(4,903)	-	-	-	-	2,030	-	-	(2,873)	(3,888)
21	Insurance Variance	114	-	-	-	-	(114)	-	-	(0)	57
22	Pension & OPEB Variance	25,209	-	-	-	-	(5,039)	-	-	20,170	22,690
23	BCUC Levies Variance	1,134	-	-	-	-	(1,134)	-	-	(0)	567
24	Interest Variance	(3,644)	-	-	-	-	2,829	-	-	(815)	(2,229)
25	Interest Variance - Funding benefits via Customer Deposits	644	-	-	-	-	(302)	-	-	342	493
26	Tax Variance Account	2,396	-	-	-	-	(2,396)	-	-	0	1,198
27	Customer Service Variance Account	(15,374)	-	-	-	-	3,075	-	-	(12,299)	(13,837)
28	Pension & OPEB Funding	(181,671)	-	9,636	-	9,636	-	-	-	(172,035)	(176,853)
29	US GAAP Pension & OPEB Funded Status	136,103	-	(9,300)	-	(9,300)	-	-	-	126,803	131,453

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014 Appendix G2
FORECAST
Schedule 48

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries		Balance 12/31/2014	Mid-Year Average 2014
								Rider	Tax on Rider		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ 438	$ 1,000	$ (260)	$ 740	$ (236)	$ -	$ -	$ 942	$ 690
3	NGV for Transportation Application	36	-	-	-	-	(36)	-	-	(0)	18
4	Long Term Resource Plan Application	(90)	-	36	(9)	26	76	-	-	12	(39)
5	AES Inquiry Cost	518	-	-	-	-	(132)	-	-	387	453
6	Generic Cost of Capital Application	-	1,354	-	-	-	(677)	-	-	677	1,016
7	Amalgamation and Rate Design Application Costs	-	1,219	-	-	-	(407)	-	-	812	1,016
8	Rate Schedule 16 Application Cost	-	130	-	-	-	(130)	-	-	-	65
9											
10	Other Deferral Accounts										
11	2010-2011 Customer Service O&M and COS	18,806	-	-	-	-	(2,877)	-	-	15,930	17,368
12	Gas Asset Records Project	(75)	-	1,277	(332)	945	(152)	-	-	718	322
13	BC OneCall Project	174	-	712	(185)	527	(135)	-	-	566	370
14	Gains and Losses on Asset Disposition	34,749	-	5,981	-	5,981	(1,806)	-	-	38,924	36,837
15	Negative Salvage Provision/Cost	(9,500)	-	13,327	-	13,327	(17,313)	-	-	(13,485)	(11,492)
16	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
17											
18	Residual Deferred Accounts										
19	Depreciation Variance	(2,293)	-	-	-	-	2,293	-	-	-	(1,147)
20	SCP Tax Reassessment	(32)	-	-	-	-	32	-	-	-	(16)
21	BFI Costs and Recoveries	(39)	39	-	-	-	-	-	-	-	-
22	Fuelling Stations Variance Account	-	159	-	-	-	(53)	-	-	106	133
23	2011 CNG and LNG Service Costs and Recoveries	(34)	-	-	-	-	34	-	-	-	(17)
24	Olympics Security Costs Deferral	-	-	-	-	-	-	-	-	-	-
25	IFRS Conversion Costs	-	-	-	-	-	-	-	-	-	-
26	2009 ROE & Cost of Capital Application	328	-	-	-	-	(328)	-	-	-	164
27	2012-2013 Revenue Requirement Application	205	-	-	-	-	(205)	-	-	(0)	103
28	CCE CPCN Application	94	-	-	-	-	(94)	-	-	-	47
29	Deferred Removal Costs	(131)	-	-	-	-	131	-	-	-	(66)
30	US GAAP Conversion Costs	(853)	-	-	-	-	853	-	-	-	(427)
31	US GAAP Transitional Costs	1,425	-	-	-	-	(1,425)	-	-	-	713
32	Earnings Sharing Mechanism	84	(84)	-	-	-	-	-	-	-	-
33	OH&M Recoveries from NGT	-	(70)	-	-	-	70	-	-	-	(35)
34	Tilbury Property Purchase (Subdividable Land)	-	(220)	-	-	-	220	-	-	-	(110)
35	Residual Delivery Rate Riders	-	61	-	-	-	(61)	-	-	-	31
36											
37	Total Deferred Charges for Rate Base	$ (20,025)	$ 26,343	$ 60,729	$ (10,681)	$ 50,048	$ (29,288)	$ 23,410	$ (6,087)	$ 44,402	$ 25,360
38											
39	Cross Reference						- Appendix G2-FORECAST, Sch 21				- Appendix G2-FORECAST, Sch 29

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 49

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

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ -	$ 18
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	-	66
4	449-00 Local Storage Equipment (Tilbury)	25,028	0.37%	99	-	(2)	-	-	97
5	TOTAL MANUFACTURED	46,487		183	-	(2)	-	-	181
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	16,319	0.18%	27	-	(1)	-	-	26
9	463-00 Measuring Structures	5,952	0.18%	10	-	-	-	-	10
10	464-00 Other Structures & Improvements	6,189	0.14%	8	-	(15)	-	-	(7)
11	465-00 Mains	809,157	0.14%	1,175	-	(122)	-	-	1,053
12	466-00 Compressor Equipment	111,830	0.28%	333	-	(2)	-	-	331
13	467-00 Measuring & Regulating Equipment	31,406	0.18%	51	-	(103)	-	-	(52)
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	-	3
15	TOTAL TRANSMISSION	981,198		1,607	-	(243)	-	-	1,364
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	18,628	0.16%	27	-	(2)	-	-	25
19	473-00 Services	773,727	1.24%	8,984	-	(9,754)	-	-	(770)
20	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
21	474-00 House Regulators & Meter Installations	174,844	0.75%	1,188	-	(3,009)	-	-	(1,821)
22	477-00 Meters/Regulators Installations	31,537	0.75%	173	-	-	-	-	173
23	475-00 Mains	961,019	0.33%	3,107	-	(497)	-	-	2,610
24	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
25	476-00 Compressor Equipment	1,110	11.43%	165	-	-	-	-	165
26	477-00 Measuring & Regulating Equipment	91,625	0.52%	468	-	(48)	-	-	420
27	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
28	478-10 Meters	208,651	0.50%	1,031	-	169	-	-	1,200
29	TOTAL DISTRIBUTION	2,261,302		15,143	-	(13,153)	-	-	1,990
30									
31	**BIO GAS**								
32	475-20 Bio Gas Mains – Private Land	41	0.33%	1	-	-	-	-	1
33	478-30 Bio Gas Meters	9	0.50%	-	-	-	-	-	-
34	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
35	TOTAL BIO-GAS	72		2	-	-	-	-	2
36									
37	TOTALS	$ 3,289,059		$ 16,935	$ -	$ (13,399)	$ -	$ -	$ 3,536
38									
39	Cross Reference	- Appendix G2-FORECAST, Sch 33							

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 50

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2014 DEPRECIATION Provision (Cr.)	Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2013	Ending 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 18	$ 36
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	25,042	0.37%	93	-	-	-	97	190
5	TOTAL MANUFACTURED	46,501		177	-	-	-	181	358
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	16,338	0.18%	29	-	-	-	26	55
9	463-00 Measuring Structures	6,392	0.18%	12	-	-	-	10	22
10	464-00 Other Structures & Improvements	6,355	0.14%	9	-	-	-	(7)	2
11	465-00 Mains	818,802	0.14%	1,146	-	-	-	1,053	2,199
12	466-00 Compressor Equipment	111,849	0.28%	313	-	-	-	331	644
13	467-00 Measuring & Regulating Equipment	32,563	0.18%	59	-	-	-	(52)	7
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
15	TOTAL TRANSMISSION	992,645		1,571	-	-	-	1,364	2,935
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	19,036	0.16%	30	-	-	-	25	55
19	473-00 Services	789,108	1.24%	9,288	-	(9,532)	-	(770)	(1,014)
20	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
21	474-00 House Regulators & Meter Installations	174,745	0.75%	1,190	-	(2,894)	-	(1,821)	(3,525)
22	477-00 Meters/Regulators Installations	44,202	0.75%	332	-	-	-	173	505
23	475-00 Mains	974,764	0.33%	3,104	-	(901)	-	2,610	4,813
24	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
25	476-00 Compressor Equipment	1,110	11.43%	127	-	-	-	165	292
26	477-00 Measuring & Regulating Equipment	94,656	0.52%	492	-	-	-	420	912
27	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
28	478-10 Meters	210,285	0.50%	1,001	-	-	-	1,200	2,201
29	TOTAL DISTRIBUTION	2,308,069		15,564	-	(13,327)	-	1,990	4,227
30									
31	**BIO GAS**								
32	475-20 Bio Gas Mains – Private Land	41	0.33%	-	-	-	-	1	1
33	478-30 Bio Gas Meters	10	0.50%	-	-	-	-	-	-
34	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
35	TOTAL BIO-GAS	73		-	-	-	-	2	2
36									
37	TOTALS	$ 3,347,288		$ 17,312	$ -	$ (13,327)	$ -	$ 3,536	$ 7,521
38									
39	Cross Reference	- Appendix G2-FORECAST, Sch 36							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 51

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

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	2013 PROJECTED 2013 Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
						(Column (5) - Column (3))	
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 9,202	$ 7,121	$ 8,216	$ 8,216	$ 1,095	- Appendix G2-FORECAST, Sch 53
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(6,282)	(4,588)	(5,760)	(5,760)	(1,172)	
9							
10	Withholdings From Employees	(4,819)	(5,163)	(4,359)	(4,359)	804	
11							
12	Subtotal	(1,899)	(2,630)	(1,903)	(1,903)	727	- Appendix G2-FORECAST, Sch 28
13							
14	**Other Working Capital Items**						
15	Construction Advances	(439)	(620)	-	-	620	
16	Transmission Line Pack Gas	3,924	3,566	2,846	2,846	(720)	
17	Gas in Storage	97,294	97,242	78,766	78,766	(18,476)	
18	Inventory - Materials & Supplies	637	1,434	1,509	1,509	75	
19							
20	Subtotal	101,416	101,622	83,121	83,121	(18,501)	- Appendix G2-FORECAST, Sch 28
21							
22	Total	$ 99,517	$ 98,992	$ 81,218	$ 81,218	$ (17,774)	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 52

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	2014 FORECAST 2013 Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 8,216	$ 9,627	$ 9,646	$ 1,430	- Appendix G2-FORECAST, Sch 53
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(5,760)	(5,459)	(5,459)	301	
9						
10	Withholdings From Employees	(4,359)	(4,489)	(4,489)	(130)	
11						
12	Subtotal	(1,903)	(321)	(302)	1,601	- Appendix G2-FORECAST, Sch 29
13						
14	**Other Working Capital Items**					
15	Construction Advances	-	-	-	-	
16	Transmission Line Pack Gas	2,846	2,662	2,662	(184)	
17	Gas in Storage	78,766	74,841	74,841	(3,925)	
18	Inventory - Materials & Supplies	1,509	1,536	1,536	27	
19						
20	Subtotal	83,121	79,039	79,039	(4,082)	- Appendix G2-FORECAST, Sch 29
21						
22	Total	$ 81,218	$ 78,718	$ 78,737	$ (2,481)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2013 Days	2013 Expenses	2013 Cash Working Capital	2014 Days	2014 Expenses	2014 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASH WORKING CAPITAL**							
2								
3	Revenue Lag Days	39.0			39.0			- Appendix G2-FORECAST, Sch 54
4	Expense Lead Days	35.9			35.4			- Appendix G2-FORECAST, Sch 55
5								
6	Net Lead/(Lag) Days	3.1	$ 967,312	$ 8,216	3.6	$ 976,031	$ 9,627	- Appendix G2-FORECAST, Sch 51
7								- Appendix G2-FORECAST, Sch 52
8								
9								
10	**CASH WORKING CAPITAL, REVISED RATES**							
11								
12	Revenue Lag Days	39.0			39.0			- Appendix G2-FORECAST, Sch 54
13	Expense Lead Days	35.9			35.4			- Appendix G2-FORECAST, Sch 55
14								
15	Net Lead/(Lag) Days	3.1	$ 967,311	$ 8,216	3.6	$ 978,008	$ 9,646	- Appendix G2-FORECAST, Sch 51
16								- Appendix G2-FORECAST, Sch 52
17								
18								
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 19	
20								
21								
22								
23	Cash working capital = Col. 2 x Col. 3 / 365 days							

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 54

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

		2013			2014			
Line No.	Particulars	Revenue At 2013 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2013 Rates	Lag Days Service to Collection	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**REVENUE**							
2								
3	Gas Sales and Transportation Service Revenue							
4	Residential and Commercial	$ 1,000,861	38.3	$ 38,376,423	$ 991,092	38.3	$ 38,002,583	- Appendix G2-FORECAST, Sch 10
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	75,110	45.1	3,386,250	76,903	45.1	3,467,282	
6	NGV Fuel - Stations	461	41.7	19,233	461	41.7	19,233	
7								
8	Rates 16, 46, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	55,792	42.9	2,390,757	55,359	42.7	2,364,396	
9								
10	Total Gas Sales	1,132,225	39.0	44,172,663	1,123,815	39.0	43,853,494	
11								
12	Other Revenues							
13	Late Payment Charges	2,109	38.3	80,767	2,089	38.3	79,993	- Appendix G2-FORECAST, Sch 12 - 13
14	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Appendix G2-FORECAST, Sch 12 - 13
15	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Appendix G2-FORECAST, Sch 12 - 13
16	Other Utility Income	1,118	38.3	42,835	1,625	39.1	63,568	- Appendix G2-FORECAST, Sch 12 - 13
17								
18								
19	Total Revenue	$ 1,138,153	39.0	$ 44,399,717	$ 1,130,244	39.0	$ 44,101,066	
20								
21								
22	**REVENUE, REVISED RATES**							
23								
24	Gas Sales and Transportation Service Revenue							
25	Residential and Commercial	$ 1,000,861	38.3	$ 38,376,423	$ 997,101	38.3	$ 38,233,023	- Appendix G2-FORECAST, Sch 10
26	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	75,110	45.1	3,386,250	77,689	45.1	3,502,774	
27	NGV Fuel - Stations	461	41.7	19,233	464	41.7	19,358	
28								
29	Rates 16, 46, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	55,792	42.9	2,390,757	55,650	42.7	2,377,472	
30								
31	Total Gas Sales	1,132,225	39.0	44,172,663	1,130,904	39.0	44,132,627	
32								
33	Other Revenues							
34	Late Payment Charges	2,109	38.3	80,767	2,089	38.3	79,993	- Appendix G2-FORECAST, Sch 12 - 13
35	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Appendix G2-FORECAST, Sch 12 - 13
36	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Appendix G2-FORECAST, Sch 12 - 13
37	Other Utility Income	1,118	38.3	42,835	1,625	39.1	63,568	- Appendix G2-FORECAST, Sch 12 - 13
38								
39								
40	Total Revenue	$ 1,138,153	39.0	$ 44,399,717	$ 1,137,333	39.0	$ 44,380,199	

