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December 3, 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)

Application for 2015 and 2016 Revenue Requirements and Rates for the Fort Nelson Service Area (the Application)

Attached please find FEI's Application for 2015 and 2016 Revenue Requirements and Rates for the Fort Nelson Service Area (FEFN). In this Application FEI is seeking Commission approval of its rates for delivery service to customers on the natural gas distribution system in FEFN for 2015 and 2016 (the Test Period). Specifically, FEI is seeking:

- Effective January 1, 2015, a 24.26 percent increase in delivery rates (Section 9, Schedule 2.0, Line 15) reflecting an increase in its revenue requirements of 10.57 percent (Section 9, Schedule 2.0, Line 17) or a revenue deficiency of approximately $473 thousand.

- Effective January 1, 2016, an additional 7.58 percent increase in delivery rates (Section 9, Schedule 3.0, Line 15) reflecting an increase in revenue requirements of 3.31 percent (Section 9, Schedule 3.0, Line 17) or a revenue deficiency of approximately $153 thousand.

- Effective January 1, 2015, the Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider to be set to $0.039 per GJ (a decrease of $0.045 per GJ compared to 2014).

- The amortization of the Fort Nelson Revenue Surplus/Deficit account and approval of a 2015-2016 Revenue Requirement Application Deferral Account.

As described in the Application, a significant portion of the increase in the FEFN revenue requirements for the Test Period is due to the Muskwa River Pipeline Crossing project, for which a Certificate of Public Convenience and Necessity (CPCN) was granted by the Commission in Order C-2-14.

Given that permanent rates will not be able to be issued prior to the beginning of the Test Period, FEI is seeking approval, by December 12, 2014, of an interim, refundable delivery rate increase of 24.26 percent effective January 1, 2015, and an interim, refundable RSAM Rate Rider of $0.039 per GJ effective January 1, 2015. A draft of the interim order sought is included within Appendix A and the proposed rates, tariff continuity and bill impacts schedules are included as Appendix B.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Fort Nelson Regional District and BCOAPO

FortisBC Energy Inc.
Fort Nelson Service Area

Application for 2015 and 2016 Revenue Requirements and Rates

Volume 1 - Application

December 3, 2014

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1. SUMMARY, BACKGROUND, APPROVALS SOUGHT AND PROPOSED REGULATORY PROCESS

FortisBC Energy Inc. (FEI or the Company) is seeking approval of its rates for delivery service to customers on the natural gas distribution system in FEI's Fort Nelson service area (FEFN) for 2015 and 2016 (the Test Period). Specifically, FEI is seeking:

- Effective January 1, 2015, a 24.26 percent increase in delivery rates (Section 9, Schedule 2.0, Line 15) reflecting an increase in its revenue requirements of 10.57 percent (Section 9, Schedule 2.0, Line 17) or a revenue deficiency of approximately $473 thousand.
- Effective January 1, 2016, an additional 7.58 percent increase in delivery rates (Section 9, Schedule 3.0, Line 15) reflecting an increase in revenue requirements of 3.31 percent (Section 9, Schedule 3.0, Line 17) or a revenue deficiency of approximately $153 thousand.
- Effective January 1, 2015, the Revenue Stabilization Adjustment Mechanism (RSAM) Rate Rider to be set to $0.039 per GJ (a decrease of $0.045 per GJ compared to 2014).
- The amortization of the Fort Nelson Revenue Surplus/Deficit account and approval of a 2015-2016 Revenue Requirement Application Deferral Account.

As explained in this Application, the rate increases over the Test Period and other approvals sought are required to ensure that the Company's rates recover the costs of serving its customers in FEFN. Overall, a significant portion of the increase in the FEFN revenue requirement is due to the Muskwa River Pipeline Crossing project, for which a Certificate of Public Convenience and Necessity (CPCN) was granted by the Commission in Order C-2-14. The rate increases due to this project that are included in this Application are lower than the forecasts provided to the Commission in the CPCN proceeding.[1]

Given that permanent rates will not be able to be issued prior to the beginning of the Test Period, FEI is seeking approval of an interim, refundable delivery rate increase of 24.26 percent effective January 1, 2015, and an interim, refundable RSAM Rate Rider of $0.039 per GJ effective January 1, 2015.

[1] FEI Application for a Certificate of Public Convenience and Necessity to Construct and Operate a Transmission Pressure Pipeline Crossing of the Muskwa River for the Fort Nelson Service Area, Streamlined Review Oral Hearing, Volume 1, Pages 148-149, an estimate of the Residential annual bill was estimated to be approximately $90 per year. This compares to the total annual bill impact of all changes, including the impact of the Muskwa River Crossing Project, provided in this Application of approximately $91 per year for a Residential customer (Appendix B, Tab 4, Page 1). The standalone impact of the Muskwa River Crossing Project is $79 per year for a Residential customer as discussed further below.

1.1 SUMMARY

Operations in Fort Nelson consist of a transmission lateral from the nearby Spectra Energy processing plant to the town of Fort Nelson, together with a gas distribution system. Also included in the service area is the distribution system in Prophet River.

FEFN customers have benefited and continue to benefit in various ways from being served by FEI, a much larger gas distribution company than FEFN would be on a standalone basis. Some of these benefits include:

- Access to the necessary resources, expertise and training in all areas affecting gas distribution utilities;
- Access to low cost capital funding;
- Access to the buying power of a larger company, reducing the costs of pipe and other materials and supplies; and
- Access to the commodity-related benefits of being in a company that is a large regional buyer of natural gas and a significant holder of various natural gas storage, transportation, peaking and other gas supply arrangements designed to mitigate and optimize gas supply costs.

FEFN's gas supply has typically been obtained through one contract. For the past number of years, the Company has used a small portion of its contracted gas storage capacity at Aitken Creek to improve the load factor of the Fort Nelson load and to mitigate the impact of gas volatility for Fort Nelson customers. The diversity of FEI's overall gas supply portfolio has assisted over the years in providing favourable gas supply arrangements for FEFN.

The Company is not requesting approval of forecast gas costs with this Application. Instead, any rate changes related to the flow-through of gas costs are dealt with in separate applications to the Commission. Any variations between forecast and actual gas costs will continue to be returned or recovered from customers through the existing deferral account mechanisms approved by the Commission.

The Company is requesting approval of delivery rate increases to recover forecast revenue deficiencies in 2015 and 2016. The requirement for an increase in revenues is determined by various business drivers including capital expenditures, projected customer use rates, volumes and revenues, and operating and maintenance expenses of FEFN. Detailed support material has been provided in Sections 2 through 9 which show the impact of these business drivers on the FEFN revenue requirements. The major contributors to the revenue deficiency over the Test Period are summarized briefly below.

The largest driver of the increase in the revenue requirements over the Test Period is the Muskwa River Crossing Project. This project was completed in 2014 and will be added to rate base at the beginning of 2015 at a capital cost of $4,210 thousand, or approximately $1,840 thousand under budget.[2] Also included in the revenue requirement commencing in 2015 is the amortization of the Muskwa River Crossing Project Costs deferral account, which has captured the development costs for the project. This account has an opening 2015 balance of $815[3] thousand which is being recovered from customers over a three year period.[4] These deferred costs are partially offset by the refund of approximately $347 thousand in the Muskwa River Crossing Cost of Service (COS) deferral account, which is also amortized into rates over three years commencing January 1, 2015.[5] The Muskwa River Crossing COS deferral account was first created in 2011 and later extended to 2012, 2013 and 2014. The forecast Project costs had been incorporated in rates and due to the delays in the project in service date, the deferral account was used to refund that impact back to customers until the project was actually put into rate base.[6]

In accordance with the lower capital costs noted above, the forecast increase in FEFN's revenue requirements due to the Muskwa River Crossing Project is lower with the rate impact forecast by FEI in the CPCN proceeding. The approximate impact of the Muskwa River Crossing Project is approximately $365 thousand of the total 2015 revenue deficiency of $473 thousand. This equates to an approximate annual bill impact of $79 per year in 2015 for a Residential customer and is approximately $11 per year lower than the Residential customer annual bill estimate provided in the CPCN proceeding.[7]

In addition to the impacts of the Muskwa River Crossing Project, the 2016 revenue deficiency is also attributable to the forecast for the renewal of a right-of-way land agreement with the First Nations to replace old expired agreements and other capital expenditures required for the continued integrity and reliability of the transmission and distribution systems and the ongoing safety of customers and employees. These capital expenditures are going into service in 2015, and being depreciated (recovered) in rates beginning in 2016.

A certain percentage of FEFN's costs are impacted by allocations from FEI or by the accounting policies approved for FEI. Order G-17-14 in FEFN's Application for Approval of Deferral account Treatment for 2014 approved the adoption of accounting changes approved as a result of FEI's Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014-2018 (PBR Application). Consistent with Order G-17-14, the amounts in this Application have been updated for any impacts resulting from the Commission Decision and Order G-138-14 issued September 15, 2014 (PBR Decision). Below is a summary of the accounting changes adopted by FEFN:

- Capitalized overhead rate of 12% (previously 14%);
- Depreciation to begin the year after the asset is put into service; and

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2 Capital cost of $4,054 thousand plus AFUDC of $156 thousand and as compared to CPCN capital cost estimate, inclusive of AFUDC, of $6,050 thousand (CPCN Proceeding, Exhibit B-1, Section 6.1.1, Page 47, Line 16).
3 January 1, 2015 after-tax balance, additions to the account are $894 thousand on a before-tax basis.
4 Order C-2-14.
5 Order C-2-14.
6 Please refer to Section 7.4.3 for a complete description of the history of this account.
7 Residential customer consuming 140 GJs per year at approved commodity rates.

- Utilization of lead/lag days for calculation of the cash working capital calculation.

The approvals sought in this Application appropriately recover the costs of serving FEFN customers and the required capital improvements to continue that service. Although the proposed rates reflect a cumulative increase of 31.84 percent over the existing delivery rates (a cumulative increase of 13.88% on an average burner tip[8] basis), due to the relatively small customer base in Fort Nelson it is not uncommon for significant rate changes to occur. For example, in the last five years, the burner tip rates in FEFN have fluctuated between decreases of 12 percent and increases of 33 percent. The key driver of the proposed rate change is the Muskwa River Crossing Project, the rate impacts of which were discussed and reviewed as a part of the CPCN process. FEI believes that the proposed rates for FEFN are fair and reasonable, allowing the Company to recover its prudently incurred costs of providing efficient and effective natural gas service to customers.

1.2 *ORGANIZATION OF THIS APPLICATION*

- **Section 1** Summary, Background, Approvals Sought and Proposed Regulatory Process - discusses in summary the Revenue Requirement Application, FEI and FEFN background including operations and historical revenue requirement changes.
- **Section 2** Revenue Requirement and Rates – discusses the revenue requirement and the proposed rates the Company is requesting.
- **Section 3** Gas Sales and Demand and Other Revenue – discusses the impact of use rates, customer additions and other factors affecting demand, revenue and margin in the Fort Nelson region.
- **Section 4** Cost of Gas – discusses the impact of gas costs on total revenue requirement changes.
- **Section 5** Operating and Maintenance (O&M) Expenses-discusses the labour and non-labour costs required to continue to operate and maintain the business.
- **Section 6** Taxes – discusses Property Tax, Income Tax, and Other Taxes
- **Section 7** Rate Base and Capital Expenditures – discusses rate base overall, as well as each of its components including plant additions, deferral accounts and working capital.
- **Section 8** Financing and Capital Structure –discusses the financing of rate base assets and the debt and equity components of financing.
- **Section 9** Financial Schedules.

8 Commodity plus delivery or total bill basis.

1.3 BACKGROUND

This section outlines the corporate history of FEI and FEFN, followed by the applicable regulatory context.

1.3.1 History of FEI

FEI is one of the largest natural gas distribution companies in Canada, based on number of customers and service area. With the amalgamation of FEI with FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) as of January 1, 2015[9], FEI's customer base for the provision of natural gas transmission and distribution services includes approximately 952,655 residential, commercial and industrial customers located in the Inland, Columbia, Fort Nelson, Lower Mainland and Vancouver Island service areas. FEI, through its parent company FortisBC Holdings Inc., is a wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada.

FEI is responsible for the procurement and supply of natural gas to the majority of its customers. For customers in all of its service areas, the Company purchases its supply of gas from a number of producers, aggregators and marketers. FEI also contracts with various providers for service on upstream pipelines, capacity in underground storage facilities and various types of peaking and gas supply cost mitigation arrangements.

The gas supply, transmission and distribution functions of FEI focus on activities that are integral to the safe, reliable and efficient running of utility operations. Beyond the front line activities such as responding to emergencies, constructing, installing and operating the transmission and distribution system, there are a number of key support functions. These include planning and designing facilities, corrosion control, metering, meter reading, leak surveying, right of way management and materials management and distribution.

Also important are the systems and services that allow FEI to meet its responsibilities effectively in today's dynamic business environment. These supporting systems include Information Systems, Energy Supply and Resource Development, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources and Corporate.

1.3.2 FEFN Background

The natural gas distribution system in the Fort Nelson area was acquired in 1985 through the acquisition of Fort Nelson Gas Ltd. by Inland Natural Gas Co. Ltd. Fort Nelson Gas Ltd. was amalgamated in 1989 with Inland Natural Gas and other companies and continued as BC Gas Inc., later BC Gas Utility Ltd., then Terasen Gas Inc., and now FortisBC Energy Inc.

[9] Order G-21-14 in the FEU Application for Reconsideration and Variance on the FEI Common Rates, Amalgamation and Rate Design Application.

Rates have been set separately for FEFN from the date the company was acquired to the present. FEI (as BC Gas Utility Ltd.) sought regulatory consolidation of FEFN with the remainder of the Company in its 1992 Revenue Requirement Application, and again in its 2011 Common Rates, Amalgamation and Rate Design Application, but these applications were not approved. Therefore, FEFN has been excluded from the Company's general revenue requirement applications and Performance Based Ratemaking plans. As such, FEFN is excluded from the common rates for the amalgamated utility.[10]

1.3.3 Regulatory Background

The most recent revenue requirement change approved by the Commission was on April 12, 2012 by Order G-44-12. In that Order, the Commission approved an increase in rates for FEFN effective January 1, 2013 to recover a revenue deficiency of $35 thousand. By Order G-17-14 dated February 13, 2014, the Commission approved the continuation of 2013 delivery rates for 2014, with the actual 2014 revenue surplus or deficiency to be captured in the Fort Nelson Revenue Surplus/Deficit deferral account. Order G-17-14 also stated "This approval is subject to the examination of the 2014 actual results that are added to the corrected December 31, 2013 balances of the deferral accounts, and the cost recovery, in the next revenue requirement proceeding."

1.4 *APPROVALS SOUGHT*

The Company seeks the following approvals from the Commission, pursuant to Sections 58, 60 and 61 of the *Utilities Commission Act* (the Act):

- Approval of an interim, refundable delivery rate increase of 24.26 percent effective January 1, 2015, and approval of an interim RSAM Rate Rider of $0.039 per GJ effective January 1, 2015;
- A permanent delivery rate increase of 24.26 percent effective January 1, 2015, to recover the forecast revenue deficiency of $473 thousand in 2015;
- A permanent delivery rate increase of 7.58 percent (cumulative increase of 31.84 percent over the Test Period) in 2016 to recover the forecast revenue deficiency of $153 thousand in 2016 (cumulative $626 thousand over the Test Period);
- The RSAM rider to be set to $0.039 per GJ (a decrease of $0.045 per GJ compared to 2014) as set out in Section 2.5 Table 2-4 effective January 1, 2015;
- Approval to amortize the Fort Nelson Revenue Surplus/Deficit account as described in Section 7.4.2.1; and
- Approval of the 2015-2016 Revenue Requirement Application deferral account as described in Section 7.4.1.1.

[10] Order G-21-14 in the FEU Application for Reconsideration and Variance on the FEI Common Rates, Amalgamation and Rate Design Application.

A draft form of both an Order for interim rates and permanent rates is provided in Appendix A.

1.5 *PROPOSED REGULATORY PROCESS*

FEI is of the view that a written hearing process is appropriate for the review of this Application, and proposes the following regulatory timetable:

Table 1-1: Proposed Regulatory Timetable

ACTION	DATE (2014)
Intervener Registration	Monday, December 29
	DATE (2015)
BCUC and Intervener Information Request No. 1	Monday, January 12
FEFN Response to Information Requests No. 1	Tuesday, February 10
FEFN Final Argument Submissions	Monday, February 23
Intervener Final Argument Submissions	Monday, March 2
FEFN Reply Argument Submissions	Monday, March 9

Due to the timing of this Application and the regulatory review process, the Commission will be unable to render its decision in this Application respecting FEFN permanent rates in time to be effective January 1, 2015. Therefore, FEI is requesting approval pursuant to Section 89 of the Act of the 2015 rates sought in this Application on an interim basis, effective January 1, 2015.

2. REVENUE REQUIREMENTS AND RATES

2.1 INTRODUCTION

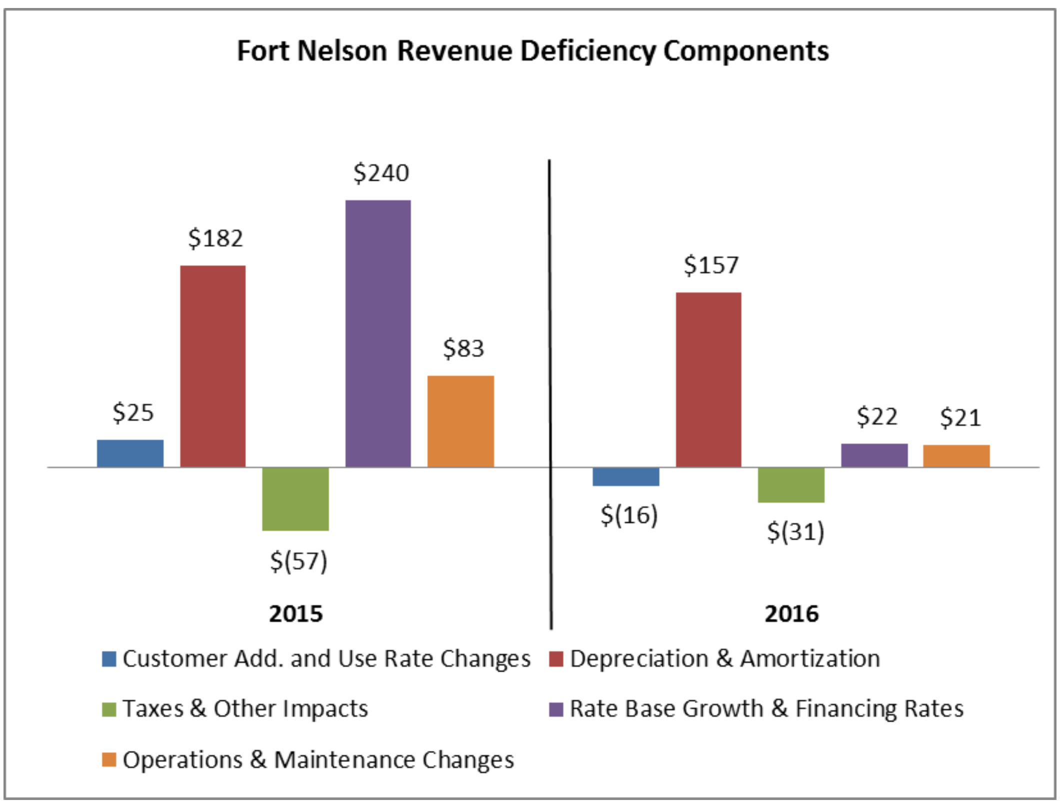
The purpose of this section is to provide an overview of the total revenue requirements and rates for the forecast periods of 2015 and 2016. The supporting discussion can be found in Sections 3 through 8, with financial schedules provided in Section 9.

FEFN's revenue requirement is $4,474 thousand (Section 9, Schedule 2, Line 4) in 2015 and $4,509 thousand in 2016 (Section 9, Schedule 3, Line 4). This results in an approximate 24.26 percent increase to delivery rates in 2015 and an additional increase of 7.58 percent to delivery rates (cumulative increase of 31.84 percent) in 2016. For a typical FEFN residential customer consuming an average of 140 GJ per year, this equates to an increase of approximately $91 annually (9.06 percent) in 2015 and an additional incremental increase of $30 annually (2.71%) in 2016 to an annual bill.

2.2 REVENUE DEFICIENCY

FEFN is forecasting a total revenue deficiency of $473 thousand in 2015 (Section 9, Schedule 2.0, Line 13) and an additional $153 thousand in 2016 (cumulative deficiency of $626 thousand (Section 9, Schedule 3.0, Line 13). These deficiencies are summarized in Figure 2-1 below.

Figure 2-1: FEFN Revenue Deficiency in 2015 and 2016 (amounts in $ thousands)



As displayed in Figure 2-1 above, the largest contributors to the revenue deficiency are rate base growth, and depreciation and amortization. In 2015, the increases to these two categories are being driven by costs associated with the Muskwa River Crossing Project being placed into service. In 2016, the revenue deficiency is driven by changes in amortization expense.[11]

2.2.1 Revenue at Existing Rates

The Demand Forecast discussed in Section 3 is used to determine the revenue surplus or deficiency. Existing approved rates are applied to the demand forecast to determine the variance (surplus or deficiency) between existing revenues and the revenue requirement for the years. The decrease in demand in 2015 is attributable to declines in the use rate per customer, which more than offset increases due to customer growth, and result in a revenue deficiency of approximately $25 thousand in 2015. Customer growth contributes to a revenue surplus of $16 thousand in 2016.

2.2.2 Operations and Maintenance Expense

The impact of changes in O&M is an increase to the revenue requirement of $83 thousand in 2015 and an increase to the revenue requirement of $21 thousand (cumulative $104 thousand) in 2016, net of capitalized overhead. The items contributing to the O&M amounts are discussed more fully in Section 5, and have been properly reflected in the calculation of the Company's revenue requirement.

2.2.3 Depreciation and Amortization Expense

The capital costs of $4,210 thousand related to the Muskwa River Crossing project will begin to depreciate in 2015. A full year of depreciation in 2015 associated with the project results in higher depreciation from net additions of $131 thousand in 2015 and a further $57 thousand (cumulative $188 thousand) in 2016 associated with additional capital projects forecast for 2015 (which begin depreciating in 2016).

In addition, changes in amortization expense of approximately $51 thousand in 2015 and $100 thousand (cumulative $151 thousand) in 2016 further increase the deficiency.

2.2.4 Taxes

As discussed in Section 6, forecast levels of property taxes and changes in income tax rates, new taxes, and changes to capital cost allowances (CCA) rates all have an impact on the revenue requirement calculation.

[11] Please refer to Schedule 68. The one year amortization of the $55 thousand surplus balance in the Fort Nelson Revenue Surplus /Deficit Account and the $44 thousand credit in the Depreciation Variance Account in 2015 creates an incremental revenue deficiency in 2016 of approximately $99 thousand.

The property tax decrease of $27 thousand in 2015 results in a decrease to the revenue requirement, which is partially offset by an increase of $1 thousand in 2016, for a cumulative $26 thousand decrease over the Test Period.

Other changes to income tax rates and timing differences result in a decrease in revenue requirements in 2015 of $19 thousand, and a further incremental decrease to the revenue requirement of $32 thousand in 2016 (cumulative decrease of $51 thousand over the Test Period). An increase in CCA related to the large capital costs associated with the Muskwa Project, is a significant contributor to the decrease in income tax for 2015 and 2016.

2.2.5 Earned Return and Financing Costs

Changes in the amount of rate base affect the amount of return on the rate base. The increase in return on rate base is largely due to capital related to the Muskwa River Crossing project. The rate base has increased from $5,698 thousand in 2014 to $11,744 thousand in 2015 (Section 9, Schedule 41, Line 24) and to 12,170 thousand in 2016 (Section 9, Schedule 42, Line 24). This contributes $129 thousand to the revenue deficiency in 2015 and an additional $14 thousand in 2016 (cumulative $143 thousand over the Test Period).

The final component of the revenue requirement calculation is financing costs. Financing costs are discussed in Section 8. The amount of financing required is determined by the rate base; the financing costs themselves are determined by a combination of the amount of financing and the forecast interest rates. Increases in financing, caused by the higher rate base, and changes in interest rates, result in a net increase associated with financing costs of $111 thousand in 2015, followed by an increase of $8 thousand in 2016.

2.3 *RATES*

Based on the revenue deficiencies, Fort Nelson is seeking an increase in its delivery rates of 24.26 percent in 2015, with an additional increase of 7.58 percent) in 2016, for a cumulative increase of 31.84 percent over the Test Period. The annual dollar and percentage impacts to rates are provided in Appendix B and summarized below in Table 2-1.

Table 2-1: Annual Dollar and Percentage Bill Impacts for Average Customers[12]

		2015		2016	
Rate Category	**GJ**	**Annual $ Increase**	**% of Previous Annual Bill**	**Annual $ Increase**	**% of Previous Annual Bill**
Rate 1- Domestic (Residential) Serivce	140	$ 91.41	9.06%	$ 29.88	2.71%
Rate 2.1-General (Commercial) Service	460	$ 353.66	9.98%	$ 117.71	3.02%
Rate 2.2-General (Commercial) Service	3100	$ 2,006.30	8.99%	$ 674.75	2.77%
Rate 25-Transportation Service	6890	$ 4,618.38	22.92%	$ 1,416.56	5.72%

12 Calculated using commodity rates effective January 1, 2015 as approved by Order L-60-14. Please note that since they are Transportation Service customers, the annual bill impacts to RS 25 appear higher than other rate schedules because only the delivery portion of the annual bill is included in the calculation.

FEFN does not have any customers served under Rate Schedules 2.3, 2.4, 3.1, 3.2 and 3.3. The Company proposes to increase the delivery component of the rates by 24.26 percent in 2015 and 7.58 percent in 2016 (cumulative increase of 31.84 percent).

2.4 *RSAM*

In its 2004 Revenue Requirements Application, FEI sought approval from the Commission to implement a RSAM account for FEFN to capture variations in the delivery margin (Revenue less Cost of Gas) for residential, commercial and industrial rate classes. Commission Order G-17-04, dated February 5, 2004, granted approval for the implementation of the RSAM account and Commission Order G-17-14 approved the change in the amortization period for the RSAM account from three years to two years. The account accumulates the annual RSAM debits and credits with one half of the net balance being recovered or refunded in the following year via a positive or negative rate rider.

The RSAM rate rider has been calculated consistent with past practice and is $0.039/GJ effective January 1, 2015 (a decrease of $0.045/GJ from the 2014 rider) (Section 9, Schedule 86). In the fourth quarter of 2015, FEFN will recalculate the rate rider to reflect 2014 actual information as well as updated projections for 2015, and accordingly will file for approval of a revised RSAM rate rider effective January 1, 2016 if necessary.

3. GAS SALES AND DEMAND, AND OTHER REVENUE

3.1 INTRODUCTION

This section describes FEFN's forecast revenue at existing rates based on the forecast total energy demand from residential, commercial and industrial customers over the Test Period for FEFN, as well as the forecast of Other Revenue. Consistent with the forecasting process followed by FEI for its other service areas, the forecast demand is comprised of three main components:

- Customer additions (account) forecast;
- Average use per customer (UPC) forecast; and
- Industrial Forecast.

The residential and commercial energy forecast, consisting of customers served under Rate Schedules 1, 2.1, and 2.2[13], is driven by the respective account and use per customer forecasts. Consistent with the methodology used across the other service areas for FEI, the average use per customer is estimated for customers served under Rate Schedules 1, 2.1, and 2.2 and then is multiplied by the corresponding forecast of customers in each rate class to derive energy consumption.

The industrial energy forecast reflects the forecast demand based on survey results from the one remaining FEFN industrial customer which is served at two locations under Rate Schedule 25.

Current approved rates (i.e. 2014 rates) are applied against the energy forecast to calculate the forecast at existing rates. The cost of gas is subtracted from this forecast revenue to calculate the delivery margin (also referred to as gross margin), which is used as part of the calculation of the revenue deficiency for the Test Period

The Other Revenue components are primarily comprised of revenue for service work (connection charges) and late payment charges. Revenue for service work is $25 for customer additions and account transfers and late payment charges have been forecast based on 2013 actual data.

