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February 5, 2015

Via Email
Original via Mail

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On December 3, 2014, FEI filed the Application as referenced above. In accordance with Commission Order G-192-14 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

1. Reference: Exhibit B-1, Section 1, Page 4

> 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

1.1 Please describe the circumstances (including the year) that gave rise to a 12% reduction in burner tip rates, and to which customer group they applied.

Response:

Effective January 1, 2014, as per Commission Order G-203-13, the Commission approved (among other things), a decrease to FEFN's Gas Cost Recovery Charge of $0.707 per gigajoule (GJ), (from $3.533 per GJ to $2.846 per GJ), and a decrease to FEFN's Revenue Stabilization Adjustment Mechanism (RSAM) rate rider of $0.061 per GJ (from $0.145 per GJ to $0.084 per GJ). These reductions resulted in a burner-tip decrease effective January 1, 2014, for a residential customer with an average consumption of 140 GJs per year of approximately 12 percent. The resulting decreases for commercial customers with average annual consumptions of 460 GJs and 3,100 GJs were approximately 11 percent and 12 percent respectively. The decrease for Rate Schedule 25, Transportation service customers with an average annual consumption of 6,890 GJs was approximately 2 percent, (the impact of the RSAM reduction only since Transportation service customers do not pay the Gas Cost Recovery Charge).

1.2 Please describe the circumstances (including the year) that gave rise to a 33% increase in burner tip rates and to which customer group they applied.

Response:

Effective April 1, 2014, as per Commission Order G-39-14, the Commission directed FEFN to increase FEFN's Gas Cost Recovery Charge by $1.929 per gigajoule (GJ), (from $2.846 per GJ to $4.775 per GJ). This increase resulted in a burner-tip increase effective April 1, 2014, for a residential customer with an average consumption of 140 GJs per year of approximately 33 percent. The resulting increases for commercial customers with average annual consumptions of 460 GJs and 3,100 GJs were approximately 31 percent and 33 percent respectively. The one transportation service customer was not impacted by the increase in FEFN's Gas Cost

Recovery Charge but may have been subject to changes in their cost of gas as per the contract with their customer agent.

1.3 Please confirm that regardless of past practices, rate stability is an important objective of rate setting.

Response:

Rate stability is only one of several important objectives in rate setting and is secondary to the primary requirement that rates must be set to allow the utility to have a reasonable opportunity to earn a fair return. For example, Bonbright, Danielsen, and Kamerschen in their book, Principles of Public Utility Rates, 2nd Edition, state the primary objective of rate setting is to allow the utility to recover its revenue requirement; rate stability is a secondary objective.[1]

In British Columbia this concept is set out in the Utilities Commission Act Sections 59(1) and (5):

> *"A public utility must not make, demand or receive (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia …"*

> *"In this section, a rate is "unjust" or "unreasonable" if the rate is…(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property…"*

The applicable legal principle is the same as that pronounced by the B.C. Court of Appeal in *Hemlock Valley Electrical Services Ltd. v. B.C. Utilities Commission and AGBC*, 1992 66 B.C.L.R. (2d) 1. Paragraph 64 of the case states:

> *"The Utilities Commission Act empowers the commission to determine what is a fair and reasonable rate of return upon the appraised value of the property of regulated utilities, but, having done so, requires the commission to set rates so as to allow recovery of a rate which permits an opportunity to earn that return. In this case, the commission correctly exercised its discretion to determine what a just and reasonable return was, but wrongly failed to permit HVES to charge a rate which gave it an opportunity to earn that return."*

[1] Bonbright, James C., Danielsen, Albert L. and Kamerschen, David R. Principles of Public Utility Rates, 2nd Ed., Public Utility Reports Inc., 1988, Arlington, VA, Pages 377, 383 – 385, 387.

Where appropriate, FEI will seek approval of deferral accounts or other mechanisms to help achieve the objective of rate stability. In the case of FEFN, the rate increase is primarily driven by the approved and completed Muskwa River Crossing project, the costs of which will already be depreciated over the life of the asset. There is no reasonable basis on which to smooth the impacts of the project into rates while still recovering the revenue requirement.

1.3.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.1.3.

1.4 What options are available to FEFN to provide for greater stability in rates? Please describe.

Response:

In the absence of significant increases in load growth and customer base, options for rate stability in Fort Nelson are very limited and are generally confined to the short term option of deferral account treatment or the long term option of adoption of common rates.

Deferral account treatment of costs or revenue deficiencies/surpluses is a short term option that can provide some rate stability in certain situations. Deferral treatment, for example, can be effectively used to smooth the impact of one-time or short-term expenses. The deferral approach, however, cannot be effectively used to defer the impact of capital investment in the system, such as those of the Muskwa River Crossing Project, which are already capitalized and will be depreciated over long periods of time. Nor can deferral account treatment change the underlying cause of rate instability in Fort Nelson.

In FEI’s opinion, due to the existing small customer base and limited forecast growth, the only real long term solution for rate stability in Fort Nelson is the adoption of common rates with FEI. Although this option provides increased rate stability, it may also result in a fairly substantial initial increase to the existing rates of Fort Nelson customers.

As suggested by the Commission in their Decision pertaining to Order G-21-14 (page 19), FEI will be reviewing the inclusion of Fort Nelson in common rates as part of the comprehensive rate design application that will be filed before December 31, 2016.

2. Reference: Exhibit B-1, Page 9

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.

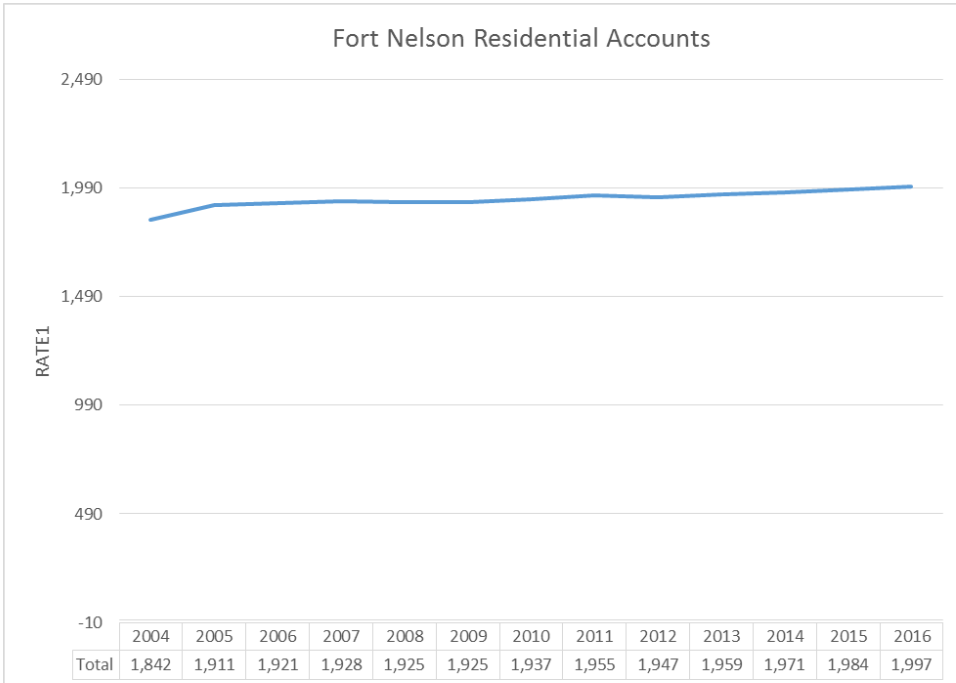
2.1 Please provide a discussion of the factors contributing to declining use rates per customer, and why FEFN anticipates that they are sufficient to more than offset increases in customer growth in 2015.

