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October 9, 2015

Via Email
Original via Mail

British Columbia Utilities Commission
Sixth Floor
900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Performance Based Ratemaking Plan for 2014 through 2019 approved by British Columbia Utilities Commission (Commission or BCUC) Order G-138-14 (the PBR Plan) – Annual Review for 2016 Rates (the Application)

Response to BCUC Information Request (IR) No. 1

On September 3, 2015, FEI filed the Application referenced above. In accordance with Commission Order G-138-15 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

Due to a number of corrections and updates to the forecasts in the Application, FEI will be filing an Evidentiary Update prior to the Annual Review Workshop. The Evidentiary Update will include the items listed below, as discussed in the referenced IR responses:

- Correction to include AFUDC return on the earnings sharing amount (see response to CEC IR 1.33.3);
- Corrections to various Biomethane line items (see response to BCUC IR 1.19.1);
- Update to the forecast for the BC One Call project (see response to BCUC IR 1.25.2)
- Update for new information regarding the VIGJV 2016 Contract Demand and termination of service to Burrard Thermal (see response to BCUC IR 1.10.2); and

- Update for new information regarding Rate Schedule 46 LNG volumes (see responses to BCUC IR 1.18.3 and 1.18.4).

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc: Registered Parties (e-mail only)

A. EVALUATION OF THE PERFORMANCE BASED RATE-MAKING PLAN FOR 2014

1.0 Reference: STAFFING LEVELS

Exhibit B-2, Section 1.4.2, Table 1-2, pp. 4-5; FEI Annual Review of 2015 Delivery Rates, Exhibit B-2, BCUC IR 1.1.1

In Table 1-2 of the Application, FEI provides the following Headcount and Full Time Employee (FTE) information for 2014 Actual: (i) 2014 Actual Headcount = 1,704; (ii) 2014 Actual FTEs = 1,650.

Footnote 5 of Table 1-2 of the Application states:

> Figures provided are total FTEs and include FTEs that charge time to O&M, capital, deferral accounts, and Core Market Administration Expense. The FTEs are the average FTEs for the 12 month calendar year, consistent with other reporting provided to the Commission.

In response to BCUC IR 1.1.1 in the FEI Annual Review of 2015 Delivery Rates (2015 Annual Review) proceeding, FEI states: "At the end of 2014, FEVI had 113 FTEs and FEW had 1 FTE, which when added to the FEI FTEs results in total FEI Amalgamated FTEs of 1,624."[1] [emphasis added]

On page 35 of the 2015 Annual Review Decision, the Commission states: "…the Panel directs FEI to include in its annual review filings both the total year-end number of employees and the total year-end number of Full Time Equivalent Employees." [emphasis added]

1.1 Please explain why the Actual 2014 FTEs provided in Table 1-2 of the Application are different than the number of 2014 FTEs provided in response to BCUC IR 1.1.1 in the 2015 Annual Review (difference of 26 FTEs).

Response:

The Actual 2014 FTEs provided in Table 1-2 of the Application are different than the number of 2014 FTEs provided in response to BCUC IR 1.1.1 in the 2015 Annual Review because Table 1-2 provides average FTEs, whereas the response to BCUC IR 1.1.1 in the 2015 Annual Review provides the number of FTEs at the end of the year. Please refer to the response to BCUC IR 1.1.4 for a detailed explanation of the calculation and the difference between the end-of-year FTEs and average FTEs.

The information provided in Table 1-2 was not calculated in a manner consistent with the Commission's directive in the 2015 Annual Review Decision, which FEI has remedied in the

[1] FEI Annual Review of 2015 Delivery Rates (2015 Annual Review), Exhibit B-2, BCUC IR 1.1.1.

table below. FEI provided average FTEs in Table 1-2 as it was using the average FTE changes year-over-year to explain the projected O&M savings for 2015. Average FTEs are what determine the level of labour-related expenses (O&M and capital) for the Company over the course of the year whereas year end FTEs are a point in time snapshot only. Additionally, the average FTE methodology is what FEI uses for its annual reporting to the Commission..

The following table provides headcount, average FTEs and end-of year FTEs for 2013 Actual, 2014 Actual and 2015 Projected:

	Headcount	Average FTEs	End of Year FTEs
2013 Actual	1,764	1,679	1,682
2014 Actual	1,704	1,650	1,624
2015 Projected	1,686	1,598	1,656

1.2 Please explain if the FTE amounts provided in Table 1-2 of the Application have been calculated in a manner consistent with the Commission's directive in the 2015 Annual Review Decision.