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 55

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars		2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	2014 Amount	2014 Lead Days Expense to Payment	2014 Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**								
2									
3	Operating And Maintenance								- Appendix G2-FORECAST, Sch 3
4	Expenses		$ 196,170	25.5	$ 5,002,335	$ 204,454	25.5	$ 5,213,577	- Appendix G2-FORECAST, Sch 4
5	Gas Purchases (excl Royalty Credits)		505,614	40.2	20,325,683	496,151	40.2	19,945,270	
6									
7	Taxes Other Than Income								- Appendix G2-FORECAST, Sch 18
8	Property Taxes		47,698	2.0	95,396	48,797	2.0	97,594	- Appendix G2-FORECAST, Sch 19
9	Franchise Fees		8,048	420.3	3,382,574	7,927	420.3	3,331,718	
10	Carbon Tax		169,709	29.1	4,938,525	169,966	29.1	4,946,021	
11	HST - Net	*	6,565	38.8	254,735			-	
12	PST Component of HST (REC)	*	(2,326)	33.8	(78,624)			-	
13	GST - Net	**	7,257	38.8	281,553	9,604	38.8	372,650	
14	PST - Net	**	3,252	37.1	120,641	4,067	37.1	150,869	
15	Income Tax		25,324	15.2	384,925	35,065	15.2	532,988	- Appendix G2-FORECAST, Sch 22
16									- Appendix G2-FORECAST, Sch 23
17	Total Expenses		$ 967,311	35.9	$ 34,707,743	$ 976,031	35.4	$ 34,590,687	
18									
19									
20	**EXPENSES, REVISED RATES**								
21									
22	Operating And Maintenance								- Appendix G2-FORECAST, Sch 3
23	Expenses		$ 196,170	25.5	$ 5,002,335	$ 204,454	25.5	$ 5,213,577	- Appendix G2-FORECAST, Sch 4
24	Gas Purchases (excl Royalty Credits)		505,614	40.2	20,325,683	496,151	40.2	19,945,270	
25									
26	Taxes Other Than Income								- Appendix G2-FORECAST, Sch 18
27	Property Taxes		47,698	2.0	95,396	48,797	2.0	97,594	- Appendix G2-FORECAST, Sch 19
28	Franchise Fees		8,048	420.3	3,382,574	7,978	420.3	3,353,153	
29	Carbon Tax		169,709	29.1	4,938,525	169,966	29.1	4,946,021	
30	HST - Net	*	6,565	38.8	254,735			-	
31	PST Component of HST (REC)	*	(2,326)	33.8	(78,624)			-	
31	GST - Net	**	7,257	38.8	281,553	9,665	38.8	375,018	
32	PST - Net	**	3,252	37.1	120,641	4,088	37.1	151,662	
33	Income Tax		25,325	15.2	384,940	36,908	15.2	561,002	- Appendix G2-FORECAST, Sch 22
34									- Appendix G2-FORECAST, Sch 23
35	Total Expenses		$ 967,312	35.9	$ 34,707,758	$ 978,008	35.4	$ 34,643,297	
36									

37 * January to March 2013 is computed at 25% of 2013 Approved cash outflows.
38 ** April to December 2013 is computed at 75% of 2013 Projected cash outflows.

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 56

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Total DIT Liability- After Tax	(210,925)	(215,501)	(216,512)	(216,224)	
2						
3	Tax Gross Up	(70,308)	(71,834)	(72,171)	(72,075)	
4						
5	DIT Liability/Asset - End of Year	(281,233)	(287,335)	(288,683)	(288,298)	
6						
7	DIT Liability/Asset - Opening Balance	(282,624)	(277,382)	(281,233)	(288,683)	
8						
9	DIT Liability/Asset - Mid Year	(281,929)	(282,359)	(284,958)	(288,491)	
10						
11	Cross Reference			- Appendix G2-FORECAST, Sch 28		
12					- Appendix G2-FORECAST, Sch 29	
13						
14	Note: * Excludes Land, Software CIAC, and WIP.					

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 57

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

Line No.	Particulars	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 RATES							
2	Long-Term Debt		$ 1,576,778	58.64%	6.87%	4.03%	$ 108,279	- Appendix G2-FORECAST, Sch 59
3	Unfunded Debt		76,918	2.86%	3.50%	0.10%	2,692	
4	Common Equity		1,035,240	38.50%	9.52%	3.66%	98,604	
5								
6			$ 2,688,936	100.00%		7.79%	$ 209,576	- Appendix G2-FORECAST, Sch 28
7								
8								
9								
10	2013 REVISED RATES - PROJECTED							
11	Long-Term Debt		$ 1,576,778	58.64%	6.87%	4.03%	$ 108,279	- Appendix G2-FORECAST, Sch 59
12	Unfunded Debt	$ 76,918						
13	Adjustment, Revised Rates	-	76,918	2.86%	3.50%	0.10%	2,692	
14	Common Equity		1,035,240	38.50%	9.52%	3.66%	98,604	
15								- Appendix G2-FORECAST, Sch 3
16			$ 2,688,936	100.00%		7.79%	$ 209,576	- Appendix G2-FORECAST, Sch 28

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 58

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2014 AT 2013 RATES							
2	Long-Term Debt		$ 1,575,088	56.68%	6.83%	3.87%	$ 107,613	- Appendix G2-FORECAST, Sch 60
3	Unfunded Debt		133,961	4.82%	1.75%	0.08%	2,344	
4	Common Equity		1,069,893	38.50%	8.26%	3.19%	88,371	
5								
6			$ 2,778,942	100.00%		7.14%	$ 198,328	- Appendix G2-FORECAST, Sch 29
7								
8								
9								
10	2014 REVISED RATES							
11	Long-Term Debt		$ 1,575,088	56.68%	6.83%	3.87%	$ 107,613	- Appendix G2-FORECAST, Sch 60
12	Unfunded Debt	$ 133,961						
13	Adjustment, Revised Rates	12	133,973	4.82%	1.75%	0.08%	2,345	
14	Common Equity		1,069,900	38.50%	8.75%	3.37%	93,616	
15								- Appendix G2-FORECAST, Sch 4
16			$ 2,778,961	100.00%		7.33%	$ 203,574	- Appendix G2-FORECAST, Sch 29

FORTISBC ENERGY INC. G-44-12 (May 1, 2012) Appendix G2 FORECAST Schedule 59

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
FOR THE YEAR ENDING DECEMBER 31, 2013 *** APPROVED ***
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,882	**	10.461%	158,110	16,540
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-Oct-2011	1-Oct-2021	4.500%	100,000	1,000	99,000		4.626%	100,000	4,626
13											
14	LILO Obligations - Kelowna								6.445%	21,892	1,411
15	LILO Obligations - Nelson								7.872%	3,519	277
16	LILO Obligations - Vernon								9.153%	10,466	958
17	LILO Obligations - Prince George								8.067%	27,085	2,185
18	LILO Obligations - Creston								7.218%	2,577	186
19											
20	Vehicle Lease Obligation								5.685%	13,510	768
21											
22	Sub-Total									$ 1,582,114	$ 108,645
23	Less: Fort Nelson Division Portion of Long Term Debt									5,336	366
24	Total									$ 1,576,778	$ 108,279
25											
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.87%
27	**Includes adjustment of $836 for BC Hydro Premium (Series B).										
28	Cross Reference									- Appendix G2-FORECAST, Sch 57	

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 60

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	158,450	**	10.461%	160,678	16,809
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	1,234	98,766		6.645%	100,000	6,645
11	2011 Medium Term Debt Issue - Series 25	9-Dec-2011	9-Dec-2041	4.250%	100,000	1,410	98,590		4.334%	100,000	4,334
12											
13	LILO Obligations - Kelowna								6.469%	20,963	1,356
14	LILO Obligations - Nelson								7.983%	3,382	270
15	LILO Obligations - Vernon								9.276%	10,037	931
16	LILO Obligations - Prince George								8.182%	26,057	2,132
17	LILO Obligations - Creston								7.330%	2,483	182
18											
19	Vehicle Lease Obligation								2.115%	11,868	251
20											
21	Sub-Total									$ 1,580,423	$ 107,977
22	Less: Fort Nelson Division Portion of Long Term Debt									5,335	364
23	Total									$ 1,575,088	$ 107,613
24											
25	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.83%
26	**Includes adjustment of $3,404 for BC Hydro Premium (Series B).										
27	Cross Reference									- Appendix G2-FORECAST, Sch 58	

Summary of Rate Change

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 61

Line No.	Particulars	2014 ($ Millions)		2015 Incremental ($ Millions)		2015 Cumulative ($ Millions)		2016 Incremental ($ Millions)		2016 Cumulative ($ Millions)		2017 Incremental ($ Millions)		2017 Cumulative ($ Millions)		2018 Incremental ($ Millions)		2018 Cumulative ($ Millions)		Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
1	Volume/Revenue Related																			
2	Customer Growth and Use Rates	(7.2)		(3.1)		(10.3)		(5.9)		(16.2)		(5.4)		(21.6)		(5.0)		(26.7)		
3	Change in Other Revenue	0.2	(7.0)	(0.7)	(3.8)	(0.5)	(10.8)	(0.7)	(6.6)	(1.2)	(17.4)	(0.9)	(6.3)	(2.1)	(23.7)	(1.2)	(6.3)	(3.3)	(30.0)	
4																				
5	O&M Changes																			
6	Gross O&M Increases	1.8		5.7		7.6		6.6		14.2		6.8		21.0		8.5		29.5		
7	Less: Capitalized Overhead	(0.3)	1.5	(0.8)	4.9	(1.1)	6.4	(0.9)	5.7	(2.1)	12.1	(1.0)	5.9	(3.0)	18.0	(1.2)	7.3	(4.2)	25.3	
8																				
9	Depreciation Expense																			
10	Change in Depreciation Rates	(0.2)		1.7		1.5		1.3		2.8		(0.2)		2.6		0.2		2.8		
11	Tax Expense Impact of Depreciation Changes	0.3		2.1		2.4		2.0		4.5		1.3		5.8		1.7		7.5		
12	Depreciation from Net Additions	1.0	1.1	4.8	8.6	5.8	9.7	4.8	8.2	10.6	17.9	4.2	5.3	14.8	23.2	4.8	6.7	19.6	29.9	
13																				
14	Amortization Expense																			
15	CIAC	(0.0)		0.3		0.3		0.0		0.3		0.2		0.5		0.2		0.7		
16	Deferral Accounts	3.7	3.7	(1.6)	(1.3)	2.1	2.4	6.0	6.1	8.2	8.5	3.3	3.5	11.5	12.0	2.1	2.3	13.6	14.3	
17																				
18	Other																			
19	Property and Other Taxes	(2.4)		0.5		(1.9)		1.3		(0.6)		1.0		0.4		1.1		1.5		
20	Other (NSP Provision)	-		-		-		-		-		-		-		-		-		
21	Income Tax Rate Change	1.9		0.0		1.9		0.2		2.1		0.1		2.2		0.1		2.4		
22	Other Income Tax Changes	10.7		(1.3)		9.4		1.1		10.5		1.2		11.7		0.7		12.4		
23	Financing Rate Changes	(2.9)		(0.5)		(3.4)		(3.1)		(6.5)		(8.0)		(14.4)		(0.8)		(15.3)		
24	Financing Changes	0.2		1.6		1.8		1.3		3.1		4.2		7.3		4.1		11.4		
25	Rate Base Growth	0.4	7.8	2.7	3.2	3.1	11.0	2.0	2.7	5.1	13.7	1.4	0.0	6.5	13.7	1.2	6.3	7.7	20.0	
26																				
27	**Revenue Deficiency (Surplus)**		**7.1**				**18.7**				**34.8**				**43.1**				**59.5**	
28			- Appendix G2-FORECAST, Sch 1																	
29			- Appendix G2-FORECAST, Sch 2				- Appendix G2-FORECAST, Sch 62				- Appendix G2-FORECAST, Sch 67				- Appendix G2-FORECAST, Sch 72				- Appendix G2-FORECAST, Sch 77	

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Non-Bypass Sales	2015 Non-Bypass Transportation	2015 Bypass and Special Rates	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,105,679	$ 1,008,157	$ 84,934	$ 11,524	$ 1,104,615	$ (1,064)	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,138	-	-	18,149	18,149	11	
8								
9	Total Revenue	1,123,817	1,008,157	84,934	29,673	1,122,764	(1,053)	
10								
11	Less - Cost of Gas	(495,059)	(489,657)	(253)	(249)	(490,159)	4,900	
12								
13	Gross Margin	$ 628,758	$ 518,500	$ 84,681	$ 29,424	$ 632,605	$ 3,847	
14								
15	Revenue Deficiency (Surplus)	$ 7,089	$ 16,099	$ 2,629	$ -	**$ 18,728**	$ 11,639	- Appendix G2-FORECAST, Sch 61
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	1.13%	3.10%	3.10%	0.00%	2.96%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.63%	1.60%	3.10%	0.00%	1.67%		
20								