Response:

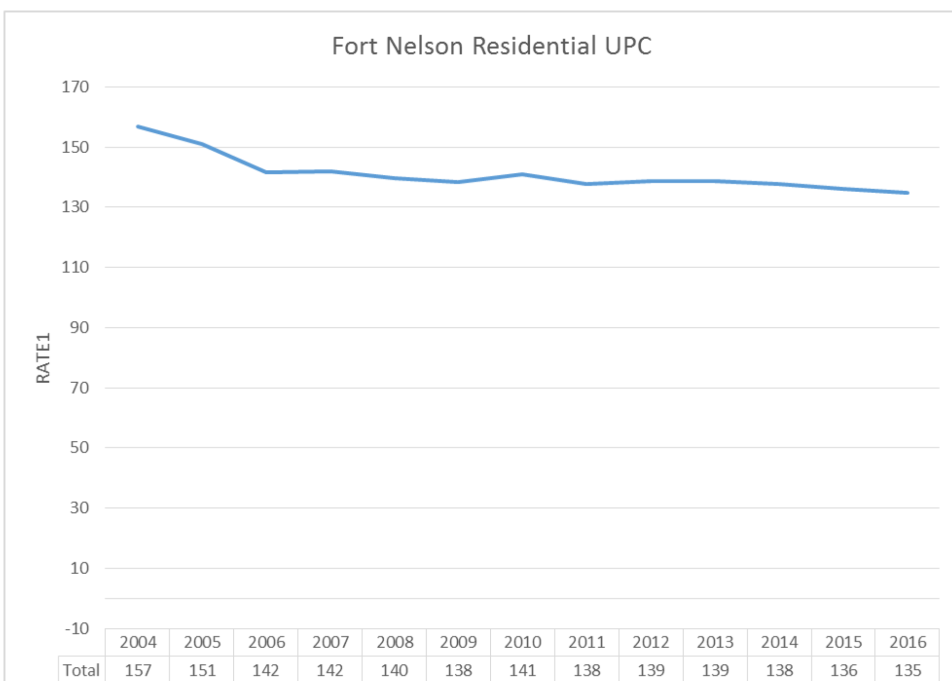
There are many factors implicit in the declining use per customer (UPC). Energy Efficiency and Conservation (EEC), customer behavior, improved appliance efficiency and housing stock are four factors that may be affecting the decline. While factors that may be contributing to the decline can be identified, the relative contribution of each factor cannot be identified. All factors are intrinsic in the historic data used to prepare the forecast.

The following three charts provide a graphic representation of the relationship between account growth and declining UPC, highlighting that the growth in customer accounts is not sufficient to offset the impact of the decline in UPC on the forecast.

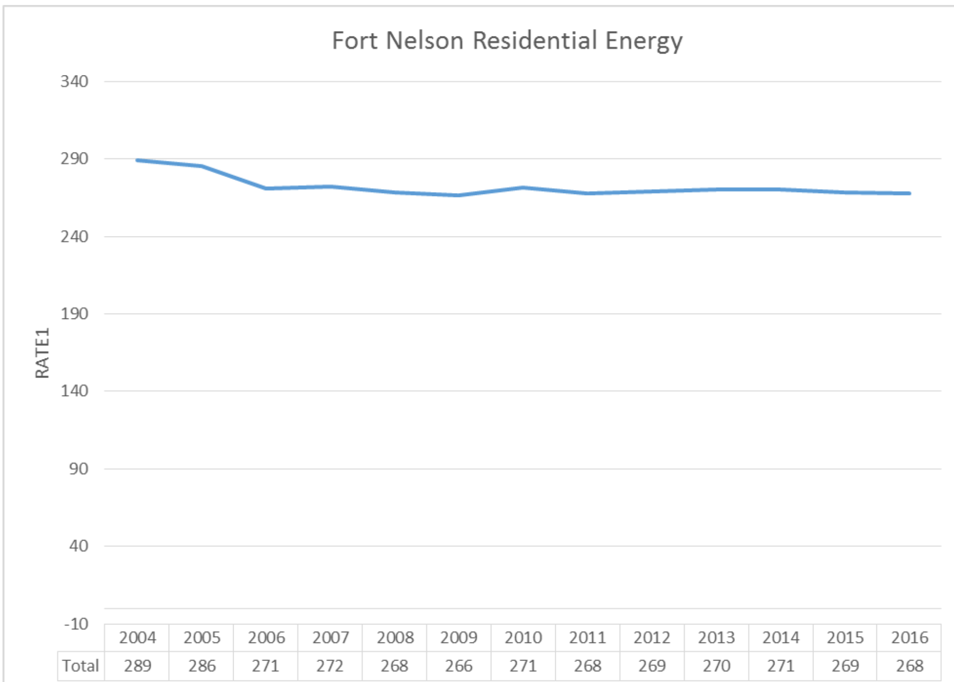
The following chart shows that residential accounts are increasing, which would, all else equal, lead to an increase in demand:



But, as shown in the chart below, residential UPC is declining which, all else equal, should lead to a decrease in demand:



As shown in the chart below, the total residential demand is decreasing which demonstrates that the increase in customers is not great enough to offset the decline in UPC.



2.2 Please provide FEFN's perspective on whether the declining use rates will continue indefinitely, or if use rates are expected to stabilize at some point? Please explain.

Response:

The short term forecast developed for this Application assumes any trends experienced in recent years will continue through the forecasting horizon. The short term forecast is updated as required using methods consistent with past practice. It should be noted that while the UPC for Rate Schedules 1 and 2.1 are decreasing, the UPC for Rate Schedule 2.2 is increasing. The long term expectation from the 2014 Long Term Resource Plan is that the declining trend experienced in Rate Schedules 1 and 2.1 is forecast to stabilize as the rate of turnover of old, low-efficiency end-use appliances with high-efficiency models slows down due to the stock of old, low-efficiency end-use appliances being depleted.

2.2.1 If FEFN anticipates that declining use rates will stabilize, when does FEFN expect this to occur?

Response:

Please refer to the response to CEC IR 1.2.2.

2.3 Are the declining use rates a result of activities or programs undertaken by the utility or are they occurring naturally? Please explain.

Response:

The decline in residential customers' use rates is attributable to "naturally occurring" efficiency improvements and FEI's EEC programming. The declining use rate across FEI customers generally, including those in FEFN, can be attributed to the following factors:

- Changes to building codes and minimum equipment performance standards (MEPS), such as the provincial furnace MEPS of 92 percent;
- Energy efficiency upgrades undertaken by customers, such as to appliances, insulation, windows, doors, and fireplaces, whether or not the customer has participated in an FEI efficiency program;
- Advances in technology;
- Behaviour changes by customers; and
- Public policies and programs, such as the carbon tax.

2.4 What activities and programs does FEFN undertake to reduce customer use? Please explain.

Response:

The programs offered to customers in the FEFN service area that will reduce a customer's natural gas use are primarily FEI's EEC Programs, as most recently approved by the Commission in Order G-138-14 pursuant to section 44.2 of the *Utilities Commission Act*.

FEI's on-line home energy calculator is also available to help FEFN customers reduce their energy consumption by allowing the customer to undertake a range of energy use comparisons of various space and water heating equipment, thereby allowing the customer to make new equipment purchasing choices with better information about energy efficiency.

2.5 What activities does FEFN undertake to increase use per customer and/or minimize the decline in use rates? Please explain.

Response:

The programs offered to customers in the FEFN service area that will increase a customer's natural gas use are the activities that FEI undertakes throughout the province generally and include customer education, awareness and outreach programs, the advancement of natural gas end-use technologies and applications and community investment in education. Each of these is described briefly below:

- **Customer Education, Awareness, and Outreach Programs:** This initiative is aimed at increasing preferences and demand for natural gas use through comprehensive customer education, awareness and outreach programs.
- **Advancing Natural Gas end-use Technologies and Applications:** This initiative is aimed at advancing gas end-use technologies to support the efficient use of gas applications in the residential, commercial and industrial market and ensuring they are more affordable and widely available, by working collaboratively with key stakeholders, including industry and the Canadian Gas Association (CGA).
- **Community Investment in Education:** This initiative is to build and foster relations amongst educational institutions in the province, as these establishments are becoming increasingly influential in municipal and provincial policy changes.

