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September 1, 2016

British Columbia Public Interest Advocacy Centre
Suite 208 – 1090 West Pender Street
Vancouver, B.C.
V6E 2N7

Attention: Ms. Tannis Braithwaite, Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Energy Inc. (FEI)

Project No. 3698885

Application for 2017 and 2018 Revenue Requirements and Rates for the Fort Nelson Service Area (the Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 1

On June 30, 2016, FEI filed the Application referenced above. In accordance with the British Columbia Utilities Commission Order G-108-16 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submit the attached response to BCOAPO 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

1.0 Reference: Exhibit B-1, page 1, Revenue Deficiency in 2017 and in 2018

The referenced page states:

Based on the forecast energy demand for FEFN, FEFN's forecast revenue at 2016 Approved rates is not sufficient to recover FEFN's required revenue requirement over the Test Period. Specifically, there is a revenue deficiency of $301 thousand in 2017 and an incremental revenue surplus of $146 thousand in 2018, for a cumulative 2018 revenue deficiency of $155 thousand compared to forecasted 2018 revenue at existing 2016 rates.

1.1 Please confirm that the selected text means that given the forecast demand, at existing rates and with no smoothing there would be a revenue deficiency of $301K in 2017 and a revenue deficiency of $155K in 2018 such that over the 2017-2018 Test Period there is a revenue deficiency of $456K. If unable to so confirm, please provide the revenue deficiency/(surplus) for 2017 and 2018 separately at existing rates assuming no rate smoothing.

<u>Response:</u>

Confirmed. This information is also provided on page 38, footnote 22 of the Application.

2.0 Reference: Exhibit B-1, Section 9, Schedule 1

2.1 Can FEFN confirm that if one takes column 3 of the referenced schedule and adds the components from the top down to line 28, the sum therefore obtained gives the <u>revenue deficiency without smoothing for 2017</u>, i.e., $0.319M?

<u>Response:</u>

FEI confirms that adding the components of column 3 from the top down to line 28 results in the revenue deficiency without smoothing for 2017. However, the sum of those amounts is $0.301 million, not $0.319 million as noted in the question. The amount of $0.301 million is the same amount that was discussed in the response to BCOAPO IR 1.1.1.

2.2 Can FEFN confirm that if one takes column 5 of the referenced schedule and adds the components from the top down to line 28, the sum therefore obtained gives the <u>incremental revenue surplus without smoothing for 2018</u>, which, when subtracted from the 2017 revenue deficiency, gives the 2018 deficiency?

<u>Response:</u>

FEI confirms that adding the components of column 5 from the top down to line 28 results in an incremental revenue surplus without smoothing of $0.146 million. This amount, shown as a negative amount on the financial schedules, is then <u>netted against</u> the 2017 revenue deficiency of $0.301 million to provide a net 2018 revenue deficiency of $0.155 million (compared to 2016 rates) without smoothing.

3.0 Reference: Exhibit B-1, Appendix A3, Demand Forecast Methodology - General

3.1 Please confirm that there have been no changes in the demand forecast methodology used by FEFN for developing any components of the demand forecasts presented in Appendices A1 and A2. If unable to so confirm, please provide a summary table of all methodological changes made in this application along with the rationale for each change.

Response:

FEI has made one change to its demand forecast methodology for this Application, which is described below. All other methods are unchanged from previous forecasts.

The change to the demand forecast was required due to the large one-time switch of customers from rate schedule 2.2 to 2.1 in 2015. Given the forecast uses three years of actual data to calculate the average UPC for each customer class, FEI restated the 2013 and 2014 results as if the customer switch had happened January 1, 2013. This restatement provides comparable figures across the three years of test data to more accurately forecast 2017 and 2018 demand.

4.0 Reference: Exhibit B-1, page 33, Table 7-2, Distribution Plant Additions
Exhibit B-1, page 34, Distribution Plant
Exhibit B-1, Section 9, Schedule 5.1, Plant In Service 2017
Exhibit B-1, Section 9, Schedule 6.1, Plant In Service 2018

The first referenced table shows Gross Distribution Plant Additions of $307K for 2017 and $388K for 2018.

However, in the accompanying text describing distribution plant additions on page 34, the application states:

Distribution Plant

The component of growth related distribution capital (new mains, new services, and new meters) forecast for the Test Period is $37 thousand in 2017 and $38 thousand in 2018, consistent with 2015 actual and 2016 projected amounts. Growth capital investments are incurred to install gas mains, services and meters to attach new customers.