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 63

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars (1)	2014 FORECAST (2)	2015 Existing 2013 Rates (3)	2015 Revised Revenue (4)	2015 Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,087	114,254	-	114,254	167	
3	Transportation	98,330	99,501	-	99,501	1,171	
4		212,417	213,755	-	213,755	1,338	
5							
6	Average Rate per GJ						
7	Sales	$8.916	$8.824	$0.000	$8.965	$0.049	
8	Transportation	$0.972	$0.969	$0.000	$0.996	$0.024	
9	Average	$5.239	$5.168	$0.000	$5.255	$0.016	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,011,096	$ 1,008,157	$ -	$ 1,008,157	$ (2,939)	
13	- Increase / (Decrease)	6,109	-	16,099	16,099	9,990	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	94,582	96,459	-	96,459	1,877	
16	- Increase / (Decrease)	980		2,629	2,629	1,649	
17							
18	**Total Revenue**	1,112,767	1,104,616	18,728	1,123,344	10,577	
19							
20	Cost of Gas Sold (Including Gas Lost)	496,151	492,036	-	492,036	(4,115)	
21							
22	**Gross Margin**	616,616	612,580	18,728	631,308	14,692	
23							
24	Operation and Maintenance	204,454	209,380	-	209,380	4,926	
25	Property and Sundry Taxes	48,797	49,335	-	49,335	538	
26	Depreciation and Amortization	147,450	152,613	-	152,613	5,163	
27	Other Operating Revenue	(24,567)	(25,293)	-	(25,293)	(726)	
28	Sub-total	376,134	386,035	-	386,035	9,901	
29	Utility Income Before Income Taxes	240,482	226,545	18,728	245,273	4,791	
30							
31	Income Taxes	36,908	32,962	4,868	37,830	922	
32							
33	**EARNED RETURN**	$ 203,574	$ 193,583	$ 13,860	$ 207,443	$ 3,869	- Appendix G2-FORECAST, Sch 66
34							
35							
36	**UTILITY RATE BASE**	$ 2,778,961	$ 2,859,869	$ 320	$ 2,860,189	$ 81,228	- Appendix G2-FORECAST, Sch 65
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.33%	6.77%		7.25%	-0.07%	- Appendix G2-FORECAST, Sch 66

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 64

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 203,574	$ 193,583	$ 13,860	$ 207,443	$ 3,869	- Appendix G2-FORECAST, Sch 63
3	Deduct - Interest on Debt	(109,958)	(111,085)	(5)	(111,090)	(1,132)	- Appendix G2-FORECAST, Sch 66
4	Add (Deduct) - Permanent & Timing Differences	11,429	11,317	-	11,317	(112)	
5	Accounting Income After Tax	$ 105,045	93,815	13,855	$ 107,670	2,625	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 141,953	$ 126,777	$ 18,723	$ 145,500	$ 3,547	
11							
12							
13	Income Tax - Current	$ 36,908	$ 32,962	$ 4,868	$ 37,830	$ 922	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 36,908	$ 32,962	$ 4,868	$ 37,830	$ 922	- Appendix G2-FORECAST, Sch 63
17							

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 65

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Adjustments	2015 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,870,810	$ 4,021,274	$ -	$ 4,021,274	$ 150,464	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,021,274	4,171,296	-	4,171,296	150,022	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,102,885)	$ (1,203,788)	$ -	$ (1,203,788)	$ (100,903)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,203,788)	(1,315,508)	-	(1,315,508)	(111,720)	
8							
9	CIAC, Beginning	$ (200,601)	$ (202,655)	$ -	$ (202,655)	$ (2,054)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(202,655)	(206,760)	-	(206,760)	(4,105)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 57,281	$ 60,018	$ -	$ 60,018	$ 2,737	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	60,018	64,501	-	64,501	4,483	
16							
17	Net Plant in Service, Mid-Year	$ 2,649,727	$ 2,694,189	$ -	$ 2,694,189	$ 44,462	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	25,360	60,015	-	60,015	34,655	
22	Cash Working Capital	(302)	(342)	320	(22)	280	
23	Other Working Capital	79,039	80,704	-	80,704	1,665	
24	Deferred Income Taxes Regulatory Asset	288,491	287,865	-	287,865	(626)	
25	Deferred Income Taxes Regulatory Liability	(288,491)	(287,865)	-	(287,865)	626	
26	LILO Benefit	(983)	(817)	-	(817)	166	
27	**Utility Rate Base**	$ 2,778,961	$ 2,859,869	$ 320	$ 2,860,189	$ 81,228	- Appendix G2-FORECAST, Sch 66

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2015 AT 2013 RATES							
2	Long-Term Debt		$ 1,573,266	55.01%	6.77%	3.72%		
3	Unfunded Debt		185,553	6.49%	2.50%	0.16%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,101,050	38.50%	7.49%	2.89%		
6								
7			$ 2,859,869	100.00%		6.77%		- Appendix G2-FORECAST, Sch 65
8								
9	2015 REVISED RATES							
10	Long-Term Debt		$ 1,573,266	55.01%	6.77%	3.72%	$ 106,446	
11	Unfunded Debt	$ 185,553						
12	Adjustment, Revised Rates	197	185,750	6.49%	2.50%	0.16%	4,644	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,101,173	38.50%	8.75%	3.37%	96,353	
15								- Appendix G2-FORECAST, Sch 63
16			$ 2,860,189	100.00%		7.25%	$ 207,443	- Appendix G2-FORECAST, Sch 65
17								
18	2014 REVISED RATES							
19	Long-Term Debt		$ 1,575,088	56.68%	6.83%	3.87%	$ 107,613	
20	Unfunded Debt	$ 133,961						
21	Adjustment, Revised Rates	12	133,973	4.82%	1.75%	0.08%	2,345	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,069,900	38.50%	8.75%	3.37%	93,616	
24								
25			$ 2,778,961	100.00%		7.33%	$ 203,574	
26								
27	CHANGE FROM 2014 REVISED RATES							
28	Long-Term Debt		$ (1,822)	-1.67%	-0.06%	-0.15%	$ (1,167)	
29	Unfunded Debt	$ 51,592						
30	Adjustment, Revised Rates	185	51,777	1.67%	0.75%	0.08%	2,299	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		31,273	0.00%	0.00%	0.00%	2,737	
33								
34			$ 81,228	0.00%		-0.07%	$ 3,869	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 67

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Non-Bypass Sales	2016 Non-Bypass Transportation	2016 Bypass and Special Rates	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,104,615	$ 1,015,848	$ 86,825	$ 11,524	$ 1,114,197	$ 9,582	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,149	-	-	18,160	18,160	11	
8								
9	Total Revenue	1,122,764	1,015,848	86,825	29,684	1,132,357	9,593	
10								
11	Less - Cost of Gas	(490,159)	(490,321)	(255)	(252)	(490,828)	(669)	
12								
13	Gross Margin	$ 632,605	$ 525,527	$ 86,570	$ 29,432	$ 641,529	$ 8,924	
14								
15	Revenue Deficiency (Surplus)	$ 18,728	$ 29,840	$ 4,915	$ -	**$ 34,755**	$ 16,027	- Appendix G2-FORECAST, Sch 61
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	2.96%	5.68%	5.68%	0.00%	5.42%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.67%	2.94%	5.66%	0.00%	3.07%		
20								

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 68

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

			2016				
Line No.	Particulars	2015 FORECAST	Existing 2013 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,254	115,079	-	115,079	825	
3	Transportation	99,501	100,439	-	100,439	938	
4		213,755	215,518	-	215,518	1,763	
5							
6	Average Rate per GJ						
7	Sales	$8.965	$8.827	$0.000	$9.087	$0.122	
8	Transportation	$0.996	$0.979	$0.000	$1.028	$0.032	
9	Average	$5.255	$5.170	$0.000	$5.331	$0.076	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,008,157	$ 1,015,848	$ -	$ 1,015,848	$ 7,691	
13	- Increase / (Decrease)	16,099	-	29,839	29,839	13,740	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	96,459	98,349	-	98,349	1,890	
16	- Increase / (Decrease)	2,629		4,916	4,916	2,287	
17							
18	**Total Revenue**	1,123,344	1,114,197	34,755	1,148,952	25,608	
19							
20	Cost of Gas Sold (Including Gas Lost)	492,036	495,712	-	495,712	3,676	
21							
22	**Gross Margin**	631,308	618,485	34,755	653,240	21,932	
23							
24	Operation and Maintenance	209,380	215,100	-	215,100	5,720	
25	Property and Sundry Taxes	49,335	50,614	-	50,614	1,279	
26	Depreciation and Amortization	152,613	164,830	-	164,830	12,217	
27	Other Operating Revenue	(25,293)	(26,013)	-	(26,013)	(720)	
28	Sub-total	386,035	404,531	-	404,531	18,496	
29	Utility Income Before Income Taxes	245,273	213,954	34,755	248,709	3,436	
30							
31	Income Taxes	37,830	32,076	9,036	41,112	3,282	
32							
33	**EARNED RETURN**	$ 207,443	$ 181,878	$ 25,719	$ 207,597	$ 154	- Appendix G2-FORECAST, Sch 71
34							
35							
36	**UTILITY RATE BASE**	$ 2,860,189	$ 2,918,439	$ 101	$ 2,918,540	$ 58,351	- Appendix G2-FORECAST, Sch 70
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.25%	6.23%		7.11%	-0.14%	- Appendix G2-FORECAST, Sch 71

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 69

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 207,443	$ 181,878	$ 25,719	$ 207,597	$ 154	- Appendix G2-FORECAST, Sch 68
3	Deduct - Interest on Debt	(111,090)	(109,277)	(2)	(109,279)	1,811	- Appendix G2-FORECAST, Sch 71
4	Add (Deduct) - Permanent & Timing Differences	11,317	18,693	-	18,693	7,376	
5	Accounting Income After Tax	$ 107,670	91,294	25,717	$ 117,011	9,341	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 145,500	$ 123,370	$ 34,753	$ 158,123	$ 12,623	
11							
12							
13	Income Tax - Current	$ 37,830	$ 32,076	$ 9,036	$ 41,112	$ 3,282	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 37,830	$ 32,076	$ 9,036	$ 41,112	$ 3,282	- Appendix G2-FORECAST, Sch 68
17							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 70

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Adjustments	2016 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,021,274	$ 4,171,296	$ -	$ 4,171,296	$ 150,022	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,171,296	4,301,841	-	4,301,841	130,545	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,203,788)	$ (1,315,508)	$ -	$ (1,315,508)	$ (111,720)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,315,508)	(1,416,227)	-	(1,416,227)	(100,719)	
8							
9	CIAC, Beginning	$ (202,655)	$ (206,760)	$ -	$ (206,760)	$ (4,105)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(206,760)	(210,045)	-	(210,045)	(3,285)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 60,018	$ 64,501	$ -	$ 64,501	$ 4,483	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	64,501	68,116	-	68,116	3,615	
16							
17	Net Plant in Service, Mid-Year	$ 2,694,189	$ 2,728,607	$ -	$ 2,728,607	$ 34,418	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	60,015	79,345	-	79,345	19,330	
22	Cash Working Capital	(22)	359	101	460	482	
23	Other Working Capital	80,704	84,659	-	84,659	3,955	
24	Deferred Income Taxes Regulatory Asset	287,865	286,758	-	286,758	(1,107)	
25	Deferred Income Taxes Regulatory Liability	(287,865)	(286,758)	-	(286,758)	1,107	
26	LILO Benefit	(817)	(651)	-	(651)	166	
27	**Utility Rate Base**	$ 2,860,189	$ 2,918,439	$ 101	$ 2,918,540	$ 58,351	- Appendix G2-FORECAST, Sch 71

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 71

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	-------- Capitalization Amount --------		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2016 AT 2013 RATES							
2	Long-Term Debt		$ 1,571,414	53.84%	6.49%	3.49%		
3	Unfunded Debt		223,426	7.66%	3.25%	0.25%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,123,599	38.50%	6.46%	2.49%		
6								
7			$ 2,918,439	100.00%		6.23%		- Appendix G2-FORECAST, Sch 70
8								
9	2016 REVISED RATES							
10	Long-Term Debt		$ 1,571,414	53.84%	6.49%	3.49%	$ 102,016	
11	Unfunded Debt	$ 223,426						
12	Adjustment, Revised Rates	62	223,488	7.66%	3.25%	0.25%	7,263	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,123,638	38.50%	8.75%	3.37%	98,318	
15								- Appendix G2-FORECAST, Sch 68
16			$ 2,918,540	100.00%		7.11%	$ 207,597	- Appendix G2-FORECAST, Sch 70
17								
18	2015 REVISED RATES							
19	Long-Term Debt		$ 1,573,266	55.01%	6.77%	3.72%	$ 106,446	
20	Unfunded Debt	$ 185,553						
21	Adjustment, Revised Rates	197	185,750	6.49%	2.50%	0.16%	4,644	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,101,173	38.50%	8.75%	3.37%	96,353	
24								
25			$ 2,860,189	100.00%		7.25%	$ 207,443	- Appendix G2-FORECAST, Sch 66
26								
27	CHANGE FROM 2015 REVISED RATES							
28	Long-Term Debt		$ (1,852)	-1.17%	-0.28%	-0.23%	$ (4,430)	
29	Unfunded Debt	$ 37,873						
30	Adjustment, Revised Rates	(135)	37,738	1.17%	0.75%	0.09%	2,619	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		22,465	0.00%	0.00%	0.00%	1,965	
33								
34			$ 58,351	0.00%		-0.14%	$ 154	

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 72

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Non-Bypass Sales	2017 Non-Bypass Transportation	2017 Bypass and Special Rates	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,114,197	$ 1,022,967	$ 88,748	$ 11,525	$ 1,123,240	$ 9,043	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,160	-	-	18,159	18,159	(1)	
8								
9	Total Revenue	1,132,357	1,022,967	88,748	29,684	1,141,399	9,042	
10								
11	Less - Cost of Gas	(490,828)	(491,181)	(259)	(253)	(491,693)	(865)	
12								
13	Gross Margin	$ 641,529	$ 531,786	$ 88,489	$ 29,431	$ 649,706	$ 8,177	
14								
15	Revenue Deficiency (Surplus)	$ 34,755	$ 36,957	$ 6,150	$ -	**$ 43,107**	$ 8,352	- Appendix G2-FORECAST, Sch 61
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	5.42%	6.95%	6.95%	0.00%	6.63%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.07%	3.61%	6.93%	0.00%	3.78%		
20								