The following subsections discuss the components of the demand forecast and the calculation of revenue at existing rates, the gross margin and Other Revenue.

[13] Rate Schedule 1 represents Residential customers. Rate Schedules 2.1 and 2.2 are both Commercial customer rate schedules (with the same applicable delivery rates) and the delineation between Rate Schedule 2.1 and 2.2 is based on an annual demand of 6,000 GJs. Rate Schedule 25 is for large volume firm transportation customers.

3.2 CUSTOMER ADDITIONS

The forecast of customer accounts is the first component of determining the total energy demand.

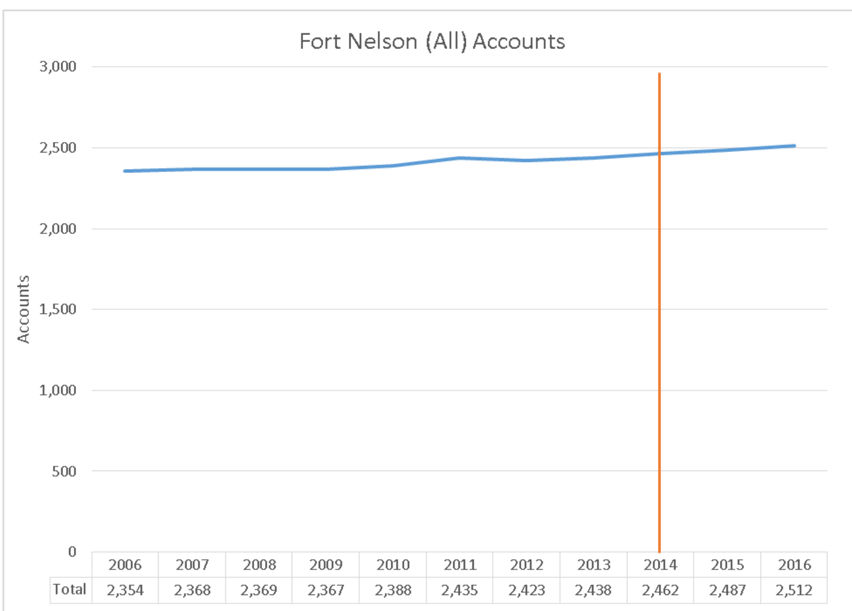
The Conference Board of Canada (CBOC) housing starts forecast provides a proxy for Fort Nelson's residential customer additions. Year over year growth rate is calculated for 2014 and 2015 based on the CBOC Provincial Medium Term forecast as of December 6, 2013.[14] The 2014 single family dwelling growth rate is -1%, while the 2015 rate is 9% and the 2016 rate is 2%.

The commercial additions forecast is based on the average of the actual additions over the last 3 years for which a full year of actual data is available (i.e. 2011 to 2013).

The industrial customer base in FEFN is limited to a single customer and that is not forecast to change during the Test Period.

As shown in Figures 3-1 to 3-3 below, the total number of customers has grown slowly in both residential and commercial segments[15]. Based on the forecast methods discussed above, the level of growth experienced recently is forecast to continue.

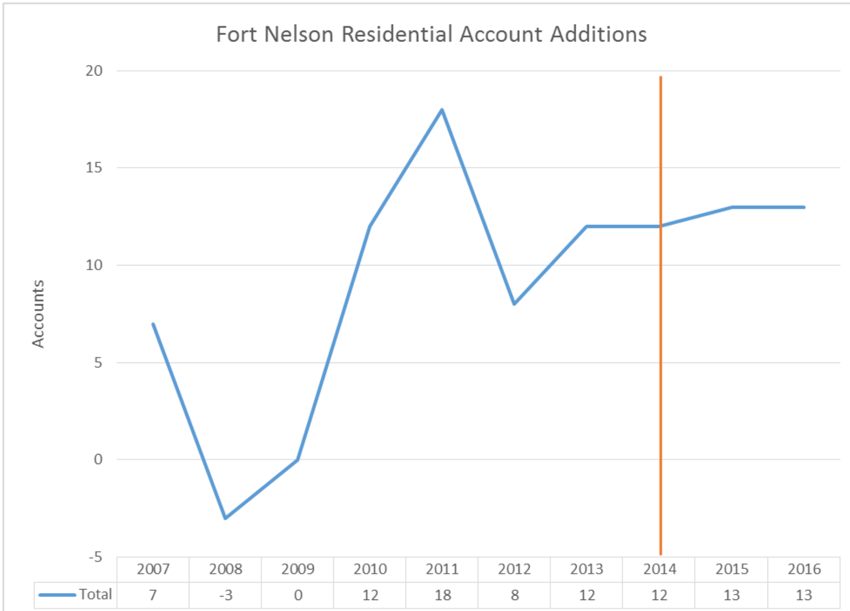
Figure 3-1: Total Customers



As shown in Figure 3-2 below, the residential customer additions in FEFN have been minimal since 2007. In 2013 there were 12 net additions. Based on the CBOC housing starts forecast, additions at this level are forecast for the Test Period.

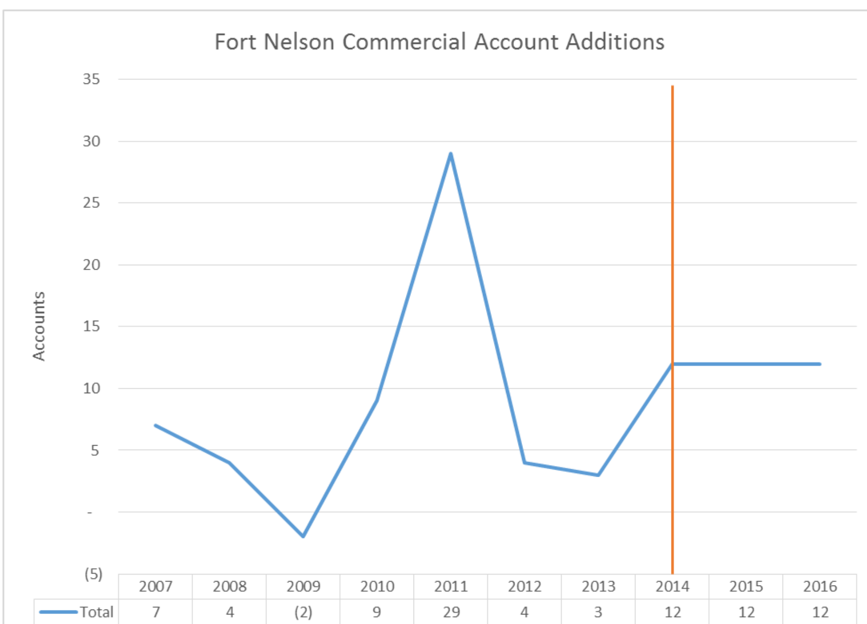
[14] Table 156: HOUSING STARTS: SINGLES (UNITS).
[15] 2014 data in the figures represents projected average customers.

Figure 3-2: Residential Customer Additions



Small Commercial customer additions since 2007 are shown in Figure 3-3 below. The forecast commercial customer additions in Figure 3-3 are based on the three-year historical average 2010 to 2013.

Figure 3-3: Commercial Customer Additions

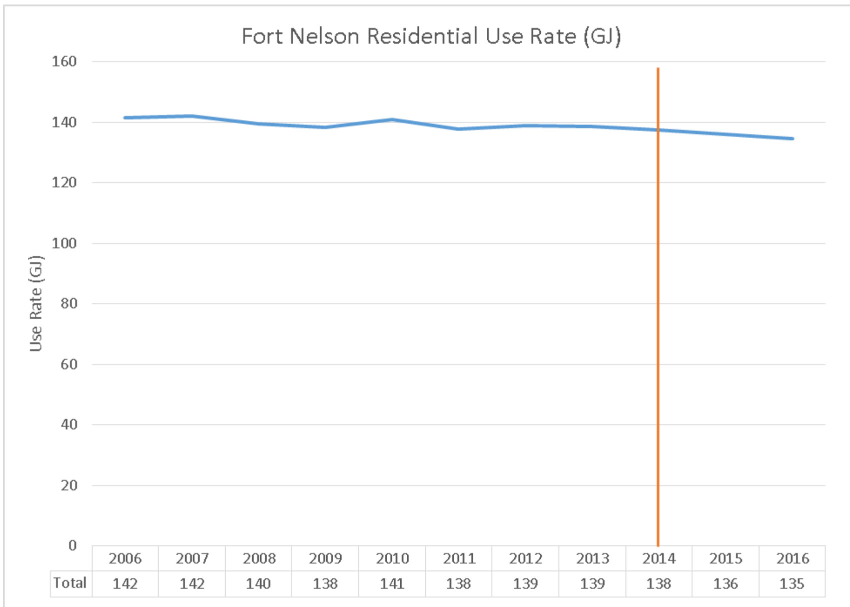


3.3 *USE RATES (RESIDENTIAL AND COMMERCIAL CUSTOMERS)*

Individual UPC projections are developed for each rate class by considering the recent (three year) historical weather-normalized use per account.

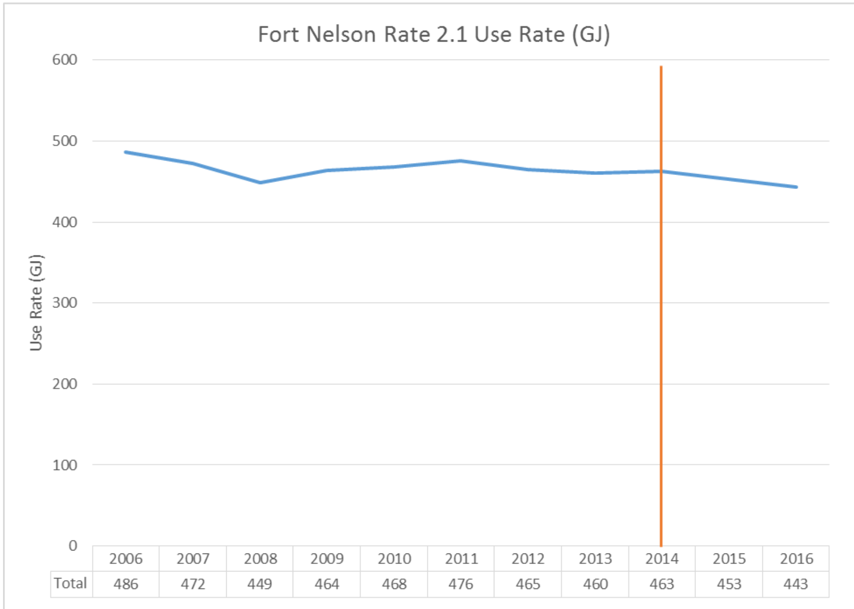
The Rate Schedule 1 UPC is forecast to decline through the Test Period as seen in Figure 3-4 below.

Figure 3-4: Residential UPC for Rate Schedule 1



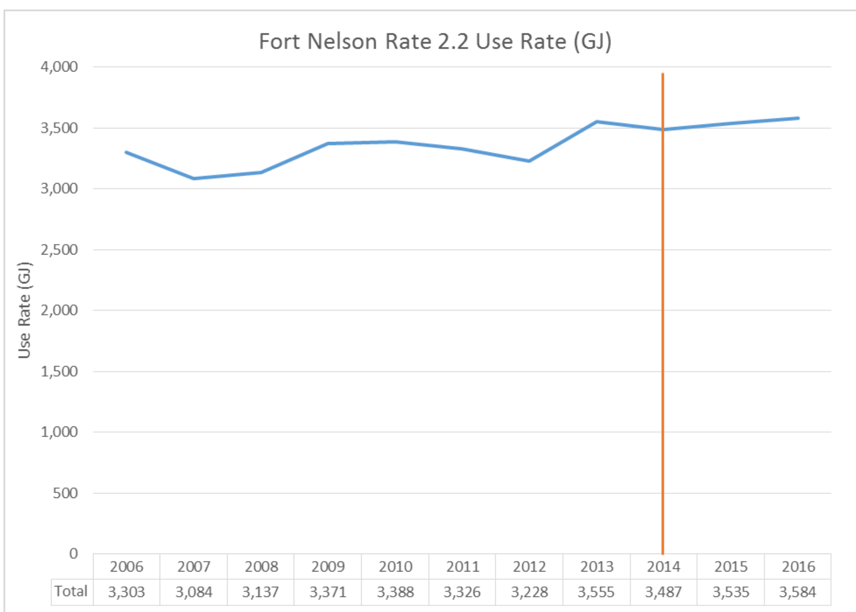
Rate Schedule 2.1 UPC has declined in recent years as seen in Figure 3-5 below. This trend is forecast to continue throughout the Test Period.

Figure 3-5: Commercial UPC for Rate Schedule 2.1



Rate Schedule 2.2 UPC is showing an increase in recent years as seen in Figure 3-6 below. The forecast continues the trend through the Test Period.

Figure 3-6: Commercial UPC for Rate Schedule 2.2

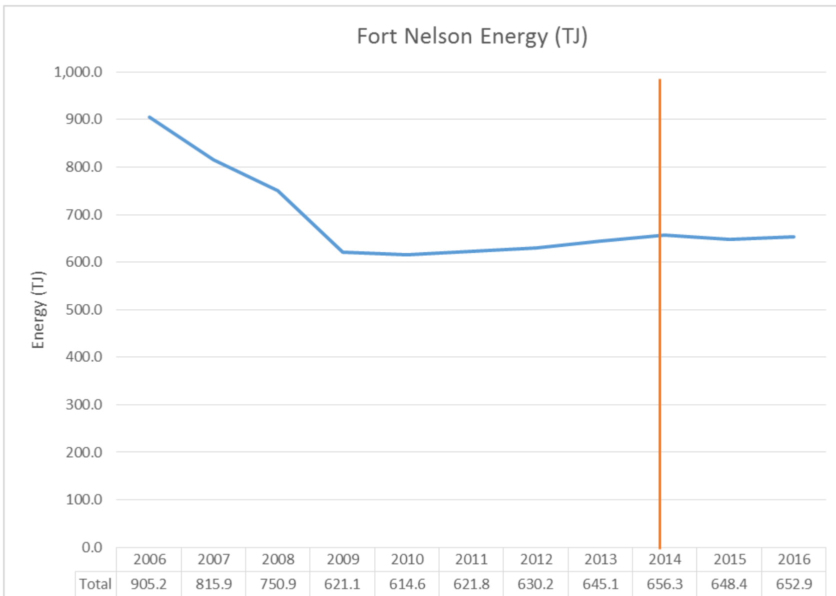


3.4 *DEMAND FORECAST*

The energy demand forecast for each residential and commercial rate class is derived by applying the total forecast customers, including customer additions, to the average UPC forecast for each rate class. As discussed below, the future forecast of energy demand from FEFN's remaining industrial customer is based on its response to the annual industrial survey. The total forecast energy demand is the sum of the energy for the individual rate classes.

The following Figure 3-7 illustrates the total historical and forecast normalized energy demand over the period 2006 to 2016. FEFN is forecasting a slight decrease in total energy demand for 2015 and 2016 as compared to 2014 projected demand. Additionally, the total energy demand for 2015 and 2016 represents a slight decrease as compared to the energy demand embedded in existing rates.[16]

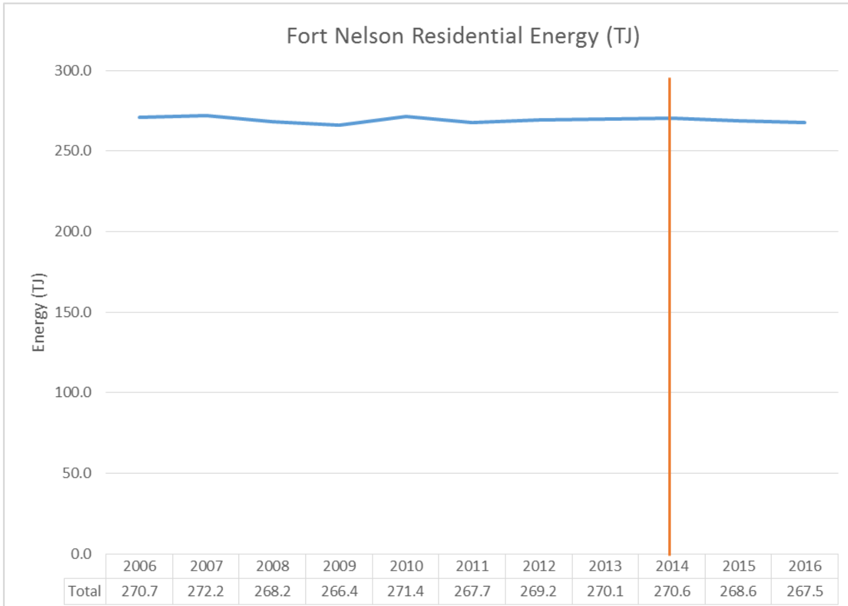
Figure 3-7: Total Energy Demand



As seen in Figure 3-8 below, the modest increase in the number Rate Schedule 1 customers is more than offset by the declining use rate, so a slight decrease in overall residential demand is forecast.

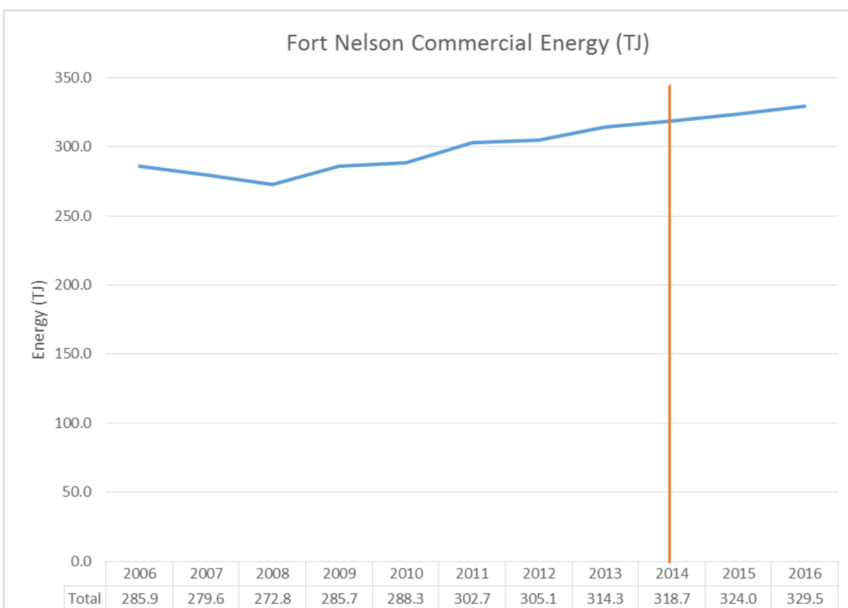
[16] Approved 2014 total energy demand of 654 TJs (Schedule 7, Column 4, Row 13).

Figure 3-8: Residential Energy Demand



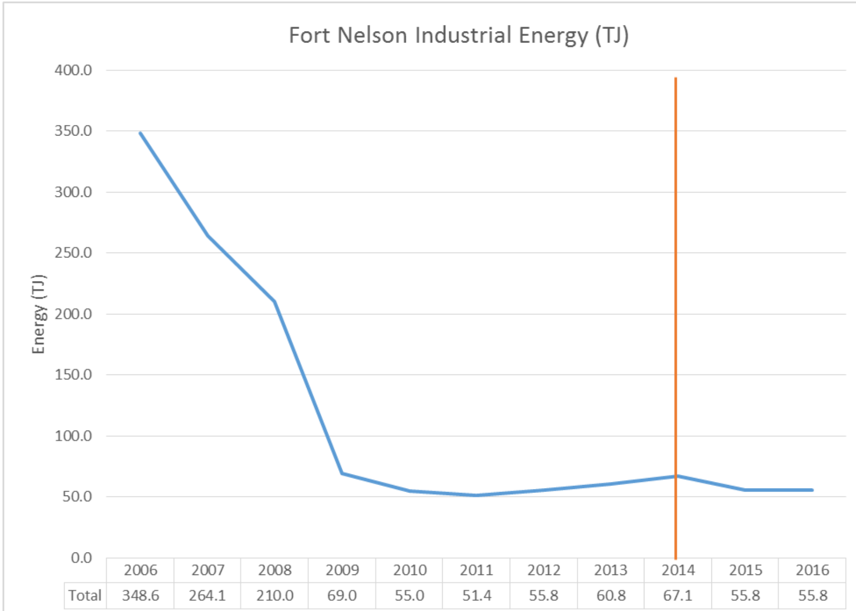
As seen in Figure 3-9 below, the increase in commercial volume is the result of stable customer growth coupled with an increasing use rate for Rate Schedule 2.2 customers.

Figure 3-9: Commercial Energy Demand



FEI has only one Industrial customer served under FEFN's Rate Schedule 25. In 2008, this customer's two facilities in Fort Nelson were closed and now only consume gas to heat the facilities. The future forecast of energy demand is based on the industrial customer's response to the annual industrial survey which indicates that the two plants will only maintain heat load consumption over the Test Period. The Industrial Energy Demand is seen in Figure 3-10 below.

Figure 3-10: Industrial Energy Demand



3.5 REVENUE AND DELIVERY MARGIN FORECAST

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEFN has developed its forecast of revenues by applying the total energy forecast to the currently approved rates for each customer segment.

Table 3-1 below summarizes the revenues projected for 2014 and forecast for 2015 and 2016, based on the currently approved 2014 rates.

Table 3-1: Forecast Sales Revenue[17]

Revenue ($ thousands)	2013A	2014P	2015F	2016F
FORT NELSON				
Residential[1]	1,767	1,793	1,917	1,911
Commercial[2]	2,156	2,209	2,407	2,449
Industrial[3]	161	174	150	150
Grand Total	**4,084**	**4,176**	**4,474**	**4,509**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2
3. Rate Schedule 25

[17] The cost of gas was lower in 2014 as compared to 2015, and this is reflected in the increased residential revenue in 2015. That is, on a total revenue basis, although the overall demand is lower in 2015, the increase in the cost of gas in 2015 as compared to 2014 offsets the UPC decline between 2014 to 2015.

The delivery margin is the forecast of revenues at existing approved rates, minus the cost of natural gas. Table 3-2 below summarizes the delivery margin projected for 2014 and forecast for 2015 and 2016, by customer segment, at 2014 approved rates.

Table 3-2: Forecast Delivery Margin

Margin ($ thousands)	2013A	2014P	2015F	2016F
FORT NELSON				
Residential[1]	807	778	773	771
Commercial[2]	1,040	1,010	1,027	1,046
Industrial[3]	160	174	149	149
Grand Total	**2,007**	**1,962**	**1,950**	**1,966**

Notes:
1. Rate Schedule 1
2. Rate Schedules 2.1, 2.2
3. Rate Schedule 25

3.6 *OTHER REVENUE*

There are three components of Other Revenue, as shown in Section 9, Schedule 18-20, lines 3-7:

- Late Payment Charges;
- Revenue from Service Work (primarily connection charges and transfer fees); and
- Other (primarily non-sufficient funds cheque administration fees).

The Other Revenue components are primarily comprised of revenue for service work (connection charges) and late payment charges. Revenue for service work is $25 for customer additions and account transfers and late payment charges have been forecast based on 2013 actual data. As such, and as shown in Schedule 19 and Schedule 20 (Lines 3 and 5), the forecast for the Test Period is consistent with the 2014 projected results.

Please note that the Muskwa Cost of Service line item included in Other Revenue in the financial schedules is for accounting purposes only and reflects the credit to the cost of service for depreciation, earned return and tax amounts embedded in 2014 delivery rates related to the Muskwa Project prior to the actual addition to rate base. The amount shown in Section 9, Schedules 18-20, line 14 represents the addition to the deferral account for refund to customers, as shown in Section 9, Schedule 66, line 8.

4. COST OF GAS

It is important to note that this Application only seeks approval of FEFN delivery rates and that the actual cost of gas is flowed through to customers through existing deferral accounts approved by the Commission. Although FEI is not requesting approval of forecast gas costs with this Application, forecast gas costs, including unaccounted for gas (UAF) estimates, are required in the determination of the gas cost reconciliation account (GCRA) forecasts which are included in deferred charges.

The forecast cost of gas sold is determined by multiplying forecast sales volumes by the approved gas cost recovery charge for each rate schedule. The gas cost recovery charge embedded within rates is based on the forecast gas costs for the next 12-month period, including the current balance within the GCRA. As the actual commodity costs invariably differ from the forecast costs, consistent with past practice, any differences between the costs incurred to purchase gas and the gas cost recoveries collected through rates will continue to be collected in the GCRA.

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use; UAF includes measurement variances and cannot be projected with precision. Consistent with past practice, the UAF percentages are calculated based on the historical five-year rolling average UAF percentage for FEFN. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered via the gas cost recovery charge, whereas the cost of UAF related to the Transportation Service Rate Schedule 25 is included in the determination of the delivery rates.

The FEFN gas cost recovery charge is the same for all sales rate classes.

The current gas cost recovery charge is $4.259 per GJ, approved by Commission Order G-135-14, dated September 12, 2014 and effective October 1, 2014. The 2014 Fourth Quarter Gas Cost Report for Fort Nelson, filed on November 5, 2014, recommended the gas cost recovery rate remain unchanged at January 1, 2015; Commission Letter L-60-15, dated November 13, 2014 accepted the Company's recommendation.

The GCRA balance at the end of 2014, net of tax, is projected to be a deficit of approximately $118 thousand, with no remaining balance at the end of 2015.

Consistent with established Commission practice, FEI will continue to review and report on the gas costs and the gas cost recovery rates for FEFN on a quarterly basis and, as necessary, will make application for any rate changes to recover the cost of gas.

5. OPERATING AND MAINTENANCE EXPENSES

5.1 INTRODUCTION

FEFN has forecast its operating and maintenance expenses (O&M) for 2015 and 2016 as part of determining its revenue requirements. The O&M expenses included in this Application are required to continue to serve customers in a safe and efficient manner.

5.2 DETERMINATION OF O&M

To determine the FEFN-related total O&M costs, both actual and forecast, the following process is used:

1. Determine the FEFN direct O&M costs. These costs consist of labour for the two employees noted below, vehicle usage, and materials and services used in direct system operations.
2. Allocate O&M costs from those FEI departments that provide functional support to FEFN. These shared services costs would include charges related to Information Systems, Energy Supply and Resource Development, Transmission, Customer Service, Energy Solutions and External Relations, Engineering Services, Finance and Regulatory, Operations Support, Governance, Human Resources and Corporate.

   Up to and including 2007, the allocation factor used to allocate these costs was FEFN's sales volumes as a percentage of FEI's sales volumes. The resulting allocation factor of 0.4% was used to determine the FEFN portion of the Shared Services for these years.

   Effective 2008, by Commission Order G-27-08, in respect of the FEFN 2008 Revenue Requirements Application, the Commission approved the use of customers served as the allocation factor, stating:

   > "*Shared Services received by TG Fort Nelson from TGI for 2008 are to be allocated to the Company on the basis of customers…*"

   The Shared Services allocation was therefore based upon the 2008 projection of total customers served by FEI of 829,970 and by FEFN of 2,341.[18] The calculation resulted in an allocation factor of 0.3% which was used for rates from 2008 through 2013 and including the 2014 Projection.

   The 2015 proposed rates use the same methodology as approved in Order G-27-08. Based on the 2015 forecast average number of customers for FEI, FEVI, FEW and FEFN of 952,655 and FEFN of only 2,459 (Section 9, Schedule 14, Line 14), respectively, the allocation factor is 0.257%. The reduction in the allocation factor

[18] Refer to the 2008 Revenue Requirements Application, Response to Commission Information Request No. 2, Question 22.2.

compared to 2014 is due to including FEVI and FEW customers in the total customers for FEI (due to the amalgamation of the three utilities effective December 31, 2014). As noted above, this is offset by a larger pool of O&M costs due to the inclusion of FEVI and FEW O&M. The new allocation factor of 0.257% has been used for 2015 and 2016 proposed rates.