Response:

Please refer to the response to BCUC IR 1.1.1.

1.2.1 If not, please explain why not.

Response:

Please refer to the response to BCUC IR 1.1.1.

1.3 Please re-calculate the 2013 Actual, 2014 Actual, and 2015 Projected FTEs in a manner consistent with the calculation performed in the response to BCUC IR

1.1.1 of the 2015 Annual Review proceeding so that the FTEs are comparable with the information provided in the response to BCUC IR 1.1.1.

Response:

Please refer to the response to BCUC IR 1.1.1.

Based on the information provided in Table 1-2 of the Application, 2015 Projected Headcount has decreased by 18 from 2014 Actual Headcount; whereas 2015 Projected FTEs have decreased by 52 from 2014 Actual FTEs.

1.4 Please explain how the Headcount amount is calculated and what is included in this amount.

Response:

This response addresses BCUC IRs 1.1.4 and 1.1.5.

The Headcount calculation represents the total number of employees at a certain time (i.e. December 31, 2014). It includes all active and inactive full-time regular (FTR), full-time temporary (FTT), part-time regular (PTR) and part-time temporary (PTT) employees, except inactive employees on long term disability. Each employee is counted as one headcount.

The 2014 Actual Headcount (1,704) and 2015 Projected Headcount (1,686) provided in Table 1-2 of the Application represent Headcount as at the end of each year.

The Full Time Equivalent (FTE) calculation represents the total number employees as measured in full time equivalents. It includes all current (active) full-time regular (FTR), full-time temporary (PTT), part-time regular (PTR), and part-time temporary (PTT) employees at the end of the month. FTEs including full time and part time employees are calculated as follows:

- A full-time employee is counted as one FTE if it meets the criteria of being an active employee at the end of the month.
- A part-time employee is counted as less than one FTE. Part-time employees are converted into FTEs by taking their total part-time hours for the month and dividing by the total annual full-time hours (i.e. ~1,957.5 hours), and then multiplying by 12 (i.e. months) and multiplying by the working days in a month including statutory holidays and dividing by total days for the pay periods in the month.

The 2014 Actual FTEs (1,650) and 2015 Projected FTEs (1,598) provided in Table 1-2 of the Application represent the average FTEs and are calculated using the average of monthly FTEs for the 12 month calendar period from January to December.

Headcount may vary from average FTE depending on how long the employee is in the position during the 12 month calendar period and whether the employee is still employed at the Company on the reporting date.

Example

A full time regular employee is hired on April 1, 2014. On December 31, 2014, the employee is still employed at the Company.

<u>For 2014</u>

Full time equivalent basis – 0.75 FTE
Headcount basis – 1 headcount

The FTE calculation depends on such factors as the timing of the hiring and termination dates and, for part-employees, the number of hours worked.

Generally, FTEs reported are lower than the headcount in a calendar year in situations where during the year positions are unfilled for a period of time (i.e. new positions, staff turnover during the year) and then are filled by December 31 of the calendar year. This was the case for FEI for the years 2013 to 2015. Headcount as at December 31 of each year was higher than the FTEs.

Generally, FTEs reported are higher than headcount in a calendar year in situations where staff turnover is experienced in the latter part of a year

1.5 Please explain how the Headcount calculation differs from the calculation of FTEs and make specific reference to the differing amounts between Headcount and FTEs shown in Table 1-2 of the Application.

<u>Response:</u>

Please refer to the response to BCUC IR 1.1.4.

Footnote 6 on page 5 of the Application states: "2013 Actual FTEs is used as the reference point for the start of the PBR Plan as a 2014 Base average FTEs is not available. The O&M savings are calculated by comparing the 2013 actual average FTEs to the 2015 projected average FTEs."

1.6 Please clarify what is meant by the statement "a 2014 Base average FTEs is not available".

Response:

The success of the PBR in terms of efficiencies achieved is measured against the 2013 Base that was set at the outset of the PBR Term. As such, the statement should have read "a **2013** Base average FTEs is not available." A 2013 Base FTE is not available since FEI did not have an approved number of FTEs for 2013. This was discussed in the response to BCUC IR 1.77.1 in the FEI PBR proceeding where FEI stated in reference to 2013 approved figures: "A number of costs including a $4 million productivity challenge were directed by the Commission which were reflected at a high level in O&M and Capital spending but not at the FTE level."