2.6 Please provide, in dollars and dollars per customer, the spending that has been undertaken to increase use per customer over the last 5 years.

Response:

Any costs that have been incurred to add customers and/or increase the use per customer reside in FEI's ES&ER departmental O&M. Costs for ES&ER department O&M expenditures are allocated from FEI to FEFN based on the formula approach that is described in the Application. FEI does not track costs at the level of detail that would be required to provide the dollars associated with these activities within the ES&ER department since they are undertaken by existing FEI staff as part of their overall responsibilities.

2.7 Please provide, in dollars and dollars per customer, the spending that has been undertaken to support decreasing use per customer and/or increase the decline in use rates?

Response:

Approximately $25 thousand has been spent on EEC programming including incentives for FEFN customers and education and outreach activities targeting FEFN customers. This level of spending equals approximately $10 per customer during this period.[2] This amount does not include additional O&M expenditures, such as those one-time costs incurred for the development and maintenance of the on-line home energy calculator, that are administered on behalf of FEFN through the O&M Shared Services allocation formula approved by the Commission. FEI does not track these other O&M expenditures in a manner that allows a breakout of these costs as requested.

[2] Using the 2013 year end customer count of 2,438.

3. Reference: Exhibit B-1, Section 2, Page 10 (Table 2-1), Footnote 12

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.

3.1 Why is Rate Category 2.1 increased nearly 10% in 2015 while Rate Categories 1 and 2.2 increases are closer to 9%?

Response:

Rate Schedules 2.1 and 2.2 (General Service) have identical rates. The difference in the annual bill impact between Rate Schedule 2.1 and Rate Schedule 2.2 is a result of the difference between average annual use rates used to calculate the annual bill impacts for each rate schedule. For Rate Schedule 2.1, 460 GJs is used and the resulting annual bill impact is 9.98 percent. For Rate Schedule 2.2, 3,100 GJs is used, and the resulting annual bill impact is 8.99 percent. More specifically, larger volume customers have a larger annual bill which means that a larger denominator is used as the basis for the calculation of the annual bill impact and percentage increase. All else being equal, the same change will result in a lower percentage bill impact when compared to a smaller denominator.

With respect to Rate Schedule 1 (Residential Service), which has different and slightly lower rates than Rate Schedule 2.1 and Rate Schedule 2.2, the annual bill impact calculation for this rate schedule also uses a different average annual use rate, which therefore affects the overall increase. The average annual use rate used to calculate the annual bill impact for Rate Schedule 1 is 140 GJs, which results in an annual bill impact of 9.06 percent.

Overall, given the increase to the delivery rates, the decrease to the Rate Stabilization Adjustment Amount (RSAM) rate rider, and the declining block rate design, the bill impacts for each rate schedule vary by less than 1 percent.

3.2 Why is Rate Category 2.1 increased by 3.02%, while Rate Categories 1 and 2.2 increases are closer to 2.75%?

Response:

Please refer to the response to CEC IR 1.3.1.

4. Reference: Exhibit B-1, Page 10 (Table 2-1), Footnotes 11 and 12

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

Rate Category	GJ	2015 Annual $ Increase	2015 % of Previous Annual Bill	2016 Annual $ Increase	2016 % of Previous Annual Bill
Rate 1- Domestic (Residential) Serivce	140	$ 91.41	9.06%	$ 29.88	2.71%
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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.

4.1 Please explain why Rate Category 25 – Transportation Service received a 22.92% increase in the delivery rate component when FEFN proposes to increase the delivery component by 24.26% overall.

Response:

The 22.92 percent increase for Rate Schedule 25 represents the annual bill impact including the change to the Rate Stabilization Adjustment Mechanism (RSAM) rate rider, not solely the increase in the delivery component of the rate. Effective January 1, 2015, the RSAM rate rider per GJ for FEFN customers decreased by $0.045 per GJ (from $0.084 per GJ to $0.039 per GJ). Therefore the combined annual bill impact, taking into account the decrease in the RSAM rate rider, was 22.92 percent.

4.2 Please provide the delivery rate component and other rate component percentage increases for each Rate schedule by year.

Response:

Please refer to Attachment 4.2.

5. Reference: Exhibit B-1, Section 1, Page 12

> 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.

5.1 Does FEFN include a factor/adjustment for the elasticity impacts of projected rate changes in its UPC and total demand estimates?

Response:

No, FEI does not include an adjustment for the elasticity impacts of projected rate changes in its UPC and total demand forecast.

FEI's elasticity analysis of its service territories did not result in reliable elasticity estimates. The regressions resulted in very low R-squared results. There are several potential causes for these results. One reasonable explanation is that there are other factors driving the decline in UPC, overpowering any effects that price has on consumption.

5.1.1 If yes, please quantify the adjustments incorporated and the logic used to develop adjustments.

Response:

Please refer to the response to CEC IR 1.5.1.

5.1.2 If no, please discuss why FEFN does not think it is necessary to adjust estimated UPC and total demand amounts in response to the elasticity impacts of projected rate changes.

Response:

Please refer to the response to CEC IR 1.5.1.

6. Reference: Exhibit B-1, Section 1, Page 13

> 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%.

6.1 Please provide FEFN's evidence that the CBOC housing starts forecast represent an appropriate proxy for Fort Nelson's customer growth.

Response:

Please refer to the response to BCUC IRs 1.5.3 and 1.5.4.

6.2 Please confirm that growth in Fort Nelson may be partially tied to development in the Horn River Basin.

Response:

FEI is aware that there is potential for development in the Horn River Basin over the next five years and FEI believes it is a reasonable assumption that long term growth in Fort Nelson may be partially tied to this development.

It is FEI's understanding, however, that there is still some uncertainty around the degree and timing of this growth, particularly within the short term. The Conference Board of Canada (CBOC), for example, published an article in The Province newspaper on April 24, 2014, and stated that they, "expect Canadian gas production to begin rising again by the end of this decade".

FEI has not applied any incremental adjustments to its customer additions forecast to reflect the potential development in the Horn River Basin for 2015 and 2016. Consistent with past practice and other FEI service territories, residential customer growth in FEFN is forecast based on the provincial housing starts forecast from the CBOC. As a result, the FEFN forecast of residential additions considers development in the Horn River Basin to the same extent that the CBOC forecast considers development in the Horn River Basin. FEI is unable to determine what assumptions around development in the Horn River Basin, if any, are embedded in the CBOC forecast and thus embedded in the forecast of residential customer additions.

6.2.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.6.2.

6.2.2 If confirmed, please provide FEI's knowledge of forecasts for development in the Horn River basin over the next 5 years and explain if this has been factored into the growth forecast.

Response:

Please refer to the response to CEC IR 1.6.2.