Finally, the 2015 and 2016 O&M costs used in the allocation reflect a forecast gross O&M for FEI for 2015 and 2016 that takes into consideration the formula drivers approved under the PBR as well as a forecast of the O&M items that are excluded from the formula calculation. In consideration of the fact that the 2015 and 2016 O&M for FEI has not yet been approved by the Commission, FEFN proposes that any variation in the allocated O&M to FEFN that results from the approval of the FEI O&M is accounted for in the existing Fort Nelson Revenue Surplus/Deficit Account and to be refunded or collected from customers in future years. It should be noted that due to the small allocation factor, FEFN does not expect that changes to the forecast FEI O&M for the Test Period that may occur will have a significant impact on the forecast FEFN O&M. For example, to achieve a delivery rate change of approximately 1%, an approximate change of $20 thousand is required to the O&M allocated to FEFN. An allocation of $20 thousand to FEFN equates to a change in the FEI O&M of approximately $7,800 thousand.[19] As such, FEFN believes that the forecast provided in Table 5-1 below reflects a reasonable forecast of O&M to determine the delivery rates for FEFN for the Test Period.

3. An overhead capitalization rate is then applied to the sum of the direct and allocated O&M costs. As a result of the PBR Decision, the allowed overhead capitalization rate has been decreased from 14 to 12 percent. Due to the decrease in the capitalization rate, the net O&M increased for 2015 & 2016 as compared to what was approved for 2014, adding to the revenue deficiencies.

Table 5-1 below provides a combined resource view of the direct and allocated O&M costs for 2013 actual, along with the 2014 year-end projection and 2015 and 2016 forecasts. The O&M forecasts for 2015 and 2016 were determined in accordance with the methodology described above.

[19] Calculation is for illustrative purposes only and does not take into account the impact of capitalized overhead

Table 5-1: O&M Resources Required for FEFN ($ thousands)[20]

Particulars	2013 Approved	2013 Actual	2014 Projected	2015 Forecast	2016 Forecast
M&E Costs	$ 32	$ 30	$ 15	$ 15	$ 15
COPE Costs	-	1	-	-	-
COPE Customer Services Costs	-	-	-	-	-
IBEW Costs	270	289	324	334	344
Labour Costs	**302**	**321**	**339**	**349**	**359**
Vehicle Costs	47	43	43	43	44
Employee Expenses	11	14	18	29	29
Materials and Supplies	4	74	1	1	1
Computer Costs	0	-	-	-	-
Fees and Administration Costs	512	514	506	540	551
Contractor Costs	9	201	5	5	5
Facilities	11	18	36	37	37
Recoveries & Revenue	(2)	(2)	(2)	(2)	(2)
Non-Labour Costs	**592**	**862**	**606**	**652**	**665**
Total Gross O&M Expenses	**894**	**1,183**	**945**	**1,001**	**1,024**
Less: Capitalized Overhead	(125)	(125)	(113)	(120)	(123)
Total O&M Expenses	**$ 769**	**$ 1,058**	**$ 831**	**$ 881**	**$ 901**

Major changes in Gross O&M line items are discussed below:

Total Labour costs – Operations staffing at FEFN includes two full-time IBEW employees supported periodically by specialized pressure control technicians, management and clerical staff in Prince George. Operations costs are primarily IBEW field costs incurred in routine operations and maintenance activities (station checks, meter exchanges, odour calls, customer service, leak survey and repairs, etc). Increased pension/benefits costs are the primary driver of the 2014 labour increases. Forecasted wage increases included in the 2015 and 2016 labour forecasts are 2% based on the recent signing of a four year IBEW contract. A portion of the Prince George Operations management team salary is allocated to FEFN based on the level of support provided for management oversight of operation, maintenance, and recurring capital activities (i.e. mains, services).

Employee Expenses - These expenses are forecast to be higher in the Test Period owing to the Prince George Operations management team anticipating additional trips to FEFN to provide oversight for O&M and capital activities. As discussed below, there are capital projects forecast for FEFN over the period which will require operating and project management oversight.

Facilities - These are costs to operate and maintain the local office including janitorial and telephone services as well as line heater fuel for the distribution station. The communication

[20] HST savings in 2010 are included for comparative purposes only and have no impact on 2010 Service Rates.

costs and line heater fuel costs were previously centralized in FEI and were not allocated to FEFN. FEI has since identified these amounts as direct FEFN costs and accordingly included these in the FEFN O&M forecast.

Fees and Administration Costs – the 2015 forecast includes $537 thousand in the shared services fee which is an increase of $34 thousand from the 2014 Projection of $503 thousand. The 2016 forecast includes $548 thousand in the shared services fee, representing a further $11 thousand increase in 2016. While the allocation factor decreased from 0.3% to 0.257%, the fee increased due to the inclusion of FEVI and FEW O&M in the allocation base.

The above pressures, combined with customer growth, result in an increase in Gross O&M. When adjusted for inflation, the 2015 O&M per customer shows an increase of $15 per customer over 2014 ($402 vs. $387) and the 2016 O&M per customer shows an increase of $10 per customer over 2014 ($397 vs $387) . Table 5-2 below shows the calculations.

Table 5-2: Gross O&M per Customers[21]

	2014	2015	2016
Total Gross O&M Expenses ($'000's)	945	1,001	1,024
Average Number of Customers	2,445	2,459	2,484
Inflation Rate	1.460%	1.303%	2.417%
Gross O&M per Customer	$ 387	$ 407	$ 412
O&M in 2014 Dollars	$ 387	$ 402	$ 397

5.3 SUMMARY

FEFN believes that the forecast amounts of O&M for the years 2015 and 2016 as included in this Application take into consideration the planned and required activities and appropriate forecasting methodologies for those years. They are required to continue to operate the FEFN natural gas distribution system and to meet the needs of customers.

[21] CPI/AWE inflation rate used for 2014, 2015 & 2016

6. TAXES

6.1 *INTRODUCTION*

In carrying out its mandate as an energy service provider, FEI incurs taxes that are imposed by different government bodies. FEI manages these expenditures through the tax audit process and various tax planning strategies, as well as ongoing compliance activities. The tax expenses included in this Application reflect the current enacted tax legislation which was applied in calculating the forecasted revenue requirement for the Company.

6.2 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments, and as such appropriately includes these costs in calculating FEFN's revenue requirements. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with Commission approved past practice, at the corporate tax rate of 26 percent. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation.

As approved by Commission Order G-53-94, deferred charges, to the extent they are tax deductible, and deferred credits, to the extent they are taxable, are treated on a net-of-tax basis. Under the net-of-tax method, the gross addition to a deferral account is offset by the tax savings or tax cost (as the case may be) calculated at the prevailing income tax rate for the current year.

6.3 *PROPERTY TAX*

Details of 2013 property tax expense and the forecasts for 2014 through 2016 can be found in Table 6-1 below.

Over the period 2014 to 2016, property taxes are forecast to increase between 1.0 percent and 2.1 percent per year, primarily due to changes in revenues from gas expected to be consumed within the municipality, increases to assessed property values from normal construction activities, market value increases and changes in tax policies of local taxing authorities.

Table 6-1: Property Tax Expense ($000)

Asset Type	Approved 2013	Actual 2013	Approved 2014	Projected 2014	Forecast 2015	Forecast 2016
Distribution Assets	104.4	74.7	81.9	55.1	58.6	59.1
Transmission Assets	1.3	0.4	0.4	0.4	0.4	0.4
General Assets	14.9	18.2	19.9	18.0	18.2	18.3
In-Lieu	54.9	40.4	39.2	39.2	37.9	38.4
OGC Fees	2.5	1.4	2.5	1.4	1.5	1.5
	178	135	144	114	117	118
Forecast Change ($000)					$ 3	$ 1
Forecast Percent Change					2.63%	0.98%

6.3.1 Property Tax Forecasts

Property taxes for 2015 and 2016 use Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within the municipality. Consistent with past practice, variances between the property tax amounts forecast in rates and actual amounts paid are captured in the Property Tax Variance account and returned to or recovered from customers over the following three years.

6.3.2 Assessment Policy

Assessment policy is set out in Provincial legislation under the Assessment Act and is primarily concerned with valuation principles and methodologies as well as classification of properties for taxation purposes. Valuations of utility properties are highly dependent on legislated manuals and rates to determine market values.

FEI is required to report assessable additions annually to BC Assessment.

Property assessment values for the current tax year reflect the market value at July 1 of the previous year based on the state and condition of the property at October 31 of that year.

6.3.3 Tax Policy

Tax policy is applied by various taxing authorities under their legislated authority and determines how their budgets will be distributed to various classes of properties through the property tax. Property tax payable by FEI on behalf of FEFN is categorized into four (4) general categories of taxes as follows:

1. General Taxes: These are typically levied directly by the primary taxation authority and include municipalities, First Nations and the Surveyor of Taxes for rural areas.
2. School Taxes: These are levied directly by the Province.
3. Other Taxes: These include all taxes levied by other taxation authorities and include levies for BC Assessment, Municipal Finance Authority, Regional Districts, Hospital Districts, etc.
4. Taxes Based on Revenues: Section 353 of the Local Government Act require "utility companies" to pay a portion (1.0 percent) of revenues in lieu of taxes that would otherwise be paid on improvements specified in legislation other than buildings. For FEFN, revenues only include those earned from gas consumed within the specific municipality.

6.4 *CARBON TAX*

The Carbon Tax represents a cost to FEI on its own consumption of fuel to operate line heaters, motor vehicles and space heating for FEFN. The Carbon Tax rate applicable to natural gas since July 1, 2012 is $1.49 per GJ. There are no further announced increases beyond this date.

The estimated cost to FEFN with respect to Carbon Tax on own-use fuel is embedded in O&M and capital.

6.5 PROVINCIAL SALES TAX, INNOVATIVE CLEAN ENERGY (ICE) LEVY, AND GOODS AND SERVICES TAX

Effective April 1, 2013, the Province of BC has returned to a commodity tax regime of BC Provincial Sales Tax (PST) and federal Goods and Services Tax (GST).

The PST is a tax of 7 percent on purchases of tangible property and certain services that the Company uses in its operations. The ICE Levy of 0.4 percent on purchases of energy, including natural gas, was also reinstated effective April 1, 2013. PST and ICE Levy paid by FEI on behalf of FEFN are not recoverable from the government and therefore represent a net cost to the Company, which can vary widely based on the level of purchases and capital expenditures. This cost is embedded in capital and O&M depending on the nature of the property or services acquired.

The GST is a federal commodity tax eligible on goods and services at a rate of 5 percent. FEI, as a GST registrant, is entitled to recover virtually all of the GST it pays on its taxable purchases of goods and services from the government. As such, the tax does not represent a net cost to the Company.

6.6 SUMMARY

FEI will continue to incur income taxes, property taxes and other taxes that are imposed by different government bodies on behalf of FEFN. The Company manages these expenditures through ongoing compliance activities, as well as through the tax audit process and various tax planning strategies. The tax expenses included in this Application reflect the current enacted tax legislation that has been applied in calculating forecasts for FEFN.

7. RATE BASE AND CAPITAL EXPENDITURES

7.1 *INTRODUCTION*

The 2015 and 2016 rate base amounts of $11,744 thousand and $12,170 thousand respectively, as determined in Section 9, Schedules 41 and 42, represents the mid-year average rate base which reflects the investment by the Company in utility assets necessary to provide service to our customers in FEFN.

The table below sets out FEFN's 2013 through 2016 rate base.

Table 7-1: Rate Base (amounts in $000s)

	Approved 2013	Actual 2013	Projected 2014	Forecast 2015	Forecast 2016
Net Plant in Service, Mid-Year	9,412	5,744	6,032	9,194	11,902
Adjustment to 13 - Month Average	-	(177)	-	2,105	-
Work in Progress, No AFUDC	-	62	35	35	35
Unamortized Deferred Charges	19	(283)	(393)	372	195
Cash Working Capital	9	(2)	10	24	24
Other Working Capital	4	14	14	14	14
Utility Rate Base	$ 9,444	$ 5,358	$ 5,698	$ 11,744	$ 12,170

The growth in rate base for the forecast period is largely attributable to the Muskwa River Crossing Project. Each of the main components of rate base (plant balances, deferral accounts, and working capital) is discussed separately below.

7.2 *NET PLANT IN-SERVICE (NPIS)*

The mid-year NPIS balance of $9,194 thousand in 2015 and $11,902 thousand in 2016 per Table 7-1 above is the sum of the mid-year average of the gross plant in-service, contributions in aid of construction (CIAC), and accumulated depreciation and amortization related to these two items.

7.2.1 Gross Plant In-Service (GPIS)

The ending GPIS balance of $10,619 thousand in 2014, Section 9, Schedule 40, Line 3 is made up of opening GPIS plus plant additions, less retirements. Plant additions are comprised of capital expenditures adjusted for opening and closing work in progress (WIP), plus allowance for funds used during construction and overheads capitalized, where applicable. A description of the major changes in plant additions over the years 2014 to 2016 follows.

Table 7-2 below summarizes FEFN's plant additions for each of 2013 Approved and Actual, 2014 Projection, and 2015 and 2016 Forecast, excluding the Muskwa River Crossing Project.

Table 7-2: Summary of Gross Plant Additions, excluding Muskwa River Crossing Project ($000s)

	Approved 2013	Actual 2013	Projected 2014	Forecast 2015	Forecast 2016
INTANGIBLE PLANT	-	64	62	62	62
TRANSMISSION PLANT	10	20	601	845	63
DITRIBUTION PLANT	256	229	381	449	119
GENERAL PLANT	10	75	61	204	76
TOTAL ADDITIONS	$ 276	$ 389	$ 1,105	$ 1,560	$ 320

A description of the major changes in plant additions over the years 2013 to 2016 follows.

Transmission Plant - Mains

As discussed earlier, the significant addition of $4,210 thousand to transmission plant in 2015 (Schedule 48, Column 3, Row 7) is the replacement of a section of pipeline across the Muskwa River on the southeast side of Fort Nelson. As approved by the Commission in Order C-2-14 on January 30, 2014, FEI replaced the existing in-stream pipeline crossing with a new pipeline crossing installed by Horizontal Directional Drilling.

The large forecast additions to transmission plant in 2015 are related to:

- an updated right-of-way agreement with the Fort Nelson First Nations for the transmission pipelines located within their lands ($410 thousand) is required to replace and supersede old expired agreements;
- the replacement of a complex valve assembly due to non-operable valves as a result of wear and age ($210 thousand);
- the replacement of the pipeline across a road to ensure code compliance and maintain the existing operating pressure in the pipeline ($150 thousand); and
- the installation of protection over the pipeline within a creek as the pipeline is nearly exposed ($75 thousand).

These capital additions are forecast to be completed in 2015.

Distribution Plant

The component of growth related distribution capital (new mains, new services, and new meters) additions forecast for the Test Period are consistent with 2014 projected amounts.

Growth capital investments are incurred to install gas mains, services and meters to attach new customers. Over the past few years, new services activity has been between 25 and 35 services annually; however, new mains activity has been minimal. Similar activity levels are expected for the Test Period.

The other forecast additions to distribution plant in the Test Period are related to:

- the forecast installation of telemetry at the Fort Nelson Gate Station to better monitor operating conditions and to ensure reliability ($70 thousand);
- the forecast alterations to the distribution system and increase in operating pressure to increase the gas supply to the airport due to increased demand at the airport ($85 thousand); and,
- a distribution capacity system improvement is required to increase the tail end pressure to ensure adequate supply to customers ($60 thousand).

Similar to the Transmission capital additions, these three distribution plant additions are forecast to be completed in 2015.

General Plant

The large addition in 2015 in General Plant is related to the replacement of the septic system at FEI's Fort Nelson office ($153 thousand). The current system has recently failed and is being managed by a temporary portable toilet. A permanent solution is required because this temporary solution does not meet BC Building Code and WorkSafe BC regulation.

FEI is currently investigating options of replacement of the septic system. There are two options for a permanent solution: 1) replace with a new septic system and field (septic field option) and 2) a connection to the City of Fort Nelson sewer system which has recently been extended closer to the property. The capital cost of both options is approximately the same.

Since FEI has not yet selected a chosen option, the forecast addition has been based on a recent office sewer connection for a similar FortisBC Inc. property. Final selection of the option will be dependent on preliminary engineering design requirements and asset lifecycle and will be implemented in 2015 to ensure a safe and healthy workplace and compliance with building code regulations.

7.2.2 Contributions in Aid of Construction (CIAC)

Gross CIAC is composed of opening contributions plus additions and less retirements throughout the year. There are no CIAC additions forecast for 2015 and 2016, and as such the year end CIAC amounts of $1.3 million in 2015 and $1.3 million in 2016 (Section 9 Schedule 42 Line 11) are unchanged from the 2013 ending balance.[22]

7.2.3 Accumulated Depreciation

The depreciation rates used for 2015 and 2016 are the FEI depreciation rates embedded in the delivery rates approved by Commission Order G-178-14. In the past FEFN depreciation rates have been equal to those of FEI. Upon amalgamation, the depreciation rates for FEI Amalgamated are assumed to be the weighted average of FEI, FEVI and FEW. Starting in 2015, FEFN's depreciation rates will assume those of the FEI amalgamated entity. Depreciation for 2015 and 2016 has been calculated starting January 1 of the year after the assets are placed in service, which is the treatment approved in the PBR Decision.

The rate base of FEFN includes both the accumulated depreciation of plant in service, and accumulated amortization of CIAC. Both are increased through depreciation or amortization expense, and decreased through retirements.

7.3 WORK IN PROGRESS

Consistent with past practice, Work in Progress included in Rate Base represents construction work in progress for projects that are shorter than three months in duration and less than $50 thousand. Projects over this threshold attract AFUDC, and are not included in rate base until they are available for use, at which time AFUDC is no longer charged to the capital project.

7.4 DEFERRAL ACCOUNTS

The mid-year balances of the deferral accounts included in rate base are provided in Table 7-3 below.

[22] Historically, FEFN CIAC additions have been minimal in dollar value and are difficult to predict.

Table 7-3: Deferral Balances included in Rate Base ($000s)

	Approved 2013	Actual 2013	Projection 2014	Forecast 2015	Forecast 2016
Margin Related					
Revenue Stabilization Adjustment Mechanism (RSAM)	(26)	76	47	28	9
Interest on CCRA/MCRA/RSAM/Gas in Storage	1	(2)	(2)	-	-
Gas Cost Reconciliation Account (GCRA)	(0)	(84)	(3)	59	-
Energy Policy Deferral Accounts					
Non-Controllable Items Deferral Accounts					
Property Tax Deferral	(1)	(31)	(50)	(42)	(19)
Interest Variance	(14)	(49)	(63)	(47)	(26)
Customer Service Variance Account	-	(54)	(72)	(58)	(42)
Application Costs Deferral Accounts					
Generic Cost of Capital Application	-	-	6	3	0
2015-2016 Revenue Requirement Application	-	-	-	13	9
Other Deferral Accounts					
Gains and Losses on Asset Disposition	92	108	116	111	104
Negative Salvage Provision/Cost	-	31	18	(24)	(67)
Muskwa River Crossing COS	-	(182)	(310)	(289)	(173)
Fort Nelson Revenue Surplus/Deficit Account	(32)	(47)	(42)	(28)	-
Muskwa River Crossing Project Costs	-	-	-	679	407
Residual Deferred Accounts					
Depreciation Variance	-	(51)	(39)	(22)	-
2012-2013 Revenue Requirement Application	1	3	1	-	-
Fort Nelson ROE and Capital Structure Deferral	(1)	(1)	(1)	-	-
Total Mid-Year Deferred Charges in Rate Base	19	(283)	(393)	383	203

The section below includes a discussion on new rate base deferral accounts and changes to or discontinuation of existing rate base deferral accounts.

7.4.1 New Deferral Accounts

FEFN is proposing to create one new deferral account to address the costs of the present Application.

2015-2016 Revenue Requirement Application

FEFN will incur costs in 2014 and 2015 related to the 2015 and 2016 Revenue Requirements and Rates Application of approximately $50 thousand (on a pre-tax basis). Costs incurred will consist of legal fees, intervener and participant funding costs, Commission costs, required public notifications, and miscellaneous facilities, stationery and supplies costs. Consistent with past practice, FEFN requests approval to capture the full costs of this Application in this account and to amortize these costs over two years, in 2015 and 2016, which represents the period covered by this Application. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates in 2017.

7.4.2 Changes to Existing Deferral Accounts

FEFN is proposing alterations to the account discussed below.

Fort Nelson Revenue Surplus/Deficit Account

As approved through Commission Order G-75-13, the Fort Nelson Revenue Surplus/Deficit Account was used to capture the impact of the 2013 GCOC Stage 1 Decision for changes in equity thickness and ROE when compared to then-existing approved 2013 rates. The 2013 after-tax addition to the deferral account was a credit of $28 thousand.

Additionally, as approved in the 2014 Fort Nelson Request for Deferral Account Treatment through Commission Order G-17-14, this account is being used to capture the actual realized revenue surplus or deficiency in 2014. As reflected in the attached financial schedules, FEFN is currently forecasting revenues of $4,204 thousand and costs of $4,167 thousand in 2014 which result in a forecasted pre-tax surplus of $37 thousand ($27 thousand after-tax). This amount has been added to the deferral account balance in 2014 in the attached financial schedules, for a total ending 2014 after-tax credit balance of $55 thousand, $28 thousand related to the GCOC Stage 1 Decision and $27 thousand related to the 2014 revenue surplus (Section 9, Schedule 66, Line 9).

FEFN is seeking approval to amortize the forecasted Fort Nelson Revenue Surplus/Deficit Account ending 2014 credit balance of $55 thousand through delivery rates over one year beginning in 2015. FEFN believes this amortization period is appropriate given it serves to mitigate some of the other rate impacts on FEFN customers in 2015.

7.4.3 Information and Updates to Existing Deferral Accounts

Muskwa River Crossing Cost of Service

The Muskwa River Crossing Project was first approved by Order G-27-11 with an original in-service date of October 1, 2011. As a result of delays in receiving approval from Public Works and Government Services Canada (PWGSC) to attach the pipeline to the Muskwa River bridge, the Muskwa River Crossing deferral account was first created in 2011 and later extended to 2012, 2013 and 2014 to capture the cost of service of the Project. The intent of the deferral account was to capture the cost of service of the Project that had been recovered from customers through delivery rates and hold customers whole regardless of the delay of the project.

Forecast additions of $3.1 million to rate base were originally estimated in 2011; these were subsequently reforecast to occur in 2012. The 2011 cost of service impact of $87 thousand was refunded to Fort Nelson customers in 2012. The 2012-2014 cost of service variances were also recorded in the deferral account given that no actual amounts for capital are included in rate base until 2015, due to the completion of the project in 2014. The final projected balance in the deferral account owing to customers at the end of 2014 is $347 thousand, which will be credited back to customers over three years beginning in 2015 as approved by Order C-2-14.

The actual projected final capital cost of the project was $4,210 thousand and went into service in May 2014. The capital costs will be held in work in progress until December 31, 2014, attracting AFUDC, and then transferred to rate base January 1, 2015, with depreciation also commencing on January 1, 2015.

Muskwa River Crossing Project Costs

As approved in Order C-2-14, the Muskwa River Crossing Project Cost non-rate base deferral account, attracting a weighted average cost of capital return, is being used to capture the development and application costs of the project. The ending 2014 after-tax balance in the account of $815[23] thousand will be transferred to rate base January 1, 2015 and amortized into rates over three years from 2015 to 2017 as approved by Order C-2-14.

7.5 13-MONTH ADJUSTMENT

Rate base calculations assume that plant additions are included into rate base at mid-year. Therefore, a rate base addition of $2,105 thousand (Section 9, Schedule 2.0, Line 23) is necessary to reflect a January 1, 2015 in-service date for the Muskwa River Crossing project.

7.6 CASH WORKING CAPITAL

Cash Working Capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days, and are supported by a Lead Lag Study. Cash working capital of $64 thousand (Section 9, Schedule 77, Line 15) in 2015 and $63 thousand (Section 9, Schedule 77, Line 15) in 2016 has been deducted from rate base.

FEFN has utilized the lead/lag days as approved in the PBR Decision (Order G-138-14).

The next and final step in the calculation of cash working capital is to adjust the cash working capital for the reserve for bad debts and the withholdings from employees. The reserve for bad debts has been forecast based on customer additions and customer deposit requirements, while employee withholdings are calculated based on historical levels.

[23] January 1, 2015 pre-tax additions to the account are $894 thousand, excluding AFUDC, as shown in the Project Cost section in Order C-2-14 Compliance Filing Final Report on the Project.

7.7 *OTHER WORKING CAPITAL*

Other working capital consists of inventories of material and supplies.

The forecast 2015 and 2016 costs for these items have been calculated based on historical levels for inventories. Please refer to Section 9, Schedule 74-76.

7.8 *RATE BASE SUMMARY*

The rate base amounts that have been forecasted for 2015 and 2016 incorporate required expenditures to meet our customers' needs and make improvements related to system integrity and reliability.

8. FINANCING AND CAPITAL STRUCTURE

The Company finances its rate base assets with a mix of debt and equity, as approved by the Commission from time to time. Subject to Commission Order G-75-13, the Company has an approved capital structure of 61.5 percent debt and 38.5 percent equity with an allowed Return on Equity (ROE) of 8.75 percent, effective January 1, 2013 until December 31, 2014, with an Automatic Adjustment Mechanism (AAM) in place. The AAM was not triggered for 2013 or 2014, such that the ROE and common equity percentage remain as approved in Order G-75-13. As part of Order G-75-13, the Commission has directed FEI to file a cost of capital application no later than November 2015, for determination of cost of capital for periods beyond December 31, 2015. The outcome of such a proceeding will be reflected in rates once determined. FEFN shares the same capital structure and ROE as FEI. In this Application, FEFN has forecast its share of FEI's debt financing costs for 2015 and 2016.

8.1 *FINANCING COSTS*

Debt financing costs include the interest expense on issued debt as well as interest expense on new issuances that are forecast. Debt consists of both Long-term Debt and Short-term (Unfunded) Debt.

8.1.1 Long-Term Debt

FEFN receives an allocation of FEI's long term debt. FEI's long-term debt issues in 2015 and 2016 of $75 million and $200 million, respectively, were discussed in the PBR Application. FEI has not forecast any other long-term debt issues or retirements in either 2015 or 2016. FEFN's share of FEI's long-term debt is $6,058 thousand (Section 9, Schedule 84, Line 31) in 2015 and $6,190 thousand (Section 9, Schedule 85, Line 30) in 2016.

8.1.2 Short-Term Debt

FEFN's short-term debt represents the difference between its long-term debt allocation from FEI and 61.5% of rate base. Interest rate forecasts reflect FEI's methodology as discussed in the PBR Application and repeated below.

> *FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FEI under its commercial paper program. CDOR is used because FEI's short-term borrowings under its credit facility are priced off of CDOR and so CDOR is tracked relative to FEI's commercial paper borrowings. CDOR is not forecast by economists either; therefore, FEI must first obtain the 3-Month T-Bill rate forecast then convert it to a CDOR forecast. FEI does this by taking the 3 year historical spread between CDOR and the 3-month T-Bill rate. To then derive the short-term borrowing rate forecast, FEI further adjusts the*

CDOR forecast with the 3-year historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill rate is projected to increase from approximately 1.05 percent in 2014 to approximately 2.4 percent by 2016. FEI's short-term borrowing rate forecasts are shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecasts

	2014	2015	2016
3-month T-BILLS	1.05%	1.36%	2.37%
Spread to CDOR	0.29%	0.29%	0.29%
CDOR	1.34%	1.64%	2.66%
Spread to CP	-0.23%	-0.23%	-0.23%
CP Dealer Commission	0.10%	0.10%	0.10%
Standby Fee on undrawn Credit (1)	0.48%	0.38%	0.32%
FEFN Short-Term Rate (Rounded)	1.75%	2.00%	2.75%

NOTE: (1) Amounts undrawn on the credit facility are subject to a Standby Fee, which is estimated to be 16 bps in 2014 and beyond. The Standby Fee as shown reflects the amount payable had it been converted to a rate applied to the Commercial Paper borrowings and has been shown as such to develop an all-in Short-Term Rate.

Due to the uncontrollable nature and forecasting uncertainty associated with interest rates, FEFN has an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances and variances in the amount of debt as compared to forecast.