1.6.1 Please explain why FEI is not able to utilize the 2014 Actual FTEs of 1,650 provided in Table 1-2 to estimate the O&M savings between 2014 Actual and 2015 Projected.

Response:

2013 is the appropriate reference point for determining the success of the PBR Plan overall, and this is what FEI has utilized through Section 1.4 of the Application as a basis of comparison. Although staffing levels may fluctuate somewhat from year to year, it is the overall trend in staffing over time that shows the impact of FEI's efforts to find efficiencies. Sustainable efficiencies realized as the result of productivity initiatives in 2014 are inherently carried over into 2015 and contribute to the projected O&M savings when comparing the 2015 Projected formula O&M to the 2015 Approved formula O&M.

2.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2, Section 1.4.3, pp. 5-6

Regionalization Initiative

FEI states on page 5 of the Application: "Included in the estimated total of $1.7 million in Operations savings are reductions related to the Regionalization initiative started in 2014, contributing to an estimated annual O&M labour savings of <u>$0.850 million</u>." [emphasis added]

FEI states on page 6 of the Application, regarding the Regionalization Initiative: "2015 O&M savings projected for the Operations department compared to 2013 actuals are approximately $1 million."

2.1 Based on the above information, please confirm, or explain otherwise, that the Regionalization Initiative has resulted in approximately $0.850 million of labour savings and approximately $0.150 million of non-labour savings.

<u>Response:</u>

Confirmed.

On page 12 of the Proposal to Include FEVI and FEW into the PBR Plan Decision, the Commission stated the following:

> Embedded in FEI's proposed sustainable increase is the $267 thousand in allocated costs to FEVI related to the Regionalization Initiative. These costs are already included in the pre-amalgamated FEI PBR Base O&M. Accordingly, it is inappropriate to also include them in the FEVI 2014 Base O&M.

2.2 Please explain if the $0.850 million O&M labour savings includes the $267 thousand of labour reductions resulting from the transfer of FEI employees to FEVI which occurred in 2014 (described in the above preamble).

<u>Response:</u>

The $0.850 million O&M labour savings due to the Regionalization Initiative are the savings on an amalgamated company basis and do not include the $267 thousand of labour reductions to FEI (pre-amalgamation) resulting from the transfer of FEI employees to FEVI which occurred in 2014.

2.2.1 If yes, please explain why FEI has characterized the re-allocation of this labour as savings given that the Commission did not approve an increase to FEVI's 2014 Base O&M related to this re-allocation.

Response:

Please refer to the response to BCUC IR 1.2.2.

3.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2: Section 1.4.3, p. 6; Appendix C3, Table D-2, p. 2; FEI Annual Review of 2015 Delivery Rates, Exhibit B-2, BCUC IR 1.3.3, 1.3.7.1

Project Blue Pencil

FEI states on page 6 of the Application: "Specifically, initiatives are currently underway in the areas of new service connections, meter exchange, collections and high bill inquiry…"

Table D-2 of Appendix C3 describes labour savings in 2015 as follows: "Approximately $1 million annual contact centre and billing operations O&M savings."

In response to BCUC IR 1.3.3 in the 2015 Annual Review proceeding, FEI estimated $100 to $200 savings in the average cost of a new service installation related to Project Blue Pencil.[2]

3.1 Are the majority of the $1 million annual contact centre and billing operations O&M savings the result of FTE reductions?

Response:

Yes, the majority of the $1 million annual contact center and billing operations O&M savings are the result of the savings initiatives noted above that resulted in reduced FTE requirements.

3.1.1 If no, please specifically describe how these other savings are being achieved and please indicate what proportion of the $1 million annual savings are the result of these other savings.

Response:

Please refer to the response to BCUC IR 1.3.1.

[2] FEI Annual Review of 2015 Delivery Rates, Exhibit B-2, BCUC IR 1.3.3.

3.2 Based on 2015 Projected results, does FEI anticipate savings in the average cost of a new service installation? If yes, please quantify these savings. If not, please explain why not.

Response:

Yes. Based on 2015 year to date results to mid-September, FEI is realizing savings of $90 per service installation on those services that were part of the Project Blue Pencil initiative (i.e. standard distribution pressure residential services less than or equal to 20 metres in length). FEI anticipates this trend to continue during the peak Fall construction season. The savings is from eliminating planner involvement (design and site visits) in the standard service installation process.

3.3 Based on 2015 Projected results, does FEI anticipate savings in meter exchanges? If yes, please quantify these savings. If not, please explain why not.