6.2.2.1 If it has not been factored in, please explain why not.

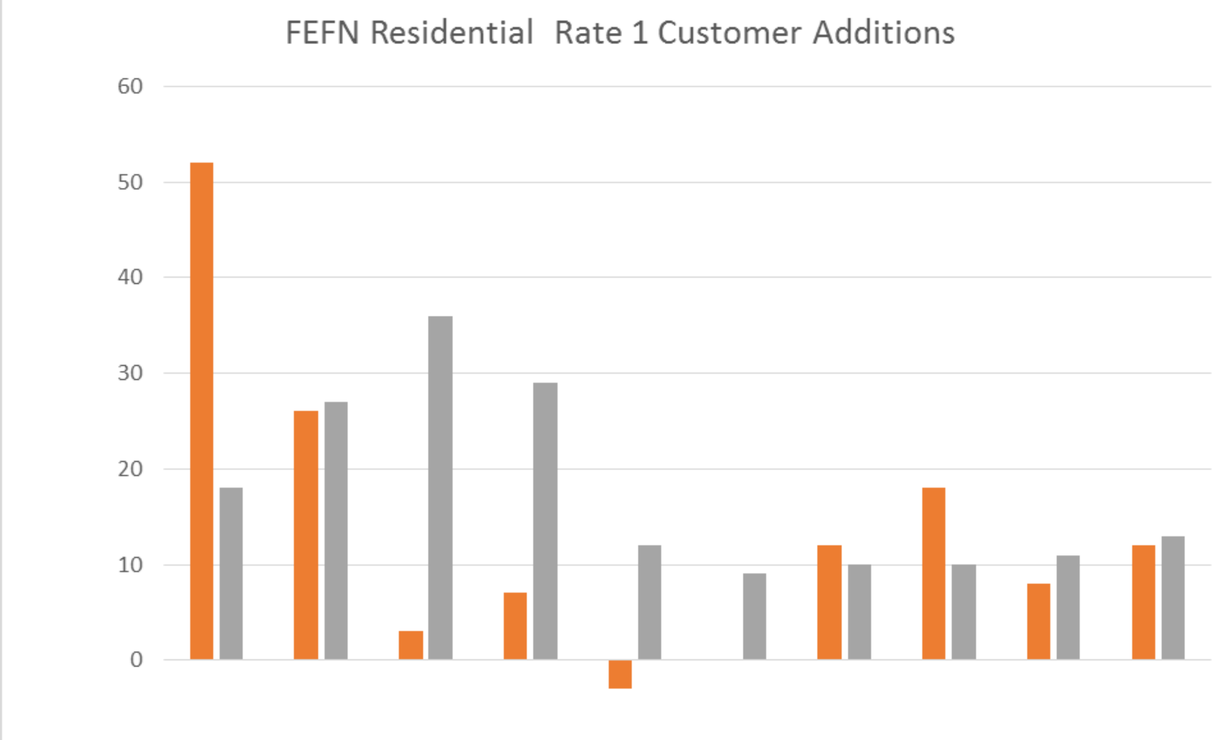
Response:

Please refer to the response to CEC IR 1.6.2.

6.3 Please provide a table and graph comparing the forecast additions FEFN has used each year for the last ten years, and the actual customer additions that have occurred during the same period.

Response:

Please refer to the table below for a comparison of the forecast and actual customer additions for 2004 through 2013.



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Actual	52	26	3	7	-3	0	12	18	8	12
Forecast	18	27	36	29	12	9	10	10	11	13

6.4 When was the CBOC forecast made?

Response:

The CBOC forecast used was the "CBOC Provincial Medium Term Forecast as of December 6, 2013", as stated in the filing in Section 1 on page 13. Please also refer to the response to BCUC IR 1.5.2 where FEFN discusses a more recent forecast.

6.5 Given FEFN's current understanding of the factors that were probably considered by the CBOC at the time it projected a 9% growth rate for single family dwellings in 2015, does FEFN currently view the projected 9% growth rate in single family dwellings in 2015 to be realistic?

Response:

Since preparing the forecast in the Application a more recent CBOC forecast has become available and is showing -9 percent for single family dwellings in 2015. Please refer to the response to BCUC IR 1.5.2 for the impact of using the more recent forecast.

6.6 Does FEI believe that circumstances may have changed since the CBOC forecast was made?

Response:

The growth rates from the CBOC forecast are an input into the FEFN econometric forecast for Rate Schedule 1 additions. Since preparing the Rate Schedule 1 forecast in the Application, a more recent CBOC forecast has become available. Please refer to the response to BCUC IR 1.5.2 for the impact of the new forecast.

The CBOC does not publish rationales for its forecasts and, as FEFN is not privy to the inner workings of the CBOC forecast and its proprietary models, FEFN does not have information about what changes in CBOC's inputs or model were made to arrive at the new forecast.

6.6.1 If circumstances may have changed, please provide FEFN's understanding of what has changed and how it might affect growth rates.

Response:

Please refer to the response to CEC IR 1.6.6.

6.6.2 Please provide the rationale that supports a 9% projected growth rate in single family dwellings in 2015.

Response:

Please refer to the response to CEC IR 1.6.6.

7. Reference: Exhibit B-1, Page 14

> 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

7.1 Please confirm, or otherwise explain that the forecast commercial customer additions of '12' for 2014 are based on a three year historical average from 2011 to 2013 inclusive, not 2010 to 2013.

<u>Response:</u>

Confirmed. The sentence should have stated:

"The forecast commercial customer additions in Figure 3-3 are based on a three year historical average 2011-2013."

7.1.1 If not, please clarify which year is excluded in the 'three-year historical average 2010 to 2013.

Response:

Please refer to the response to CEC IR 1.7.1.

7.1.1.1 Is it typical for FEFN to project commercial customer additions two or more years out as stable rather than changing based on prior year forecasts? I.e. 2015 and 2016 are the same (12) as the 2014 forecast, whereas if a three year historical average was calculated for 2015 based on historical years of 2012 and 2013 and the 2014 forecast, the 2015 forecast would be for 6 commercial additions. Please explain.

Response:

Yes. The existing methodology is based on the use of historical data only and FEI believes the most recent 3 years' data are the best indicator given the volatility of additions data. FEI believes that holding the 3 year average constant is a better approach than a rolling approach which would use a forecasted 2014 value to forecast the 2015 value. Further the 2016 value would be based on only a single actual value (from 2013) and two forecasted values (from 2014 and 2015).

7.1.1.2 Please explain either why FEFN does not adjust its predictions beyond the current forecast or why FEFN changed its process in this instance.

Response:

Please refer to the response to CEC IR 1.7.1.1.

7.1.1.3 Would FEFN agree that not changing the longer range forecast (i.e. 2-3 years out) to account for the current year forecast does not represent the utility's best information?

Response:

No, FEI does not agree. FEI believes that historical data is the best information available to determine commercial customer additions. Please refer to the response to CEC IR 1.7.1.1.1.

7.2 Would FEFN agree that the 2011 figure of '29' customer additions is an outlier in a pattern of otherwise much fewer customer additions?

Response:

Although the customer additions of 29 in 2011 are certainly significantly greater than most years, FEI does not agree that 2011 should be considered an outlier and ignored. Commercial additions in Fort Nelson are small and as a result volatile. As such, customer additions of 2 may be considered an outlier in some circumstances. For example, a simple outlier test on the years 2007 through 2013 indicates that 4 out of the 7 data points could be considered outliers:

Year	2007	2008	2009	2010	2011	2012	2013
Commercial Additions	7	4	-2	8	29	4	3
MAD	3						
Median	4						
Result	Normal	Normal	Outlier	Outlier	Outlier	Normal	Outlier
Source	http://www.examiner.com/article/statistical-outliers-detection-microsoft-excel-worksheet						

Thus, FEI believes that these results are inconclusive based on the frequency of the outliers in the historical data. These results highlight the fact that outlier detection is difficult in such volatile datasets.

Rather than discount a significant portion of the historical data, FEI has chosen to remain consistent with past practices and other service territories and use the simple three year average for the determination of commercial customer additions in Fort Nelson.

7.2.1 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.7.2.

7.2.2 If yes, please explain what situation occurred that resulted in such a significant increase in commercial customer additions in 2011.

Response:

Please refer to the response to CEC IR 1.7.2.

7.2.2.1 Does FEFN have any reason to believe that such a situation, or other circumstances, will occur again in the next five years?

Response:

Please refer to the response to CEC IR 1.7.2.