The other forecast additions to distribution plant in 2017 and 2018 are related to:

- *The installation of a new line heater burner management system at the Fort Nelson Gate Station to add industry standard safety features to achieve regulatory compliance, improve reliability, and improve combustion efficiency ($60 thousand in 2017);*
- *The replacement of steel distribution mains and services to address those that are prone to leaks, and due to their location in Fort Nelson, of greater risk to public safety due to longer periods of frozen ground and remoteness from emergency repair personnel ($175 thousand in 2017 and $275 thousand in 2018).*

4.1 The figures mentioned in the text total $272K in 2017 and $313K in 2018 for distribution plant additions for a total of $585K in both years, as compared to the figures in the table indicating additions of $307K in 2017 and $388K in 2018 for a total of $695K for the two years. Please reconcile the figures in the table with the text.

<u>Response:</u>

The table below reconciles the forecast additions explained in the above text to those totals seen in Table 7-2. It also reconciles to the totals seen in financial schedules 5.1 and 6.1 in Section 9 of the Application for Distribution plant additions.

Distribution Plant Additions Reconciliation
($ thousands)

Description	2017	2018
Explained in write-up		
Growth capital	37.0	38.0
Stations	60.0	
Distribution mains and services	175.0	275.0
Total	272.0	313.0
Additional capital		
Cathodic Protection	5.0	30.0
Stations		15.0
Service line hazards mitigation	5.0	5.0
Service line alterations (receivable)	5.0	5.0
Service line and mains alterations (non-receivable)	20.0	20.0
Total	35.0	75.0
Total in table 7-2	307.0	388.0
Capitalized overheads	99.0	120.0
Total in schedules 5.1, 6.1	406.0	508.0

4.2 Please explain how the distribution plant additions referred to in 6.1 immediately above can be reconciled with the distribution plant additions shown in the Plant In Service Continuity Schedules 5.1 and 6.1.

Response:

Please refer to the response to BCOAPO IR 1.4.1.

5.0 Reference: Exhibit B-1, Appendix A2, page 1, FEFN Table A2-1, Customer Counts, Customer Additions, Use per Customer, and Energy

5.1 Please provide the number of months of actual data and forecast data used in calculating the 2016 Seed Year numbers.

<u>Response:</u>

The number of months of actual and forecast data used in calculating the 2016 Seed Year customers, UPC and energy demand are provided below.

Customers and Customer Additions:

<u>Rate Schedule 1:</u>

12 months of actual data from 2015 were used to calculate the 2016 seed year forecast. No forecast data was used to calculate the 2016 seed year forecast.

<u>Rate Schedule 2.1 and 2.2:</u>

48 months of actual data from 2012 through 2015 were used to calculate the 2016 seed year forecast. No forecast data was used to calculate the 2016 seed year forecast.

Use per customer (UPC):

<u>Rate Schedule 1, 2.1 and 2.2:</u>

48 months of actual data from 2012 through 2015 were used to calculate the 2016 seed year forecast. No forecast data was used to calculate the 2016 seed year forecast.

Energy:

The energy forecast is the product of the customers forecast and the UPC forecast for both residential and commercial rate schedules. The customer and UPC forecast use varying amounts of monthly data as described above.

Please also refer to the responses to BCUC IRs 1.2.2 and 1.2.3.

5.2 Please provide a comparison – and discussion in the event of material changes – of the 2016 Seed Year data with the 2016 Forecast data that was presented in the FEFN 2015-2016 RRA.

Response:

Since the 2016 Forecast data that was presented in the FEFN 2015-2016 RRA was approved as filed, the comparisons below are between 2016 Approved (equal to Forecast) and 2016 Seed amounts.