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 73

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,079	115,784	-	115,784	705	
3	Transportation	100,439	101,477	-	101,477	1,038	
4		215,518	217,261	-	217,261	1,743	
5							
6	Average Rate per GJ						
7	Sales	$9.087	$8.835	$0.000	$9.154	$0.067	
8	Transportation	$1.028	$0.988	$0.000	$1.049	$0.021	
9	Average	$5.331	$5.170	$0.000	$5.368	$0.037	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,015,848	$ 1,022,967	$ -	$ 1,022,967	$ 7,119	
13	- Increase / (Decrease)	29,839	-	36,956	36,956	7,117	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	98,349	100,273	-	100,273	1,924	
16	- Increase / (Decrease)	4,916		6,151	6,151	1,235	
17							
18	**Total Revenue**	1,148,952	1,123,240	43,107	1,166,347	17,395	
19							
20	Cost of Gas Sold (Including Gas Lost)	495,712	499,335	-	499,335	3,623	
21							
22	**Gross Margin**	653,240	623,905	43,107	667,012	13,772	
23							
24	Operation and Maintenance	215,100	220,952	-	220,952	5,852	
25	Property and Sundry Taxes	50,614	51,598	-	51,598	984	
26	Depreciation and Amortization	164,830	172,294	-	172,294	7,464	
27	Other Operating Revenue	(26,013)	(26,890)	-	(26,890)	(877)	
28	Sub-total	404,531	417,954	-	417,954	13,423	
29	Utility Income Before Income Taxes	248,709	205,951	43,107	249,058	349	
30							
31	Income Taxes	41,112	32,617	11,206	43,823	2,711	
32							
33	**EARNED RETURN**	$ 207,597	$ 173,334	$ 31,901	$ 205,235	$ (2,362)	- Appendix G2-FORECAST, Sch 76
34							
35							
36	**UTILITY RATE BASE**	$ 2,918,540	$ 2,959,916	$ 402	$ 2,960,318	$ 41,778	- Appendix G2-FORECAST, Sch 75
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.11%	5.86%		6.93%	-0.18%	- Appendix G2-FORECAST, Sch 76

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 74

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 207,597	$ 173,334	$ 31,901	$ 205,235	$ (2,362)	- Appendix G2-FORECAST, Sch 73
3	Deduct - Interest on Debt	(109,279)	(105,499)	(10)	(105,509)	3,770	- Appendix G2-FORECAST, Sch 76
4	Add (Deduct) - Permanent & Timing Differences	18,693	25,000	-	25,000	6,307	
5	Accounting Income After Tax	$ 117,011	92,835	31,891	$ 124,726	7,715	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 158,123	$ 125,453	$ 43,096	$ 168,549	$ 10,426	
11							
12							
13	Income Tax - Current	$ 41,112	$ 32,618	$ 11,205	$ 43,823	$ 2,711	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 41,112	$ 32,618	$ 11,205	$ 43,823	$ 2,711	- Appendix G2-FORECAST, Sch 73
17							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 75

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Adjustments	2017 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,171,296	$ 4,301,841	$ -	$ 4,301,841	$ 130,545	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,301,841	4,451,260	-	4,451,260	149,419	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,315,508)	$ (1,416,227)	$ -	$ (1,416,227)	$ (100,719)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,416,227)	(1,531,246)	-	(1,531,246)	(115,019)	
8							
9	CIAC, Beginning	$ (206,760)	$ (210,045)	$ -	$ (210,045)	$ (3,285)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(210,045)	(212,948)	-	(212,948)	(2,903)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 64,501	$ 68,116	$ -	$ 68,116	$ 3,615	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	68,116	71,198	-	71,198	3,082	
16							
17	Net Plant in Service, Mid-Year	$ 2,728,607	$ 2,760,975	$ -	$ 2,760,975	$ 32,368	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	79,345	82,465	-	82,465	3,120	
22	Cash Working Capital	460	330	402	732	272	
23	Other Working Capital	84,659	90,511	-	90,511	5,852	
24	Deferred Income Taxes Regulatory Asset	286,758	285,204	-	285,204	(1,554)	
25	Deferred Income Taxes Regulatory Liability	(286,758)	(285,204)	-	(285,204)	1,554	
26	LILO Benefit	(651)	(485)	-	(485)	166	
27	**Utility Rate Base**	$ 2,918,540	$ 2,959,916	$ 402	$ 2,960,318	$ 41,778	- Appendix G2-FORECAST, Sch 76

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2017 AT 2013 RATES							
2	Long-Term Debt		$ 1,670,476	56.44%	5.98%	3.38%		
3	Unfunded Debt		149,872	5.06%	3.75%	0.19%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,139,568	38.50%	5.95%	2.29%		
6								
7			$ 2,959,916	100.00%		5.86%		- Appendix G2-FORECAST, Sch 75
8								
9	2017 REVISED RATES							
10	Long-Term Debt		$ 1,670,476	56.43%	5.98%	3.37%	$ 99,879	
11	Unfunded Debt	$ 149,872						
12	Adjustment, Revised Rates	248	150,120	5.07%	3.75%	0.19%	5,630	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,139,722	38.50%	8.75%	3.37%	99,726	
15								- Appendix G2-FORECAST, Sch 73
16			$ 2,960,318	100.00%		6.93%	$ 205,235	- Appendix G2-FORECAST, Sch 75
17								
18	2016 REVISED RATES							
19	Long-Term Debt		$ 1,571,414	53.84%	6.49%	3.49%	$ 102,016	
20	Unfunded Debt	$ 223,426						
21	Adjustment, Revised Rates	62	223,488	7.66%	3.25%	0.25%	7,263	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,123,638	38.50%	8.75%	3.37%	98,318	
24								
25			$ 2,918,540	100.00%		7.11%	$ 207,597	- Appendix G2-FORECAST, Sch 71
26								
27	CHANGE FROM 2016 REVISED RATES							
28	Long-Term Debt		$ 99,062	2.59%	-0.51%	-0.12%	$ (2,137)	
29	Unfunded Debt	$ (73,554)						
30	Adjustment, Revised Rates	186	(73,368)	-2.59%	0.50%	-0.06%	(1,633)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		16,084	0.00%	0.00%	0.00%	1,408	
33								
34			$ 41,778	0.00%		-0.18%	$ (2,362)	

FORTISBC ENERGY INC. Evidentiary Update - February 21, 2014 Appendix G2 FORECAST Schedule 77

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Non-Bypass Sales	2018 Non-Bypass Transportation	2018 Bypass and Special Rates	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,123,240	$ 1,029,249	$ 90,719	$ 11,525	$ 1,131,493	$ 8,253	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,159	-	-	18,159	18,159	-	
8								
9	Total Revenue	1,141,399	1,029,249	90,719	29,684	1,149,652	8,253	
10								
11	Less - Cost of Gas	(491,693)	(491,767)	(262)	(255)	(492,284)	(591)	
12								
13	Gross Margin	$ 649,706	$ 537,482	$ 90,457	$ 29,429	$ 657,368	$ 7,662	
14								
15	Revenue Deficiency (Surplus)	$ 43,107	$ 50,969	$ 8,578	$ -	**$ 59,547**	$ 16,440	- Appendix G2-FORECAST, Sch 61
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	6.63%	9.48%	9.48%	0.00%	9.06%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	3.78%	4.95%	9.46%	0.00%	5.18%		
20								

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 78

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars (1)	2017 FORECAST (2)	2018 Existing 2013 Rates (3)	2018 Revised Revenue (4)	2018 Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,784	116,394	-	116,394	610	
3	Transportation	101,477	102,556	-	102,556	1,079	
4		217,261	218,950	-	218,950	1,689	
5							
6	Average Rate per GJ						
7	Sales	$9.154	$8.843	$0.000	$9.281	$0.127	
8	Transportation	$1.049	$0.997	$0.000	$1.081	$0.032	
9	Average	$5.368	$5.168	$0.000	$5.440	$0.072	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,022,967	$ 1,029,249	$ -	$ 1,029,249	$ 6,282	
13	- Increase / (Decrease)	36,956	-	50,968	50,968	14,012	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	100,273	102,244	-	102,244	1,971	
16	- Increase / (Decrease)	6,151		8,579	8,579	2,428	
17							
18	**Total Revenue**	1,166,347	1,131,493	59,547	1,191,040	24,693	
19							
20	Cost of Gas Sold (Including Gas Lost)	499,335	502,541	-	502,541	3,206	
21							
22	**Gross Margin**	667,012	628,952	59,547	688,499	21,487	
23							
24	Operation and Maintenance	220,952	228,276	-	228,276	7,324	
25	Property and Sundry Taxes	51,598	52,691	-	52,691	1,093	
26	Depreciation and Amortization	172,294	179,658	-	179,658	7,364	
27	Other Operating Revenue	(26,890)	(28,120)	-	(28,120)	(1,230)	
28	Sub-total	417,954	432,505	-	432,505	14,551	
29	Utility Income Before Income Taxes	249,058	196,447	59,547	255,994	6,936	
30							
31	Income Taxes	43,823	30,817	15,479	46,296	2,473	
32							
33	**EARNED RETURN**	$ 205,235	$ 165,630	$ 44,068	$ 209,698	$ 4,463	- Appendix G2-FORECAST, Sch 81
34							
35							
36	**UTILITY RATE BASE**	$ 2,960,318	$ 2,994,863	$ 492	$ 2,995,355	$ 35,037	- Appendix G2-FORECAST, Sch 80
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.93%	5.53%		7.00%	0.07%	- Appendix G2-FORECAST, Sch 81

FORTISBC ENERGY INC. | Evidentiary Update - February 21, 2014 | Appendix G2 FORECAST Schedule 79

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 205,235	$ 165,630	$ 44,068	$ 209,698	$ 4,463	- Appendix G2-FORECAST, Sch 78
3	Deduct - Interest on Debt	(105,509)	(108,778)	(14)	(108,792)	(3,283)	- Appendix G2-FORECAST, Sch 81
4	Add (Deduct) - Permanent & Timing Differences	25,000	30,859	-	30,859	5,859	
5	Accounting Income After Tax	$ 124,726	87,711	44,054	$ 131,765	7,039	
6							
7	Current Income Tax Rate	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	74.00%	74.00%	74.00%	74.00%	0.00%	
9							
10	Taxable Income	$ 168,549	$ 118,528	$ 59,532	$ 178,061	$ 9,512	
11							
12							
13	Income Tax - Current	$ 43,823	$ 30,817	$ 15,478	$ 46,296	$ 2,473	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 43,823	$ 30,817	$ 15,478	$ 46,296	$ 2,473	- Appendix G2-FORECAST, Sch 78
17							

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 80

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Adjustments	2018 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,301,841	$ 4,451,260	$ -	$ 4,451,260	$ 149,419	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,451,260	4,611,772	-	4,611,772	160,512	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,416,227)	$ (1,531,246)	$ -	$ (1,531,246)	$ (115,019)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,531,246)	(1,658,360)	-	(1,658,360)	(127,114)	
8							
9	CIAC, Beginning	$ (210,045)	$ (212,948)	$ -	$ (212,948)	$ (2,903)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(212,948)	(219,153)	-	(219,153)	(6,205)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 68,116	$ 71,198	$ -	$ 71,198	$ 3,082	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	71,198	77,384	-	77,384	6,186	
16							
17	Net Plant in Service, Mid-Year	$ 2,760,975	$ 2,794,954	$ -	$ 2,794,954	$ 33,979	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	82,465	76,900	-	76,900	(5,565)	
22	Cash Working Capital	732	527	492	1,019	287	
23	Other Working Capital	90,511	96,690	-	96,690	6,179	
24	Deferred Income Taxes Regulatory Asset	285,204	282,818	-	282,818	(2,386)	
25	Deferred Income Taxes Regulatory Liability	(285,204)	(282,818)	-	(282,818)	2,386	
26	LILO Benefit	(485)	(328)	-	(328)	157	
27	**Utility Rate Base**	$ 2,960,318	$ 2,994,863	$ 492	$ 2,995,355	$ 35,037	- Appendix G2-FORECAST, Sch 81

FORTISBC ENERGY INC.

Evidentiary Update - February 21, 2014

Appendix G2
FORECAST
Schedule 81

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2018 AT 2013 RATES							
2	Long-Term Debt		$ 1,768,209	59.04%	5.95%	3.51%		
3	Unfunded Debt		73,632	2.46%	4.75%	0.12%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,153,022	38.50%	4.93%	1.90%		
6								
7			$ 2,994,863	100.00%		5.53%		- Appendix G2-FORECAST, Sch 80
8								
9	2018 REVISED RATES							
10	Long-Term Debt		$ 1,768,209	59.03%	5.95%	3.51%	$ 105,280	
11	Unfunded Debt	$ 73,632						
12	Adjustment, Revised Rates	302	73,934	2.47%	4.75%	0.12%	3,512	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,153,212	38.50%	8.75%	3.37%	100,906	
15								- Appendix G2-FORECAST, Sch 78
16			$ 2,995,355	100.00%		7.00%	$ 209,698	- Appendix G2-FORECAST, Sch 80
17								
18	2017 REVISED RATES							
19	Long-Term Debt		$ 1,670,476	56.43%	5.98%	3.37%	$ 99,879	
20	Unfunded Debt	$ 149,872						
21	Adjustment, Revised Rates	248	150,120	5.07%	3.75%	0.19%	5,630	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,139,722	38.50%	8.75%	3.37%	99,726	
24								
25			$ 2,960,318	100.00%		6.93%	$ 205,235	- Appendix G2-FORECAST, Sch 76
26								
27	CHANGE FROM 2017 REVISED RATES							
28	Long-Term Debt		$ 97,733	2.60%	-0.03%	0.14%	$ 5,401	
29	Unfunded Debt	$ (76,240)						
30	Adjustment, Revised Rates	54	(76,186)	-2.60%	1.00%	-0.07%	(2,118)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		13,490	0.00%	0.00%	0.00%	1,180	
33								
34			$ 35,037	0.00%		0.07%	$ 4,463	

Appendix H

NATURAL GAS FOR TRANSPORTATION EVIDENTIARY UPDATE FEBRUARY 21, 2014

FORTIS BC™

Natural Gas for Transportation

February 2014

Evidentiary Update February 21, 2014

Table of Contents

1. INTRODUCTION 1
1.1 Regulatory History 2
1.1.1 Initiation of the NGT Program 2
1.1.2 GGRR Incentive Funding 2
1.1.3 The AES Inquiry Report 4
1.1.4 Order in Council No. 557, Special Direction No. 5 5
2. CNG AND LNG SUPPLY 5
2.1 LNG Supply 5
2.1.1 LNG Fueling Stations to Date 5
2.2 CNG Supply 6
3. FORECAST DEMAND FOR NGT 6
3.1 Recent Market Developments and Impacts on Forecasts 6
3.2 Forecast GGRR Incentives 7
3.3 Forecast Vehicle Additions 8
3.4 Forecast Gas Demand from NGT 9
4. NGT FUELING STATIONS & CAPITAL REQUIREMENTS FORECAST 9
4.1 Operations and Maintenance (O&M) 11
4.2 Overhead and Marketing (OH&M) Charge 11
5. OTHER REVENUE REQUIREMENT COMPONENTS 12
5.1 Deferred Charges 12
5.1.1 Fueling Station Variance Account (FSVA) 12
5.1.2 BFI Costs and Recoveries 13
5.1.3 CNG & LNG Service Recoveries 13
5.2 NGT Revenue, Cost of Gas and Delivery Margin Forecast 13
6. CONCLUSION 15

1. INTRODUCTION

The following appendix will provide details on FEI's Natural Gas for Transportation (NGT) program.