8.2 SUMMARY OF FINANCING AND RETURN ON EQUITY

FEI continues to prudently manage its capital structure and address financing requirements in an appropriate manner.

9. FINANCIAL SCHEDULES

Line No.	Particulars	2015 ($ Thousands)		2016 ($ Thousands)		Cumulative ($ Thousands)	
1	(1)	(2)	(3)	(4)	(5)	(6)	(7)
2	Volume/Revenue Related						
3	Customer Growth and Use Rates	20		(16)		4	
4	Change in Other Revenue	5	25	-	(16)	5	9
5							
6	O&M Changes						
7	Gross O&M Increases	74		23		97	
8	Less: Capitalized Overhead	9	83	(2)	21	7	104
9							
10	Depreciation Expense						
11	Tax Expense Impact of Depreciation Changes	34		15		49	
12	Depreciation from Net Additions	97	131	42	57	139	188
13							
14	Amortization Expense						
15	CIAC	(1)		-		(1)	
16	Deferral Accounts	52	51	100	100	152	151
17							
18	Other						
19	Property and Other Taxes	(27)		1		(26)	
20	Deferred Surplus 2014	(17)		-		(17)	
21	Income Tax Rate Change	112		(17)		95	
22	Other Income Tax Changes	(125)		(15)		(140)	
23	Financing Rate Changes	(12)		(4)		(16)	
24	Financing Changes	123		12		135	
25	Rate Base Growth	129	183	14	(9)	143	174
26							
27	**Revenue Deficiency (Surplus)**		**473**		**153**		**626**
28							
29							
30	Cross Reference	- Tab 9-FORECAST, Sch 2				- Tab 9-FORECAST, Sch 3	

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	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	$ 4,176	$ 4,324	$ 150	$ -	$ 4,474	$ 298	- Tab 9-FORECAST, Sch 11
5								
6								
7	Total Revenue	4,176	4,324	150	-	4,474	298	
8								
9	Less - Cost of Gas	(2,214)	(2,524)	-	-	(2,524)	(310)	- Tab 9-FORECAST, Sch 13
10								
11	Gross Margin	$ 1,962	$ 1,800	$ 150	$ -	$ 1,950	$ (12)	
12								
13	Revenue Deficiency (Surplus)	$ -	$ 437	$ 36	$ -	**$ 473**	$ 473	
14								
15	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	24.28%	24.00%	0.00%	24.26%		
16								
17	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	10.11%	24.00%	0.00%	10.57%		
18								

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	$ 4,474	$ 4,359	$ 150	$ -	$ 4,509	$ 35	- Tab 9-FORECAST, Sch 12
5								
6								
7	Total Revenue	4,474	4,359	150	-	4,509	35	
8								
9	Less - Cost of Gas	(2,524)	(2,543)	-	-	(2,543)	(19)	- Tab 9-FORECAST, Sch 13
10								
11	Gross Margin	$ 1,950	$ 1,816	$ 150	$ -	$ 1,966	$ 16	
12								
13	Revenue Deficiency (Surplus)	$ 473	$ 578	$ 48	$ -	**$ 626**	$ 153	
14								
15	Revenue Deficiency (Surplus) as a % of Gross Margin	24.26%	31.83%	32.00%	0.00%	31.84%		
16								
17	Revenue Deficiency (Surplus) as a % of Total Revenue	10.57%	13.26%	32.00%	0.00%	13.88%		
18								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	ENERGY VOLUMES (TJ)					
2	Sales	584	606	589	(17)	- Tab 9-FORECAST, Sch 7
3	Transportation	61	48	67	19	- Tab 9-FORECAST, Sch 7
4		645	654	656	2	
5						
6	Average Rate per GJ					
7	Sales	$ 6.717	$ 6.583	$ 6.793	$ 0.210	
8	Transportation	$ 2.639	$ 2.792	$ 2.612	$ (0.180)	
9	Average	$ 6.371	$ 6.304	$ 6.409	$ 0.105	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 3,923	$ 3,989	$ 4,001	$ 12	- Tab 9-FORECAST, Sch 10
13	- Increase / (Decrease)	-	-	-	-	
14	RSAM Revenue	25	-	28	28	
15	Transportation - Existing Rates	161	134	175	41	- Tab 9-FORECAST, Sch 10
16	- Increase / (Decrease)	-	-	-	-	
17						
18	**Total Revenue**	4,109	4,123	4,204	81	
19						
20	Cost of Gas Sold (Including Gas Lost)	2,077	2,153	2,214	61	- Tab 9-FORECAST, Sch 13
21						
22	**Gross Margin**	2,032	1,970	1,990	20	
23						
24	Operation and Maintenance	1,058	797	831	34	- Tab 9-FORECAST, Sch 21
25	Property and Sundry Taxes	178	144	144	-	- Tab 9-FORECAST, Sch 25
26	Depreciation and Amortization	332	368	372	4	- Tab 9-FORECAST, Sch 28
27	Deferred Surplus 2014	-	17	37	20	
28	2012/2013 Revenue Deficiencies	(58)	-	-	-	
29	Other Operating Revenue	189	(25)	71	96	- Tab 9-FORECAST, Sch 18
30	Sub-total	1,699	1,301	1,455	154	
31	Utility Income Before Income Taxes	333	669	535	(134)	
32						
33	Income Taxes	(72)	91	56	(35)	- Tab 9-FORECAST, Sch 31
34						
35	**EARNED RETURN**	$ 405	$ 578	479	$ (99)	- Tab 9-FORECAST, Sch 80
36						
37						
38	**UTILITY RATE BASE**	$ 5,358	$ 7,936	$ 5,698	$ (2,238)	- Tab 9-FORECAST, Sch 40
39						
40	**RATE OF RETURN ON UTILITY RATE BASE**	7.56%	7.28%	8.41%	1.12%	- Tab 9-FORECAST, Sch 80

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 FORECAST Existing 2014 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	589	593	-	593	4	- Tab 9-FORECAST, Sch 8
3	Transportation	67	56	-	56	(11)	- Tab 9-FORECAST, Sch 8
4		656	649	-	649	(7)	
5							
6	Average Rate per GJ						
7	Sales	$ 6.793	$ 7.292	$ -	$ 8.029	$ 1.236	
8	Transportation	$ 2.612	$ 2.679	$ -	$ 3.321	$ 0.709	
9	Average	$ 6.409	$ 6.894	$ -	$ 7.622	$ 1.213	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 4,001	$ 4,324	$ -	$ 4,324	$ 323	- Tab 9-FORECAST, Sch 11
13	- Increase / (Decrease)	-	-	437	437	437	- Tab 9-FORECAST, Sch 14
14	RSAM Revenue	28				(28)	
15	Transportation - Existing Rates	175	150	-	150	(25)	- Tab 9-FORECAST, Sch 11
16	- Increase / (Decrease)	-		36	36	36	- Tab 9-FORECAST, Sch 14
17							
18	**Total Revenue**	4,204	4,474	473	4,947	743	
19							
20	Cost of Gas Sold (Including Gas Lost)	2,214	2,524	-	2,524	310	- Tab 9-FORECAST, Sch 13
21							
22	**Gross Margin**	1,990	1,950	473	2,423	433	
23							
24	Operation and Maintenance	831	880	-	880	49	- Tab 9-FORECAST, Sch 21
25	Property and Sundry Taxes	144	117	-	117	(27)	- Tab 9-FORECAST, Sch 26
26	Depreciation and Amortization	372	516	-	516	144	- Tab 9-FORECAST, Sch 29
27	Deferred Surplus 2014	37	-	-	-	(37)	
28	2012/2013 Revenue Deficiencies	-	-	-	-	-	
29	Other Operating Revenue	71	(20)	-	(20)	(91)	- Tab 9-FORECAST, Sch 19
30	Sub-total	1,455	1,493	-	1,493	38	
31	Utility Income Before Income Taxes	535	457	473	930	395	
32							
33	Income Taxes	56	(11)	123	112	56	- Tab 9-FORECAST, Sch 32
34							
35	**EARNED RETURN**	$ 479	$ 468	$ 350	$ 818	$ 339	- Tab 9-FORECAST, Sch 81
36							
37							
38	**UTILITY RATE BASE**	$ 5,698	$ 11,747	$ 9	$ 11,756	$ 6,058	- Tab 9-FORECAST, Sch 41
39							
40	**RATE OF RETURN ON UTILITY RATE BASE**	8.41%	3.98%		6.96%	-1.45%	- Tab 9-FORECAST, Sch 81

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 FORECAST Existing 2014 Rates	2016 FORECAST Revised Revenue	2016 FORECAST Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	593	597	-	597	4	- Tab 9-FORECAST, Sch 9
3	Transportation	56	56	-	56	-	- Tab 9-FORECAST, Sch 9
4		649	653	-	653	4	
5							
6	Average Rate per GJ						
7	Sales	$ 8.029	$ 7.302	$ -	$ 8.270	$ 0.241	
8	Transportation	$ 3.321	$ 2.679	$ -	$ 3.536	$ 0.215	
9	Average	$ 7.622	$ 6.905	$ -	$ 7.864	$ 0.242	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 4,324	$ 4,359	$ -	$ 4,359	$ 35	- Tab 9-FORECAST, Sch 12
13	- Increase / (Decrease)	437	-	578	578	141	- Tab 9-FORECAST, Sch 16
14						-	
15	Transportation - Existing Rates	150	150	-	150	-	- Tab 9-FORECAST, Sch 12
16	- Increase / (Decrease)	36		48	48	12	- Tab 9-FORECAST, Sch 16
17							
18	**Total Revenue**	4,947	4,509	626	5,135	188	
19							
20	Cost of Gas Sold (Including Gas Lost)	2,524	2,543	-	2,543	19	- Tab 9-FORECAST, Sch 13
21							
22	**Gross Margin**	2,423	1,966	626	2,592	169	
23							
24	Operation and Maintenance	880	901	-	901	21	- Tab 9-FORECAST, Sch 21
25	Property and Sundry Taxes	117	118	-	118	1	- Tab 9-FORECAST, Sch 27
26	Depreciation and Amortization	516	658	-	658	142	- Tab 9-FORECAST, Sch 30
27	Deferred Surplus 2014	-	-	-	-	-	
28	2012/2013 Revenue Deficiencies	-	-	-	-	-	
29	Other Operating Revenue	(20)	(20)	-	(20)	-	- Tab 9-FORECAST, Sch 20
30	Sub-total	1,493	1,657	-	1,657	164	
31	Utility Income Before Income Taxes	930	309	626	935	5	
32							
33	Income Taxes	112	(68)	163	95	(17)	- Tab 9-FORECAST, Sch 33
34							
35	**EARNED RETURN**	$ 818	$ 377	$ 463	$ 840	$ 22	- Tab 9-FORECAST, Sch 82
36							
37							
38	**UTILITY RATE BASE**	$ 11,756	$ 12,167	$ 11	$ 12,178	$ 422	- Tab 9-FORECAST, Sch 42
39							
40	**RATE OF RETURN ON UTILITY RATE BASE**	6.96%	3.10%		6.90%	-0.06%	- Tab 9-FORECAST, Sch 82

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2014

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 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	270.0	269.6	270.5	-	270.5	0.9	
3	Schedule 2.1 - Commercial	204.0	226.1	208.9		208.9	(17.2)	
4	Schedule 2.2 - Commercial	110.0	110.2	109.8		109.8	(0.4)	
5								
6	Total Sales	584.0	605.9	589.2	-	589.2	(16.7)	- Tab 9-FORECAST, Sch 4
7								
8	**TRANSPORTATION SERVICE**							
9	Schedule 25 - Transportation Service	61.0	47.8	67.1	-	67.1	19.3	
10								
11	Total Transportation Service	61.0	47.8	67.1	-	67.1	19.3	- Tab 9-FORECAST, Sch 4
12								
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	645.0	654.0	656.3	-	656.3	2.6	- Tab 9-FORECAST, Sch 4
14								

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2015

Line No.	Particulars	2014 PROJECTED	2015 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	270.5	268.6	-	268.6	(1.9)	
3	Schedule 2.1 - Commercial	208.9	208.3		208.3	(0.6)	
4	Schedule 2.2 - Commercial	109.8	115.7		115.7	5.9	
5							
6	Total Sales	589.2	592.6	-	592.6	3.4	- Tab 9-FORECAST, Sch 5
7							
8	**TRANSPORTATION SERVICE**						
9	Schedule 25 - Transportation Service	67.1	55.8	-	55.8	(11.3)	
10							
11	Total Transportation Service	67.1	55.8	-	55.8	(11.3)	- Tab 9-FORECAST, Sch 5
12							
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	656.3	648.4	-	648.4	(7.9)	- Tab 9-FORECAST, Sch 5
14							- Tab 9-FORECAST, Sch 15

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2016

Line No.	Particulars	2015 FORECAST	2016 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	268.6	267.5	-	267.5	(1.1)	
3	Schedule 2.1 - Commercial	208.3	208.6		208.6	0.3	
4	Schedule 2.2 - Commercial	115.7	121.0		121.0	5.3	
5							
6	Total Sales	592.6	597.1	-	597.1	4.5	- Tab 9-FORECAST, Sch 6
7							
8	**TRANSPORTATION SERVICE**						
9	Schedule 25 - Transportation Service	55.8	55.8	-	55.8	-	
10							
11	Total Transportation Service	55.8	55.8	-	55.8	-	- Tab 9-FORECAST, Sch 6
12							
13	**TOTAL SALES AND TRANSPORTATION SERVICES**	648.4	652.9	-	652.9	4.5	- Tab 9-FORECAST, Sch 6
14							- Tab 9-FORECAST, Sch 17

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 Gas Sales Revenue At Existing 2014 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	$ 1,767	$ 1,731	$ 1,792	$ -	$ 1,792	$ 61	
3	Schedule 2.1 - Commercial	1,441	1,553	1,479		1,479	(74)	
4	Schedule 2.2 - Commercial	715	705	730		730	25	
5								
6	Total Sales	3,923	3,989	4,001	-	4,001	12	- Tab 9-FORECAST, Sch 4
7								
8	**Transportation Service**							
9	Schedule 25 - Transportation Service	161	134	175	-	175	41	
10	Total Transportation Service	161	134	175	-	175	41	- Tab 9-FORECAST, Sch 4
11								
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,084	$ 4,123	$ 4,176	$ -	$ 4,176	$ 53	- Tab 9-FORECAST, Sch 4

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 Gas Sales Revenue At Existing 2014 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	$ 1,792	$ 1,916	$ -	$ 1,916	$ 124	
3	Schedule 2.1 - Commercial	1,479	1,588		1,588	109	
4	Schedule 2.2 - Commercial	730	820		820	90	
5							
6	Total Sales	4,001	4,324	-	4,324	323	- Tab 9-FORECAST, Sch 5
7							
8	**Transportation Service**						
9	Schedule 25 - Transportation Service	175	150	-	150	(25)	
10	Total Transportation Service	175	150	-	150	(25)	- Tab 9-FORECAST, Sch 5
11							
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,176	$ 4,474	$ -	$ 4,474	$ 298	- Tab 9-FORECAST, Sch 5 - Tab 9-FORECAST, Sch 15

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Gas Sales Revenue At Existing 2014 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	$ 1,916	$ 1,910	$ -	$ 1,910	$ (6)	
3	Schedule 2.1 - Commercial	1,588	1,593		1,593	5	
4	Schedule 2.2 - Commercial	820	856		856	36	
5							
6	Total Sales	4,324	4,359	-	4,359	35	- Tab 9-FORECAST, Sch 6
7							
8	**Transportation Service**						
9	Schedule 25 - Transportation Service	150	150	-	150	-	
10	Total Transportation Service	150	150	-	150	-	- Tab 9-FORECAST, Sch 6
11							
12	TOTAL SALES AND TRANSPORTATION SERVICES	$ 4,474	$ 4,509	$ -	$ 4,509	$ 35	- Tab 9-FORECAST, Sch 6 - Tab 9-FORECAST, Sch 17

COST OF GAS
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000s)

Line No.	Particulars	2014 Projected Gas Costs Non-Bypass Sales & Transp	2014 Bypass and Special Rates	2014 Total	2015 Forecast Gas Costs Non-Bypass Sales & Transp	2015 Bypass and Special Rates	2015 Total	2016 Forecast Gas Costs Non-Bypass Sales & Transp	2016 Bypass and Special Rates	2016 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**SALES**									
2	Schedule 1 - Residential	1,016	$ -	$ 1,016	$ 1,144	$ -	$ 1,144	1,139	$ -	$ 1,139
3	Schedule 2.1 - Commercial	778		778	887		887	889		889
4	Schedule 2.2 - Commercial	420		420	493		493	515		515
5										
6	Total Sales	2,214	-	2,214	2,524	-	2,524	2,543	-	2,543
7										
8	**TRANSPORTATION SERVICE**									
9	Schedule 25 - Transportation Service	-	-	-	-	-	-	-	-	-
10										
11	Total Transportation Service	-	-	-	-	-	-	-	-	-
12										
13	TOTAL SALES AND TRANSPORTATION SERVICES	$ 2,214	$ -	$ 2,214	$ 2,524	$ -	$ 2,524	$ 2,543	$ -	$ 2,543
14										
15	Cross Reference			- Tab 9-FORECAST, Sch 4			- Tab 9-FORECAST, Sch 5			- Tab 9-FORECAST, Sch 6

REVENUE UNDER EXISTING 2014 RATES AND REVISED 2015 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2014 Rates -- Average $/GJ	Revenue -- At Existing 2014 Rates -- Revenue ($000s)	Gross Margin -- At Existing 2014 Rates -- Average $/GJ	Gross Margin -- At Existing 2014 Rates -- Margin ($000s)	Effective Increase / (Decrease) 24.28% of Margin $/GJ	Effective Increase / (Decrease) 24.28% 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	268.6	$ 7.133	$ 1,916	$ 2.878	$ 773	$ 0.700	$ 188	1,967	$ 7.833	$ 2,104
4	Schedule 2.1 - Commercial	208.3	7.624	1,588	3.361	700	0.816	170	457	8.440	1,758
5	Schedule 2.2 - Commercial	115.7	7.087	820	2.826	327	0.683	79	33	7.770	899
6											
7	Total Sales	592.6		4,324		1,800		437	2,457		4,761
8											
9	TRANSPORTATION SERVICE										
10	Schedule 25 - Transportation Service	55.8	2.688	150	2.688	150	0.645	36	2	3.333	186
11											
12	Total Transportation Service	55.8		150		150		36	2		186
13											
14	Total Non-Bypass Sales & Transportation Service	648.4		$ 4,474		$ 1,950		$ 473	2,459		$ 4,947
15											
16	Cross Reference	Tab 9-FORECAST, Sch 8	- Tab 9-FORECAST, Sch 11				- Tab 9-FORECAST, Sch 2				

REVENUE UNDER EXISTING 2014 RATES AND REVISED 2015 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

			Revenue -- At Existing 2014 Rates --		Gross Margin -- At Existing 2014 Rates --		Increase / (Decrease) 24.28% of Margin			Revenue	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	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										
3											
4	Total Bypass Sales and										
5	Transportation Service	-		-		-		-	-		-
6											
7	TOTAL NON-BYPASS AND BYPASS SALES AND										
8	TRANSPORTATION SERVICE	648.4		$ 4,474		$ 1,950		$ 473	2,459		$ 4,947
9											
10	Cross Reference	Tab 9-FORECAST, Sch 8	- Tab 9-FORECAST, Sch 11				- Tab 9-FORECAST, Sch 2				

REVENUE UNDER EXISTING 2014 RATES AND REVISED 2016 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2014 Rates -- Average $/GJ	Revenue -- At Existing 2014 Rates -- Revenue ($000)	Gross Margin -- At Existing 2014 Rates -- Average $/GJ	Gross Margin -- At Existing 2014 Rates -- Margin ($000s)	Effective Increase / (Decrease) of Margin 31.83% $/GJ	Effective Increase / (Decrease) of Margin Revenue ($000)	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	267.5	$ 7.140	$ 1,910	$ 2.882	$ 771	$ 0.916	$ 245	1,980	$ 8.056	$ 2,155
4	Schedule 2.1 - Commercial	208.6	7.637	1,593	3.375	704	1.074	224	468	8.711	1,817
5	Schedule 2.2 - Commercial	121.0	7.074	856	2.818	341	0.901	109	34	7.975	965
6											
7	Total Sales	597.1		4,359		1,816		578	2,482		4,937
8											
9	TRANSPORTATION SERVICE										
10	Schedule 25 - Transportation Service	55.8	2.688	150	2.688	150	0.860	48	2	3.548	198
11											
12	Total Transportation Service	55.8		150		150		48	2		198
13											
14	Total Non-Bypass Sales & Transportation Service	652.9		$ 4,509		$ 1,966		$ 626	2,484		$ 5,135
15											
16	Cross Reference	Tab 9-FORECAST, Sch 9	- Tab 9-FORECAST, Sch 12				- Tab 9-FORECAST, Sch 3				

REVENUE UNDER EXISTING 2014 RATES AND REVISED 2016 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

			Revenue -- At Existing 2014 Rates --		Gross Margin -- At Existing 2014 Rates --		Increase / (Decrease) 31.83% of Margin			Revenue	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	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										
3											
4	Total Bypass Sales and										
5	Transportation Service	-		-		-		-	-		-
6											
7	TOTAL NON-BYPASS AND BYPASS SALES AND										
8	TRANSPORTATION SERVICE	652.9		$ 4,509		$ 1,966		$ 626	2,484		$ 5,135
9											
10	Cross Reference	Tab 9-FORECAST, Sch 9	- Tab 9-FORECAST, Sch 12				- Tab 9-FORECAST, Sch 3				

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 16	$ 14	$ 8	$ (6)	- Tab 9-FORECAST, Sch 78
4						
5	Connection Charge	9	11	11	-	- Tab 9-FORECAST, Sch 78
6						
7	Other Recoveries	-	-	-	-	- Tab 9-FORECAST, Sch 78
8						
9						
10	Total Other Utility Revenue	25	25	19	(6)	
11						
12	**Miscellaneous Revenue**					
13						
14	Muskwa Cost of Service	(214)	-	(90)	(90)	- Tab 9-FORECAST, Sch 78
15						
16	**Total Other Operating Revenue**	$ (189)	$ 25	$ (71)	$ (96)	- Tab 9-FORECAST, Sch 4

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 8	$ 9	$ 1	- Tab 9-FORECAST, Sch 78
4					
5	Connection Charge	11	11	-	- Tab 9-FORECAST, Sch 78
6					
7	Other Recoveries	-	-	-	- Tab 9-FORECAST, Sch 78
8					
9					
10	Total Other Utility Revenue	19	20	1	
11					
12	**Miscellaneous Revenue**				
13					
14	Muskwa Cost of Service	(90)	-	90	- Tab 9-FORECAST, Sch 78
15					
16	**Total Other Operating Revenue**	$ (71)	$ 20	$ 91	- Tab 9-FORECAST, Sch 5

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000)

Line No.	Particulars	2015 FORECAST	2016	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 9	$ 9	$0	- Tab 9-FORECAST, Sch 78
4					
5	Connection Charge	11	11	-	- Tab 9-FORECAST, Sch 78
6					
7	Other Recoveries	-	-	-	- Tab 9-FORECAST, Sch 78
8					
9					
10	Total Other Utility Revenue	20	20	-	
11					
12	**Miscellaneous Revenue**				
13					
14	Muskwa Cost of Service	-	-	-	
15					
16	**Total Other Operating Revenue**	$ 20	$ 20	$ -	- Tab 9-FORECAST, Sch 6

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	2015 FORECAST	2016 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	M&E Costs	$ 30	$ 927	$ 15	$ 15	$ 15	
2	COPE Costs	1	-	-	-	-	
3	COPE Customer Services Costs	-	-	-	-	-	
4	IBEW Costs	289	-	324	334	344	
5							
6	**Labour Costs**	**321**	**927**	**339**	**349**	**359**	
7							
8	Vehicle Costs	43	-	43	43	44	
9	Employee Expenses	14	-	18	29	29	
10	Materials and Supplies	74	-	1	1	1	
11	Computer Costs	-	-	-	-	-	
12	Fees and Administration Costs	514	-	506	540	551	
13	Contractor Costs	201	-	5	5	5	
14	Facilities	18	-	36	37	37	
15	Recoveries & Revenue	(2)	-	(2)	(2)	(2)	
16							
17	**Non-Labour Costs**	**862**	**-**	**606**	**652**	**664**	
18							
19							
20	**Total Gross O&M Expenses**	**1,183**	**927**	**945**	**1,001**	**1,024**	
21							
22	Less: Capitalized Overhead	(125)	(130)	(113)	(120)	(123)	
23							
24	**Total O&M Expenses**	**$ 1,058**	**$ 797**	**$ 831**	**$ 880**	**$ 901**	
25							
26	Cross Reference			- Tab 9-FORECAST, Sch 4		- Tab 9-FORECAST, Sch 6	
27					- Tab 9-FORECAST, Sch 5		

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000)

Line No.	Particulars	BCUC Reference	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	2015 FORECAST	2016 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Distribution Supervision	110-11	$ 152	$ 927	$ 100	$ 105	$ 108	
2	Distribution Supervision Total	110-10	152	927	100	105	108	
3								
4	Operation Centre - Distribution	110-21	136	-	89	94	96	
5	Preventative Maintenance - Distribution	110-22	33	-	22	23	24	
6	Operations - Distribution	110-23	88	-	58	60	62	
7	Emergency Management - Distribution	110-24	75	-	50	52	53	
8	Field Training - Distribution	110-25	45	-	30	31	32	
9	Meter Exchange - Distribution	110-26	34	-	22	23	24	
10	Distribution Operations Total	110-20	411	-	270	284	291	
11								
12	Corrective - Distribution	110-31	84	-	55	58	60	
13	Distribution Maintenance Total	110-30	84	-	55	58	60	
14								
15	Account Services - Distribution	110-41	15	-	10	11	11	
16	Bad Debt Management - Distribution	110-42	9	-	6	6	6	
17	Distribution Meter to Cash Total	110-40	25	-	16	17	17	
18								
19	**Distribution Total**	**110**	**671**	**927**	**442**	**464**	**476**	
43								
44	**Operations Total**	**100**	**671**	**927**	**442**	**464**	**476**	
45								
46	Customer Service Supervision	210-11	-	-	-	-	-	
47	Customer Assistance	210-12	-	-	-	-	-	
48	Customer Billing	210-13	-	-	-	-	-	
49	Meter Reading	210-14	-	-	-	-	-	
50	Credit & Collections	210-15	-	-	-	-	-	
51	Customer Operations	210-16	-	-	-	-	-	
52	Customer Service Total	210-10	-	-	-	-	-	
53								
54	**Customer Service Total**	**210**	**-**	**-**	**-**	**-**	**-**	
55								
56	**Customer Service Total**	**200**	**-**	**-**	**-**	**-**	**-**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000)