7.2.2.2 If so, please describe the circumstances and explain why FEFN believes that they will occur.

Response:

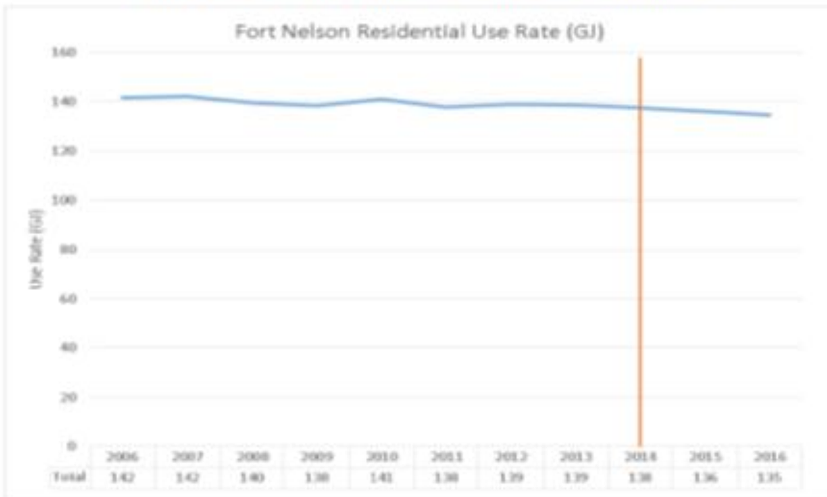
Please refer to the response to CEC IR 1.7.2.

8. Reference: Exhibit B-1, Page 15

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



8.1 Is the Residential UPC weather normalized in Figure 3-4?

Response:

Yes.

8.1.1 If not, please provide the weather normalized data.

Response:

Please refer to the response to CEC IR 1.8.1.

8.1.2 Please provide the UPC data back to 2004.

Response:

Please refer to the table below for actual normalized Residential customer UPC data from 2004 through 2013 and forecast UPC data for 2014 through 2016.

Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Use Rate (GJ)	155	154	142	142	140	138	141	138	139	139	138	136	135

8.1.3 What factors are contributing to the decline in Residential UPC in 2015 and 2016?

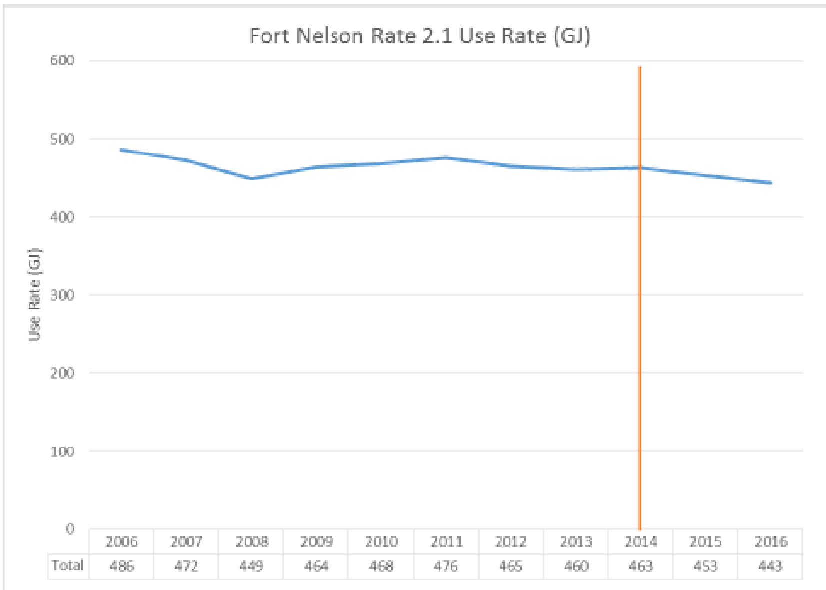
Response:

Please refer to the response to CEC IR 1.2.1.

9. Reference: Exhibit B-1, Pages 15 and 16

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



9.1 Please provide weather normalized data if the above data is not weather normalized dating back to 2004.

<u>Response:</u>

The data in figure 3-5 is weather normalized. The table with two additional years (2004 and 2005) is shown below.

Rate Schedule 2.1 UPC (GJ)													
Year	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Use Rate (GJ)	537	502	486	472	449	464	468	476	465	460	463	453	443

9.2 What circumstances are contributing to the significant decline in forecast UPC in 2015 and 2016?

Response:

Please refer to the response to BCUC IR 1.7.2.

9.2.1 Did these factors have a significant impact on UPC in 2014? Please explain why or why not.

Response:

Please refer to the response to BCUC IR 1.7.2.

9.2.2 Please provide three year historical average UPC for 2012, 2013, and 2014.

Response:

The three-year average UPC using 2012, 2013 and 2014 annual values would be:

$$Three\ Year\ Average\ = \frac{(465 + 460 + 463)}{3} = 463$$

Please note that this is not the method used to develop the UPC forecast. The methodology for the UPC forecast is described in response to BCUC IR 1.7.1.

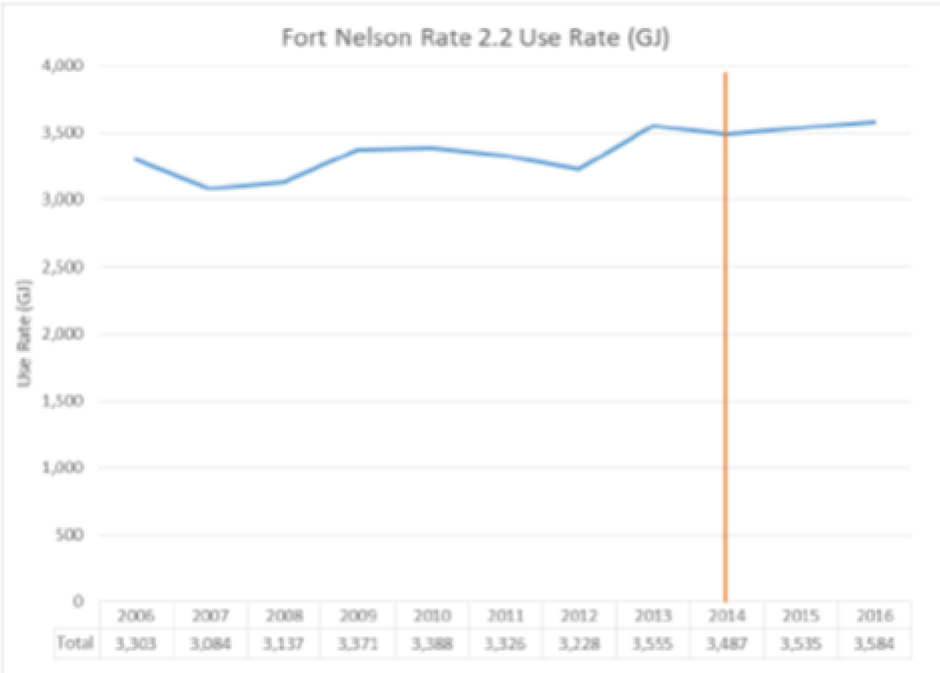
9.2.3 Why did the customer use rate for commercial peak in 2011 after the 2008 recession?

Response:

Please refer to the response to BCUC IR 1.7.2.

10. Reference: Exhibit B-1, Page 16

Figure 3-6: Commercial UPC for Rate Schedule 2.2



10.1 Please provide the weather normalized data if it is not provided in the above graph.

Response:

The Rate Schedule 2.2 UPC data is weather normalized in Figure 3-6.

10.2 What circumstances are contributing to the rise in UPC commencing in 2013?

Response:

Please refer to the response to BCUC IR 1.7.2.

10.3 Why did the UPC decline in 2014 vs. the 2013 peak?

Response:

Please refer to the response to BCUC IR 1.7.2.

11. Reference: Exhibit B-1, Section 2, Page 10, Section 6, Page 26 (Table 6-1)

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.

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%

11.1 Please discuss the reasons property taxes decreased $27 thousand between 2014 (Approved) and 2015 (Projected).

Response:

The 2014 projection and 2015 and 2016 Forecasts shown in Table 6-1 were incorrect. FEFN erroneously omitted a new distribution line assessment folio created by BC Assessment in 2014 in its Projected 2014, Forecast 2015 and Forecast 2016 columns. The table has been recreated below to include the omitted distribution line folio and has been updated to reflect the 2014 preliminary actual information.