Customers:

Customers	2016 Approved	2016 Seed	Difference	% Difference
Rate Schedule 1 - Residential	1,997	1,964	(33)	-1.7%
Rate Schedule 2.1 - Small Commercial	479	476	(3)	-0.6%
Rate Schedule 2.2 - Large Commercial	34	7	(27)	-79.4%
Rate Schedule 25 - General Firm Transportation	2	2	-	0.0%
Total	2,512	2,449	(63)	-2.5%

At the time that the 2016 Forecast for the number of customers was prepared and ultimately approved, FEI only had actual data from 2013. The forecasts for number of customers were based on 2013 Actual plus forecasts of customer additions for each of 2014, 2015 and 2016. FEI had forecast total customer additions in those years of 24, 25 and 25 respectively. In fact, customer additions were only 3 in 2014 and 5 in 2015. As a result, FEI has also lowered its expectation for customer additions for 2016 to 3 in the Seed forecast. This reduction of 63 over the three year period from Forecast to Actual/Seed is reflected in the figures above and results in the total customers being 63 lower than Approved.

The customer additions forecast that was approved was based on CBOC Provincial housing starts forecasts for residential customers and a three year average for commercial customers. The customer additions that were forecast using these sources did not materialize, at least partly due to the economic downturn that has occurred in the Fort Nelson region during this time period.

FEI notes that 24 customers switched from Rate Schedule 2.2 to Rate Schedule 2.1 in 2015 as a result of not consuming the minimum volume necessary to remain in Rate Schedule 2.2. Without this rate switching, the Rate Schedule 2.2 customers would have been 3 less than the Approved, and the Rate Schedule 2.1 customers would be 27 less than Approved in the table above.

Use Per Customer (UPC):

UPC (GJs)	2016 Approved	2016 Seed	Difference	% Difference
Rate Schedule 1 - Residential	134.7	134.4	(0.2)	-0.2%
Rate Schedule 2.1 - Small Commercial	442.9	463.1	20.2	4.6%
Rate Schedule 2.2 - Large Commercial	3,584	8,060	4,476	124.9%
Rate Schedule 25 - General Firm Transportation	27,916	24,895	(3,021)	-10.8%

The residential UPC Seed forecast is only 0.2% lower than the 2016 Approved value. FEI does not consider this difference to be material.

Twenty four customers were transitioned into Rate Schedule 2.1 from Rate Schedule 2.2 in 2015. The average UPC for this group of customers was 1,856 GJs in 2014 while the average UPC for the existing Rate Schedule 2.1 customers was lower at 456 GJs. The 4.6% increase in the 2016 Seed forecast compared to the 2016 Approved forecast is primarily due to this blending of a small group of higher UPC customers into a larger group of lower UPC customers.

The UPC Seed forecast for Rate Schedule 2.2 is significantly higher than the 2016 Approved forecast because of the customers switching rate schedules as discussed above. As a result of moving the majority of customers in Rate Schedule 2.2 into Rate Schedule 2.1 (these customers representing the lower volume customers in Rate Schedule 2.2), the UPC Seed forecast is significantly higher.

The difference in the Rate Schedule 25 UPC forecast is due to the difference in the survey results received from the two premises in this rate schedule.

Energy Demand:

Energy (GJs)	2016 Approved	2016 Seed	Difference	% Difference
Rate Schedule 1 - Residential	267,546	263,788	(3,757)	-1.4%
Rate Schedule 2.1 - Small Commercial	208,642	219,977	11,335	5.4%
Rate Schedule 2.2 - Large Commercial	120,843	56,418	(64,425)	-53.3%
Rate Schedule 25 - General Firm Transportation	55,832	49,790	(6,042)	-10.8%
Total	652,863	589,973	(62,890)	-9.6%

Overall, the differences in demand are due to the combination of the number of customer being significantly less than forecast, and the lower forecast for Rate Schedule 25 volumes.

6.0 Reference: Exhibit B-1, page 27, Table 5-1, O&M Resources Required

6.1 Please indicate the number of months of actual 2016 data that underpins the 2016 Projected Non-Labour O&M costs for each line item other than Fees and Administration costs.

Response:

Please refer to the response to BCUC IR 1.6.1.

6.2 For each line item other than Fees and Administration costs in Non-Labour O&M costs, please provide the most recent, available actual 2016 costs to date.

Response:

Please find below the 2016 Actual year to date Non-Labour O&M. Also note that given costs are not incurred on a linear basis during the year, the amounts shown below cannot be extrapolated to infer an annual amount.

	Jan to July 2016 YTD Actual Costs ($000s)
Vehicle Costs	15
Employee Expenses	11
Materials and Supplies	2
Contractor Costs	8
Facilities	18
Recoveries & Revenue	(1)
Non-Labour O&M Costs	**54**