FEI's NGT program consists of the provision of compressed natural gas (CNG) or liquefied natural gas (LNG) for the purpose of providing a suitable vehicle fuel for transportation applications. Traditional utility services are focused on delivery of low pressure natural gas to customer locations. This type of service does not provide the fuel to the customer in a form that is useable for transportation applications. To provide a useable CNG or LNG service, the traditional utility service offering must be supplemented, either by FEI or by other parties, by providing a fueling station service to provide a complete service that is useable by the customer.

FEI's approved General Terms and Conditions (GT&C) 12B set out the terms on which FEI can own and operate such stations. GT&C 12B apply to the "installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer/dehydrator, high pressure storage, dispensing equipment; and dispensing of compressed natural gas". For LNG assets, GT&C 12B apply to "the installing and maintaining of LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and dispensing of liquefied natural gas."

In addition, FEI may also provide fueling station services under the provisions of the Greenhouse Gas Reduction (Clean Energy Act) Regulation (the GGRR) issued May 14, 2012 by the government of British Columbia. This regulation enables public utilities to make expenditures of up to $12 million to own and operate CNG fueling stations and infrastructures and make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure. The GGRR was amended on November 27, 2013 as further discussed in Section 1.1.2 below.

This appendix is organized as follows:

Section	Section Title	Purpose
1	Introduction	Section 1 speaks to the regulation enabling the expansion of the NGT market and the regulatory history of FEI's NGT program
2	CNG and LNG Supply	Section 2 outlines FEI's ability to supply Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG)
3	Forecast Demand	Section 3 builds on the market enabling incentives, to forecast expected vehicle additions and ultimately LNG and CNG demand
4	NGT Fueling Station and Capital Requirements Forecast	Section 4 identifies the fueling stations required to fill the vehicles that are contributing to the CNG and LNG demand

Section	Section Title	Purpose
6	Other Revenue Requirement Components	Section 5 identifies the various deferral accounts associated with NGT as well as the revenue and margin forecasts embedded within the Revenue Requirement
7	Conclusion	Section 7 describes how FEI's role in the continued development of the NGT market in B.C. will provide benefits to all natural gas ratepayer customers and will assist the Province in achieving its greenhouse gas reduction initiatives

1.1 REGULATORY HISTORY

1.1.1 Initiation of the NGT Program

On December 1, 2010, FEI filed an Application for Approval of GT&Cs for CNG and LNG Service. The proposed section 12B of FEI's GT&C was designed to facilitate the development of both CNG and LNG refueling stations on the FEI distribution system that would be owned and operated by FEI. The Commission approved revised GT&C 12B in Order G-14-12 dated February 7, 2012.

In 2011 and 2012 FEI filed applications with the BCUC for CNG and LNG service under GT&C 12B. The Commission has approved CNG service to Waste Management,[1] to the general public from FEI's Surrey Operations Centre,[2] and to BFI Canada.[3] In 2012, the Commission issued interim approval under GT&C 12B for FEI to own, construct and operate a refueling station for Vedder Transport Ltd.[4]

1.1.2 GGRR Incentive Funding

On May 14, 2012, the government of British Columbia enacted the Greenhouse Gas Reduction (Clean Energy Act) Regulation (the GGRR) that enables public utilities to:

1. Provide grants or zero-interest loans (and related expenditures) of up to $62 million in total for the purchase of eligible natural gas vehicles operating in British Columbia;
2. Make expenditures of up to $12 million to own and operate CNG fueling stations and infrastructures; and
3. Make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure.

1 Order G-128-11, dated July 19, 2011.
2 Order G-165-11A, dated September 26, 2011.
3 Order C-6-12, dated April 30, 2012 and Order G-78-13, dated May 14, 2013.
4 Order C-11-12.

The rate treatment of these expenditures was approved for FEI in BCUC Order G-161-12 on October 29, 2012. Order G-161-12 approved the NGT Incentives Account to capture costs related to Prescribed Undertaking 1: Vehicle Incentives or Zero Interest Loans. Order G-161-12 also approved the Fueling Stations Variance Account to capture costs related to Prescribed Undertaking 2: CNG Stations and Prescribed Undertaking 3: LNG Stations. The Order approved the recovery of the balances in these accounts from all non-bypass natural gas customers.

On April 11, 2013, the BCUC issued Order G-56-13 which addressed non-grant related issues with respect to the GGRR. On the same date the Commission also issued its Reasons for Decision for Order G-161-12 and Order G-56-13. The Reasons for Decision provided a number of directives with respect to Prescribed Undertakings 1 and 2. Amongst other items, Order G-56-13 states: "The Commission Panel agrees and confirms the Commission's role does not include reviewing whether FEI ought to have negotiated different terms and conditions for these agreements with NGT customers."

FEI subsequently received approval for the rate treatment of "Phase 3" GGRR Incentives of $5.6 million in BCUC Order G-67-13 dated April 30, 2013.[5] The BCUC determined that the most fair and reasonable treatment is to include these expenditures as part of the $62 million funding limit established for Prescribed Undertaking 1 under the GGRR. As a result, FEI is not permitted to spend more than $56.4 million in any further funding in this area.

Following the GGRR announcement in May 2012, FEI launched its first round of funding for vehicles. Section 4 of this appendix summarizes the incentive awards and status for FEI's NGT incentive program. The next round of funding for CNG vehicles began in April of 2013.

The rates and rate design related to each new fueling station agreement will be submitted in separate applications to the BCUC for review and approval.

FEI filed its Application for Approval to Amend Rate Schedule 16 on a Permanent Basis (Rate Schedule 16 Amendment Application) on September 24, 2012 and received a decision via BCUC Order G-88-13, on June 4, 2013. This proceeding was related to LNG supply from FEI's LNG facilities for recipients of grants under the GGRR.

On November 27, 2013, the Lieutenant Governor, by advice and consent of the Executive Council, via Order in Council No. 556[6], issued a Special Direction to the Commission amending the Greenhouse Gas Reduction (Clean Energy) Regulation. One of the key amendments made to the GGRR was including the ability to provide financial incentives to eligible operators of locomotives and mine haul trucks.

5 As per the directives in Order G-67-13, FEI will transfer the $5.6 million for the 2010-2011 Incentives from the NGV Incentives deferral account approved by Order G-44-12 to the NGT Incentives Account approved by Order G-161-12. The NGV Incentives deferral account will be closed subsequent to the transfer.

6 A copy of OIC 556 is provided in Attachment 1 to Evidentiary Update filed concurrently.

1.1.3 The AES Inquiry Report

On December 27, 2012, the BCUC issued its Report on the Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry Report). The AES Inquiry Report has implications for FEI's CNG-LNG Service offering and the use of GT&Cs 12B.

Among other items within the AES Inquiry Report, the Commission has found the following key items with respect to CNG and LNG Services (at p. 52):

"• *CNG/LNG Fueling Stations are not extensions of the distribution system;*

- *CNG/LNG fuelling infrastructure has no natural monopoly characteristics;*
- *It is not in public interest to provide FEI with a competitive advantage in this industry by allowing FEI to subsidize the costs of service with existing ratepayer funds;*
- *FEI must provide CNG/LNG Service without using any potential economic leverage it has as a public utility; and*
- *GHG emission reductions provide a justification for FEI's proposed NGV programs, [but] FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program."*

The AES Inquiry Report directed (at pages 53 and 62) that any "CNG [and LNG] activities undertaken as Prescribed Undertakings, are to be structured as a Separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit." The AES Inquiry Report states that there is no CPCN requirement for CNG-LNG services undertaken within as prescribed undertakings.[7]

The AES Inquiry Report recommends that the FEU undertake CNG and LNG activities outside the prescribed undertakings in a non-regulated business.

With respect to the approved existing CNG fueling stations, the AES Inquiry Report states (at page 54):

> *"The Panel notes that the BFI CNG station is ordered to be in a Separate Class of Service. The Waste Management CNG Station was approved within the existing natural gas class of service, subject to the conditions contained in its approval. While the Panel believes it would be appropriate to have the Waste Management CNG Station within the CNG Class of Service, this report is a forward looking document and does not apply to previous decisions,*

[7] AES Inquiry Report, at pages 55, 62, 63.

unless specific issues were referred to this Inquiry. The Panel does not see this report as directing any change to the BFI or Waste Management Decisions".

1.1.4 Order in Council No. 557, Special Direction No. 5

On November 27, 2014, via Order in Council No. 557[8], the Provincial Government issued Special Direction No, 5 to the Commission implementing Rate Schedule 46 LNG Gas Sales, Dispensing and Transportation Service (RS46). RS46 permits FEI to sell LNG to customers from its LNG facilities. Unlike Rate Schedule 16, there are no explicit limits to the quantity of LNG that can be supplied to customers under RS46 and it is a permanent offering.

Further, Order in Council No. 557 directed the Commission to treat CNG service and LNG service, and all costs and revenues related to those services, as part of the utility's natural gas class of service and allocate all costs and revenues related to CNG and LNG service to all applicable customers.

2. CNG AND LNG SUPPLY

2.1 *LNG SUPPLY*

Presently, FEI is providing LNG supply to a number of customers under Rate Schedule 16 (RS16) until December 31, 2014, which is the expiration date of the RS16 Pilot Program. FEI is providing RS16 LNG supply to customers on both a firm and spot basis.

In addition to RS16, under which LNG supply is limited to 1,040 GJ per day and only available until December 31, 2014, FEI is also providing LNG supply to customers under Rate Schedule 46 (RS46). As discussed in Section **Error! Reference source not found.**, RS46 is a permanent tariff rate offering with no limit on the quantity of LNG that FEI can provide and will not expire, unlike RS16.

2.1.1 LNG Fueling Stations to Date

Presently, FEI has constructed and is operating LNG fueling stations for two customers; Vedder Transport and Denwill Enterprises Inc. (Denwill). The application for approval of the rates and rate design for Denwill is currently in progress and a Commission decision on the Denwill rate application is expected by March 2014. The capital expenditure associated with the Denwill fueling station is approved under Prescribed Undertaking 2 of the GGRR.

[8] A copy of OIC 557 is provided in Attachment 1 to Evidentiary Update filed concurrently.

2.2 CNG SUPPLY

Over the past few years, FEI has constructed four CNG fueling stations in BC. FEI has fueling station agreements with BFI, Kelowna School District and Waste Management which conform to GT&C 12B. The Waste Management agreement was developed based on previously proposed GT&Cs, and was accepted "on an exception basis only".

Presently, CNG customers under FEI Tariff Supplements J-1 and J-2 in FEI's approved GT&C 12B generate delivery revenues under Rate Schedule 25.[9] Revenues collected under Rate Schedule 25 include a fixed monthly charge, delivery and demand charge. Revenues generated by CNG customers positively impact delivery margin, which is a benefit to all natural gas for distribution customers by reducing the pressure on delivery margin rate increases.

On July 31, 2013 via Order G-113-13, the Commission approved FEI's application for rates and rate design to construct and operate a CNG fueling station for Smithrite Disposal (Smithrite). The fueling station for Smithrite represents FEI's first CNG fueling station provided under Prescribed Undertaking 2 of the GGRR and is the fourth CNG fueling station constructed by FEI overall in the last few years.

3. FORECAST DEMAND FOR NGT

This section provides forecasts related to GGRR expenditures expected to be awarded over the remaining prescribed undertaking period, natural gas vehicle additions, and overall CNG and LNG demand for transportation.

The forecasts provided in this section differ from the forecasts presented in FEI's evidentiary update dated September 6, 2013. The forecasts presented in this section contain actual data up to and including December 2013 as FEI has newer information regarding vehicle additions and actual consumption to date. Additionally, recent BCUC decisions, legislation and other external market trends that have impacted the NGT program have also been considered in the forecasts presented below.

3.1 RECENT MARKET DEVELOPMENTS AND IMPACTS ON FORECASTS

The forecasts presented in Sections 4 and 5 related to GGRR expenditures, vehicle additions and gas demand additions have all been revised in response to a number of recent regulatory and market developments impacting the NGT market, particularly the LNG market.

As discussed in Section 1.1.4, the Direction regarding RS46 and the amendments to the GGRR provides the basis for the LNG forecasts presented in sections 3.3 and 3.4. RS46 provides the

[9] Rate Schedule 25 is FEI's General Firm Service used to serve larger volume customers who use gas for more than space heating and generally has a higher load factor than residential and commercial customers due to their consumption patterns.

certain price environment that customers need to make long term capital investment decisions with respect to converting fleets to LNG. However, the discontinuation of Westport's 15L HPDI LNG engine, which was the ideally suited engine offering for long haul trucking companies in BC and for converting to LNG, has resulted in a significant delay to adoption of LNG for the Class 8 trucking sector.

Presently, FEI is in discussions with OEM engine manufacturers such as Volvo and Paccar to introduce a 13L LNG engine with similar power ratings and payload capabilities as the discontinued Westport 15L engine.

Therefore, FEI is not expecting material growth in the Class 8 LNG segment in the short term as a result of very limited engine options and with customers unwilling to commit to purchasing LNG trucks without certainty regarding long term engine offerings. The growth in LNG demand for Class 8 tractors in 2014 will be a result of customers that received vehicle incentives under the 2013 and 2012 incentive calls and before Westport stopped taking orders for the 15L LNG engine[10]. These customers will put their LNG trucks in operation at various points throughout 2014 (such as Wheeler Transport, Denwill, Arrow Transport, and Sutco).