The revised difference between 2015 Forecast and the amount in the 2014 application is now approximately $6 thousand. Furthermore, the difference between the 2015 Forecast and the 2014 Preliminary actual amount is now approximately $4 thousand.

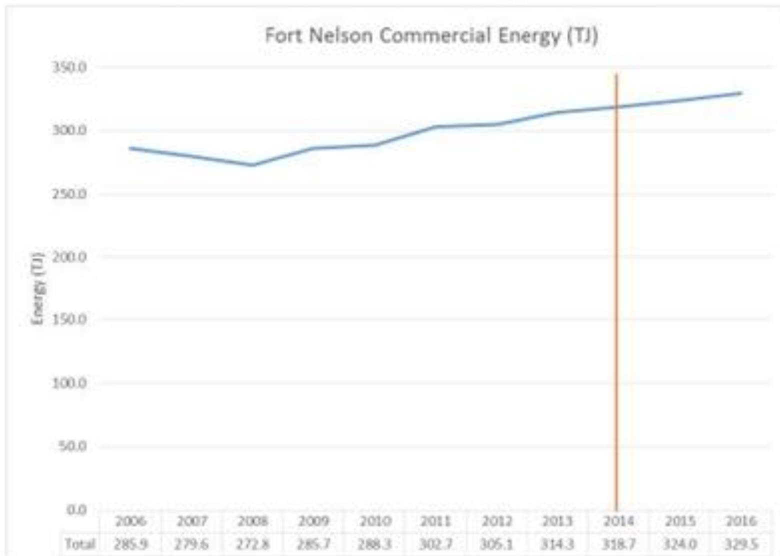
Table 6-1: Property Tax Expense ($000) [Revised]

Asset Type	Approved 2013	Actual 2013	Forecast 2014	Actual 2014	Forecast 2015	Forecast 2016
Distribution Assets	104.4	74.7	81.9	74.8	79.8	80.8
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	38.3
OGC Fees	2.5	1.4	2.5	1.4	1.5	1.5
Total Property Taxes	178.0	135.1	144.0	133.8	137.8	139.3
Forecast Change ($000)					(6.2)	1.5
Forecast Percent Change					-4.3%	1.1%

Please also refer to the response to BCUC IR 1.1.2 for the revised financial schedules reflecting this correction.

12. Reference: Exhibit B-1, Section 3, Page 18 (Figure 3-9), and Section 7, Page 31

> 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**

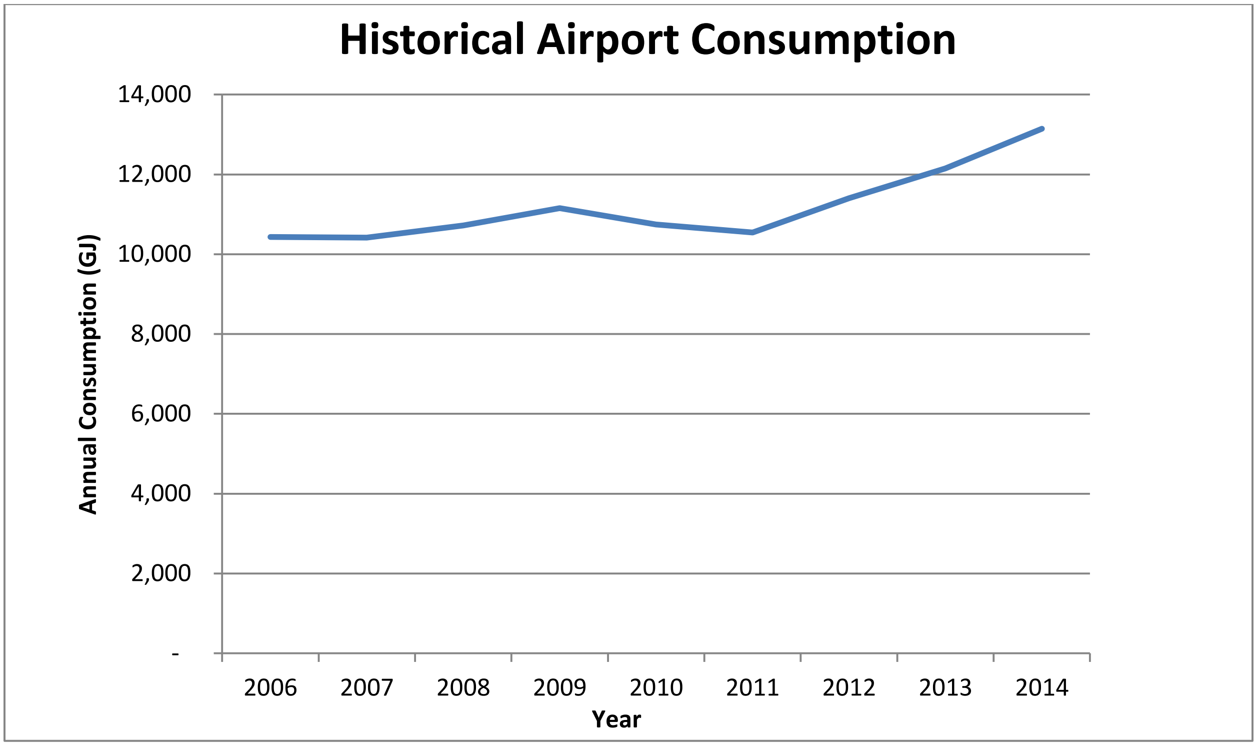


> - the forecast alterations to the distribution system and increase in operating pressure to increase the gas supply to the airport due to increased demand at the airport ($85 thousand); and,

12.1 What has the airport demand increase been historically from 2006 to 2014?

Response:

The chart and table below "Historic Airport Consumption" shows the historical natural gas consumption at the airport from 2006-2014 and provides the year-over-year change in demand:



Year	2006	2007	2008	2009	2010	2011	2012	2013	2014
Annual Consumption (GJ)	10,431	10,418	10,718	11,152	10,745	10,544	11,407	12,152	13,146
Year over Year Increase (GJ)	573	(13)	300	434	(407)	(201)	863	745	994

12.1.1 Is the airport demand expected to continue to increase and if so, why?

Response:

At this time, FEFN does not know whether demand at the airport will increase.

The demand at the airport has been fairly stable with increases seen from 2012 to 2014 which are attributable to one specific customer. Future increase in demand at the airport is largely subject to additional demand from this particular customer. At this time, this customer is not certain if their demand will continue to increase further or remain stable.

13. Reference: Exhibit B-1, Page 24, Table 5-1

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**

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.

13.1 Is the $11,000 difference in Employee Expenses (from 2014 to 2015) all related to travel for the capital projects, or are other increases included as well? Please explain, detail and quantify where possible.

<u>Response:</u>

Please refer to the response to BCUC IR 1.13.1.

13.2 For how long does FEFN anticipate requiring the additional Employee Expenses?

Response:

The additional employee expenses are ongoing in support of increased requirements for managers to perform field assessments in locations where there is no manager located on site. The activities are related to recurring O&M and capital activities and as such FEI expects that Employee Expenses will continue to be incurred into the foreseeable future.

Off-site management including associated travel expenses to be on-site regularly is still more cost effective than providing a local Fort Nelson manager, as discussed in the response to BCUC IR 1.12.3.

13.2.1 When, and to what level would FEFN anticipate reducing the Employee Expenses in the future?

Response:

Please refer to the response to CEC IR 1.13.2.

14. Reference: Exhibit B-1, Section 8, Page 38 (Table 8-1)

> 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%

14.1 Please provide the source(s) for the forecasted T-Bill rates.

Response:

The 3-month T-bill rates used in the short term interest rate forecast are based on an average of 4 sources: economic forecasts from BMO, CIBC, RBC and the 2014 BC Ministry of Finance budget (BCMOF).