Response:

Company-wide average residential meter exchange field unit costs are trending slightly higher in 2015 ($100/unit versus $96/unit in 2014). Unit costs are projected to be at this level due to slightly higher hourly technician charge-out rates in 2015. This has been partially offset by improvements in scheduling of appointments.

Overall savings have been realized through better utilization/optimization of the existing technician resources which has resulted in a 2015 projected reduction to daytime technician standby costs of approximately $350 thousand when compared to 2013 & 2014 levels.

In response to BCUC IR 1.3.7.1 in the 2015 Annual Review proceeding, FEI stated:

> Project Blue Pencil and other initiatives are expected to reduce the cost of service line addition for the entire FEI service territory, including Vancouver Island and Whistler. However, as the changes are in the early stages, it is not possible to determine at this time the reduction of the cost of a service line

addition on Vancouver Island or in Whistler relative to the average cost on the Mainland.[3]

3.4 Is FEI now able to determine the reduction of the cost of a service line addition on Vancouver Island and in Whistler relative to the average cost on the Mainland? If yes, please provide this information. If not, please explain when FEI estimates it may be able to determine these reductions.

Response:

For standard services impacted by the Project Blue Pencil initiative, the cost reduction from 2014 to mid-September 2015 for the Mainland (formerly FEI) is $96 per service. The comparative reduction for Vancouver Island (formerly FEVI) services is $80 per service.

For Whistler (formerly FEW), based on the small sample size of services installed to date, a meaningful average cost for Whistler service additions will not be available until year end. There are a number of planned service installations scheduled in October which when completed and added to the year to date total will provide a reasonable sample size in which to make the comparison to the 2014 service line costs for Whistler.

[3] Ibid… BCUC IR 1.3.7.1.

4.0 Reference: MAJOR INITIATIVES UNDERTAKEN

Exhibit B-2: Section 1.4.3, p. 6; Appendix C3, Table D-3, p. 3

Review of Technical and Infrastructure Support Provider

FEI states on page 6 of the Application: "In 2015, FEI replaced its existing technical and infrastructure support provider through an RFP process with a new service provider, Compugen."

4.1 Please indicate the term/length of the contract signed with Compugen.

Response:

The contract signed with Compugen has a three-year term, with an option for FEI to extend the term for an additional two years.

4.2 Please compare and contrast the technical and infrastructure support services provided by Compugen compared to FEI's previous service provider Telus.

Response:

Compugen provides similar technical and infrastructure services to what TELUS had previously provided. The primary difference is that the support resources are dedicated to the FEI account. This enables the Compugen resources to better understand the business and employees of FEI, as they do not support multiple companies. The result is improved responses to technical issues.

4.3 Please explain whether the change in service providers will increase or decrease the amount of in-house IT development and support functions performed by FEI employees.

Response:

The amount of service provided by in-house IT development and support functions will remain the same such that there is no change in the number of FTEs. However, the type of IT development and support functions done by in-house resources may focus more on higher-value, utility-specific technical needs, such as advanced metering, distribution automation, field tools and other utility specific technologies and systems. The third party service provider is primarily responsible for lower-value, day-to-day support, which frees up internal resources to work on higher value work that has previously been contracted out. This also helps to keep high value technical knowledge in-house.

4.3.1 Does FEI anticipate that the change in service providers will either increase or decrease its number of FTEs or the number of temporary employees in the IT (or other) department(s)? Please discuss.

Response:

FEI anticipates the change in service providers will not impact the number of FTEs or the number of temporary employees in the IT or other departments. Please refer to the response to BCUC IR 1.4.3 in regards to why FTE count will not be affected.

FEI states on page 6 of the Application: "For each new efficiency identified, on a one-time basis (i.e. first full year savings), the vendor shares in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies."

FEI further states on page 6 of the Application: "The 2015 O&M savings projected for the Information Systems department compared to 2013 actuals are approximately $1.8 million."

4.4 Please explain how FEI determines the amount of savings to be shared with Compugen. Is there an agreed upon percentage of savings to be allocated to Compugen, or is it determined based on the percentage of time spent by FEI and Compugen, respectively, on each efficiency? Please provide a hypothetical example and calculation.

<u>Response:</u>

In responding to this IR, FEI recognized an error in the Application (Exhibit B-2: Section 1.4.3, p. 6; and Appendix C3, Table D-3, p. 3), where FEI states, "For each new efficiency identified, on a one-time basis (i.e. first full year savings), the vendor shares in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies." FEI clarifies that savings are not shared only in the first year, but are shared over the term of the contract as described further below.