For CNG, FEI is conducting industry analysis on the types of markets and applications that would be best suited for a CNG engine application. In the short term, in addition to the waste hauling customers ideally suited for CNG engines, FEI will also market efforts on the day-cab market, which are tractor trailers that do not have a sleeper cab in the back and thus are used for regional trucking routes that return-to-base each day. There are a number of large customers that operate day-cabs in the Lower Mainland and other parts of BC, and FEI is currently conducting a market assessment of whether the 12L CNG (or LNG) engine would be suitable for their requirements.

3.2 *FORECAST GGRR INCENTIVES*

In 2012, GGRR vehicle incentive funding awards at a 75 percent funding level were delayed to 2013 and thus no GGRR incentives were provided in 2012.[11] The table below provides a forecast of GGRR incentive awards over the remaining prescribed undertaking period for FEI only.[12] The table illustrates the GGRR incentive expenditures on a cash basis. These GGRR incentive awarded will be tracked and accounted for in a separate NGT Incentives deferral account.

[10] http://www.truckinginfo.com/channel/fuel-smarts/news/story/2013/10/westport-dropping-15-liter-lng-engine-for-north-america.aspx

[11] In 2010 and 2011 Demonstration Period, FEI awarded $5.573 million for purchasing NGVs. The determination on the treatment of these expenditures was approved in BCUC Order G-67-13 on April 30, 2013.

[12] The 2018 forecast expenditures reflect an expectation of contracts entered into prior to April 1, 2017

Table H-2: FEI Forecast GGRR Incentives Awarded ($000s)

Incentive Forecast (2013 update for FEI)	pre-2013	2013A	2014F	2015F	2016F	2017F	2018F
Total Vehicle Incentives	$ 5,573	$ 2,330	$ 5,346	$ 4,927	$ 4,910	$ 5,870	$ 3,227
Marine, Mining & Rail	$ -	$ -	$ 2,750	$ 900	$ 8,825	$ 2,625	$ -
Admin, Education, Safety Training	$ 429	$ 499	$ 1,240	$ 1,707	$ 1,284	$ 1,352	$ 742
Total	$ 6,003	$ 2,829	$ 9,336	$ 7,534	$ 15,019	$ 9,847	$ 3,969
Cumulative	$ 6,003	$ 8,832	$ 18,168	$ 25,702	$ 40,720	$ 50,568	$ 54,536

3.3 FORECAST VEHICLE ADDITIONS

Using assumptions regarding the average price differential between a diesel fueled vehicle and natural gas fueled vehicle, FEI has forecasted the number of vehicle additions by year based on the expected GGRR incentives from Table H-2. Table H-3 below illustrates the number of vehicles that are expected to be operational in that particular year and not when the GGRR incentive call was issued. Generally speaking, there is a time lag between when the contribution agreements are executed and when the vehicles are actually put into operation.

For instance, FEI issued a 2012 call for CNG and LNG vehicle incentives and expects most of the vehicles to come into operation in 2014 . FEI has applied this experience and made reasonable assumptions based on the best information it has from the applicants to estimate their in-operation date. Going forward, FEI expects more vehicles to be in operation in that year in which the funding is issued and has incorporated a certain percentage to each year to develop this forecast. For marine, rail and mining, FEI has used feedback received from customers based on the discussions it has so far to build out the forecast.

As a result of market trends as explained in section 3.1, the forecast vehicle and gas demand additions related to CNG (vocational trucks and buses) have been revised up slightly. For instance for the period of 2014 to 2017, the previous forecast was to add 288 vocational trucks and 61 CNG buses. The revised forecast is to add 291 vocational trucks and 86 CNG buses over the same period.

The table below provides a forecast of vehicle additions by type over the remaining prescribed undertaking period.

Table H-3: Forecast Vehicle Additions (FEI Only)

Vehicle Additions (FEI)	2013A	2014F	2015F	2016F	2017F	2018F
Vocational trucks	18	44	58	89	100	76
Buses	2	-	72	10	4	-
Class 8 tractors	10	62	-	6	98	111
Mining	-	-	-	4	4	-
Rail	-	-	-	-	1	-
Marine	-	-	-	5	-	-
Total NGT Fleet	30	106	130	114	207	187

3.4 FORECAST GAS DEMAND FROM NGT

The table below provides a forecast of NGT demand volumes to the end of the prescribed undertaking period of the GGRR based on the expected number of vehicle additions as presented in the table above.

Table H-4: FEI Natural Gas Demand (GJ/Year) Forecast for NGT

Load Addition (Cumulative)	2013A	2014F	2015F	2016F	2017F	2018F
Vocational trucks (CNG)	119,753	163,763	221,763	310,763	410,763	486,763
Buses (CNG)	-	-	72,000	82,000	86,000	86,000
Class 8 tractors (LNG)	194,729	442,729	442,729	466,729	858,729	1,302,729
Mining (LNG)	-	-	-	68,000	136,000	136,000
Rail (LNG)	-	-	-	-	60,000	60,000
Marine (LNG)	-	-	-	550,000	550,000	550,000
Total NGT Fleet	314,482	606,492	736,492	1,477,492	2,101,492	2,621,492

The amendments to the GGRR permit FEI to offer incentives to companies that operate locomotives and mine haul trucks. As a result, FEI will be focusing on developing these market segments and expects to add LNG demand beginning in 2016 for mine haul trucks, and beginning in 2017 for rail/locomotive applications. Presently, FEI is in discussions with various mining and rail companies in converting parts of their fleets to LNG.

The addition of LNG marine vessels and LNG heavy duty Class 8 trucks will be the largest contributors to overall LNG demand for FEI in the long run. For marine applications, FEI has received interest from BC Ferries and Seaspan to convert a number of their marine vessels to LNG. BC Ferries, which is expected to receive incentive funding from FEI, plans to convert 3 of their inland coastal ferry vessels and will replace them with bi-fuel options that will operate on both diesel fuel and LNG. The expected in-service date for these 3 vessels is mid-2016. Seaspan is also expected to receive incentive funding to convert 2 marine vessels, and they are also expected to be in service in mid-2016. The sum of these 5 marine vessels is expected to add about 550,000 GJ per year of LNG demand starting in 2016.

4. NGT FUELING STATIONS & CAPITAL REQUIREMENTS FORECAST

Based on the forecast volume of natural gas demand for CNG and LNG and the vehicle incentive expenditures as permitted under the GGRR, FEI has forecast the number of fueling stations for both CNG and LNG that it will need to construct in the table below.

Table H-5: NGT Fueling Stations Forecast Built by FEI

FEI Station Additions	2013A	2014F	2015F	2016F	2017F	2018F
CNG	4	1	2	1	2	1
LNG	2	3	0	1	1	2
Total Stations	6	4	2	2	3	3

The numbers presented in the table above assume that all expenditures for vehicle incentives under the GGRR are awarded to qualifying customers over the prescribed undertaking period and that FEI will construct half of the CNG fueling stations required to serve CNG demand.

The other half of the required CNG fueling stations are assumed to be built by independent third parties. FEI believes that this is a reasonable assumption and therefore provides a conservative forecast of the number of CNG fueling stations that it will construct.

Based on FEI's past experience with respect to total capital requirements to build fueling stations (LNG and CNG), the figures presented in the table below assume a total capital cost for each type of fueling application:

- Vocational Trucks (CNG) - $1.25 million
- Buses (CNG) - $1.5 million
- Class 8 Tractors (LNG) - $2.75 million
- Mobile LNG - $0.8 million

Based on the forecasted station capital requirements listed above and the anticipated addition of NGT fueling stations as described in Table H-5, FEI forecasts to spend the amounts set out in Table H-6 on CNG and LNG fueling stations after 2013. For vocational trucks and buses (CNG stations), FEI is assuming that it will construct half of the fueling stations required to serve demand for these two segments of the NGT market.

Table H-6: NGT Fueling Station Capital Requirements Forecast ($ millions)[13]

Fueling Station Expenditures ($ millions)	2013A	2014F	2015F	2016F	2017F	2018F
CNG	$ 1.64	$ 1.10	$ 2.25	$ 1.25	$ 2.75	$ 1.25
LNG	$ 2.98	$ 2.25	$ -	$ 0.80	$ 2.75	$ 5.50
Total Capital	$ 4.63	$ 3.36	$ 2.25	$ 2.05	$ 5.50	$ 6.75

[13] Please note that the annual capital additions may differ slightly from the annual capital expenditures. For example, the capital additions in 2013 are approximately $4.3 million and in 2014 are approximately $3.8 million as provided in Section E, Financial Schedules 35 and 38, Line 9, Columns 3 and 4

4.1 OPERATIONS AND MAINTENANCE (O&M)

O&M expenses related to the operation of the GGRR CNG and LNG fueling stations are recovered directly from the customer(s) of each fueling station through the rates charged to those customers.

Based on FEI's experience in constructing and operating natural gas fueling stations, the forecast O&M expenses for each type of application are as follows.

Table H-7: Forecast Annual Fueling Station O&M

Fueling Application	O&M per Year per Station ($)
Vocational trucks	$ 60,000
Buses	$ 60,000
Class 8 Tractor	$ 100,000
Mobile LNG (CVA, Orca)	$ 65,000

Table H-8 provides a forecast of O&M expenses related to the forecast number of NGT GGRR fueling stations that FEI expects to construct over the next five years. The figures presented in the table below add O&M expenses for stations that will be constructed in subsequent years and are adjusted for expected in-service dates, thus the figures presented are a cumulative total of O&M dollars that will be expended over the next five years.

Table H-8: NGT GGRR Fueling Station O&M Forecast

Annual Station O&M ($ thousands)	2013A	2014F	2015F	2016F	2017F	2018F
CNG	$ 126	$ 180	$ 269	$ 361	$ 458	$ 559
LNG	$ 62	$ 253	$ 360	$ 400	$ 491	$ 652
Total O&M	$ 188	$ 433	$ 629	$ 760	$ 949	$ 1,211

4.2 OVERHEAD AND MARKETING (OH&M) CHARGE

BCUC Order G-128-11, dated July 19, 2011 directed FEI to include an overhead and marketing (OH&M) charge that would be recovered from NGT station customers through each customer's station fueling rate. On May 14, 2013, BCUC issued Order G-78-13 directing FEI to charge NGT customers $0.52 per GJ as the OH&M rate.

The forecast OH&M collected from each of the station customers is accounted for as an Other Revenue credit.

The OH&M recovery over the 2014 – 2018 period is expected to total approximately $1.7 million. This represents a net benefit of $160 thousand flowing to other natural gas ratepayers when compared to the forecast expense of $1.5 million[14]. Table H-9 below shows the forecast OH&M expense and recovery from NGT customers based on the $0.52 per GJ charge. The OH&M recoveries will continue over the term of each station contract and FEI expects that, as NGT demand increases, recoveries will surpass expenses for a net benefit to FEI's core customers as shown in Table H-9 for years starting in 2017.

Table H-9: OH&M Forecast Recovery

OH&M Recovery ($000)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast Total
Forecast OH&M	371	390	379	378	-	**1,518**
OH&M Recovery	(180)	(243)	(284)	(388)	(583)	**(1,678)**
Total Deficiency (Surplus) Collected	**191**	**147**	**95**	**(10)**	**(583)**	**(160)**

FEI has included the OH&M charge as a component of the fueling station rate for the following stations:

- BFI
- Vedder Transport
- Kelowna School District proposed station
- All forecast GGRR CNG Stations
- All forecast GGRR LNG Stations

FEI notes that with reference to the OH&M charge, BFI Order G-78-13 was not applied retroactively and, therefore, OH&M is not recovered from Waste Management or the Surrey or Burnaby pumps.

5. OTHER REVENUE REQUIREMENT COMPONENTS

5.1 *DEFERRED CHARGES*

5.1.1 Fueling Station Variance Account (FSVA)

The FSVA was established pursuant to Order G-161-12 whereby the account would capture "the total revenue surplus or deficiency pertaining to fueling station facility costs that have not been forecast in rates, as well as the administration and application costs…"

[14] BFI CPCN Order G-150-12 Compliance Filing, Table 3, years 2014 to 2017

The account is no longer required because the balance accumulated in the FSVA to date has been minimal, fueling station capital costs and associated recoveries have been included in the forecast revenue requirement and will be reforecast on an annual basis and application and administrative costs are accounted for in the fueling station rate. Thus, as identified in the Draft Order (Appendix J) and Approvals Sought (Section 2), FEI will amortize the balance in this account over the approved three year amortization period commencing in 2014 and will discontinue this account effective January 1, 2017.

5.1.2 BFI Costs and Recoveries

In accordance with Commission Orders C-6-12 and G-150-12, FEI is to include all other amounts paid by BFI for volumes in excess of the 'take or pay' commitment in a new rate base deferral account separate from the deferral account approved in the Waste Management Decision. The deferral account is to capture incremental CNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments, with the disposition to be determined at a future date.

5.1.3 CNG & LNG Service Recoveries

The CNG & LNG Service Recoveries account, approved by Order G-128-11, captures the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. The concept of this account was to capture any excess station capital and O&M recoveries and amortize them back into core customers' rates. FEI will maintain this account to capture incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand and return it to rate payers in the subsequent period.

5.2 NGT REVENUE, COST OF GAS AND DELIVERY MARGIN FORECAST

Currently, FEI delivers CNG and LNG through the GGRR and non-GGRR stations using Rate Schedules 6P, 25, 16 and 46. FEI has used the forecast volumes from this appendix to calculate revenue, cost of gas and delivery margin at existing rates.

The following three tables identify, for the rate schedules listed above, the forecast of gas (CNG and LNG) volumes sold, associated delivery margin, cost of gas (if the rate schedule is a not a transportation rate) and revenue.