14.1.1 If more than one source was utilized, please explain how the forecast rate was arrived at.

Response:

Please refer to the response to CEC IR 1.14.1.

14.2 Please provide the data from all other sources reviewed to support these forecasts.

Response:

As this forecast was an average of forecasts from four different sources, this is considered an appropriate sampling of market expectations and as such no other sources were reviewed.

14.3 Please indicate when the forecast was made.

Response:

The forecasts from the banks were provided in mid-June 2014, while the BCMOF is dated February 18, 2014.

14.4 Please describe what circumstances have changed since the forecast was made.

Response:

On January 21, 2015, the Bank of Canada announced that it was lowering its target for the overnight rate from 1.00 percent to 0.75 percent. As a consequence, 3-month Treasury bill yields experienced a decrease from approximately 0.91 percent to 0.62 percent. FEI has not performed an update to its 3-month Treasury bill yield forecast since this announcement, but it is expected that bank forecasts for this yield have decreased to some degree.

As described on page 38 of the Application, FEFN has an Interest Rate Variance deferral account that captures the impact on interest expense of interest rate variances.

15. Reference: Exhibit B-1, Tab 9, Schedule 22

FORTISBC ENERGY INC. - Fort Nelson 12/3/2014 Tab 9 FORECAST Schedule 22

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
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
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

15.1 Please discuss the factors that cause the projected and forecasts for Distribution O&M expenses to be significantly lower than the 2013 actual results.

<u>Response:</u>

The 2014 preliminary actual and 2015 to 2016 Forecasts for Distribution O&M are lower than the 2013 Actual results by $192 thousand for 2014; $207 thousand for 2015 and $195 thousand in 2016 as provided in revised Schedule 22 of Attachment 1.2 in the response to BCUC IR 1.1.2) and this is primarily due to the inclusion of Muskwa River crossing repair costs ($289 thousand) in 2013 actuals. For 2014-2016, the O&M reduction (due to the crossing repair being a one-time event in 2013) is partially offset by inclusion of previously centralized line heater fuel and communication costs as well as increased management travel expenses and IBEW labour (wage, pension and benefit changes).

Temporary repairs to the crossing were made in the Fall of 2013 in advance of the approval and completion of the Muskwa River Crossing CPCN. As stated on page 14 of the Muskwa River Crossing CPCN application:

> *"In the intervening months until the Project can be completed, FEI implemented protection measures to improve the integrity of the north bank of the Muskwa River by selective placement of a large number of 500kg sandbags."*

16. Reference: Exhibit B-1, Tab 9, Schedule 41

FORTISBC ENERGY INC. - Fort Nelson — 12/3/2014 — Tab 9 FORECAST Schedule 41

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

			2015 FORECAST				
Line No.	Particulars	2014 PROJECTED	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

16.1 Please discuss the function and contents of line 19, The Adjustment to 13-month Average.

Response:

Line 17 (Net Plant in Service Mid-Year) of Schedule 41 assumes that plant additions are added into rate base on a mid-year basis. For larger projects the timing of the addition to gas plant in service will be known to be earlier or later than mid-year and an adjustment is made to take into account the duration variance from mid-year. Line 19 (Adjustment to 13-Month Average) of Schedule 41 is used to record these adjustments.

In this Application, the adjustment shown in Line 19 of Schedule 41 is for the Muskwa River Crossing Project CPCN which cost $4.21 million (Tab 9, Schedule 48, Line 6, Column 3). As discussed on page 35 of the Application, the Muskwa River Crossing Project came into service in May 2014; however, in accordance with the treatment approved in the CPCN, these project costs enter rate base on January 1, 2015. This means that the rate base increase attributed to this project must be $4.21 million. Since the project was not included in the 2014 Gas Plant in Service additions it is not included in the 2015 Opening plant balance and correspondingly, the mid-year balance absent any adjustment would be $2.105 million (($0 million + $4.21 million)/ divided by 2). Thus, an adjustment to the rate base of $2.105 million must be made to get the full year's impact of the Muskwa River Project ($4.21 million) included in the rate base.

17. Reference: Exhibit B-1, Tab 9, Schedule 78

FORTISBC ENERGY INC. - Fort Nelson | 12/3/2014 | Tab 9 FORECAST Schedule 78

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 19-20
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	8,946	
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 19-20
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	

17.1 Please discuss how the "Dollar Days" are calculated on this statement.

Response:

The dollar days are calculated using the revenue forecasts for the various rate classes and applying their approved Lag days. The breakdown of the 2015 calculation is outlined in the table below.

2015 Dollar Day Calculation		(1) * (2) = (3)	
	Revenue	Lag Day	Dollar Day
	(1)	(2)	(3)
Schedule 1 - Residential	$ 1,916.2	38.3	$ 73,390
Schedule 2.1 - Commercial	1,587.6	39.0	61,916
Schedule 2.2 - Commercial	819.7	37.5	30,739
Total Sales	4,323.5		166,046
Schedule 25 - Transportation	149.9	45.2	6,775
Total Sales and Transportation	4,473.4		172,821
Other Revenue			
Late Payment Charge	9.1	38.3	349
Connection Charge	10.8	38.3	414
Total Dollar Days	4,493.3		173,583

17.2 Please discuss why forecasted "Dollar Days" in 2015 and 2016 are higher than 2014.

Response:

Dollar days are a function of forecast revenues as demonstrated in the response to CEC IR 1.17.1. In 2015 and 2016 revenues are forecast to increase as compared to 2014 and, consequently, the dollar days increase as well.

17.3 Please discuss why there is a credit for "Other Utility Income"- "Dollar Days" in 2014 and no projected amounts in 2015 or 2016.

Response:

The Other Utility Income forecast of ($90) thousand is related to the Muskwa Cost of Service deferral as noted on Schedule 18. This deferral only relates to 2014 as it is not needed after the project goes in service in 2015. Therefore, there is no corresponding forecast in 2015 and 2016.

Attachment 4.2

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Approved Rates	Proposed Changes	January 1, 2015 Proposed Rates	**Percentage Change**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
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	**24.31%**
10			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026	**-52.73%**
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
12			**Minimum Daily Charge** (includes first 2 gigajoules)	**$0.6029**	**$0.0743**	**$0.6772**	12.32%
13							
14			Delivery Charge per GJ	$2.461	$0.599	$3.060	**24.34%**
15			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
16			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
17			**Next 28 Gigajoules in any month**	**$6.804**	$0.554	**$7.358**	**8.14%**
18							
19			Delivery Charge per GJ	$2.391	$0.582	$2.973	**24.34%**
20			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
21			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
22			**Excess of 30 Gigajoules in any month**	**$6.734**	$0.537	**$7.271**	**7.97%**
23							
24							
25	Rate 1	No. 1.1	**Option B**				
26							
27			Delivery Charge per Day	$0.3175	$0.0772	$0.3947	**24.31%**
28			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026	**-52.73%**
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
30			**Minimum Daily Charge (includes first 2 gigajoules)**	**$0.6029**	**$0.0743**	**$0.6772**	12.32%
31							
32			Delivery Charge per GJ	$2.461	$0.599	$3.060	**24.34%**
33			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
34			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
35			**Next 28 Gigajoules in any month**	**$6.804**	$0.554	**$7.358**	**8.14%**
36							
37			Delivery Charge per GJ	$2.391	$0.582	$2.973	**24.34%**
38			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
39			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
40			**Excess of 30 Gigajoules in any month**	**$6.734**	$0.537	**$7.271**	**7.97%**