Line No.	Particulars	BCUC Reference	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	2015 FORECAST	2016 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Energy Solutions & External Relations Supervis	310-11	-	-	$ -	$ -	$ -	
2	Energy Solutions	310-12	-	-	-	-	-	
3	Energy Efficiency	310-13	-	-	-	-	-	
4	Corporate Communications and External Relati	310-14	-	-	-	-	-	
5	Forecasting, Market & Business Development	310-15	-	-	-	-	-	
6	Energy Solutions & External Relations Total	310-10	-	-	-	-	-	
7								
8	**Energy Solutions & External Relations Total**	**310**	**-**	**-**	**-**	**-**	**-**	
9								
10	**Energy Solutions & External Relations Total**	**300**	**-**	**-**	**-**	**-**	**-**	
11								
12	Energy Supply & Resource Development	410-11	-	-	-	-	-	
13	Gas Control	410-12	-	-	-	-	-	
14	Energy Supply & Resource Development Tot	410-10	-	-	-	-	-	
15								
16	**Energy Supply & Resource Development Tot**	**410**	**-**	**-**	**-**	**-**	**-**	
17								
18	Information Technology Supervision	420-11	-	-	-	-	-	
19	Application Management	420-12	-	-	-	-	-	
20	Infrastructure Management	420-13	-	-	-	-	-	
21	Information Technology Total	420-10	-	-	-	-	-	
22								
23	**Information Technology Total**	**420**	**-**	**-**	**-**	**-**	**-**	
24								
25	System Planning	430-11	-	-	-	-	-	
26	Engineering	430-12	-	-	-	-	-	
27	Project Management	430-13	-	-	-	-	-	
28	Engineering Services & Project Managemen	430-10	-	-	-	-	-	
29								
30	**Engineering Services & Project Managemen**	**430**	**-**	**-**	**-**	**-**	**-**	
31								
32	Supply Chain	440-11	-	-	-	-	-	
33	Measurement	440-12	-	-	-	-	-	
34	Property Services	440-13	-	-	-	-	-	
35	Operations Support Total	440-10	-	-	-	-	-	
36								
37	**Operations Support Total**	**440**	**-**	**-**	**-**	**-**	**-**	
38								
39	Facilities Management	450-11	-	-	-	-	-	
40	Facilities Total	450-10	-	-	-	-	-	
41								
42	**Facilities Total**	**450**	**-**	**-**	**-**	**-**	**-**	
43								
44	Environment Health & Safety	460-11	-	-	-	-	-	
45	Environment Health & Safety Total	460-10	-	-	-	-	-	
46								
47	**Environment Health & Safety Total**	**460**	**-**	**-**	**-**	**-**	**-**	
48								
49								
50	**Business Services Total**	**400**	**-**	**-**	**-**	**-**	**-**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000)

Line No.	Particulars	BCUC Reference	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	2015 FORECAST	2016 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Financial & Regulatory Services	510-11	-	-	-	-	-	
2	Financial & Regulatory Services Total	510-10	-	-	-	-	-	
3								
4	**Financial & Regulatory Services Total**	**510**	**-**	**-**	**-**	**-**	**-**	
5								
6	Human Resources	520-11	-	-	-	-	-	
7	Human Resources Total	520-10	-	-	-	-	-	
8								
9	**Human Resources Total**	**520**	**-**	**-**	**-**	**-**	**-**	
10								
11	Legal	530-11	-	-	-	-	-	
12	Internal Audit	530-12	-	-	-	-	-	
13	Risk Management/Insurance	530-13	-	-	-	-	-	
14	Governance	530-10	-	-	-	-	-	
15								
16	**Governance Total**	**530**	**-**	**-**	**-**	**-**	**-**	
17								
18	Administration & General	540-11	-	-	-	-	-	
19	Shared Services Agreement	540-12	511	-	503	537	548	
20	Retiree Benefits	540-16	-	-	-	-	-	
21	Corporate Total	540-10	511	-	503	537	548	
22								
23	**Corporate Total**	**540**	**511**	**-**	**503**	**537**	**548**	
24								
25	**Corporate Services Total**	**500**	**511**	**-**	**503**	**537**	**548**	
26								
27	**Total Gross O&M Expenses**		**1,183**	**927**	**945**	**1,001**	**1,024**	
28								
29	Less: Capitalized Overhead		(125)	(130)	(113)	(120)	(123)	
30								
31	**Total O&M Expenses**		**$ 1,058**	**$ 797**	**$ 831**	**$ 880**	**$ 901**	
32								
33	Cross Reference				- Tab 9-FORECAST, Sch 4		- Tab 9-FORECAST, Sch 6	
34						- Tab 9-FORECAST, Sch 5		

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED Total Expenses	2014 PROJECTED 2014 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	$ 40	$ 39	$ 39	$ 39	$ -	
4							
5	General, School and Other	95	105	75	75	(30)	
6							
7		135	144	114	114	(30)	
8							
9	Add / Less: Deferred Property Taxes	43	-	30	30	30	
10							
11	Total	$ 178	$ 144	$ 144	$ 144	$ -	- Tab 9-FORECAST, Sch 4

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 Total Expenses	2015 2014 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 39	$ 38	$ 38	$ (1)	
4						
5	General, School and Other	75	79	79	4	
6						
7		114	117	117	3	
8						
9	Add / Less: Deferred Property Taxes	30	-	-	(30)	
10						
11	Total	$ 144	$ 117	$ 117	$ (27)	- Tab 9-FORECAST, Sch 5

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Total Expenses	2016 2014 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 38	$ 38	$ 38	$ -	
4						
5	General, School and Other	79	80	80	1	
6						
7		117	118	118	1	
8						
9	Add / Less: Deferred Property Taxes	-	-	-	-	
10						
11	Total	$ 117	$ 118	$ 118	$ 1	- Tab 9-FORECAST, Sch 6

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 371	$ 377	$ 381	$ 4	- Tab 9-FORECAST, Sch 55
4						
5	Less: Amortization of Contributions in Aid of Construction	(35)	(35)	(36)	(1)	- Tab 9-FORECAST, Sch 62
6		336	342	345	3	- Tab 9-FORECAST, Sch 34
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ (4)	$ 26	$ 27	$ 1	- Tab 9-FORECAST, Sch 66
11						
12	TOTAL	332	368	372	$ 4	- Tab 9-FORECAST, Sch 4

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 381	$ 474	$ 93	- Tab 9-FORECAST, Sch 58
4					
5	Less: Amortization of Contributions in Aid of Construction	(36)	(36)	-	- Tab 9-FORECAST, Sch 63
6		345	438	93	- Tab 9-FORECAST, Sch 35
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 27	$ 78	$ 51	- Tab 9-FORECAST, Sch 68
11					
12	TOTAL	$ 372	516	$ 144	- Tab 9-FORECAST, Sch 5

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 474	$ 516	$ 42	- Tab 9-FORECAST, Sch 61
4					
5	Less: Amortization of Contributions in Aid of Construction	(36)	(36)	-	- Tab 9-FORECAST, Sch 64
6		438	480	42	- Tab 9-FORECAST, Sch 36
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 78	$ 178	$ 100	- Tab 9-FORECAST, Sch 70
11					
12	TOTAL	$ 516	$ 658	$ 142	- Tab 9-FORECAST, Sch 6

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED Existing Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 405	$ 578	$ 479	$ -	$ 479	$ (99)	- Tab 9-FORECAST, Sch 4
3	Deduct - Interest on Debt	(295)	(311)	(287)	-	(287)	24	- Tab 9-FORECAST, Sch 80
4	Net Additions (Deductions)	(318)	(8)	(33)	-	(33)	(25)	- Tab 9-FORECAST, Sch 34
5	Accounting Income After Tax	$ (208)	$ 259	$ 159	$ -	$ 159	$ (100)	
6								
7	Current Income Tax Rate	25.00%	26.00%	26.00%	26.00%	26.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	74.00%	74.00%	74.00%	74.00%	0.00%	
9								
10	Taxable Income	$ (280)	$ 350	$ 215	$ -	$ 215	$ (135)	
11								
12								
13	Income Tax - Current	$ (72)	$ 91	$ 56	$ -	$ 56	$ (35)	
14								
15	**Total Income Tax**	$ (72)	$ 91	$ 56	$ -	$ 56	$ (35)	- Tab 9-FORECAST, Sch 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 Existing Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 479	$ 468	$ 350	$ 818	$ 339	- Tab 9-FORECAST, Sch 5
3	Deduct - Interest on Debt	(287)	(422)	-	(422)	(135)	- Tab 9-FORECAST, Sch 81
4	Net Additions (Deductions)	(33)	(76)	-	(76)	(43)	- Tab 9-FORECAST, Sch 35
5	Accounting Income After Tax	159	$ (30)	$ 350	$ 320	$ 161	
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	215	$ (41)	$ 473	$ 432	$ 217	
11							
12							
13	Income Tax - Current	$ 56	$ (11)	$ 123	$ 112	$ 56	
14							
15	**Total Income Tax**	$ 56	$ (11)	$ 123	$ 112	$ 56	- Tab 9-FORECAST, Sch 5

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 818	$ 377	$ 463	$ 840	$ 22	- Tab 9-FORECAST, Sch 6
3	Deduct - Interest on Debt	(422)	(430)	-	(430)	(8)	- Tab 9-FORECAST, Sch 82
4	Net Additions (Deductions)	(76)	(140)	-	(140)	(64)	- Tab 9-FORECAST, Sch 36
5	Accounting Income After Tax	320	$ (193)	$ 463	$ 270	$ (50)	
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	432	$ (261)	$ 626	$ 365	$ (67)	
11							
12							
13	Income Tax - Current	$ 112	$ (68)	$ 163	$ 95	$ (17)	
14							
15	**Total Income Tax**	$ 112	$ (68)	$ 163	$ 95	$ (17)	- Tab 9-FORECAST, Sch 6

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 4	$ -	-	$ -	
3	Depreciation	336	342	345	3	- Tab 9-FORECAST, Sch 28
4	Amortization of Debt Issue Expenses	3	2	2	-	
5	Pension Expense	41	38	38	-	
6	OPEB Expense	15	15	15	-	
7	2012 Fort Nelson Revenue Surplus (Net of Tax)	(86)	-	-	-	
8	2014 Fort Nelson Revenue Surplus (Net of Tax)	-	-	27	27	
9	Bad Debt Provision	-	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	(4)	26	27	1	- Tab 9-FORECAST, Sch 28
13	Capital Cost Allowance	(476)	(377)	(352)	25	- Tab 9-FORECAST, Sch 37
14	Cumulative Eligible Capital Allowance	-	-	-	-	
15	Debt Issue Costs	(2)	-	-	-	
16	Pension Contributions	(57)	(36)	(73)	(37)	
17	OPEB Contributions	(8)	(7)	(13)	(6)	
18	Overheads Capitalized Expensed for Tax Purposes	(54)	-	(38)	(38)	
19	Removal Costs	(16)	(11)	(11)	-	
20	Major Inspection Costs	(14)	-	-	-	
21	TOTAL	(318)	(8)	$ (33)	$ (25)	- Tab 9-FORECAST, Sch 31

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ -	-	$ -	
3	Depreciation	345	438	93	- Tab 9-FORECAST, Sch 29
4	Amortization of Debt Issue Expenses	2	3	1	
5	Pension Expense	38	97	59	
6	OPEB Expense	15	47	32	
7	2012 Fort Nelson Revenue Surplus (Net of Tax)	-	-	-	
8	2014 Fort Nelson Revenue Surplus (Net of Tax)	27	-	(27)	
9	Bad Debt Provision	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	27	78	51	- Tab 9-FORECAST, Sch 29
13	Capital Cost Allowance	(352)	(599)	(247)	- Tab 9-FORECAST, Sch 38
14	Cumulative Eligible Capital Allowance	-	-	-	
15	Debt Issue Costs	-	-	-	
16	Pension Contributions	(73)	(75)	(2)	
17	OPEB Contributions	(13)	(14)	(1)	
18	Overheads Capitalized Expensed for Tax Purposes	(38)	(40)	(2)	
19	Removal Costs	(11)	(11)	-	
20	Major Inspection Costs	-	-	-	
21	TOTAL	$ (33)	$ (76)	$ (43)	- Tab 9-FORECAST, Sch 32

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ -	-	$ -	
3	Depreciation	438	480	42	- Tab 9-FORECAST, Sch 30
4	Amortization of Debt Issue Expenses	3	2	(1)	
5	Pension Expense	97	81	(16)	
6	OPEB Expense	47	47	-	
7	2012 Fort Nelson Revenue Surplus (Net of Tax)	-	-	-	
8	2014 Fort Nelson Revenue Surplus (Net of Tax)	-	-	-	
9	Bad Debt Provision	-	-	-	
10					
11	**Deductions:**				
12	Amortization of Deferred Charges	78	178	100	- Tab 9-FORECAST, Sch 30
13	Capital Cost Allowance	(599)	(799)	(200)	- Tab 9-FORECAST, Sch 39
14	Cumulative Eligible Capital Allowance	-	-	-	
15	Debt Issue Costs	-	-	-	
16	Pension Contributions	(75)	(61)	14	
17	OPEB Contributions	(14)	(16)	(2)	
18	Overheads Capitalized Expensed for Tax Purposes	(40)	(41)	(1)	
19	Removal Costs	(11)	(11)	-	
20	Major Inspection Costs	-	-	-	
21	TOTAL	$ (76)	$ (140)	$ (64)	- Tab 9-FORECAST, Sch 33

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%	$ 2,362	$ -	$ -	$ (94)	$ 2,268
2	1(b)	6%	445	-	11	(27)	429
3	2	6%	255	-	-	(15)	240
4	3	5%	13	-	-	(1)	12
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	2	-	-	-	2
8	10	30%	44	-	10	(15)	39
9	12	100%	31	-	60	(61)	30
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	249	-	620	(45)	824
18	50	55%	38	-	40	(32)	46
19	51	6%	830	-	400	(62)	1,168
20	43.2	50%	-	-	-	-	-
21		Total	$ 4,270	$ -	$ 1,141	$ (352)	$ 5,059
22							
23	Cross Reference					- Tab 9-FORECAST, Sch 34	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Class	CCA Rate	12/31/2014 UCC Balance	Adjustments	2015 Net Additions	2015 CCA	12/31/2015 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 2,268	$ -	$ -	$ (91)	$ 2,177
2	1(b)	6%	429	-	152	(30)	551
3	2	6%	240	-	-	(14)	226
4	3	5%	12	-	-	(1)	11
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	2	-	-	-	2
8	10	30%	39	-	10	(13)	36
9	12	100%	30	-	60	(60)	30
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	824	-	5,091	(270)	5,645
18	50	55%	46	-	40	(37)	49
19	51	6%	1,168	-	446	(83)	1,531
20	43.2	50%	-	-	-	-	-
21		Total	$ 5,059	$ -	$ 5,799	$ (599)	$ 10,259
22							
23	Cross Reference					- Tab 9-FORECAST, Sch 35	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Class	CCA Rate	12/31/2015 UCC Balance	Adjustments	2016 Net Additions	2016 CCA	12/31/2016 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 2,177	$ -	$ -	$ (87)	$ 2,090
2	1(b)	6%	551	-	35	(34)	552
3	2	6%	226	-	-	(14)	212
4	3	5%	11	-	-	(1)	10
5	6	10%	1	-	-	-	1
6	7	15%	-	-	-	-	-
7	8	20%	2	-	-	-	2
8	10	30%	36	-	10	(12)	34
9	12	100%	30	-	60	(60)	30
10	13	manual	-	-	-	-	-
11	14	manual	-	-	-	-	-
12	17	8%	-	-	-	-	-
13	38	30%	-	-	-	-	-
14	39	25%	-	-	-	-	-
15	45	45%	-	-	-	-	-
16	47	8%	-	-	-	-	-
17	49	8%	5,645	-	84	(455)	5,274
18	50	55%	49	-	40	(39)	50
19	51	6%	1,531	-	163	(97)	1,597
20	43.2	50%	-	-	-	-	-
21		Total	$ 10,259	$ -	$ 392	$ (799)	$ 9,852
22							
23	Cross Reference					- Tab 9-FORECAST, Sch 36	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED Existing 2014 Rates	Adjustments	2014 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	Gas Plant in Service, Beginning	$ 9,333	$ 10,010	$ 9,454	$ -	$ 9,454	$ (556)	- Tab 9-FORECAST, Sch 46
2	Opening Balance Adjustment	(37)	-	-	-	-	-	
3	Gas Plant in Service, Ending	9,454	13,898	10,619	-	10,619	(3,279)	- Tab 9-FORECAST, Sch 46
4								
5	Accumulated Depreciation Beginning - Plant	$ (2,660)	$ (2,957)	$ (3,138)	$ -	$ (3,138)	$ (181)	- Tab 9-FORECAST, Sch 55
6	Opening Balance Adjustment	-	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(3,138)	(3,331)	(3,466)	-	(3,466)	(135)	- Tab 9-FORECAST, Sch 55
8								
9	CIAC, Beginning	$ (1,300)	$ (1,300)	$ (1,313)	$ -	$ (1,313)	$ (13)	- Tab 9-FORECAST, Sch 62
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	CIAC, Ending	(1,313)	(1,300)	(1,313)	-	(1,313)	(13)	- Tab 9-FORECAST, Sch 62
12								
13	Accumulated Amortization Beginning - CIAC	$ 557	$ 591	$ 592	$ -	$ 592	$ 1	- Tab 9-FORECAST, Sch 62
14	Opening Balance Adjustment	-	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	592	626	628	-	628	2	- Tab 9-FORECAST, Sch 62
16								
17	Net Plant in Service, Mid-Year	$ 5,744	$ 8,119	$ 6,032	$ -	$ 6,032	$ (2,087)	
18								
19	Adjustment to 13-Month Average	(177)	-	-	-	-	-	
20	Work in Progress, No AFUDC	62	-	35	-	35	35	
21	Unamortized Deferred Charges	(283)	(210)	(393)	-	(393)	(183)	- Tab 9-FORECAST, Sch 66
22	Cash Working Capital	(2)	27	10	-	10	(17)	- Tab 9-FORECAST, Sch 74
23	Other Working Capital	14	-	14	-	14	14	- Tab 9-FORECAST, Sch 74
24	**Utility Rate Base**	$ 5,358	$ 7,936	$ 5,698	$ -	$ 5,698	$ (2,238)	- Tab 9-FORECAST, Sch 80
25								- Tab 9-FORECAST, Sch 4

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 FORECAST Existing 2014 Rates	Adjustments	2014 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 9,454	$ 10,619	$ -	$ 10,619	$ 1,165	- Tab 9-FORECAST, Sch 49
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	10,619	16,458	-	16,458	5,839	- Tab 9-FORECAST, Sch 49
4							
5	Accumulated Depreciation Beginning - Plant	$ (3,138)	$ (3,466)	$ -	$ (3,466)	$ (328)	- Tab 9-FORECAST, Sch 58
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(3,466)	(3,889)	-	(3,889)	(423)	- Tab 9-FORECAST, Sch 58
8							
9	CIAC, Beginning	$ (1,313)	$ (1,313)	$ -	$ (1,313)	$ -	- Tab 9-FORECAST, Sch 63
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(1,313)	(1,313)	-	(1,313)	-	- Tab 9-FORECAST, Sch 63
12							
13	Accumulated Amortization Beginning - CIAC	$ 592	$ 628	$ -	$ 628	$ 36	- Tab 9-FORECAST, Sch 63
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	628	664	-	664	36	- Tab 9-FORECAST, Sch 63
16							
17	Net Plant in Service, Mid-Year	$ 6,032	$ 9,194	$ -	$ 9,194	$ 3,163	
18							
19	Adjustment to 13-Month Average	-	2,105	-	2,105	2,105	
20	Work in Progress, No AFUDC	35	35	-	35	-	
21	Unamortized Deferred Charges	(393)	383	-	383	776	- Tab 9-FORECAST, Sch 68
22	Cash Working Capital	10	16	9	25	15	- Tab 9-FORECAST, Sch 75
23	Other Working Capital	14	14	-	14	-	- Tab 9-FORECAST, Sch 75
24	**Utility Rate Base**	$ 5,698	$ 11,747	$ 9	$ 11,756	$ 6,058	- Tab 9-FORECAST, Sch 81
25							- Tab 9-FORECAST, Sch 5

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 FORECAST Existing 2014 Rates	Adjustments	2014 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 10,619	$ 16,458	$ -	$ 16,458	$ 5,839	- Tab 9-FORECAST, Sch 52
2	Opening Balance Adjustment	-	-	-	-	-	
3	Gas Plant in Service, Ending	16,458	16,774	-	16,774	316	- Tab 9-FORECAST, Sch 52
4							
5	Accumulated Depreciation Beginning - Plant	$ (3,466)	$ (3,889)	$ -	$ (3,889)	$ (423)	- Tab 9-FORECAST, Sch 61
6	Opening Balance Adjustment	-	-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(3,889)	(4,278)	-	(4,278)	(389)	- Tab 9-FORECAST, Sch 61
8							
9	CIAC, Beginning	$ (1,313)	$ (1,313)	$ -	$ (1,313)	$ -	- Tab 9-FORECAST, Sch 64
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(1,313)	(1,313)	-	(1,313)	-	- Tab 9-FORECAST, Sch 64
12							
13	Accumulated Amortization Beginning - CIAC	$ 628	$ 664	$ -	$ 664	$ 36	- Tab 9-FORECAST, Sch 64
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	664	700	-	700	36	- Tab 9-FORECAST, Sch 64
16							
17	Net Plant in Service, Mid-Year	$ 9,194	$ 11,902	$ -	$ 11,902	$ 2,708	
18							
19	Adjustment to 13-Month Average	2,105	-	-	-	(2,105)	
20	Work in Progress, No AFUDC	35	35	-	35	-	
21	Unamortized Deferred Charges	383	203	-	203	(180)	- Tab 9-FORECAST, Sch 70
22	Cash Working Capital	25	13	11	24	(1)	- Tab 9-FORECAST, Sch 76
23	Other Working Capital	14	14	-	14	-	- Tab 9-FORECAST, Sch 76
24	**Utility Rate Base**	$ 11,756	$ 12,167	$ 11	$ 12,178	$ 422	- Tab 9-FORECAST, Sch 82
25							- Tab 9-FORECAST, Sch 6

FORTISBC ENERGY INC. - Fort Nelson

12/3/2014

Tab 9
FORECAST
Schedule 43

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000)

Line No.	Particulars (1)	2014 Projected (2)	2015 Forecast (3)	2016 Forecast (4)	Cross Reference (5)
1	**CAPITAL EXPENDITURES**				
2					
3	Regular Capital Expenditures				
4					
5	Regular Capital Expenditures	$ 1,067	$ 1,510	$ 312	
6	Muskwa River	-	-	-	
7	Total Regular Capital Expenditures	$ 1,067	$ 1,510	$ 312	
8					
9	Special Projects - CPCN's				
10	Muskwa river	3,783	4,210	-	
11					
12	Total CPCN's	$ 3,783	$ 4,210	$ -	
13					
14					
15	TOTAL CAPITAL EXPENDITURES	$ 4,850	$ 5,720	$ 312	
16					
17					
18	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**				
19					
20	Regular Capital				
21	Regular Capital Expenditures	$ 1,067	$ 1,510	$ 312	
22	Add - Opening WIP	397	397	397	
23	Less - Adjustments	-	-	-	
24	Less - Closing WIP	(397)	(397)	(397)	
25	Add - AFUDC	38	50	8	
26	Add - Overhead Capitalized	113	120	123	
27					
28	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 1,218	$ 1,680	$ 443	
29					
30	Special Projects - CPCN's				
31	CPCN Expenditures	$ 3,783	$ 4,210	$ -	
32	Add - Opening WIP	271	-	-	
33	Less - Closing WIP	-	-	-	
34	Less: Adjustments	-	-	-	
35	Add - AFUDC	156	-	-	
36					
37	TOTAL CPCN ADDITIONS	$ 4,210	$ 4,210	$ -	
38					
39	TOTAL PLANT ADDITIONS	$ 5,428	$ 5,890	$ 443	
40					
41	Cross Reference	- Tab 9-FORECAST, Sch 46		- Tab 9-FORECAST, Sch 52	
42			- Tab 9-FORECAST, Sch 49		

FORTISBC ENERGY INC. - Fort Nelson

12/3/2014 Tab 9
FORECAST
Schedule 44

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 31/12/2013	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	-	-	-	-	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	-	-	-	-	-	-	-	-
5	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
9	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	8	-	-	-	-	-	-	8	8
12	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
13	471-00 Distribution Land Rights	20	-	-	-	-	-	-	20	20
14	402-01 Application Software - 12.5%	444	-	30	1	-	(19)	-	456	450
15	402-02 Application Software - 20%	95	-	30	1	-	(12)	-	114	105
16	TOTAL INTANGIBLE	567	-	60	2	-	(31)	-	598	583
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipme	-	-	-	-	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
27	TOTAL MANUFACTURED	-	-	-	-	-	-	-	-	-

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 31/12/2013	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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	10	-	-	-	-	-	-	10	10
6	464-00 Other Structures & Improvements	-	-	-	-	-	-	-	-	-
7	465-00 Mains	675	-	575	26	69	-	-	1,345	1,010
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	-	-	-	-	-	-	670	670
12	467-20 Telemetering	6	-	-	-	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	1,361	-	575	26	69	-	-	2,031	1,696
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
19	472-00 Structures & Improvements	257	-	-	-	-	-	-	257	257
20	473-00 Services	2,325	-	38	-	5	-	-	2,368	2,347
21	474-00 House Regulators & Meter Installations	518	-	-	-	-	-	-	518	518
22	477-00 Meters/Regulators Installations	42	-	6	-	1	-	-	49	46
23	475-00 Mains	2,243	-	140	1	16	-	-	2,400	2,322
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,134	-	182	8	22	-	-	1,346	1,240
26	477-00 Telemetering	13	-	-	-	-	-	-	13	13
27	478-10 Meters	14	-	6	-	-	-	-	20	17
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,546	-	372	9	44	-	-	6,971	6,759
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 31/12/2013	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	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1	-	-	-	-	-	-	1	1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	228	-	-	-	-	-	-	228	228
6	- Masonry Buildings	428	-	10	-	-	-	-	438	433
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	6	-	-	-	-	-	-	6	6
10	483-40 GP Furniture	8	-	-	-	-	-	-	8	8
11	483-10 GP Computer Hardware	165	-	40	1	-	(19)	-	187	176
12	483-20 GP Computer Software	22	-	-	-	-	-	-	22	22
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	50	-	10	-	-	-	-	60	55
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	-	-	-	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	48	-	-	-	-	(3)	-	45	47
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	24	-	-	-	-	-	-	24	24
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	980	-	60	1	-	(22)	-	1,019	1,000
27										
28	**UNCLASSIFIED PLANT**									
29	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 9,454	$ -	$ 1,067	$ 38	$ 113	$ (53)	$ -	$ 10,619	$ 10,037
33										
34	Cross Reference	- Tab 9-FORECAST, Sch 40		- Tab 9-FORECAST, Sch 43					- Tab 9-FORECAST, Sch 40	
35			- Tab 9-FORECAST, Sch 43			- Tab 9-FORECAST, Sch 43				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Balance 12/31/2014	CPCN'S	2015 Additions	2015 AFUDC	2015 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2015	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	-	-	-	-	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	-	-	-	-	-	-	-	-
5	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
9	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	8	-	-	-	-	-	-	8	8
12	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
13	471-00 Distribution Land Rights	20	-	-	-	-	-	-	20	20
14	402-01 Application Software - 12.5%	456	-	30	1	-	(7)	-	480	468
15	402-02 Application Software - 20%	114	-	30	1	-	(16)	-	129	122
16	TOTAL INTANGIBLE	598	-	60	2	-	(23)	-	637	618
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipme	-	-	-	-	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
27	TOTAL MANUFACTURED	-	-	-	-	-	-	-	-	-

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Balance 12/31/2014	CPCN'S	2015 Additions	2015 AFUDC	2015 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2015	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	10	-	-	-	-	-	-	10	10
6	464-00 Other Structures & Improvements	-	-	-	-	-	-	-	-	-
7	465-00 Mains	1,345	4,210	809	36	78	-	-	6,478	3,912
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	-	-	-	-	-	-	670	670
12	467-20 Telemetering	6	-	-	-	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	2,031	4,210	809	36	78	-	-	7,164	4,598
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
19	472-00 Structures & Improvements	257	-	-	-	-	-	-	257	257
20	473-00 Services	2,368	-	39	-	4	-	-	2,411	2,390
21	474-00 House Regulators & Meter Installations	518	-	-	-	-	-	-	518	518
22	477-00 Meters/Regulators Installations	49	-	6	-	1	-	-	56	53
23	475-00 Mains	2,400	-	160	-	15	-	-	2,575	2,488
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,346	-	160	7	15	-	-	1,528	1,437
26	477-00 Telemetering	13	-	70	1	7	-	-	91	52
27	478-10 Meters	20	-	6	-	-	-	-	26	23
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,971	-	441	8	42	-	-	7,462	7,217
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Balance 12/31/2014	CPCN'S	2015 Additions	2015 AFUDC	2015 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2015	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1	-	-	-	-	-	-	1	1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	228	-	-	-	-	-	-	228	228
6	- Masonry Buildings	438	-	150	3	-	-	-	591	515
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	6	-	-	-	-	-	-	6	6
10	483-40 GP Furniture	8	-	-	-	-	(7)	-	1	5
11	483-10 GP Computer Hardware	187	-	40	1	-	(14)	-	214	201
12	483-20 GP Computer Software	22	-	-	-	-	(3)	-	19	21
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	60	-	10	-	-	-	-	70	65
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	-	-	-	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	45	-	-	-	-	(4)	-	41	43
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	24	-	-	-	-	-	-	24	24
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	1,019	-	200	4	-	(28)	-	1,195	1,107
27										
28	**UNCLASSIFIED PLANT**									
29	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 10,619	$ 4,210	$ 1,510	$ 50	$ 120	$ (51)	$ -	$ 16,458	$ 13,539
33										
34	Cross Reference	- Tab 9-FORECAST, Sch 41		- Tab 9-FORECAST, Sch 43				- Tab 9-FORECAST, Sch 41		
35			- Tab 9-FORECAST, Sch 43			- Tab 9-FORECAST, Sch 43				