Table H-12: Volume, Delivery Margin Cost of Gas and Revenue forecast for Rate Schedule 6P NGT Customers[15]

Volume, Revenue, Margin under RS 6P	2014F	2015F	2016F	2017F	2018F
Surrey Operation Pump (GJ)	4,725	4,725	4,725	4,725	4,725
Total Delivery Margin ($)	$ 18,654	$ 18,654	$ 18,654	$ 18,654	$ 18,654
Total Cost of Gas ($)	$ 15,971	$ 15,971	$ 15,971	$ 15,971	$ 15,971
Total Revenue ($)	$ 34,625	$ 34,625	$ 34,625	$ 34,625	$ 34,625

Table H-13: Volume, Delivery Margin and Revenue forecast for Rate Schedule 25 NGT Customers[16]

Volume, Revenue, Margin under RS 25	2014F	2015F	2016F	2017F	2018F
CNG Service Volume (GJ)					
Waste Management (Contract Demand)	19,000	19,000	19,000	19,000	19,000
BFI (Contract Demand)	60,000	60,000	60,000	60,000	60,000
Kelowna School District	5,000	5,000	5,000	5,000	5,000
Smithrite	17,400	17,400	17,400	17,400	17,400
All Other	46,610	176,610	275,610	379,610	455,610
Total Volume (GJ)	148,010	278,010	377,010	481,010	557,010
Total Delivery Margin ($)	$ 106,863	$ 200,723	$ 272,201	$ 347,289	$ 402,161

Table H-14: Volume, Delivery Margin, Cost of Gas and Revenue Forecast for Rate Schedule 16 and 46 Customers[17]

Volume, Revenue, Margin under RS 16/46	2014F	2015F	2016F	2017F	2018F
LNG Service Volume (GJ)					
Vedder Transport (Contract Demand)	140,000	140,000	140,000	140,000	140,000
Denwill (Contract Demand)	24,000	24,000	24,000	24,000	24,000
All Other	278,729	278,729	920,729	1,440,729	1,884,729
Total Volume	442,729	442,729	1,084,729	1,604,729	2,048,729
Total Delivery Margin ($)	$ 1,884,621	$ 1,925,871	$ 4,718,571	$ 6,980,571	$ 8,911,971
Total Cost of Gas ($)	$ 1,741,039	$ 1,877,297	$ 4,883,968	$ 7,642,382	$ 10,257,429
Total Revenue ($)	$ 3,625,660	$ 3,803,168	$ 9,602,540	$ 14,622,953	$ 19,169,400

The volume, delivery margins, cost of gas and revenues are components within the traditional natural gas financial schedules within this Application and are part of the overall natural gas revenue requirement.

15 Volume represents the contract volume for existing stations and GGRR forecast volumes for proposed stations whereas Table H-4 represents all GGRR and Non-GGRR volume (contract and excess of contract demand).
16 Ibid.
17 Ibid.

6. CONCLUSION

Since the initial CNG/LNG Application in late 2010, FEI has made progress in contracting with NGT customers for CNG and LNG fueling station services. Although legislation has provided the price and supply certainty being sought by the market, the discontinuation of preferred LNG engine offerings results in a significant hurdle in continuing to advance the Class 8 tractor LNG segment. This has resulted in FEI reducing its forecast of vehicle and load additions for the Class 8 tractor segment.

Conversely, FEI is forecasting to make progress in the marine, mine haul, and rail/locomotive market segments, which will use LNG to power their fleets.

For CNG applications, in addition to waste hauling customers who are ideally suited for CNG engines, FEI will develop the day-cab market. FEI is currently assessing the day-cab market for a suitable natural gas engine offering. FEI will also continue to engage CNG bus fleet operators and waste hauling companies on the benefits of converting their fleets to CNG.

Appendix J

DRAFT FORM OF ORDER
EVIDENTIARY UPDATE FEBRUARY 21, 2014

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
For Approval of a Multi-Year Performance Based Ratemaking Plan for the years 2014 through 2018

BEFORE: D.M. Morton, Panel Chair/Commissioner (Date)
D.A. Cote, Commissioner
N.E. MacMurchy, Commissioner
B. Magnan, Commissioner

ORDER

WHEREAS:

A. On June 10, 2013, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission for approval of a proposed multi-year performance based ratemaking plan (PBR Plan) for the years 2014 through 2018, and for approval of permanent natural gas delivery rates effective January 1, 2014, pursuant to sections 59 to 61 and 89 of the Utilities Commission Act (the Act);

B. On July 16, 2013, FEI filed an Evidentiary Update (Exhibit B-6);

C. On September 6, 2013, FEI filed a second Evidentiary Update (Exhibit B-15);

D. On February 21, 2014, FEI filed a third Evidentiary Update (Exhibit B-X);

E. FEI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate increase of 0.6 percent as compared to 2013 delivery rates, effective January 1, 2014;

F. FEI further seeks approval of the Revenue Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes for 2014 as set out in the Application;

G. FEI seeks, among other things, approvals including: allocation of costs for corporate and shared services; discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts;

Deleted: 1.4

Deleted: ate

H. FEI, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (together, the FEU) seek acceptance pursuant to section 44.2 of the Act for Energy Efficiency and Conservation (EEC) expenditures; and

I. The Commission has reviewed the Application and concludes that the requested changes as outlined in the Application should be approved.

NOW THEREFORE the Commission orders as follows:

1. Pursuant to sections 59 to 61 of the Utilities Commission Act (the Act), the following approvals are granted for FEI:

    a. Approval of the PBR mechanisms set out in Section B of this Application for setting delivery rates for the years 2014-2018.

    b. Approval of permanent delivery rates for all non-bypass customers effective January 1, 2014, representing an increase of 0.6 percent as compared to 2013 delivery rates. The increase is to be applied to the delivery charge and the basic charge will remain at 2013 levels.

    c. Approval of the RSAM rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2B, 2U, 2X, 3, 3B, 3U, 3X and 23 effective January 1, 2014 of ($0.120)/GJ as set out in Section E Schedule 63 of the Application (Exhibit B-1).

    d. 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 2014 through 2018 as set out in Section C2.3 of the Application.

    e. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and FEI, as reflected in the Corporate Services Agreements between FortisBC Holdings Inc. and FEI, as described in section D3.6 of the Application.

    f. Approval of the allocation of costs for shared services between FEI and FEVI, as described in section D3.6 of the Application.

    g. Approval of the allocation of costs for shared services between FEI and FEW, as described in section D3.6 of the Application.

    h. Approval of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, all as set out in section D4, Appendices F-4 and F-5 to the Application (as amended in Exhibit B-x) and summarized in the following table.

Deleted: 1.4

Deleted: Energy

Deleted: , subject to FEVI receiving regulatory approval for the allocation in its next RRA filing

Deleted: , subject to FEW receiving regulatory approval for the allocation in its next RRA filing

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change - New or Modified	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014
	Depreciation Variance	FEI	Section D4.4.1; 1 year amortization period, commencing January 1, 2014
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEI EEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	Generic Cost of Capital Application Costs	FEI	Section D4.2.8; amortization period of 2 years commencing January 1, 2014

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

Type Of Change	Account	Company	Reference
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.9; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.10; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	Fuelling Stations Variance Account	FEI	Appendix H; 3 year amortization period commencing January 1, 2014 with discontinuation of this account effective January 1, 2017
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	RS 16 Application Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2016
	RS 16 Costs and Recoveries	FEI	Section D4.4.8; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	NGV for Transportation Application	FEI	Section D4.4.9; discontinuation of this account effective January 1, 2016
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015

Deleted: CNG and LNG Recoveries

Deleted: FEI

Deleted: Section D4.4.4; discontinuation of this account effective January 1, 2015

Deleted: BFI Costs and Recoveries

Deleted: FEI

Deleted: Section D4.4.5; discontinuation of this account effective January 1, 2014

Type Of Change	Account	Company	Reference
	IFRS Implementation Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2014

i. Approval of changes to the following accounting policies to be used in the determination of rates for FEI, effective January 1, 2014:

   i. Modification to the approved Lead Lag days with the removal of the HST lead days and the insertion of GST and PST lead days as set out in Section D3.2 of the Application.

   ii. Inclusion of the retiree portion of pension and OPEB expenses in benefit loadings for O&M and capital as set out in Section D3.1 of the Application.

   iii. Capitalization of the annual software costs paid to vendors in support of upgrade capability as set out in Section D3.1 of the Application.

   iv. Depreciation of assets to commence January 1 of the year following when they are placed into service as set out in Section D3.3 of the Application.

   v. A depreciation rate of 12.5 percent for asset class 484 Vehicles as set out in Section D3.1 of the Application.

vi. Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application.

vii. Approval to allocate Executive costs between FEI and FBC effective January 1, 2014 by way of applying the Massachusetts Formula as described in Section D3.6.5 of the Application .

2. With respect to Energy Efficiency and Conservation (EEC) expenditures, the Commission orders as follows:

a. Pursuant to section 44.2(a) of the Act, the Commission accepts the following EEC expenditure schedules for the FEU to be spent on the EEC program areas described in Appendix I of the Application: Up to $34.353 million for 2014 (inclusive of the $15 million accepted by Order G-230-13), $37.30 million for 2015, $37.358 million for 2016, $37.664 million for 2017, and $38.982 million for 2018.

b. The Commission approves the continuation of the EEC framework as previously approved by the Commission, with the following changes:

i. Approval of the administration by a neutral third party of EEC funds provided to projects with a third party thermal energy component.

ii. Approval of the incorporation of spillover effects and the attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, for the purpose of reporting on cost effectiveness in the EEC Annual Report pursuant to section 43 of the Act.

iii. Approval for the FEU to transfer funds within a program area to a new program without prior Commission approval, provided that the new program is in accordance with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2014.

BY ORDER

Deleted: <#>With respect to Natural Gas for Transportation (NGT), the Commission orders approvals pursuant to sections 59-61 of the Act for the creation of separate classes of service to account for CNG and LNG Stations apart from the traditional natural gas for distribution class of service:¶
<#>Approval of a GGRR CNG Class of Service which will include CNG Stations constructed pursuant to the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 Section 2(2).¶
<#>Approval of a GGRR LNG Class of Service which will include LNG Stations constructed pursuant to the Greenhouse Gas Reduction (Clean Energy) Regulation, B.C. Reg. 102/2012 Section 2(3). ¶
<#>Approval of a Non-GGRR CNG Class of Service which will include CNG Stations constructed by FEI not otherwise included in approvals sought 10(a).¶
<#>Approval of a Non-GGRR LNG Class of Service which will include LNG Stations constructed by FEI not otherwise included in approvals sought 10(b).¶

Deleted: 3

Attachment 5

UPDATED TABLES, APPLICATION SECTION C AND D

The following attachment provides key tables from Exhibit B-1 updated to reflect the Evidentiary Update, dated February 21, 2014.

C: FORECASTS FOR THE PBR PERIOD

Table C1-5: Forecast Sales Revenue at Existing Rates

Revenue ($ millions)	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential[1]	672.2	667.3	664.9	664.9	664.9	664.7
Commercial[2]	353.2	349.9	350.8	354.6	358.5	362.3
Industrial[3]	77.1	74.9	75.1	75.2	75.3	75.3
Rate 16/46	1.5	3.6	3.8	9.6	14.6	19.2
Grand Total	**1,104.0**	**1,095.7**	**1,094.7**	**1,104.2**	**1,113.3**	**1,121.5**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 23
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

NGT revenues are embedded within the revenue numbers shown in Table C1-5. The embedded amounts are shown in Table C1-6 below.

Table C1-6: Forecast Sales Revenue for NGT at Existing Rates[1]

Revenue ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16/46	3.6	3.8	9.6	14.6	19.2
Rate 25	0.1	0.2	0.3	0.3	0.4
Total	**3.8**	**4.0**	**9.9**	**15.0**	**19.6**

[1] Rate Schedule 6P shows as zero due to presenting the dollars values as millions.

Table C1-8: Forecast Gross Margin at Existing Rates

Margin ($ millions)	Projected 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Residential[1]	361.7	361.8	362.1	362.5	362.9	363.2
Commercial[2]	169.5	171.2	173.7	176.4	179.1	181.8
Industrial[3]	66.8	64.8	65.1	65.1	65.2	65.2
Rate 16/46	0.8	1.9	1.9	4.7	7.0	8.9
Grand Total	**598.7**	**599.8**	**602.8**	**608.7**	**614.2**	**619.2**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2, 3, 23
3. Rate Schedules 4, 5, 6, 7, 22, 25, 27 (does not include Burrard Thermal or Vancouver Island Wheeling)

NGT margins are embedded within the margin numbers shown in Table C1-8. The amounts are shown in Table C1-9 below.

Table C1-9: Forecast Gross Margin for NGT at Existing Rates[2]

Margin ($ millions)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
Rate 6P	0.0	0.0	0.0	0.0	0.0
Rate 16/46	1.9	1.9	4.7	7.0	8.9
Rate 25	0.1	0.2	0.3	0.3	0.4
Total	**2.0**	**2.1**	**5.0**	**7.3**	**9.3**

[2] Rate Schedule 6P shows as zero due to presenting the dollars values as millions.

Figure C1-22 below shows the forecast demand driven by the NGT market that is incremental to the demand forecast presented in Section C1.4.5.