Savings for the purpose of sharing with Compugen must be permanent O&M savings for FEI that are attributable to efficiencies identified by Compugen which reduce Compugen's annual charges to FEI over the remainder of FEI's contract with Compugen. Twenty percent of the actual O&M savings are retained by Compugen in the first year they are realized, and for every year after for the remainder of the contract. Efficiencies that do not reduce Compugen's costs to support FEI, but otherwise reduce FEI's operating costs, are not shared with Compugen.

There are no savings subject to the sharing formula in 2015; however, FEI provides a hypothetical example of a sharing calculation below.

Hypothetical Example of Calculation:

Where an initiative is identified by Compugen that reduces Compugen's costs to support FEI by $50,000 in year 1 (partial year) and $100,000 annually (full year) for the remainder of the Compugen contract, the sharing in year one would be as follows:

- 20% ($10,000) of savings to Compugen
- 80% ($40,000) of savings to FEI

For year 2 and all remaining years of the Compugen contract, the sharing would be as follows:

- 20% ($20,000) of savings to Compugen
- 80% ($80,000) of savings to FEI

4.5 How does FEI record the O&M savings distributed to Compugen for accounting purposes?

Response:

For any qualifying savings, as described in response to BCUC IR 1.4.4, Compugen will reduce the amount of fees charged to FEI by 80% of the qualifying savings. The net amount paid to Compugen is recorded in FEI's O&M.

4.6 How much of the projected $1.8 million in O&M savings, if any, will be allocated to Compugen? How does this impact the amount of O&M savings to be shared with ratepayers? Please explain.

Response:

None of the projected $1.8 million in O&M savings will be allocated to Compugen. The savings were attributable to the switch from the TELUS contract to the Compugen contract. The savings were not included in the ongoing sharing agreement.

4.7 Please generally describe the nature of the $1.8 million non-labour O&M savings achieved as a result of this initiative.

Response:

The $1.8 million non-labour savings were attributable to a more competitive contract, reflective of market conditions. There was no reduction in services or service levels due to the contract.

In Table D-3 of Appendix C3, FEI states that "the new contract provides dedicated support resources rather than a distributed support service…"

4.8 Please provide a more detailed explanation of the changes that will result from Compugen providing "dedicated support resources" as opposed to the "distributed support service" provided by Telus.

Response:

Please refer to the responses to BCUC IRs 1.4.2 and 1.4.3.

In Table D-3 of Appendix C3, FEI indicates that it incurred a total $1.5 million in capital expenditures to replace the Service Request system.

4.9 Please provide more details on the replacement of the Service Request system, including the following:

(i) The age of the old system (when was the old system purchased?);

(ii) The net book value of the old system;

(iii) The amount of any proceeds received from the replacement of the old system; and

(iv) The treatment of the disposal of the old system for accounting and regulatory purposes.

Response:

FEI did not own the previous system. The previous Service Request system was owned and managed by the previous service provider, TELUS.

4.10 If FEI had not switched its infrastructure service provider, when does FEI anticipate it would have needed to replace its existing Service Request system?

Response:

The previous Service Request system was owned and provided by TELUS. It had reached end of life and a component of the replacement cost would have been charged to FEI as a user of the system. The system was scheduled to be replaced in 2014 and the allocation of the upgrade charged to FEI by TELUS would have been similar to the cost of the new Service Request system owned by FEI.

B. FORMULA DRIVERS

5.0 Reference: INFLATION FACTOR

Exhibit B-2, Section 2.2, Table 2-1, p. 12; FEI Annual Review of 2015 Delivery Rates, Exhibit B-1, Table 2-1, p. 11

BC AWE

In Table 2-1 of the Application, the 12-month average AWE for July 2013 through June 2014 (calculated based on the CANSIM Table 281-0063) is $884.829.

In Table 2-1 of the FEI Annual Review of 2015 Delivery Rates Application (Exhibit B-1, page 11) the 12-month average AWE for July 2013 through June 2014 (calculated based on the CANSIM Table 281-0063) is $884.193.

5.1 Please explain why the monthly AWE amounts have changed for the period of July 2013 through June 2014 in the current Application.

Response:

The monthly AWE amounts from July 2013 through June 2014 have changed because Statistics Canada periodically revises their AWE results. FEI uses the most current set of AWE results in each year's Annual Review filing.