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2015	CPCN'S	2016 Additions	2016 AFUDC	2016 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2016	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	-	-	-	-	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	-	-	-	-	-	-	-	-
5	178-00 Organization Expense	-	-	-	-	-	-	-	-	-
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	-	-	-	-	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-
9	402-00 Other Intangible Plant	-	-	-	-	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	8	-	-	-	-	-	-	8	8
12	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
13	471-00 Distribution Land Rights	20	-	-	-	-	-	-	20	20
14	402-01 Application Software - 12.5%	480	-	30	1	-	(47)	-	464	472
15	402-02 Application Software - 20%	129	-	30	1	-	(23)	-	137	133
16	TOTAL INTANGIBLE	637	-	60	2	-	(70)	-	629	633
17										
18	**MANUFACTURED GAS / LOCAL STORAGE**									
19	430-00 Manufact'd Gas - Land	-	-	-	-	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	-	-	-	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	-	-	-	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	-	-	-	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	-	-	-	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipme	-	-	-	-	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes	-	-	-	-	-	-	-	-	-
27	TOTAL MANUFACTURED	-	-	-	-	-	-	-	-	-

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2015	CPCN'S	2016 Additions	2016 AFUDC	2016 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2016	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	462-00 Compressor Structures	-	-	-	-	-	-	-	-	-
5	463-00 Measuring Structures	10	-	-	-	-	-	-	10	10
6	464-00 Other Structures & Improvements	-	-	-	-	-	-	-	-	-
7	465-00 Mains	6,478	-	60	3	43	-	-	6,584	6,531
8	465-00 Mains - INSPECTION	-	-	-	-	-	-	-	-	-
9	466-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	-	-	-	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	-	-	-	-	-	-	670	670
12	467-20 Telemetering	6	-	-	-	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	-	-	-	-	-	-	-	-
14	TOTAL TRANSMISSION	7,164	-	60	3	43	-	-	7,270	7,217
15										
16	**DISTRIBUTION PLANT**									
17	470-00 Land in Fee Simple	-	-	-	-	-	-	-	-	-
18	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
19	472-00 Structures & Improvements	257	-	-	-	-	-	-	257	257
20	473-00 Services	2,411	-	40	-	29	-	-	2,480	2,446
21	474-00 House Regulators & Meter Installations	518	-	-	-	-	-	-	518	518
22	477-00 Meters/Regulators Installations	56	-	6	-	4	-	-	66	61
23	475-00 Mains	2,575	-	15	-	11	-	-	2,601	2,588
24	476-00 Compressor Equipment	-	-	-	-	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,528	-	50	2	36	-	-	1,616	1,572
26	477-00 Telemetering	91	-	-	-	-	-	-	91	91
27	478-10 Meters	26	-	6	-	-	-	-	32	29
28	478-20 Instruments	-	-	-	-	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
30	TOTAL DISTRIBUTION	7,462	-	117	2	80	-	-	7,661	7,562
31										

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	B.C.U.C. Account	Balance 12/31/2015	CPCN'S	2016 Additions	2016 AFUDC	2016 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2016	Mid-year GPIS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT & EQUIPMENT**									
2	480-00 Land in Fee Simple	1	-	-	-	-	-	-	1	1
3	481-00 Land Rights	-	-	-	-	-	-	-	-	-
4	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
5	- Frame Buildings	228	-	-	-	-	-	-	228	228
6	- Masonry Buildings	591	-	25	-	-	-	-	616	604
7	- Leasehold Improvement	-	-	-	-	-	-	-	-	-
8	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
9	483-30 GP Office Equipment	6	-	-	-	-	-	-	6	6
10	483-40 GP Furniture	1	-	-	-	-	-	-	1	1
11	483-10 GP Computer Hardware	214	-	40	1	-	(47)	-	208	211
12	483-20 GP Computer Software	19	-	-	-	-	(3)	-	16	18
13	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
14	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
15	484-00 Vehicles	70	-	10	-	-	-	-	80	75
16	484-00 Vehicles - Leased	-	-	-	-	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	-	-	-	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	-	-	-	-	-	-	-	-
19	486-00 Small Tools & Equipment	41	-	-	-	-	(7)	-	34	38
20	487-00 Equipment on Customer's Premises	-	-	-	-	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
22	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
23	- Telephone	24	-	-	-	-	-	-	24	24
24	- Radio	-	-	-	-	-	-	-	-	-
25	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
26	TOTAL GENERAL	1,195	-	75	1	-	(57)	-	1,214	1,205
27										
28	**UNCLASSIFIED PLANT**									
29	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
31										
32	TOTAL CAPITAL	$ 16,458	$ -	$ 312	$ 8	$ 123	$ (127)	$ -	$ 16,774	$ 16,616
33										
34	Cross Reference	- Tab 9-FORECAST, Sch 42		- Tab 9-FORECAST, Sch 43					- Tab 9-FORECAST, Sch 42	
35			- Tab 9-FORECAST, Sch 43			- Tab 9-FORECAST, Sch 43				

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 31/12/2013	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	-	1.00%	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	10.00%	-	-	-	-	-
5	178-00 Organization Expense	-	1.00%	-	-	-	-	-
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	-	49.19%	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	57.14%	-	-	-	-	-
9	402-00 Other Intangible Plant	-	2.38%	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	8	0.00%	-	-	-	-	-
12	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
13	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-
14	402-01 Application Software - 12.5%	444	12.50%	56	-	(19)	141	178
15	402-02 Application Software - 20%	95	20.00%	19	-	(12)	40	47
16	TOTAL INTANGIBLE	567		75	-	(31)	181	225
17								
18	**MANUFACTURED GAS / LOCAL STORAGE**							
19	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	3.38%	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	6.63%	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	2.35%	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	5.16%	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	15.89%	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
27	TOTAL MANUFACTURED	-		-	-	-	-	-

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 31/12/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.74%	-	-	-	-	-
5	463-00 Measuring Structures	10	3.80%	-	-	-	1	1
6	464-00 Other Structures & Improvements	-	2.83%	-	-	-	-	-
7	465-00 Mains	675	1.44%	10	-	-	297	307
8	465-00 Mains - INSPECTION	-	14.87%	-	-	-	-	-
9	466-00 Compressor Equipment	-	2.87%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	4.47%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	4.27%	29	-	-	177	206
12	467-20 Telemetering	6	0.31%	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	4.37%	-	-	-	-	-
14	TOTAL TRANSMISSION	1,361		39	-	-	481	520
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	257	3.33%	9	-	-	87	96
20	473-00 Services	2,325	2.53%	59	-	-	748	807
21	474-00 House Regulators & Meter Installations	518	7.62%	39	-	-	251	290
22	477-00 Meters/Regulators Installations	42	4.55%	2	-	-	2	4
23	475-00 Mains	2,243	1.59%	36	-	-	567	603
24	476-00 Compressor Equipment	-	26.54%	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,134	4.75%	54	-	-	437	491
26	477-00 Telemetering	13	0.25%	-	-	-	12	12
27	478-10 Meters	14	8.05%	1	-	-	13	14
28	478-20 Instruments	-	3.15%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,546		200	-	-	2,117	2,317
31								

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 31/12/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	228	4.82%	11	-	-	18	29
6	- Masonry Buildings	428	2.23%	10	-	-	212	222
7	- Leasehold Improvement	-	10.00%	-	-	-	-	-
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	6	6.67%	-	-	-	3	3
10	483-40 GP Furniture	8	5.00%	-	-	-	7	7
11	483-10 GP Computer Hardware	165	20.00%	33	-	(19)	59	73
12	483-20 GP Computer Software	22	12.50%	3	-	-	7	10
13	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	50	12.50%	6	-	-	1	7
16	484-00 Vehicles - Leased	-	0.00%	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	8.96%	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	18.06%	-	-	-	-	-
19	486-00 Small Tools & Equipment	48	5.00%	2	-	(3)	38	37
20	487-00 Equipment on Customer's Premises	-	6.67%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	24	6.67%	2	-	-	14	16
24	- Radio	-	6.67%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	980		67	-	(22)	359	404
27								
28	**UNCLASSIFIED PLANT**							
29	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 9,454		$ 381	$ -	$ (53)	$ 3,138	$ 3,466
33								
34	Cross Reference	- Tab 9-FORECAST, Sch 46		- Tab 9-FORECAST, Sch 28			- Tab 9-FORECAST, Sch 40	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2015 DEPRECIATION Provision (Cr.)	Adjust- ments	Retirements	Accumulated 12/31/2014	Accumulated 12/31/2015
	(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	-	1.00%	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	10.00%	-	-	-	-	-
5	178-00 Organization Expense	-	1.00%	-	-	-	-	-
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	-	2.02%	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
9	402-00 Other Intangible Plant	-	2.05%	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	8	0.00%	-	-	-	-	-
12	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
13	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-
14	402-01 Application Software - 12.5%	456	12.50%	57	-	(7)	178	228
15	402-02 Application Software - 20%	114	20.00%	23	-	(16)	47	54
16	TOTAL INTANGIBLE	598		80	-	(23)	225	282
17								
18	**MANUFACTURED GAS / LOCAL STORAGE**							
19	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	3.40%	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	6.54%	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	2.35%	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	5.19%	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	15.89%	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
27	TOTAL MANUFACTURED	-		-	-	-	-	-

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2015 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2014	Accumulated 12/31/2015
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.66%	-	-	-	-	-
5	463-00 Measuring Structures	10	3.37%	-	-	-	1	1
6	464-00 Other Structures & Improvements	-	2.84%	-	-	-	-	-
7	465-00 Mains	1,345	1.47%	82	-	-	307	389
8	465-00 Mains - INSPECTION	-	14.73%	-	-	-	-	-
9	466-00 Compressor Equipment	-	2.88%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	17.38%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	4.28%	29	-	-	206	235
12	467-20 Telemetering	6	0.74%	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	11.34%	-	-	-	-	-
14	TOTAL TRANSMISSION	2,031		111	-	-	520	631
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	257	3.30%	8	-	-	96	104
20	473-00 Services	2,368	2.40%	57	-	-	807	864
21	474-00 House Regulators & Meter Installations	518	6.92%	36	-	-	290	326
22	477-00 Meters/Regulators Installations	49	4.55%	2	-	-	4	6
23	475-00 Mains	2,400	1.58%	38	-	-	603	641
24	476-00 Compressor Equipment	-	26.58%	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,346	4.71%	63	-	-	491	554
26	477-00 Telemetering	13	0.25%	-	-	-	12	12
27	478-10 Meters	20	7.66%	2	-	-	14	16
28	478-20 Instruments	-	3.15%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	6,971		206	-	-	2,317	2,523
31								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2015 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2014	12/31/2015
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	228	5.34%	12	-	-	29	41
6	- Masonry Buildings	438	2.23%	10	-	-	222	232
7	- Leasehold Improvement	-	9.13%	-	-	-	-	-
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	6	6.67%	-	-	-	3	3
10	483-40 GP Furniture	8	5.00%	-	-	(7)	7	-
11	483-10 GP Computer Hardware	187	20.00%	38	-	(14)	73	97
12	483-20 GP Computer Software	22	12.50%	3	-	(3)	10	10
13	483-21 GP Computer Software	-	0.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	60	16.52%	10	-	-	7	17
16	484-00 Vehicles - Leased	-	9.44%	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	6.47%	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	16.36%	-	-	-	-	-
19	486-00 Small Tools & Equipment	45	5.00%	2	-	(4)	37	35
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	24	6.67%	2	-	-	16	18
24	- Radio	-	6.68%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	1,019		77	-	(28)	404	453
27								
28	**UNCLASSIFIED PLANT**							
29	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 10,619		$ 474	$ -	$ (51)	$ 3,466	$ 3,889
33								
34	Cross Reference	- Tab 9-FORECAST, Sch 49		- Tab 9-FORECAST, Sch 29			- Tab 9-FORECAST, Sch 41	

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	GPIS for Depreciation	Average Depreciation Rate %	2016 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2015	Accumulated 12/31/2016
	(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	-	1.00%	-	-	-	-	-
4	175-00 Unamortized Conversion Expense - Squamish	-	10.00%	-	-	-	-	-
5	178-00 Organization Expense	-	1.00%	-	-	-	-	-
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	-	2.02%	-	-	-	-	-
8	402-00 Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-
9	402-00 Other Intangible Plant	-	2.05%	-	-	-	-	-
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	8	0.00%	-	-	-	-	-
12	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
13	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-
14	402-01 Application Software - 12.5%	480	12.50%	60	-	(47)	228	241
15	402-02 Application Software - 20%	129	20.00%	26	-	(23)	54	57
16	TOTAL INTANGIBLE	637		86	-	(70)	282	298
17								
18	**MANUFACTURED GAS / LOCAL STORAGE**							
19	430-00 Manufact'd Gas - Land	-	0.00%	-	-	-	-	-
20	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
21	432-00 Manufact'd Gas - Struct. & Improvements	-	3.40%	-	-	-	-	-
22	433-00 Manufact'd Gas - Equipment	-	6.54%	-	-	-	-	-
23	434-00 Manufact'd Gas - Gas Holders	-	2.35%	-	-	-	-	-
24	436-00 Manufact'd Gas - Compressor Equipment	-	5.19%	-	-	-	-	-
25	437-00 Manufact'd Gas - Measuring & Regulating Equipment	-	15.89%	-	-	-	-	-
26	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
27	TOTAL MANUFACTURED	-		-	-	-	-	-

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	GPIS for Depreciation	Average Depreciation Rate %	2016 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2015	Accumulated 12/31/2016
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	462-00 Compressor Structures	-	3.66%	-	-	-	-	-
5	463-00 Measuring Structures	10	3.37%	-	-	-	1	1
6	464-00 Other Structures & Improvements	-	2.84%	-	-	-	-	-
7	465-00 Mains	6,478	1.47%	95	-	-	389	484
8	465-00 Mains - INSPECTION	-	14.73%	-	-	-	-	-
9	466-00 Compressor Equipment	-	2.88%	-	-	-	-	-
10	466-00 Compressor Equipment - OVERHAUL	-	17.38%	-	-	-	-	-
11	467-10 Measuring & Regulating Equipment	670	4.28%	29	-	-	235	264
12	467-20 Telemetering	6	0.74%	-	-	-	6	6
13	468-00 Communication Structures & Equipment	-	11.34%	-	-	-	-	-
14	TOTAL TRANSMISSION	7,164		124	-	-	631	755
15								
16	**DISTRIBUTION PLANT**							
17	470-00 Land in Fee Simple	-	0.00%	-	-	-	-	-
18	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
19	472-00 Structures & Improvements	257	3.30%	8	-	-	104	112
20	473-00 Services	2,411	2.40%	58	-	-	864	922
21	474-00 House Regulators & Meter Installations	518	6.92%	36	-	-	326	362
22	477-00 Meters/Regulators Installations	56	4.55%	3	-	-	6	9
23	475-00 Mains	2,575	1.58%	41	-	-	641	682
24	476-00 Compressor Equipment	-	26.58%	-	-	-	-	-
25	477-00 Measuring & Regulating Equipment	1,528	4.71%	72	-	-	554	626
26	477-00 Telemetering	91	0.25%	-	-	-	12	12
27	478-10 Meters	26	7.66%	2	-	-	16	18
28	478-20 Instruments	-	3.15%	-	-	-	-	-
29	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
30	TOTAL DISTRIBUTION	7,462		220	-	-	2,523	2,743
31								

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	GPIS for Depreciation	Average Depreciation Rate %	2016 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2015	Accumulated 12/31/2016
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**GENERAL PLANT & EQUIPMENT**							
2	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-
3	481-00 Land Rights	-	0.00%	-	-	-	-	-
4	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
5	- Frame Buildings	228	5.34%	12	-	-	41	53
6	- Masonry Buildings	591	2.23%	13	-	-	232	245
7	- Leasehold Improvement	-	9.13%	-	-	-	-	-
8	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
9	483-30 GP Office Equipment	6	6.67%	-	-	-	3	3
10	483-40 GP Furniture	1	5.00%	-	-	-	-	-
11	483-10 GP Computer Hardware	214	20.00%	43	-	(47)	97	93
12	483-20 GP Computer Software	19	12.50%	2	-	(3)	10	9
13	483-21 GP Computer Software	-	0.00%	-	-	-	-	-
14	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
15	484-00 Vehicles	70	16.52%	12	-	-	17	29
16	484-00 Vehicles - Leased	-	9.44%	-	-	-	-	-
17	485-10 Heavy Work Equipment	-	6.47%	-	-	-	-	-
18	485-20 Heavy Mobile Equipment	-	16.36%	-	-	-	-	-
19	486-00 Small Tools & Equipment	41	5.00%	2	-	(7)	35	30
20	487-00 Equipment on Customer's Premises	-	0.00%	-	-	-	-	-
21	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
22	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
23	- Telephone	24	6.67%	2	-	-	18	20
24	- Radio	-	6.68%	-	-	-	-	-
25	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
26	TOTAL GENERAL	1,195		86	-	(57)	453	482
27								
28	**UNCLASSIFIED PLANT**							
29	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
30	TOTAL UNCLASSIFIED	-		-	-	-	-	-
31								
32	TOTALS	$ 16,458		$ 516	$ -	$ (127)	$ 3,889	$ 4,278
33								
34	Cross Reference	- Tab 9-FORECAST, Sch 52		- Tab 9-FORECAST, Sch 30			- Tab 9-FORECAST, Sch 42	

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 31/12/2013	Adjustment	2014 PROJECTED Additions	2014 PROJECTED Retirements	Balance 12/31/2014	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,148	$ -	$ -	$ -	$ 1,148	
4							
5	Transmission Contributions	165	-	-	-	165	
6							
7	TOTAL Contributions	1,313	-	-	-	1,313	- Tab 9-FORECAST, Sch 40
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(580)	-	(36)	-	(616)	
14							
15	Transmission Contributions	(12)	-	-	-	(12)	
16							
17	TOTAL CIAC Amortization	(592)	-	(36)	-	(628)	- Tab 9-FORECAST, Sch 40
18							
19	**NET CONTRIBUTIONS**	$ 721	$ -	$ (36)	$ -	$ 685	
20							
21							
22				- Tab 9-FORECAST, Sch 28			
23							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Balance 12/31/2014	Adjustment	2015 FORECAST Additions	Retirements	Balance 12/31/2015	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,148	$ -	$ -	$ -	$ 1,148	
4							
5	Transmission Contributions	165	-	-	-	165	
6							
7	TOTAL Contributions	1,313	-	-	-	1,313	- Tab 9-FORECAST, Sch 41
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(616)	-	(36)	-	(652)	
14							
15	Transmission Contributions	(12)	-	-	-	(12)	
16							
17	TOTAL CIAC Amortization	(628)	-	(36)	-	(664)	- Tab 9-FORECAST, Sch 41
18							
19	**NET CONTRIBUTIONS**	$ 685	$ -	$ (36)	$ -	$ 649	
20							
21							
22				- Tab 9-FORECAST, Sch 29			
23							

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Balance 12/31/2015	Adjustment	2016 FORECAST Additions	Retirements	Balance 12/31/2016	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 1,148	$ -	$ -	$ -	$ 1,148	
4							
5	Transmission Contributions	165	-	-	-	165	
6							
7	TOTAL Contributions	1,313	-	-	-	1,313	- Tab 9-FORECAST, Sch 42
8							
9							
10							
11	**Amortization**						
12							
13	Distribution Contributions	(652)	-	(36)	-	(688)	
14							
15	Transmission Contributions	(12)	-	-	-	(12)	
16							
17	TOTAL CIAC Amortization	(664)	-	(36)	-	(700)	- Tab 9-FORECAST, Sch 42
18							
19	**NET CONTRIBUTIONS**	$ 649	$ -	$ (36)	$ -	$ 613	
20							
21							
22				- Tab 9-FORECAST, Sch 30			
23							

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	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	Revenue Stabilization Adjustment Mechanism (RSAM)	$ 57	$ -	$ 28	$ (7)	$ 20	$ -	$ (54)	$ 14	$ 37	$ 47
3	Interest on CCRA / MCRA / RSAM / Gas Storage	(4)	-	6	(2)	5	-	(1)	-	-	(2)
4	Gas Cost Reconciliation Account (GCRA)	(124)	-	327	(85)	242	-	-	-	118	(3)
5											
6	Energy Policy Deferral Accounts										
7											
8	Non-Controllable Items Deferral Accounts										
9	Property Tax Deferral	(46)	-	(30)	8	(22)	15	-	-	(53)	(50)
10	Interest Variance	(68)	-	(7)	2	(5)	15	-	-	(58)	(63)
11	Customer Service Variance Account	(79)	-	-	-	-	13	-	-	(66)	(72)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	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	2013-2015 Generic Cost of Capital Application	$ -	$ 7	$ -	$ -	$ -	$ (2)	$ -	$ -	$ 4	$ 6
3	2015-2016 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
4											
5	Other Deferral Accounts										
6	Gains and Losses on Asset Disposition	119	-	-	-	-	(5)	-	-	114	116
7	Negative Salvage Provision/Cost	39	-	11	-	11	(54)	-	-	(4)	18
8	Muskwa River Crossing COS	(273)	-	(90)	16	(74)	-	-	-	(347)	(310)
9	Fort Nelson Revenue Surplus/Deficit Account	(28)	-	(37)	10	(27)	-	-	-	(55)	(42)
10	Muskwa River Crossing Project Costs	-	-	-	-	-	-	-	-	-	-
11											
12	Residual Deferred Accounts										
13	Depreciation Variance	(35)	-	-	-	-	(9)	-	-	(44)	(39)
14	2012-2013 Revenue Requirement Application	2	-	-	-	-	(2)	-	-	-	1
15	Fort Nelson ROE & Capital Structure Deferral	(1)	-	-	-	-	1	-	-	-	(1)
16											
17	Total Deferred Charges for Rate Base	$ (441)	$ 7	$ 208	$ (59)	$ 149	$ (27)	$ (55)	$ 14	$ (352)	$ (393)
18											
19	Cross Reference						- Tab 9-FORECAST, Sch 28			- Tab 9-FORECAST, Sch 40	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Forecast Balance 12/31/2014	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2015	Mid-Year Average 2015
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	$ 37	$ -	$ -	$ -	$ -	$ -	$ (25)	$ 7	$ 19	$ 28
3	Interest on CCRA / MCRA / RSAM / Gas Storage	-	-	-	-	-	-	-	-	-	-
4	Gas Cost Reconciliation Account (GCRA)	118	-	(159)	41	(118)	-	-	-	-	59
5											
6	Energy Policy Deferral Accounts										
7											
8	Non-Controllable Items Deferral Accounts										
9	Property Tax Deferral	(53)	-	-	-	-	23	-	-	(31)	(42)
10	Interest Variance	(58)	-	-	-	-	21	-	-	(36)	(47)
11	Customer Service Variance Account	(66)	-	-	-	-	16	-	-	(50)	(58)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	Forecast Balance 12/31/2014	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2015	Mid-Year Average 2015
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2013-2015 Generic Cost of Capital Application	$ 4	$ -	$ -	$ -	$ -	$ (3)	$ -	$ -	$ 1	$ 3
3	2015-2016 Revenue Requirement Application	-	7	40	(10)	30	(19)	-	-	19	13
4											
5	Other Deferral Accounts										
6	Gains and Losses on Asset Disposition	114	-	-	-	-	(6)	-	-	107	111
7	Negative Salvage Provision/Cost	(4)	-	11	-	11	(53)	-	-	(45)	(24)
8	Muskwa River Crossing COS	(347)	-	-	-	-	116	-	-	(231)	(289)
9	Fort Nelson Revenue Surplus/Deficit Account	(55)	-	-	-	-	55	-	-	-	(28)
10	Muskwa River Crossing Project Costs	-	815	-	-	-	(272)	-	-	543	679
11											
12	Residual Deferred Accounts										
13	Depreciation Variance	(44)	-	-	-	-	44	-	-	-	(22)
14	2012-2013 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
15	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
16											
17	Total Deferred Charges for Rate Base	$ (352)	$ 822	$ (108)	$ 31	$ (77)	$ (78)	$ (25)	$ 7	$ 296	$ 383
18											
19	Cross Reference						- Tab 9-FORECAST, Sch 29			- Tab 9-FORECAST, Sch 41	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Forecast Balance 12/31/2015	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2016	Mid-Year Average 2016
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Revenue Stabilization Adjustment Mechanism (RSAM)	$ 19	$ -	$ -	$ -	$ -	$ -	$ (25)	$ 7	$ -	$ 9
3	Interest on CCRA / MCRA / RSAM / Gas Storage	-	-	-	-	-	-	-	-	-	-
4	Gas Cost Reconciliation Account (GCRA)	-	-	-	-	-	-	-	-	-	-
5											
6	Energy Policy Deferral Accounts										
7											
8	Non-Controllable Items Deferral Accounts										
9	Property Tax Deferral	(31)	-	-	-	-	23	-	-	(8)	(19)
10	Interest Variance	(36)	-	-	-	-	21	-	-	(15)	(26)
11	Customer Service Variance Account	(50)	-	-	-	-	16	-	-	(34)	(42)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	Forecast Balance 12/31/2015	Opening Bal. Transfer / Adjustment	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2016	Mid-Year Average 2016
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2013-2015 Generic Cost of Capital Application	$ 1	$ -	$ -	$ -	$ -	$ (1)	$ -	$ -	$ -	$ 0
3	2015-2016 Revenue Requirement Application	19	-	-	-	-	(19)	-	-	-	9
4											
5	Other Deferral Accounts										
6	Gains and Losses on Asset Disposition	107	-	-	-	-	(6)	-	-	101	104
7	Negative Salvage Provision/Cost	(45)	-	11	-	11	(55)	-	-	(89)	(67)
8	Muskwa River Crossing COS	(231)	-	-	-	-	116	-	-	(116)	(173)
9	Fort Nelson Revenue Surplus/Deficit Account	-	-	-	-	-	-	-	-	-	-
10	Muskwa River Crossing Project Costs	543	-	-	-	-	(272)	-	-	272	407
11											
12	Residual Deferred Accounts										
13	Depreciation Variance	-	-	-	-	-	-	-	-	-	-
14	2012-2013 Revenue Requirement Application	-	-	-	-	-	-	-	-	-	-
15	Fort Nelson ROE & Capital Structure Deferral	-	-	-	-	-	-	-	-	-	-
16											
17	Total Deferred Charges for Rate Base	$ 296	$ -	$ 11	$ -	$ 11	$ (178)	$ (25)	$ 7	$ 110	$ 203
18											
19	Cross Reference						- Tab 9-FORECAST, Sch 30			- Tab 9-FORECAST, Sch 42	