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Approved Rates	Proposed Changes	January 1, 2015 Proposed Rates	**Percentage Change**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate 2.1	No. 2	Delivery Charge per Day	$0.9236	$0.2239	$1.1475	**24.24%**
2			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026	**-52.73%**
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
4			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.2090**	**$0.2210**	**$1.4300**	**18.28%**
5							
6			Delivery Charge per GJ	$2.768	$0.671	$3.439	**24.24%**
7			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
8			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
9			**Next 298 Gigajoules in any month**	**$7.111**	$0.626	**$7.737**	**8.80%**
10							
11			Delivery Charge per GJ	$2.682	$0.650	$3.332	**24.24%**
12			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
13			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
14			**Excess of 300 Gigajoules in any month**	**$7.025**	$0.605	**$7.630**	**8.61%**
15							
16	Rate 2.2	No. 2	Delivery Charge per Day	$0.9236	$0.2239	$1.1475	**24.24%**
17			Revenue Stabilization Adjustment Amount per Day	$0.0055	($0.0029)	$0.0026	**-52.73%**
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
19			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.2090**	**$0.2210**	**$1.4300**	**18.28%**
20							
21			Delivery Charge per GJ	$2.768	$0.671	$3.439	**24.24%**
22			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
23			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
24			**Next 298 Gigajoules in any month**	**$7.111**	$0.626	**$7.737**	**8.80%**
25							
26			Delivery Charge per GJ	$2.682	$0.650	$3.332	**24.24%**
27			Revenue Stabilization Adjustment Amount per GJ	$0.084	($0.045)	$0.039	**-53.57%**
28			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
29			**Excess of 300 Gigajoules in any month**	**$7.025**	$0.605	**$7.630**	**8.61%**

Line No.	Schedule	Tariff Page	Particulars	October 1, 2014 Approved Rates	Proposed Changes	January 1, 2015 Proposed Rates	**Percentage Change**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate 3.1	No. 3	Delivery Charge				
2							
3			First 20 Gigajoules in any month	$2.965	$0.833	$3.798	**28.09%**
4			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524	**28.38%**
5			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880	**29.21%**
6							
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039	**-53.57%**
8			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
9							
10			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
11							
12							
13	Rate 3.2	No. 3	Delivery Charge				
14							
15			First 20 Gigajoules in any month	$2.965	$0.833	$3.798	**28.09%**
16			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524	**28.38%**
17			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880	**29.21%**
18							
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039	**-53.57%**
20			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
21							
22			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
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	**28.09%**
28			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524	**28.38%**
29			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880	**29.21%**
30							
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039	**-53.57%**
32			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
33							
34			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
35							
36							
37	Rate 25	No. 4.21	Delivery Charge				
38							
39			First 20 Gigajoules in any month	$2.965	$0.833	$3.798	**28.09%**
40			Next 260 Gigajoules in any month	$2.745	$0.779	$3.524	**28.38%**
41			Excess over 280 Gigajoules in any month	$2.229	$0.651	$2.880	**29.21%**
42							
43			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.084	($0.045)	$0.039	**-53.57%**
44							
45			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**

Line No.	Schedule (1)	Tariff Page (2)	Particulars (3)	January 1, 2015 Proposed Rates (4)	Proposed Changes (5)	January 1, 2016 Proposed Rates (6)	**Percentage Change** (7)
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	**6.00%**
10			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026	**0.00%**
11			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
12			**Minimum Daily Charge** (includes first 2 gigajoules)	**$0.6772**	**$0.0237**	**$0.7009**	**3.50%**
13							
14			Delivery Charge per GJ	$3.060	$0.183	$3.243	**5.98%**
15			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
16			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
17			**Next 28 Gigajoules in any month**	**$7.358**	$0.183	**$7.541**	**2.49%**
18							
19			Delivery Charge per GJ	$2.973	$0.178	$3.151	**5.99%**
20			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
21			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
22			**Excess of 30 Gigajoules in any month**	**$7.271**	$0.178	**$7.449**	**2.45%**
23							
24							
25	Rate 1	No. 1.1	**Option B**				
26							
27			Delivery Charge per Day	$0.3947	$0.0237	$0.4184	**6.00%**
28			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026	**0.00%**
29			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
30			**Minimum Daily Charge (includes first 2 gigajoules)**	**$0.6772**	**$0.0237**	**$0.7009**	**3.50%**
31							
32			Delivery Charge per GJ	$3.060	$0.183	$3.243	**5.98%**
33			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
34			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
35			**Next 28 Gigajoules in any month**	**$7.358**	$0.183	**$7.541**	**2.49%**
36							
37			Delivery Charge per GJ	$2.973	$0.178	$3.151	**5.99%**
38			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
39			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
40			**Excess of 30 Gigajoules in any month**	**$7.271**	$0.178	**$7.449**	**2.45%**

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Proposed Rates	**Percentage Change**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate 2.1	No. 2	Delivery Charge per Day	$1.1475	$0.0704	$1.2179	**6.14%**
2			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026	**0.00%**
3			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
4			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.4300**	**$0.0704**	**$1.5004**	**4.92%**
5							
6			Delivery Charge per GJ	$3.439	$0.211	$3.650	**6.14%**
7			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
8			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
9			**Next 298 Gigajoules in any month**	**$7.737**	$0.211	**$7.948**	**2.73%**
10							
11			Delivery Charge per GJ	$3.332	$0.205	$3.537	**6.15%**
12			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
13			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
14			**Excess of 300 Gigajoules in any month**	**$7.630**	$0.205	**$7.835**	**2.69%**
15							
16	Rate 2.2	No. 2	Delivery Charge per Day	$1.1475	$0.0704	$1.2179	**6.14%**
17			Revenue Stabilization Adjustment Amount per Day	$0.0026	$0.0000	$0.0026	**0.00%**
18			Gas Cost Recovery Charge Prorated to Daily Basis	$0.2799	$0.0000	$0.2799	**0.00%**
19			**Minimum Daily Charge (includes first 2 gigajoules)**	**$1.4300**	**$0.0704**	**$1.5004**	**4.92%**
20							
21			Delivery Charge per GJ	$3.439	$0.211	$3.650	**6.14%**
22			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
23			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
24			**Next 298 Gigajoules in any month**	**$7.737**	$0.211	**$7.948**	**2.73%**
25							
26			Delivery Charge per GJ	$3.332	$0.205	$3.537	**6.15%**
27			Revenue Stabilization Adjustment Amount per GJ	$0.039	$0.000	$0.039	**0.00%**
28			Gas Cost Recovery Charge per GJ	$4.259	$0.000	$4.259	**0.00%**
29			**Excess of 300 Gigajoules in any month**	**$7.630**	$0.205	**$7.835**	**2.69%**

Line No.	Schedule	Tariff Page	Particulars	January 1, 2015 Proposed Rates	Proposed Changes	January 1, 2016 Proposed Rates	**Percentage Change**
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Rate 3.1	No. 3	Delivery Charge				
2							
3			First 20 Gigajoules in any month	$3.798	$0.245	$4.043	**6.45%**
4			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751	**6.44%**
5			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064	**6.39%**
6							
7			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039	**0.00%**
8			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
9							
10			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
11							
12							
13	Rate 3.2	No. 3	Delivery Charge				
14							
15			First 20 Gigajoules in any month	$3.798	$0.245	$4.043	**6.45%**
16			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751	**6.44%**
17			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064	**6.39%**
18							
19			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039	**0.00%**
20			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
21							
22			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
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	**6.45%**
28			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751	**6.44%**
29			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064	**6.39%**
30							
31			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039	**0.00%**
32			Gas Cost Recovery Charge per Gigajoule	$4.259	$0.000	$4.259	**0.00%**
33							
34			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**
35							
36							
37	Rate 25	No. 4.21	Delivery Charge				
38							
39			First 20 Gigajoules in any month	$3.798	$0.245	$4.043	**6.45%**
40			Next 260 Gigajoules in any month	$3.524	$0.227	$3.751	**6.44%**
41			Excess over 280 Gigajoules in any month	$2.880	$0.184	$3.064	**6.39%**
42							
43			Rider 5 - Revenue Stabilization Adjustment Charge per GJ	$0.039	$0.000	$0.039	**0.00%**
44							
45			Minimum Monthly Delivery Charge	$1,826.00	$0.00	$1,826.00	**0.00%**