Figure C1-22: NGT Demand, TJ's

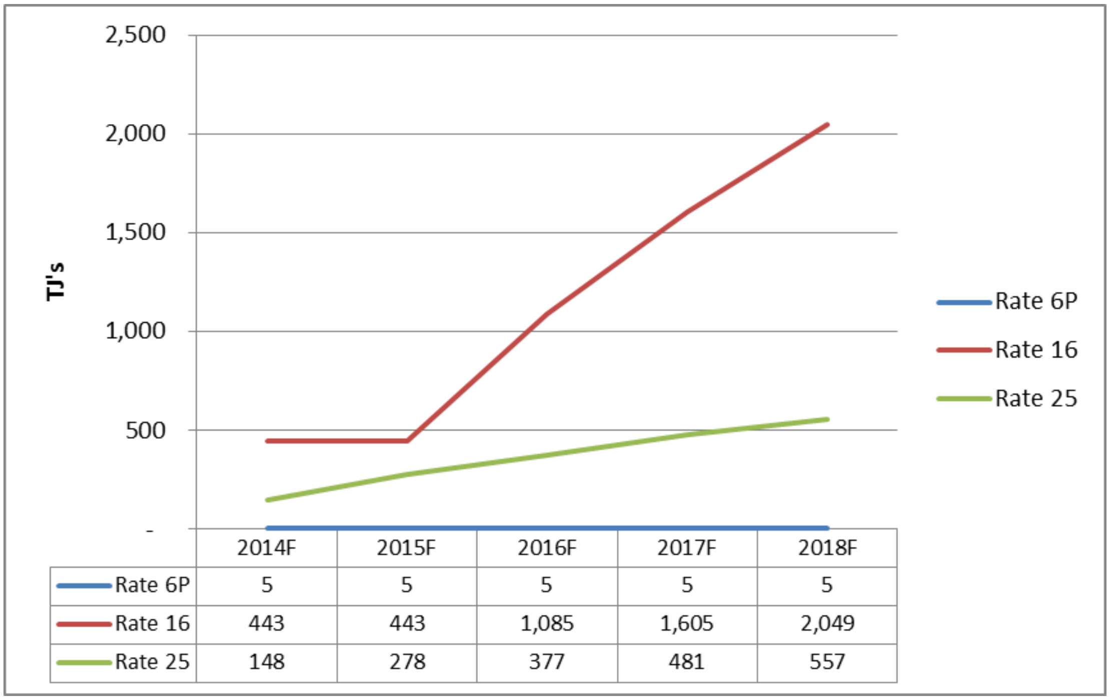


Table C2-1: 2013 and 2014 Other Revenue Components

Other Operating Revenue, ($ thousands)			
	Approved 2013	**Projected 2013**	**Forecast 2014**
Late Payment Charge	$ 2,333	$ 2,109	$ 2,089
Connection Charge	2,685	2,622	2,636
NSF Returned Cheque Charges	79	79	79
Other Recoveries	126	284	284
FEVI Wheeling Charge	3,464	3,464	3,365
SCP Third Party Revenue	14,827	14,773	14,773
NGT Overhead and Marketing Recovery	-	-	180
Burnaby & Surrey Operations Pump Charges	-	-	-
Biomethane Other Revenue	(29)	(97)	(198)
CNG & LNG Service Revenues	1,304	931	1,359
Total Other Operating Revenue	**$ 24,789**	**$ 24,165**	**$ 24,567**

FORTIS BC™

Table C3-1: Departmental O&M Review ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Actual	2013 Approved
Operations	54,444	55,756	59,806	58,599	64,226	63,189
Customer Service [1]	53,278	56,575	40,737	49,115	36,630	52,452
Energy Solutions & External Relations	14,636	15,456	18,075	17,509	19,022	18,181
Energy Supply & Resource Dev	2,075	3,409	3,488	3,664	3,937	3,738
Information Technology	17,320	18,654	23,442	24,553	24,249	25,379
Engineering Services & PM	13,566	14,329	13,599	16,705	15,297	16,956
Operations Support	10,916	10,580	11,038	12,132	11,718	12,990
Facilities	7,329	6,835	9,563	9,509	9,230	9,259
Environment Health & Safety	2,427	2,445	2,481	2,749	2,680	2,999
Finance & Regulatory Services	12,177	12,064	12,149	13,129	12,872	14,184
Human Resources	8,823	8,170	8,610	8,983	8,305	8,511
Governance	7,368	7,895	7,366	7,602	7,995	7,935
Corporate	2,158	1,439	1,915	2,743	(247)	230
	206,518	213,606	212,269	226,993	215,914	236,003

1 Excludes deferred Customer Service O&M for 2012 and 2013 Actual

Table C3-2: 2013 Departmental O&M Reconciliation ($ thousand)

		Productivity		2013 Deferrals			Accounting Changes		
	2013 Approved	(Sustainable Savings)	2013 Sustainable	PST (full year)	BCUC Fees & Insurance	Pension/OPEB O&M portion	Pension/OPEB Retiree portion	Software Fees	2013 Base
Operations	63,189	540	63,729	137		3,667	1,704		69,236
Customer Service 1	52,452	(12,498)	39,954	18		1,744	810		42,527
Energy Solutions & External Relations	18,181	1,034	19,215	23		1,012	470		20,721
Energy Supply & Resource Dev	3,738	262	4,000	7		295	137		4,440
Information Technology	25,379	(1,162)	24,217	340		691	321	(1,800)	23,768
Engineering Services & PM	16,956	(1,500)	15,456	58		1,027	477		17,018
Operations Support	12,990	(1,123)	11,867	69		802	373		13,111
Facilities	9,259	324	9,583	40		147	68		9,838
Environment Health & Safety	2,999	(319)	2,681	12		123	57		2,872
Finance & Regulatory Services	14,184	(1,086)	13,099	3	923	597	277		14,899
Human Resources	8,511	(53)	8,458	22		487	226		9,192
Governance	7,935	-	7,935	-	93	-	-		8,028
Corporate	230	(587)	(358)	34		13	(5,851)		(6,161)
	236,003	(16,167)	219,836	762	1,016	10,605	(930)	(1,800)	229,489

1 2013 Projection excludes Customer Service deferred O&M

Table C3-3: Forecast Labour and Benefit Inflation ($ thousands)

	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	1,110	1,029	1,293	1,441	1,942
Customer Service	515	478	600	669	902
Energy Solutions & External Relations	306	284	357	398	536
Energy Supply & Resource Dev	89	83	104	116	156
Information Technology	209	194	244	272	366
Engineering Services & PM	311	288	362	404	544
Operations Support	243	225	283	315	425
Facilities	44	41	52	58	78
Environment Health & Safety	37	34	43	48	65
Finance & Regulatory Services	176	164	206	229	309
Human Resources	150	139	175	195	263
Governance	-	-	-	-	-
Corporate	4	4	5	5	7
	3,196	2,964	3,722	4,150	5,591
Annualized Labour and Benefit Inflation	2.4%	2.2%	2.6%	2.8%	3.7%

Table C3-5: Departmental O&M Forecasts ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Operations	$ 69,236	$ 71,285	$ 73,522	$ 75,311	$ 77,483	$ 79,884
Customer Service	42,527	43,442	44,371	45,876	47,024	48,860
Energy Solutions & External Relations	20,720	23,275	23,769	24,341	24,959	25,719
Energy Supply & Resource Dev	4,440	4,738	4,918	5,040	5,174	5,349
Information Technology	23,768	24,392	24,910	25,486	26,096	26,807
Engineering Services & PM	17,018	17,735	17,764	18,212	18,690	19,323
Operations Support	13,111	13,698	14,011	14,385	14,792	15,311
Facilities	9,838	10,299	10,517	10,824	11,067	11,435
Environment Health & Safety	2,872	2,934	2,997	3,069	3,147	3,242
Finance & Regulatory Services	14,899	15,217	15,539	15,907	16,302	16,779
Human Resources	9,192	9,398	9,601	9,840	10,101	10,430
Governance	8,028	8,371	8,742	9,135	9,544	9,974
Corporate	(6,161)	(6,384)	(6,475)	(6,595)	(6,719)	(6,906)
Total Gross O&M	$ 229,488	$ 238,400	$ 244,186	$250,829	$257,658	$266,207
Less: O&M transferred to BVA		(570)	(620)	(612)	(633)	(662)
Total Delivery Rate Gross O&M		**$ 237,830**	**$ 243,566**	**$250,217**	**$257,025**	**$265,546**

Table C4-1: Historical FEI Capital Expenditures ($ thousands)

	2010 Actual	2011 Actual	2012 Actual	2012 Approved	2013 Actual	2013 Approved
Sustainment Capital						
Meter Recalls/Exchanges	19,126	22,922	24,197	20,668	25,644	21,272
Transmission System Reinforcements	9,771	10,808	14,964	20,350	20,247	24,386
Distribution System Reinforcements	5,198	7,670	8,574	7,170	7,726	7,610
Distribution Mains & Service Renewals & Alt.	11,342	17,736	16,556	17,330	24,858	21,845
Total Sustainment Capital	45,437	59,137	64,291	65,517	78,475	75,114
Growth Capital						
New Customer Mains	4,538	4,510	5,374	6,127	5,614	6,500
New Customer Services	13,874	14,423	17,423	12,050	17,318	12,910
New Customer Meters	1,905	1,699	1,403	1,965	2,308	2,105
Total Growth Capital	20,317	20,632	24,200	20,142	25,240	21,515
Other						
Equipment	3,434	3,499	3,951	3,310	4,544	2,930
Facilities	4,177	5,840	1,996	8,424	7,937	4,124
IT	12,418	14,503	13,983	18,000	22,008	18,000
Total Other	20,029	23,841	19,930	29,734	34,489	25,054
Total Gross Capex	85,783	103,610	108,421	115,393	138,204	121,683
CIAC	(3,922)	(7,948)	(5,830)	(5,341)	(9,163)	(5,400)
Total Net Capex	81,861	95,662	102,591	110,052	129,041	116,283

Table C4-2: 2013 Base Adjustments ($ thousands)

	2013	2013 Adjustments				2013
Sustainment Capital	Approved	PST	Pension	Vehicles	IT Cap	Base
Meter Recalls/Exchanges	21,272	362	837	-	-	22,470
Transmission System Reinforcements	24,386	416	378	-	-	25,180
Distribution System Reinforcements	7,610	130	118	-	-	7,858
Distribution Mains & Service Renewals & Alt.	21,845	372	339	-	-	22,556
Total Sustainment Capital	75,114	1,280	1,672	0	0	78,065
Growth Capital						
New Customer Mains	6,500	111	172	-	-	6,783
New Customer Services	12,910	220	341	-	-	13,471
New Customer Meters	2,105	36	56	-	-	2,197
Total Growth Capital	21,515	367	569	0	0	22,451
Other						
Equipment	2,930	50	-	2,860	-	5,840
Facilities	4,124	70	-	-	-	4,194
IT	18,000	307	-	-	1,800	20,107
Total Other	25,054	427	0	2,860	1,800	30,141
Total Gross Capex	121,683	2,074	2,241	2,860	1,800	130,657
CIAC	(5,400)	(92)	-	-	-	(5,492)
Total Net Capex	116,283	1,982	2,241	2,860	1,800	125,165

Table C4-3: Forecast FEI Capital Expenditures ($ thousands)

	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
Sustainment Capital						
Meter Recalls/Exchanges	22,471	25,967	26,852	25,869	24,225	25,085
Transmission System Reinforcements	25,180	16,555	20,479	15,537	14,221	14,298
Distribution System Reinforcements	7,858	10,112	7,282	7,546	8,073	8,653
Distribution Mains & Service Renewals & Alt.	22,556	25,815	24,433	28,245	34,059	34,304
Total Sustainment Capital	78,065	78,449	79,045	77,198	80,578	82,340
Growth Capital						
New Customer Mains	6,783	5,374	5,462	5,561	5,664	5,798
New Customer Services	13,471	18,360	19,502	20,214	20,337	20,363
New Customer Meters	2,197	1,664	1,805	1,876	1,877	1,862
Total Growth Capital	22,451	25,398	26,769	27,651	27,878	28,022
Other						
Equipment	5,840	6,818	7,328	7,127	7,358	6,702
Facilities	4,194	3,904	4,026	4,122	4,269	4,626
IT	20,107	20,105	20,105	20,106	20,102	20,098
Total Other	30,141	30,828	31,460	31,354	31,729	31,425
Total Gross Capex	130,657	134,675	137,274	136,203	140,185	141,788
CIAC	(5,492)	(5,821)	(5,821)	(5,821)	(5,820)	(5,819)
Total Net Capex	125,165	128,854	131,454	130,382	134,366	135,969

D: *FINANCING, TAXES, ACCOUNTING POLICIES AND DEFERRALS*

Figure D4-1: FEI Forecast Mid-Year Balances of Deferral Accounts by Category

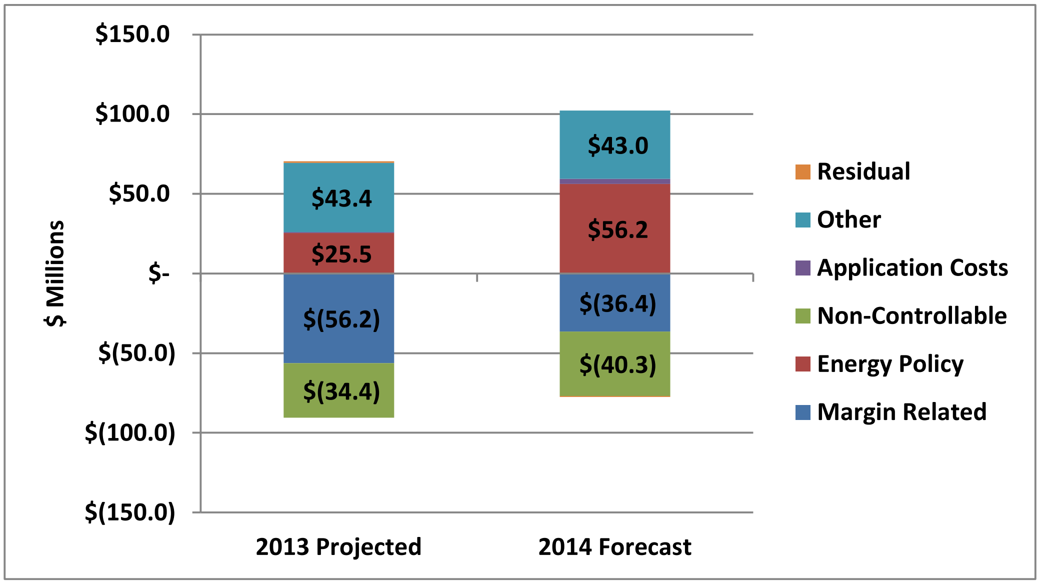


Table D4-5: Summary of Deferral Account Requests

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change - New or Modified	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014

Type Of Change	Account	Company	Reference
	Depreciation Variance	FEI	Section D4.4.1; 1 year amortization period, commencing January 1, 2014
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 1. An decrease from $35.6 million (the approved FEU funding envelope in 2013) to a total of $34.4 million in 2014 and and then an increase to the portfolio in 2015 through 2018 up to $39.0 million in 2018 for Mainland FEI, Vancouver Island and Whistler combined; 2. The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEIEEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	Generic Cost of Capital Application Costs	FEI	Section D4.2.8; amortization period of 2 years commencing January 1, 2014
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.9; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.10; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	Fuelling Stations Variance Account	FEI	Appendix H; 3 year amortization period commencing January 1, 2014 with discontinuation of this account effective January 1, 2017

Type Of Change	Account	Company	Reference
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	RS 16 Application Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2016
	RS 16 Costs and Recoveries	FEI	Section D4.4.8; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	NGV for Transportation Application	FEI	Section D4.4.9; discontinuation of this account effective January 1, 2016
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	IFRS Implementation Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.10; discontinuation of this account effective January 1, 2014