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 31/12/2013	Ending 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	461-00 Transmission Land Rights	$ 8	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
3	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-	-
4	402-01 Application Software - 12.5%	444	0.00%	-	-	-	-	-	-
5	402-02 Application Software - 20%	95	0.00%	-	-	-	-	-	-
6									
7	**TRANSMISSION PLANT**								
8	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-	-
9	463-00 Measuring Structures	10	0.18%	-	-	-	-	-	-
10	465-00 Mains	675	0.14%	2	-	-	-	-	2
11	467-10 Measuring & Regulating Equipment	670	0.18%	1	-	-	-	-	1
12	467-20 Telemetering	6	0.00%	-	-	-	-	-	-
13									
14	**DISTRIBUTION PLANT**								
15	472-00 Structures & Improvements	257	0.16%	-	-	-	-	-	-
16	473-00 Services	2,325	1.24%	33	-	(9)	-	(11)	12
17	474-00 House Regulators & Meter Installations	518	0.75%	4	-	(2)	-	-	2
18	477-00 Meters/Regulators Installations	42	0.75%	-	-	-	-	(2)	(2)
19	475-00 Mains	2,243	0.33%	8	-	-	-	(26)	(18)
20	477-00 Measuring & Regulating Equipment	1,134	0.52%	6	-	-	-	-	6
21	477-00 Telemetering	13	0.00%	-	-	-	-	-	-
22	478-10 Meters	14	0.50%	-	-	-	-	-	-
23									
24	**GENERAL PLANT & EQUIPMENT**								
25	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-	-
26	- Frame Buildings	228	0.00%	-	-	-	-	-	-
27	- Masonry Buildings	428	0.00%	-	-	-	-	-	-
28	483-30 GP Office Equipment	6	0.00%	-	-	-	-	-	-
29	483-40 GP Furniture	8	0.00%	-	-	-	-	-	-
30	483-10 GP Computer Hardware	165	0.00%	-	-	-	-	-	-
31	483-20 GP Computer Software	22	0.00%	-	-	-	-	-	-
32	484-00 Vehicles	50	0.00%	-	-	-	-	-	-
33	486-00 Small Tools & Equipment	48	0.00%	-	-	-	-	-	-
34	- Telephone	24	0.00%	-	-	-	-	-	-
35									
36	TOTALS	$ 9,454		$ 54	$ -	$ (11)	$ -	$ (39)	$ 3
37									
38	Cross Reference	- Tab 9-FORECAST, Sch 46							- Tab 9-FORECAST, Sch 66

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2015 DEPRECIATION Provision (Cr.)	Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2014	Ending 12/31/2015
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	461-00 Transmission Land Rights	$ 8	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
3	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-	-
4	402-01 Application Software - 12.5%	456	0.00%	-	-	-	-	-	-
5	402-02 Application Software - 20%	114	0.00%	-	-	-	-	-	-
6									
7	**TRANSMISSION PLANT**								
8	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-	-
9	463-00 Measuring Structures	10	0.09%	-	-	-	-	-	-
10	465-00 Mains	1,345	0.10%	6	-	-	-	2	8
11	467-10 Measuring & Regulating Equipment	670	0.19%	1	-	-	-	1	2
12	467-20 Telemetering	6	0.00%	-	-	-	-	-	-
13									
14	**DISTRIBUTION PLANT**								
15	472-00 Structures & Improvements	257	0.16%	-	-	-	-	-	-
16	473-00 Services	2,368	1.15%	28	-	(9)	-	12	31
17	474-00 House Regulators & Meter Installations	518	0.69%	4	-	(2)	-	2	4
18	477-00 Meters/Regulators Installations	49	0.75%	-	-	-	-	(2)	(2)
19	475-00 Mains	2,400	0.32%	8	-	-	-	(18)	(10)
20	477-00 Measuring & Regulating Equipment	1,346	0.47%	6	-	-	-	6	12
21	477-00 Telemetering	13	0.00%	-	-	-	-	-	-
22	478-10 Meters	20	0.47%	-	-	-	-	-	-
23									
24	**GENERAL PLANT & EQUIPMENT**								
25	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-	-
26	- Frame Buildings	228	0.00%	-	-	-	-	-	-
27	- Masonry Buildings	438	0.00%	-	-	-	-	-	-
28	483-30 GP Office Equipment	6	0.00%	-	-	-	-	-	-
29	483-40 GP Furniture	8	0.00%	-	-	-	-	-	-
30	483-10 GP Computer Hardware	187	0.00%	-	-	-	-	-	-
31	483-20 GP Computer Software	22	0.00%	-	-	-	-	-	-
32	484-00 Vehicles	60	0.00%	-	-	-	-	-	-
33	486-00 Small Tools & Equipment	45	0.00%	-	-	-	-	-	-
34	- Telephone	24	0.00%	-	-	-	-	-	-
35									
36	TOTALS	$ 10,619		$ 53	$ -	$ (11)	$ -	$ 3	$ 45
37									
38	Cross Reference	- Tab 9-FORECAST, Sch 49							- Tab 9-FORECAST, Sch 68

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2016 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2015	Ending 12/31/2016
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	461-00 Transmission Land Rights	$ 8	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
3	471-00 Distribution Land Rights	20	0.00%	-	-	-	-	-	-
4	402-01 Application Software - 12.5%	480	0.00%	-	-	-	-	-	-
5	402-02 Application Software - 20%	129	0.00%	-	-	-	-	-	-
6									
7	**TRANSMISSION PLANT**								
8	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-	-
9	463-00 Measuring Structures	10	0.09%	-	-	-	-	-	-
10	465-00 Mains	6,478	0.10%	6	-	-	-	8	14
11	467-10 Measuring & Regulating Equipment	670	0.19%	1	-	-	-	2	3
12	467-20 Telemetering	6	0.00%	-	-	-	-	-	-
13									
14	**DISTRIBUTION PLANT**								
15	472-00 Structures & Improvements	257	0.16%	-	-	-	-	-	-
16	473-00 Services	2,411	1.15%	29	-	(9)	-	31	51
17	474-00 House Regulators & Meter Installations	518	0.69%	4	-	(2)	-	4	6
18	477-00 Meters/Regulators Installations	56	0.75%	-	-	-	-	(2)	(2)
19	475-00 Mains	2,575	0.32%	8	-	-	-	(10)	(2)
20	477-00 Measuring & Regulating Equipment	1,528	0.47%	7	-	-	-	12	19
21	477-00 Telemetering	91	0.00%	-	-	-	-	-	-
22	478-10 Meters	26	0.47%	-	-	-	-	-	-
23									
24	**GENERAL PLANT & EQUIPMENT**								
25	480-00 Land in Fee Simple	1	0.00%	-	-	-	-	-	-
26	- Frame Buildings	228	0.00%	-	-	-	-	-	-
27	- Masonry Buildings	591	0.00%	-	-	-	-	-	-
28	483-30 GP Office Equipment	6	0.00%	-	-	-	-	-	-
29	483-40 GP Furniture	1	0.00%	-	-	-	-	-	-
30	483-10 GP Computer Hardware	214	0.00%	-	-	-	-	-	-
31	483-20 GP Computer Software	19	0.00%	-	-	-	-	-	-
32	484-00 Vehicles	70	0.00%	-	-	-	-	-	-
33	486-00 Small Tools & Equipment	41	0.00%	-	-	-	-	-	-
34	- Telephone	24	0.00%	-	-	-	-	-	-
35									
36	TOTALS	$ 16,458		$ 55	$ -	$ (11)	$ -	$ 45	$ 89
37									
38	Cross Reference	- Tab 9-FORECAST, Sch 52							- Tab 9-FORECAST, Sch 70

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 ACTUAL	2014 APPROVED	2014 PROJECTED Existing 2014 Rates	2014 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	$ 67	$ 63	$ 47	$ 47	$ (16)	- Tab 9-FORECAST, Sch 77
4							
5	Less - Funds Available:						
6	Reserve for Bad Debts	(45)	(14)	(13)	(13)	1	
7							
8	Withholdings From Employees	(24)	(22)	(24)	(24)	(2)	
9							
10	Subtotal	(2)	27	10	10	(17)	- Tab 9-FORECAST, Sch 40
11							
12	**Other Working Capital Items**						
13	Construction Advances	-	-	-	-	-	
14	Transmission Line Pack Gas	-	-	-	-	-	
15	Gas in Storage	-	-	-	-	-	
16	Inventory - Materials & Supplies	14	-	14	14	14	
17	Refundable Contributions	-	-	-	-	-	
18							
19	Subtotal	14	-	14	14	14	- Tab 9-FORECAST, Sch 40
20							
21	Total	$ 12	$ 27	$ 24	$ 24	$ (3)	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 PROJECTED	2015 FORECAST Existing 2014 Rates	2015 FORECAST Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 47	$ 55	$ 64	$ 17	- Tab 9-FORECAST, Sch 77
4						
5	Less - Funds Available:					
6	Reserve for Bad Debts	(13)	(14)	(14)	(1)	
7						
8	Withholdings From Employees	(24)	(25)	(25)	(1)	
9						
10	Subtotal	10	16	25	15	- Tab 9-FORECAST, Sch 41
11						
12	**Other Working Capital Items**					
13	Construction Advances	-	-	-	-	
14	Transmission Line Pack Gas	-	-	-	-	
15	Gas in Storage	-	-	-	-	
16	Inventory - Materials & Supplies	14	14	14	-	
17	Refundable Contributions	-	-	-	-	
18						
19	Subtotal	14	14	14	-	- Tab 9-FORECAST, Sch 41
20						
21	Total	$ 24	$ 30	$ 39	$ 15	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 FORECAST Existing 2014 Rates	2016 FORECAST Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 64	$ 52	$ 63	$ (1)	- Tab 9-FORECAST, Sch 77
4						
5	Less - Funds Available:					
6	Reserve for Bad Debts	(14)	(14)	(14)	-	
7						
8	Withholdings From Employees	(25)	(25)	(25)	-	
9						
10	Subtotal	25	13	24	(1)	- Tab 9-FORECAST, Sch 42
11						
12	**Other Working Capital Items**					
13	Construction Advances	-	-	-	-	
14	Transmission Line Pack Gas	-	-	-	-	
15	Gas in Storage	-	-	-	-	
16	Inventory - Materials & Supplies	14	14	14	-	
17	Refundable Contributions	-	-	-	-	
18						
19	Subtotal	14	14	14	-	- Tab 9-FORECAST, Sch 42
20						
21	Total	$ 39	$ 27	$ 38	$ (1)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000s)

Line No.	Particulars	2014 Days	2014 Expenses	2014 Cash Working Capital	2015 Days	2015 Expenses	2015 Cash Working Capital	2016 Days	2016 Expenses	2016 Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**CASH WORKING CAPITAL**										
2											
3	Revenue Lag Days	38.7			38.6			38.6			- Tab 9-FORECAST, Sch 78
4	Expense Lead Days	34.4			34.1			34.3			- Tab 9-FORECAST, Sch 79
5											
6	Net Lead/(Lag) Days	4.3	$ 4,005	$ 47	4.5	$ 4,460	$ 55	4.3	$ 4,451	$ 52	- Tab 9-FORECAST, Sch 74
7											- Tab 9-FORECAST, Sch 75
8											
9											
10	**CASH WORKING CAPITAL, REVISED RATES**										
11											
12	Revenue Lag Days	38.7			38.7			38.7			- Tab 9-FORECAST, Sch 78
13	Expense Lead Days	34.4			33.6			33.7			- Tab 9-FORECAST, Sch 79
14											
15	Net Lead/(Lag) Days	4.3	$ 4,005	$ 47	5.1	$ 4,590	$ 64	5.0	$ 4,624	$ 63	- Tab 9-FORECAST, Sch 74
16											- Tab 9-FORECAST, Sch 75
17											
18											
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ 9			$ 11	
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, 2014 TO 2016
($000s)

		2014			2015			2016			
Line No.	Particulars	Revenue At 2014 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2014 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2014 Rates	Lag Days Service to Collection	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**REVENUE**										
2											
3	Gas Sales and Transportation Service Revenue										
4	Residential and Commercial	$ 4,001	38.4	$ 153,686	$ 4,324	38.4	$ 166,045	$ 4,358	38.4	$ 167,349	- Tab 9-FORECAST, Sch 14
5	Industrials & Others	175	45.2	7,887	150	45.2	6,775	150	45.2	6,775	
6	Transportation Service	-	0.0	-	-	0.0	-	-	0.0	-	
7											
8	Total Sales and Transportation	4,175	38.7	161,573	4,473	38.6	172,820	4,508	38.6	174,124	
9											
10	Other Revenues										- Tab 9-FORECAST, Sch 18-20
11	Late Payment Charges	8	40.3	322	9	38.8	349	9	39.1	352	
12	Returned Cheque Charges	-	0.0	-	-	0.0	-	-	0.0	-	
13	Connection Charges	11	37.6	414	11	37.6	414	11	37.6	414	
14	Other Utility Income	(90)	38.3	(3,447)	-	0.0	-	-	0.0	-	
15											
16											
17	Total Revenue	$ 4,104	38.7	$ 158,862	$ 4,493	38.6	$ 173,583	$ 4,528	38.6	$ 174,890	
18											
19											
20	**REVENUE, REVISED RATES**										
21											
22	Gas Sales and Transportation Service Revenue										
23	Residential and Commercial	$ 4,001	38.4	$ 153,686	$ 4,762	38.4	$ 182,876	$ 4,936	38.4	$ 189,555	- Tab 9-FORECAST, Sch 14
24	Industrials & Others	175	45.2	7,887	186	45.2	8,403	198	45.2	8,945	
25	Transportation Service	-	0.0	-	-	0.0	-	-	0.0	-	
26											
27	Total Sales and Transportation	4,175	38.7	161,573	4,947	38.7	191,279	5,134	38.7	198,500	
28											
29	Other Revenues										- Tab 9-FORECAST, Sch 18-20
30	Late Payment Charges	8	40.3	322	9	38.8	349	9	39.1	352	
31	Returned Cheque Charges	-	0.0	-	-	0.0	-	-	0.0	-	
32	Connection Charges	11	37.6	414	11	37.6	414	11	37.6	414	
33	Other Utility Income	(90)	38.3	(3,447)	-	0.0	-	-	0.0	-	
34											
35											
36	Total Revenue	$ 4,104	38.7	$ 158,862	$ 4,967	38.7	$ 192,042	$ 5,154	38.7	$ 199,266	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2014 TO 2016
($000s)

		2014			2015			2016			
Line No.	Particulars	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Amount	Lead Days Expense to Payment	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**EXPENSES**										
2											
3	Operating And Maintenance										- Tab 9-FORECAST, Sch 4
4	Expenses	$ 831	25.5	$ 21,191	$ 880	25.5	$ 22,440	$ 901	25.5	$ 22,976	- Tab 9-FORECAST, Sch 5
5	Transportation Costs	-	0.0	-	-	0.0	-	-	0.0	-	
6	Gas Purchases	2,214	40.2	89,003	2,524	40.2	101,465	2,543	40.2	102,229	
7											
8	Taxes Other Than Income										- Tab 9-FORECAST, Sch 25
9	Property Taxes	-	2.0	-	117	2.0	234	118	2.0	236	- Tab 9-FORECAST, Sch 26
10	Franchise Fees	-	0.0	-	-	0.0	-	-	0.0	-	
11	Carbon Tax	878	29.1	25,544	883	29.1	25,691	890	29.1	25,886	
12	GST - Net	-	0.0	-	38	38.8	1,486	39	38.8	1,499	
13	PST - Net	27	37.1	990	29	37.1	1,066	29	37.1	1,085	
14	Income Tax	56	15.2	851	(11)	15.2	(167)	(68)	15.2	(1,034)	- Tab 9-FORECAST, Sch 31
15											- Tab 9-FORECAST, Sch 32
16	Total Expenses	$ 4,005	34.4	$ 137,579	$ 4,460	34.1	$ 152,215	$ 4,451	34.3	$ 152,877	
17											
18											
19	**EXPENSES, REVISED RATES**										
20											
21	Operating And Maintenance										- Tab 9-FORECAST, Sch 4
22	Expenses	$ 831	25.5	$ 21,191	$ 880	25.5	$ 22,440	$ 901	25.5	$ 22,976	- Tab 9-FORECAST, Sch 5
23	Transportation Costs	-	0.0	-	-	0.0	-	-	0.0	-	
24	Gas Purchases	2,214	40.2	89,003	2,524	40.2	101,465	2,543	40.2	102,229	
25											
26	Taxes Other Than Income										- Tab 9-FORECAST, Sch 25
27	Property Taxes	-	2.0	-	117	2.0	234	118	2.0	236	- Tab 9-FORECAST, Sch 26
28	Franchise Fees	-	0.0	-	-	0.0	-	-	0.0	-	
29	Carbon Tax	878	29.1	25,544	883	29.1	25,691	890	29.1	25,886	
30	GST - Net	-	0.0	-	42	38.8	1,645	44	38.8	1,712	
31	PST - Net	27	37.1	990	32	37.1	1,180	33	37.1	1,237	
32	Income Tax	56	15.2	851	112	15.2	1,702	95	15.2	1,444	- Tab 9-FORECAST, Sch 31
33											- Tab 9-FORECAST, Sch 32
34	Total Expenses	$ 4,005	34.4	$ 137,579	$ 4,590	33.6	$ 154,357	$ 4,624	33.7	$ 155,720	
35											
36											
37											

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 RATES							
2	Long-Term Debt		$ 4,436	77.85%	6.83%	5.32%	$ 303	- Tab 9-FORECAST, Sch 83
3	Unfunded Debt		(932)	-16.35%	1.75%	-0.29%	(16)	
4	Common Equity		2,194	38.50%	8.75%	3.38%	192	
5								
6			$ 5,698	100.00%		8.41%	$ 479	- Tab 9-FORECAST, Sch 40
7								
8								
9								
10	2014 REVISED RATES - PROJECTED							
11	Long-Term Debt		$ 4,436	77.85%	6.83%	5.32%	$ 303	- Tab 9-FORECAST, Sch 83
12	Unfunded Debt	$ (932)						
13	Adjustment, Revised Rates	-	(932)	-16.35%	1.75%	-0.29%	(16)	
14	Common Equity		2,194	38.50%	8.75%	3.38%	192	
15								- Tab 9-FORECAST, Sch 4
16			$ 5,698	100.00%		8.41%	$ 479	- Tab 9-FORECAST, Sch 40

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2015 AT 2014 RATES							
2	Long-Term Debt		$ 6,058	51.57%	6.59%	3.40%	$ 399	- Tab 9-FORECAST, Sch 84
3	Unfunded Debt		1,166	9.93%	2.00%	0.20%	23	
4	Common Equity		4,523	38.50%	1.02%	0.38%	46	
5								
6			$ 11,747	100.00%		3.98%	$ 468	- Tab 9-FORECAST, Sch 41
7								
8								
9								
10	2015 REVISED RATES							
11	Long-Term Debt		$ 6,058	51.53%	6.59%	3.40%	$ 399	- Tab 9-FORECAST, Sch 84
12	Unfunded Debt	$ 1,166						
13	Adjustment, Revised Rates	6	1,172	9.97%	2.00%	0.20%	23	
14	Common Equity		4,526	38.50%	8.75%	3.37%	396	
15								- Tab 9-FORECAST, Sch 5
16			$ 11,756	100.00%		6.96%	$ 818	- Tab 9-FORECAST, Sch 41

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2016 AT 2014 RATES							
2	Long-Term Debt		$ 6,190	50.87%	6.37%	3.24%	$ 394	- Tab 9-FORECAST, Sch 85
3	Unfunded Debt		1,293	10.63%	2.75%	0.29%	36	
4	Common Equity		4,684	38.50%	-1.13%	-0.43%	(53)	
5								
6			$ 12,167	100.00%		3.10%	$ 377	- Tab 9-FORECAST, Sch 42
7								
8								
9								
10	2016 REVISED RATES							
11	Long-Term Debt		$ 6,190	50.83%	6.37%	3.24%	$ 394	- Tab 9-FORECAST, Sch 85
12	Unfunded Debt	$ 1,293						
13	Adjustment, Revised Rates	6	1,299	10.67%	2.75%	0.29%	36	
14	Common Equity		4,689	38.50%	8.75%	3.37%	410	
15								- Tab 9-FORECAST, Sch 6
16			$ 12,178	100.00%		6.90%	$ 840	- Tab 9-FORECAST, Sch 42

FORTISBC ENERGY INC. - Fort Nelson

Tab 9
FORECAST
Schedule 83

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA)
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	197,772	**	10.461%	160,923	16,834
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								2.281%	11,006	251
20											
21	Total FEI									$ 1,579,806	$ 108,002
22	Fort Nelson Division Portion of Long Term Debt									$ 4,436	$ 303
23											
24	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.83%
25	**Includes adjustment of $3,649 for BC Hydro Premium (Series B).										
26	Cross Reference									- Tab 9-FORECAST, Sch 80	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2015
($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%	$ 55,857	$ 6,733
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	160,512	**	10.461%	165,846	17,349
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	FEI 2015 Issue - Series A Renewal	30-Sep-2015	30-Sep-2045	5.150%	75,000	750	74,250	*	5.216%	19,110	997
13									0.000%	-	-
14									0.000%	-	-
15											
16	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999		6.109%	250,000	15,273
17	FEVI L/T Debt Issue - 2010	6-Dec-2010	6-Dec-2040	5.200%	100,000	1,164	98,836		5.278%	100,000	5,278
18											
19											
20	FEW Intercompany Loan 2014	1-Jun-2014	1-Jun-2019	5.110%	20,000	-	20,000		5.110%	20,000	1,022
21											
22	LILO Obligations - Kelowna								6.489%	20,034	1,300
23	LILO Obligations - Nelson								8.105%	3,245	263
24	LILO Obligations - Vernon								9.418%	9,609	905
25	LILO Obligations - Prince George								8.307%	25,028	2,079
26	LILO Obligations - Creston								7.451%	2,389	178
27											
28	Vehicle Lease Obligation								1.904%	9,243	176
29											
30	Total FEU Amalgamated									$ 1,950,361	$ 128,564
31	Fort Nelson Division Portion of Long Term									$ 6,058	$ 399
32											
33	*Includes adjustment of $16,012 for BC Hydro Premium (original Series A issued Dec-1990). No further BCH Premium adjustment required on renewed Series A issue.									Average Embedded Cost	6.59%
34	**Includes adjustment of $5,466 for BC Hydro Premium (Series B).										
35	Cross Reference									- Tab 9-FORECAST, Sch 81	

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2016
($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 B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	$ 157,274	$ 2,228	$ 160,512 *	10.461%	$ 153,822	$ 16,091
2										
3	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
4	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
5	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
6	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
7	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
8	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
9	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
10	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
11	FEI 2015 Issue - Series A Renewal	30-Sep-2015	30-Sep-2045	5.150%	75,000	750	74,250	5.216%	75,000	3,912
12	FEI 2016 Issue - Series B Renewal	30-Nov-2016	30-Nov-2046	5.400%	157,274	1,573	166,986 *	5.468%	14,737	806
13								0.000%	-	-
14										
15	FEVI L/T Debt Issue - 2008	16-Feb-2008	15-Feb-2038	6.050%	250,000	2,001	247,999	6.109%	250,000	15,273
16	FEVI L/T Debt Issue - 2010	6-Dec-2010	6-Dec-2040	5.200%	100,000	1,164	98,836	5.278%	100,000	5,278
17										
18										
19	FEW Intercompany Loan 2014	1-Jun-2014	1-Jun-2019	5.110%	20,000	-	20,000	5.110%	20,000	1,022
20										
21	LILO Obligations - Kelowna							6.511%	19,106	1,244
22	LILO Obligations - Nelson							8.237%	3,108	256
23	LILO Obligations - Vernon							9.564%	9,180	878
24	LILO Obligations - Prince George							8.442%	24,000	2,026
25	LILO Obligations - Creston							7.541%	2,294	173
26										
27	Vehicle Lease Obligation							1.630%	6,995	114
28										
29	Total FEU Amalgamated								$ 1,948,242	$ 124,084
30	Fort Nelson Division Portion of Long Term								$ 6,190	$ 394
31										
32	*Includes adjustment of $5,466 for BC Hydro Premium (Series B).								Average Embedded Cost	6.37%
33										
34	Cross Reference								- Tab 9-FORECAST, Sch 82	

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2015 Volumes (TJ)	2015 Amortization ($000s)	2015 Amortization of RSAM Unit Rider ($/GJ)
	(1)	(2)	(3)	(4)
1	**RSAM (Rider 5) Calculation**			
2				
3	Schedule 1 - Residential	268.6		$0.039
4	Schedule 2.1 - Commercial	208.3		$0.039
5	Schedule 2.2 - Commercial	115.7		$0.039
7	Schedule 25 - Transportation Service	55.8		$0.039
8				
9		648.4	$25 (1)	
10				
11				
12	Note 1: RSAM Rider Change			
13				
14	In 2014, FortisBC Energy forecasts that there will be approximately $20,000 (net-of-tax) of RSAM additions.			
15	After offsetting the 2014 RSAM Rider recovery, the RSAM account including interest is now projected to be a			
16	debit balance of $37,000 on a net-of-tax basis by the end of 2014. The RSAM balance is to be amortized			
17	over two years. Accordingly, the net-of-tax RSAM balance to be amortized in 2015 is a credit of			
18	$19,000. On a pre-tax basis, this amounts to $25,000 or a charge to customers of $0.039/GJ			
19	in 2015, which is a $0.045 decrease from the existing charge of $0.084/GJ.			
20				
21				
22				
23	2015 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2014 RSAM Balance			
24	= 1/2 * ($37 RSAM + $ RSAM Interest)			
25	= 1/2 * $37			
26	= $18 Net-of-tax amortization			
27				
28	2015 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate)			
29	= $18 / (1 - 26%)			
30	= $25 Pre-tax amortization			

Appendix A

DRAFT ORDERS

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

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 the Fort Nelson Service Area
for Approval of its 2015 and 2016 Revenue Requirements and to Amend its Schedule of Rates

BEFORE:

(Date)

WHEREAS:

A. On December 3, 2014, FortisBC Energy Inc. submitted its 2015-2016 Revenue Requirements and Rates Application for the Fort Nelson Service Area (FEFN), seeking approval to recover a revenue deficiency of $473 thousand in 2015 and $153 thousand in 2016 through a permanent increase in its delivery rates, effective January 1, 2015 and January 1, 2016 respectively;

B. In the Application, FEFN also sought approval of an interim, refundable delivery rate increase of 24.26 percent, effective January 1, 2015, and approval of an interim decrease of $0.045 per GJ for an interim RSAM Rate Rider of $0.039 per GJ effective January 1, 2015;

C. The Commission has reviewed the Application and concludes that interim rate request as outlined in the Application should be approved.

NOW THEREFORE pursuant to Sections 59 to 61 and 89 of the Utilities Commission Act and section 15 of the Administrative Tribunals Act, the Commission orders as follows:

1. The Commission approves on an interim and refundable basis a 24.26 per cent increase in FEFN delivery rates effective January 1, 2015, as set out in Appendix B of the Application.

2. The RSAM rider is to be set at $0.039 effective January 1, 2015, on an interim and refundable basis.

3. FEI is directed to notify its customers in the Fort Nelson Service Area about the delivery rate and rate rider changes by a bill message.

4. FEI is directed to file amended Gas Tariff Rate Schedules for the Fort Nelson Service Area in accordance with this Order in a timely manner.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

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 the Fort Nelson Service Area
for Approval of its 2015 and 2016 Revenue Requirements and to Amend its Schedule of Rates

BEFORE:

(Date)

WHEREAS:

A. On December 3, 2014, FortisBC Energy Inc. submitted its 2015-2016 Revenue Requirements Application for the Fort Nelson Service Area (FEFN), seeking approval to recover a revenue deficiency of $473 thousand in 2015 and $153 thousand in 2016 through a permanent increase in its delivery rates, effective January 1, 2015 and January 1, 2016, respectively;

B. In the Application, FEFN sought approval of an interim, refundable delivery rate increase of 24.26 percent, effective January 1, 2015, and approval of an interim decrease of $0.045 per GJ for an interim RSAM Rate Rider of $0.039 per GJ effective January 1, 2015;

C. On December XX, 2014, the Commission issued Order G-XX-XX approving interim rates, on a refundable basis, as applied for, effective January 1, 2015;

D. In the Application, FEFN sought approvals as follows:

- a permanent delivery rate increase of 24.26 percent effective January 1, 2015, to recover the forecast revenue deficiency of $473 thousand in 2015;

- a permanent delivery rate increase of 7.58 percent (cumulative increase of 31.84 percent over the Test Period), effective January 1, 2016 to recover the forecast revenue deficiency of $153 thousand in 2016 (cumulative $626 thousand over the Test Period);
- the RSAM Rate Rider to be set to $0.039 per GJ (a decrease of $0.045 per GJ compared to 2014) as set out in Section 2.5 Table 2-4 effective January 1, 2015;
- to amortize the Fort Nelson Revenue Surplus/Deficit account as described in Section 7.4.2; and
- to establish a new rate base deferral account for the 2015-2016 Revenue Requirement Application (RRA) Costs as described in Section 7.4.1 of the Application;

E. The Commission has reviewed the Application and concludes that approval is warranted.

NOW THEREFORE pursuant to Sections 59 to 61 of the Utilities Commission Act, the Commission orders as follows:

1. FortisBC Energy Inc. FEFN delivery rates for 2015 and 2016 as set out in Appendix B of the Application are approved on a permanent basis, resulting in a 24.26 percent increase in FEFN delivery rates effective January 1, 2015, and a further 7.58 percent increase in FEFN delivery rates effective January 1, 2016.
2. FEFN RSAM Rate Rider is approved on a permanent basis at $0.039 effective January 1, 2015.
3. The amortization of the Revenue Surplus/Deficit Account beginning in January 1, 2015 as described in Section 7.4.2 of the Application is approved.
4. The establishment of a new rate base deferral account for the 2015-2016 RRA Costs as described in Section 7.4.1 of the Application is approved.
5. FEI is directed to file amended Gas Tariff Rate Schedules for the Fort Nelson Service Area in accordance with this Order in a timely manner.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER

Appendix B

TARIFF CONTINUITY AND BILL IMPACT SCHEDULES

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
PROPOSED January 1, 2015 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Existing Rates	Proposed Changes	January 1, 2015 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3175	$0.0772	$0.3947
10			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
12			**Minimum Daily Charge** (includes first 2 gigajoules)	**$0.6029**	**$0.0743**	**$0.6772**
13						
14			Delivery Charge per GJ	$2.461	$0.599	$3.060
15			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
16			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
17			**Next 28 Gigajoules in any month**	**$6.804**	$0.554	**$7.358**
18						
19			Delivery Charge per GJ	$2.391	$0.582	$2.973
20			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
21			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
22			**Excess of 30 Gigajoules in any month**	**$6.734**	$0.537	**$7.271**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3175	$0.0772	$0.3947
28			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
30			**Minimum Daily Charge (includes first 2 gigajoules)**	**$0.6029**	**$0.0743**	**$0.6772**
31						
32			Delivery Charge per GJ	$2.461	$0.599	$3.060
33			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
34			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
35			**Next 28 Gigajoules in any month**	**$6.804**	$0.554	**$7.358**
36						
37			Delivery Charge per GJ	$2.391	$0.582	$2.973
38			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
39			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
40			**Excess of 30 Gigajoules in any month**	**$6.734**	$0.537	**$7.271**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
PROPOSED January 1, 2015 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Existing Rates	Proposed Changes	January 1, 2015 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9236	$0.2239	$1.1475
2			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
4			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.2090**	**$0.2210**	**$1.4300**
5						
6			Delivery Charge per GJ	$2.768	$0.671	$3.439
7			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
8			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
9			**Next 298 Gigajoules in any month**	**$7.111**	$0.626	**$7.737**
10						
11			Delivery Charge per GJ	$2.682	$0.650	$3.332
12			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
13			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
14			**Excess of 300 Gigajoules in any month**	**$7.025**	$0.605	**$7.630**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9236	$0.2239	$1.1475
17			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
19			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.2090**	**$0.2210**	**$1.4300**
20						
21			Delivery Charge per GJ	$2.768	$0.671	$3.439
22			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
23			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
24			**Next 298 Gigajoules in any month**	**$7.111**	$0.626	**$7.737**
25						
26			Delivery Charge per GJ	$2.682	$0.650	$3.332
27			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039
28			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
29			**Excess of 300 Gigajoules in any month**	**$7.025**	$0.605	**$7.630**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
PROPOSED January 1, 2015 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Existing Rates	Proposed Changes	January 1, 2015 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.965	$0.833	$3.798
4			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524
5			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039
8			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
9						
10			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$2.965	$0.833	$3.798
16			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524
17			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039
20			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
21						
22			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$2.965	$0.833	$3.798
28			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524
29			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039
32			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
33						
34			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
PROPOSED January 1, 2015 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	April 1, 2014 Existing Rates	Proposed Changes	January 1, 2015 Effective Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$2.965	$0.833	$3.798
4			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524
5			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880
6						
7			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	$0.084	($0.045)	$0.039

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		Existing October 1, 2014 Rates				January 1, 2015 Proposed Rates				Annual Increase/(Decrease)		
1	**Rate 1 Domestic Service Option B**	Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
2												
3	Monthly Charge											
4	Delivery Charge per Day (Note A)	365.25	days x	$0.3175	$115.9669	365.25	days x	$0.3947	$144.1642	$0.0772	$28.1973	2.79%
5	Rider 5 - RSAM per Day	365.25	days x	$0.0055	2.0089	365.25	days x	$0.0026	0.9497	($0.0029)	($1.0592)	-0.10%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.2799	102.2335	365.25	days x	$0.2799	102.2335	$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)			$0.6029	**$220.21**			$0.6772	**$247.35**	$0.0743	$27.14	2.69%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$2.461	$285.4760	116	GJ x	$3.060	$354.9600	$0.599	$69.484	6.88%
11	Rider 5 - RSAM per GJ	116	GJ x	0.084	9.7440	116	GJ x	0.039	4.5240	(0.045)	(5.220)	-0.52%
12	Gas Cost Recovery Charge per GJ	116	GJ x	4.259	494.0440	116	GJ x	4.259	494.0440	0.000	0.000	0.00%
13	Total Charges per GJ			$6.804	**$789.26**			$7.358	**$853.53**	$0.554	$64.27	6.37%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.391	$0.0000	0	GJ x	$2.973	$0.0000	$0.582	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	0.084	0.0000	0	GJ x	0.039	0.0000	(0.045)	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	4.259	0.0000	0	GJ x	4.259	0.0000	0.000	0.000	0.00%
19	Total Charges per GJ			$6.734	**$0.00**			$7.271	**$0.00**	$0.537	$0.00	0.00%
20												
21	Total	140	GJ		**$1,009.47**	140	GJ		**$1,100.88**		**$91.41**	**9.06%**
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$413.1958				$504.5978		$91.4021	9.05%
25	Commodity Charge				596.2775				596.2775		0.0000	0.00%
26	Total				**$1,009.47**				**$1,100.88**		**$91.41**	**9.06%**

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

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		Existing October 1, 2014 Rates						January 1, 2015 Proposed Rates						Annual Increase/(Decrease)		
		Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.1 General Service**															
2																
3	Monthly Charge															
4	Delivery Charge per Day (Note A)	365.25	days x	$0.9236	=	$337.3449		365.25	days x	$1.1475	=	$419.1244		$0.2239	$81.7795	2.31%
5	Rider 5 - RSAM per Day	365.25	days x	$0.0055	=	2.0089		365.25	days x	$0.0026	=	0.9497		($0.0029)	($1.0592)	-0.03%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.2799	=	102.2335		365.25	days x	$0.2799	=	102.2335		$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)			$1.2090		**$441.59**				$1.4300		**$522.31**		$0.2210	$80.72	2.28%
8																
9	Next 298 Gigajoules in any month															
10	Delivery Charge per GJ	436	GJ x	$2.768	=	$1,206.8480		436	GJ x	$3.439	=	$1,499.4040		$0.671	$292.556	8.26%
11	Rider 5 - RSAM per GJ	436	GJ x	0.084	=	36.6240		436	GJ x	0.039	=	17.0040		(0.045)	(19.620)	-0.55%
12	Gas Cost Recovery Charge per GJ	436	GJ x	4.259	=	1,856.9240		436	GJ x	4.259	=	1,856.9240		0.000	0.000	0.00%
13	Total Charges per GJ			$7.111		**$3,100.40**				$7.737		**$3,373.33**		$0.626	$272.93	7.71%
14																
15	Excess of 300 Gigajoules in any month															
16	Delivery Charge per GJ	0	GJ x	$2.682	=	$0.0000		0	GJ x	$3.332	=	$0.0000		$0.650	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	0.084	=	0.0000		0	GJ x	0.039	=	0.0000		(0.045)	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	4.259	=	0.0000		0	GJ x	4.259	=	0.0000		0.000	0.000	0.00%
19	Total Charges per GJ			$7.025		**$0.00**				$7.630		**$0.00**		$0.605	$0.00	0.00%
20																
21	Total	460	GJ			**$3,541.99**		460	GJ			**$3,895.64**			**$353.65**	**9.98%**
22																
23	Summary of Annual Delivery and Commodity Charges															
24	Delivery Charge (including RSAM)					$1,582.8258						$1,936.4820			$353.6563	9.98%
25	Commodity Charge					1,959.1575						1,959.1575			0.0000	0.00%
26	Total					**$3,541.98**						**$3,895.64**			**$353.66**	**9.98%**

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

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		Existing October 1, 2014 Rates			January 1, 2015 Proposed Rates			Annual Increase/(Decrease)		
		Volume	Rate	Annual $	Volume	Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.2 General Service**									
2										
3	Monthly Charge									
4	Delivery Charge per Day (Note A)	365.25 days x	$0.9236 =	$337.3449	365.25 days x	$1.1475 =	$419.1244	$0.2239	$81.7795	0.37%
5	Rider 5 - RSAM per Day	365.25 days x	$0.0055 =	2.0089	365.25 days x	$0.0026 =	0.9497	($0.0029)	($1.0592)	0.00%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25 days x	$0.2799 =	102.2335	365.25 days x	$0.2799 =	102.2335	$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)		$1.2090	**$441.59**		$1.4300	**$522.31**	$0.2210	$80.72	0.36%
8										
9	Next 298 Gigajoules in any month									
10	Delivery Charge per GJ	3,076 GJ x	$2.768 =	$8,514.3680	3,076 GJ x	$3.439 =	$10,578.3640	$0.671	$2,063.996	9.25%
11	Rider 5 - RSAM per GJ	3,076 GJ x	0.084 =	258.3840	3,076 GJ x	0.039 =	119.9640	(0.045)	(138.420)	-0.62%
12	Gas Cost Recovery Charge per GJ	3,076 GJ x	4.259 =	13,100.6840	3,076 GJ x	4.259 =	13,100.6840	0.000	0.000	0.00%
13	Total Charges per GJ		$7.111	**$21,873.44**		$7.737	**$23,799.01**	$0.626	$1,925.57	8.63%
14										
15	Excess of 300 Gigajoules in any month									
16	Delivery Charge per GJ	0 GJ x	$2.682 =	$0.0000	0 GJ x	$3.332 =	$0.0000	$0.650	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0 GJ x	0.084 =	0.0000	0 GJ x	0.039 =	0.0000	(0.045)	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0 GJ x	4.259 =	0.0000	0 GJ x	4.259 =	0.0000	0.000	0.000	0.00%
19	Total Charges per GJ		$7.025	**$0.00**		$7.630	**$0.00**	$0.605	$0.00	0.00%
20										
21	Total	3,100 GJ		**$22,315.03**	3,100 GJ		**$24,321.32**		**$2,006.29**	**8.99%**
22										
23	Summary of Annual Delivery and Commodity Charges									
24	Delivery Charge (including RSAM)			$9,112.1058			$11,118.4020		$2,006.2963	8.99%
25	Commodity Charge			13,202.9175			13,202.9175		0.0000	0.00%
26	Total			**$22,315.02**			**$24,321.32**		**$2,006.30**	**8.99%**

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

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 25 - TRANSPORTATION SERVICE

Line No.		Existing April 1, 2014 Rates						January 1, 2015 Proposed Rates						Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bil
2																
3	Transportation Delivery Charges															
4																
5	Delivery Charge per Gigajoule															
6	i) First 20 Gigajoules	240	GJ x	$2.965	=	$711.6000		240	GJ x	$3.798	=	$911.5200		$0.833	$199.9200	0.99%
7	ii) Next 260 Gigajoules	3,120	GJ x	$2.745	=	8,564.4000		3,120	GJ x	$3.524	=	10,994.8800		$0.779	2,430.4800	12.06%
8	iii) Excess over 280 Gigajoules	3,530	GJ x	$2.229	=	7,868.3700		3,530	GJ x	$2.880	=	10,166.4000		$0.651	2,298.0300	11.41%
9	iv) Minimum Delivery Charge per month	12	months x	$1,826.00		-		12	months x	$1,826.00		-		$0.00	$0.00	0.00%
10																
11	Administration Charge per month	12	months x	$202.00	=	$2,424.00		12	months x	$202.00	=	$2,424.00		$0.00	$0.00	0.00%
12																
13	Rider 5: RSAM per GJ	6,890	GJ x	$0.084	=	$578.7600		6,890	GJ x	$0.039	=	$268.7100		($0.045)	($310.0500)	-1.54%
14																
15	Total Transportation Delivery & Administration Charges	6,890	GJ x	*$2.924*		**$20,147.13**		6,890	GJ x	*$3.594*		**$24,765.51**		*$0.670*	**$4,618.38**	**22.92%**
16																
17																
18	Summary of Annual Delivery, Administration and Commodity Charges															
19	Delivery & Administration Charge (including RSAM)	6,890	GJ x	$2.924	=	$20,147.1300		6,890	GJ x	$3.594	=	$24,765.5100		$0.670	$4,618.3800	22.92%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ	0.000	=	0.0000		0	GJ	0.000	=	0.0000		0.000	0.0000	0.00%
21	Total	6,890	GJ x	*$2.924*	=	**$20,147.13**		6,890	GJ x	*$3.594*	=	**$24,765.51**		*$0.670*	**$4,618.38**	**22.92%**

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

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 1 DOMESTIC SERVICE
PROPOSED January 1, 2016 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 1	No. 1	**Option A**			
2						
3			Minimum Daily Charge			
4			plus $0.0391 times			
5			the amount of the promotional			
6			incentive divided by $100			
7			(includes the first 2 Gigajoules per month prorated to daily basis)			
8						
9			Delivery Charge per Day	$0.3947	$0.0237	$0.4184
10			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
12			**Minimum Daily Charge** (includes first 2 gigajoules)	**$0.6772**	**$0.0237**	**$0.7009**
13						
14			Delivery Charge per GJ	$3.060	$0.183	$3.243
15			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
16			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
17			**Next 28 Gigajoules in any month**	**$7.358**	$0.183	**$7.541**
18						
19			Delivery Charge per GJ	$2.973	$0.178	$3.151
20			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
21			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
22			**Excess of 30 Gigajoules in any month**	**$7.271**	$0.178	**$7.449**
23						
24						
25	Rate 1	No. 1.1	**Option B**			
26						
27			Delivery Charge per Day	$0.3947	$0.0237	$0.4184
28			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
30			**Minimum Daily Charge (includes first 2 gigajoules)**	**$0.6772**	**$0.0237**	**$0.7009**
31						
32			Delivery Charge per GJ	$3.060	$0.183	$3.243
33			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
34			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
35			**Next 28 Gigajoules in any month**	**$7.358**	$0.183	**$7.541**
36						
37			Delivery Charge per GJ	$2.973	$0.178	$3.151
38			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
39			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
40			**Excess of 30 Gigajoules in any month**	**$7.271**	$0.178	**$7.449**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 2.1, 2.2 & 2.3 GENERAL SERVICE
PROPOSED January 1, 2016 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 2.1	No. 2	Delivery Charge per Day	$1.1475	$0.0704	$1.2179
2			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
4			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.4300**	**$0.0704**	**$1.5004**
5						
6			Delivery Charge per GJ	$3.439	$0.211	$3.650
7			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
8			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
9			**Next 298 Gigajoules in any month**	**$7.737**	$0.211	**$7.948**
10						
11			Delivery Charge per GJ	$3.332	$0.205	$3.537
12			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
13			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
14			**Excess of 300 Gigajoules in any month**	**$7.630**	$0.205	**$7.835**
15						
16	Rate 2.2	No. 2	Delivery Charge per Day	$1.1475	$0.0704	$1.2179
17			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799
19			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.4300**	**$0.0704**	**$1.5004**
20						
21			Delivery Charge per GJ	$3.439	$0.211	$3.650
22			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
23			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
24			**Next 298 Gigajoules in any month**	**$7.737**	$0.211	**$7.948**
25						
26			Delivery Charge per GJ	$3.332	$0.205	$3.537
27			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039
28			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259
29			**Excess of 300 Gigajoules in any month**	**$7.630**	$0.205	**$7.835**

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATES 3.1, 3.2 & 3.3 INDUSTRIAL SERVICE
PROPOSED January 1, 2016 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Proposed Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 3.1	No. 3	Delivery Charge			
2						
3			First 20 Gigajoules in any month	$3.798	$0.245	$4.043
4			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751
5			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064
6						
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039
8			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
9						
10			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
11						
12						
13	Rate 3.2	No. 3	Delivery Charge			
14						
15			First 20 Gigajoules in any month	$3.798	$0.245	$4.043
16			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751
17			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064
18						
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039
20			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
21						
22			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
23						
24						
25	Rate 3.3	No. 3.1	Delivery Charge			
26						
27			First 20 Gigajoules in any month	$3.798	$0.245	$4.043
28			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751
29			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064
30						
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039
32			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259
33						
34			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
CALCULATION OF CUSTOMERS' RATES AND TARIFF CONTINUITY FOR
RATE 25 TRANSPORTATION SERVICE
PROPOSED January 1, 2016 RATES
BCUC ORDER NO. G-XX-14

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Effective Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Rate 25	No. 4.21	Transportation Delivery Charge			
2						
3			First 20 Gigajoules in any month	$3.798	$0.245	$4.043
4			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751
5			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064
6						
7			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00
8						
9			Administration Charge per Month	$202.00	$0.00	$202.00
10						
11			Delivery Margin Related Rider			
12			Rider 5: RSAM per GJ	$0.039	$0.000	$0.039

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 1 - DOMESTIC (RESIDENTIAL) SERVICE - OPTION B

Line No.		Proposed January 1, 2015 Rates				January 1, 2016 Proposed Rates				Annual Increase/(Decrease)		
		Volume		Rate	Annual $	Volume		Rate	Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 1 Domestic Service Option B**											
2												
3	Monthly Charge											
4	Delivery Charge per Day (Note A)	365.25	days x	$0.3947	$144.1642	365.25	days x	$0.4184	$152.8206	$0.0237	$8.6564	0.79%
5	Rider 5 - RSAM per Day	365.25	days x	$0.0026	0.9497	365.25	days x	$0.0026	0.9497	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.2799	102.2335	365.25	days x	$0.2799	102.2335	$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)			$0.6772	**$247.35**			$0.7009	**$256.00**	$0.0237	$8.65	0.79%
8												
9	Next 28 Gigajoules in any month											
10	Delivery Charge per GJ	116	GJ x	$3.060	$354.9600	116	GJ x	$3.243	$376.1880	$0.183	$21.228	1.93%
11	Rider 5 - RSAM per GJ	116	GJ x	0.039	4.5240	116	GJ x	0.039	4.5240	0.000	0.000	0.00%
12	Gas Cost Recovery Charge per GJ	116	GJ x	4.259	494.0440	116	GJ x	4.259	494.0440	0.000	0.000	0.00%
13	Total Charges per GJ			$7.358	**$853.53**			$7.541	**$874.76**	$0.183	$21.23	1.93%
14												
15	Excess of 30 Gigajoules in any month											
16	Delivery Charge per GJ	0	GJ x	$2.973	$0.0000	0	GJ x	$3.151	$0.0000	$0.178	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	0.039	0.0000	0	GJ x	0.039	0.0000	0.000	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	4.259	0.0000	0	GJ x	4.259	0.0000	0.000	0.000	0.00%
19	Total Charges per GJ			$7.271	**$0.00**			$7.449	**$0.00**	$0.178	$0.00	0.00%
20												
21	Total	140	GJ		**$1,100.88**	140	GJ		**$1,130.76**		**$29.88**	**2.71%**
22												
23	Summary of Annual Delivery and Commodity Charges											
24	Delivery Charge (including RSAM)				$504.5978				$534.4823		$29.8844	2.71%
25	Commodity Charge				596.2775				596.2775		0.0000	0.00%
26	Total				**$1,100.88**				**$1,130.76**		**$29.88**	**2.71%**

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

FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 2.1 - GENERAL (COMMERCIAL) SERVICE

Line No.		Proposed January 1, 2015 Rates					January 1, 2016 Proposed Rates					Annual Increase/(Decrease)		
1	**Rate 2.1 General Service**	Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
2														
3	Monthly Charge													
4	Delivery Charge per Day (Note A)	365.25	days x	$1.1475	=	$419.1244	365.25	days x	$1.2179	=	$444.8380	$0.0704	$25.7136	0.66%
5	Rider 5 - RSAM per Day	365.25	days x	$0.0026	=	0.9497	365.25	days x	$0.0026	=	0.9497	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.2799	=	102.2335	365.25	days x	$0.2799	=	102.2335	$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)			$1.4300		**$522.31**			$1.5004		**$548.02**	$0.0704	$25.71	0.66%
8														
9	Next 298 Gigajoules in any month													
10	Delivery Charge per GJ	436	GJ x	$3.439	=	$1,499.4040	436	GJ x	$3.650	=	$1,591.4000	$0.211	$91.996	2.36%
11	Rider 5 - RSAM per GJ	436	GJ x	0.039	=	17.0040	436	GJ x	0.039	=	17.0040	0.000	0.000	0.00%
12	Gas Cost Recovery Charge per GJ	436	GJ x	4.259	=	1,856.9240	436	GJ x	4.259	=	1,856.9240	0.000	0.000	0.00%
13	Total Charges per GJ			$7.737		**$3,373.33**			$7.948		**$3,465.33**	$0.211	$92.00	2.36%
14														
15	Excess of 300 Gigajoules in any month													
16	Delivery Charge per GJ	0	GJ x	$3.332	=	$0.0000	0	GJ x	$3.537	=	$0.0000	$0.205	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	0.039	=	0.0000	0	GJ x	0.039	=	0.0000	0.000	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	4.259	=	0.0000	0	GJ x	4.259	=	0.0000	0.000	0.000	0.00%
19	Total Charges per GJ			$7.630		**$0.00**			$7.835		**$0.00**	$0.205	$0.00	0.00%
20														
21	Total	460	GJ			**$3,895.64**	460	GJ			**$4,013.35**		**$117.71**	**3.02%**
22														
23	Summary of Annual Delivery and Commodity Charges													
24	Delivery Charge (including RSAM)					$1,936.4820					$2,054.1916		$117.7096	3.02%
25	Commodity Charge					1,959.1575					1,959.1575		0.0000	0.00%
26	Total					**$3,895.64**					**$4,013.35**		**$117.71**	**3.02%**

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FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 2.2 - GENERAL (COMMERCIAL) SERVICE

Line No.		Proposed January 1, 2015 Rates					January 1, 2016 Proposed Rates					Annual Increase/(Decrease)		
		Volume		Rate		Annual $	Volume		Rate		Annual $	Rate	Annual $	% of Previous Annual Bill
1	**Rate 2.2 General Service**													
2														
3	Monthly Charge													
4	Delivery Charge per Day (Note A)	365.25	days x	$1.1475	=	$419.1244	365.25	days x	$1.2179	=	$444.8380	$0.0704	$25.7136	0.11%
5	Rider 5 - RSAM per Day	365.25	days x	$0.0026	=	0.9497	365.25	days x	$0.0026	=	0.9497	$0.0000	$0.0000	0.00%
6	Gas Cost Recovery Charge Prorated to Daily Basis	365.25	days x	$0.2799	=	102.2335	365.25	days x	$0.2799	=	102.2335	$0.0000	$0.0000	0.00%
7	Minimum Monthly Charge (includes the first 2 gigajoules)			$1.4300		**$522.31**			$1.5004		**$548.02**	$0.0704	$25.71	0.11%
8														
9	Next 298 Gigajoules in any month													
10	Delivery Charge per GJ	3,076	GJ x	$3.439	=	$10,578.3640	3,076	GJ x	$3.650	=	$11,227.4000	$0.211	$649.036	2.67%
11	Rider 5 - RSAM per GJ	3,076	GJ x	0.039	=	119.9640	3,076	GJ x	0.039	=	119.9640	0.000	0.000	0.00%
12	Gas Cost Recovery Charge per GJ	3,076	GJ x	4.259	=	13,100.6840	3,076	GJ x	4.259	=	13,100.6840	0.000	0.000	0.00%
13	Total Charges per GJ			$7.737		**$23,799.01**			$7.948		**$24,448.05**	$0.211	$649.04	2.67%
14														
15	Excess of 300 Gigajoules in any month													
16	Delivery Charge per GJ	0	GJ x	$3.332	=	$0.0000	0	GJ x	$3.537	=	$0.0000	$0.205	$0.000	0.00%
17	Rider 5 - RSAM per GJ	0	GJ x	0.039	=	0.0000	0	GJ x	0.039	=	0.0000	0.000	0.000	0.00%
18	Gas Cost Recovery Charge per GJ	0	GJ x	4.259	=	0.0000	0	GJ x	4.259	=	0.0000	0.000	0.000	0.00%
19	Total Charges per GJ			$7.630		**$0.00**			$7.835		**$0.00**	$0.205	$0.00	0.00%
20														
21	Total	3,100	GJ			**$24,321.32**	3,100	GJ			**$24,996.07**		**$674.75**	**2.77%**
22														
23	Summary of Annual Delivery and Commodity Charges													
24	Delivery Charge (including RSAM)					$11,118.4020					$11,793.1516		$674.7496	2.77%
25	Commodity Charge					13,202.9175					13,202.9175		0.0000	0.00%
26	Total					**$24,321.32**					**$24,996.07**		**$674.75**	**2.77%**

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FORTISBC ENERGY INC. - FORT NELSON SERVICE AREA
IMPACT ON CUSTOMERS BILLS
BCUC ORDER NO. G-XX-14

RATE 25 - TRANSPORTATION SERVICE

Line No.		Proposed January 1, 2015 Rates						January 1, 2016 Proposed Rates						Annual Increase/(Decrease)		
1	**Rate 25 Transportation Service**	Volume		Rate		Annual $		Volume		Rate		Annual $		Rate	Annual $	% of Previous Annual Bil
2																
3	Transportation Delivery Charges															
4																
5	Delivery Charge per Gigajoule															
6	i) First 20 Gigajoules	240	GJ x	$3.798	=	$911.5200		240	GJ x	$4.043	=	$970.3200		$0.245	$58.8000	0.24%
7	ii) Next 260 Gigajoules	3,120	GJ x	$3.524	=	10,994.8800		3,120	GJ x	$3.751	=	11,703.1200		$0.227	708.2400	2.86%
8	iii) Excess over 280 Gigajoules	3,530	GJ x	$2.880	=	10,166.4000		3,530	GJ x	$3.064	=	10,815.9200		$0.184	649.5200	2.62%
9	iv) Minimum Delivery Charge per month	12	months x	$1,826.00		-		12	months x	$1,826.00		-		$0.00	$0.00	0.00%
10																
11	Administration Charge per month	12	months x	$202.00	=	$2,424.00		12	months x	$202.00	=	$2,424.00		$0.00	$0.00	0.00%
12																
13	Rider 5: RSAM per GJ	6,890	GJ x	$0.039	=	$268.7100		6,890	GJ x	$0.039	=	$268.7100		$0.000	$0.0000	0.00%
14																
15	Total Transportation Delivery & Administration Charges	6,890	GJ x	*$3.594*		**$24,765.51**		6,890	GJ x	*$3.800*		**$26,182.07**		*$0.206*	**$1,416.56**	**5.72%**
16																
17																
18	Summary of Annual Delivery, Administration and Commodity Charges															
19	Delivery & Administration Charge (including RSAM)	6,890	GJ x	$3.594	=	$24,765.5100		6,890	GJ x	$3.800	=	$26,182.0700		$0.206	$1,416.5600	5.72%
20	Commodity Charge (no sales from Authorized/Unauthorized Overrun Gas)	0	GJ	0.000	=	0.0000		0	GJ	0.000	=	0.0000		0.000	0.0000	0.00%
21	Total	6,890	GJ x	*$3.594*	=	**$24,765.51**		6,890	GJ x	*$3.800*	=	**$26,182.07**		*$0.206*	**$1,416.56**	**5.72%**

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