6.0 Reference: GROWTH FACTOR

Exhibit B-2, Section 2.3, Tables 2-2 and 2-3, pp. 13-14; FEI Annual Review of 2015 Delivery Rates, Exhibit B-1, Table 2-3, p. 12

Average Customers and Service Line Additions

6.1 Please confirm, or explain otherwise, that the data in Tables 2-2 and 2-3 for average customers and service line additions, respectively, reflect actual results.

<u>Response:</u>

Confirmed.

The service line additions growth factor (@50%) used in the PBR formula for 2015 was -5.615%.[4]

The service line additions growth factor (@50%) used in the PBR formula for 2016 is 16.249%.[5]

6.2 What does FEI attribute to the large increase in service line additions in the 12-month period of July 2014 through June 2015 compared with July 2013 through June 2014? Please discuss.

<u>Response:</u>

The 32 percent increase in service line additions is likely attributable to a combination of factors, such as the following:

- An increase in both single and multi-family housing starts in 2014 and 2015.
- An increase in market capture rates by regional marketing groups who are targeting builders/developers to use natural gas in single and multi-family unit projects.
- Natural gas rate reductions for Vancouver Island/Sunshine Coast.
- A mild winter in 2014-2015, reducing usual seasonal slowdown of building activity.
- Service line costs are trending downwards.

[4] FEI Annual Review of 2015 Delivery Rates, Exhibit B-1, Table 2-3, p. 12.
[5] Exhibit B-2, Table 2-3, p. 14.

- The Switch 'n Shrink program: an energy efficiency rebate program for oil customers who convert to natural gas owing to the high cost of heating oil relative to decreasing natural gas prices.

- Targeted Marketing Campaigns: Mail outs to potential customers on or near a gas main to promote the benefits of natural gas vs. competitor energy choices.

C. DEMAND FORECAST

7.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES
Exhibit B-2, Appendix A2, Section 5, pp. 12-27
Demand Forecast Data

7.1 Please state whether the historical use per customer (UPC) and energy demand data in Section 5 of Appendix A2 is weather-normalized.

Response:

The referenced historical UPC and energy demand data is weather normalized.

8.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.7.1, Table 3-2, p. 31; Appendix A2, Section 5.8, p. 18

Demand Forecast Data - Mainland

Section 5.8 in Appendix A2 of the Application contains historical data for Mainland demand. This data includes Rate Schedules (RS) 1, 2, 3 and 23.

8.1 Please provide the historical Mainland demand data for each Industrial class rate schedule as well as large transportation customers (i.e. the rate schedules referenced in footnote 3 of Table 3-2 on page 31 of the Application).

Response:

Please see the table below for the historical Mainland demand for each respective Industrial rate schedule.

Mainland Actual Industrial Energy (Pjs) By Rate Schedule

Mainland	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Rate 5	4.4	3.8	3.5	3.2	2.9	2.5	2.5	2.3	2.3	2.3
Rate 6	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Rate 7	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0
Rate 22	37.0	32.8	35.4	32.0	26.3	30.1	34.9	38.0	36.4	36.0
Rate 25	15.1	15.7	15.3	14.4	13.1	12.8	13.2	12.9	12.6	12.6
Rate 27	6.1	5.6	5.5	5.5	5.8	6.0	6.6	6.4	7.5	6.6
Total Mainland Industrial Demand (Pjs)	**63.1**	**58.3**	**60.0**	**55.3**	**48.4**	**51.5**	**57.7**	**60.0**	**59.1**	**57.7**
Rate 6P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 16/46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3
Total MainLand NGT (Pjs)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.2**	**0.3**	**0.8**
Burrard	2.5	3.0	7.1	1.3	3.3	2.9	0.0	0.4	0.5	1.1
Total Mainland Industrial and NGT Demand (Pjs)	**65.6**	**61.3**	**67.1**	**56.6**	**51.7**	**54.4**	**57.8**	**60.5**	**59.9**	**59.6**

9.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.7.1, Table 3-2, p. 31; Appendix A2, Section 5.4, p. 14

Demand Forecast Data – Amalgamated

Section 5.4 in Appendix A2 of the Application contains historical data for amalgamated FEI demand. This data is broken down into RS 1, 2, 3, 23 and industrial demand.

9.1 Please provide a breakdown of the historical industrial demand data showing each rate schedule and large transportation customer (i.e. the rate schedules referenced in footnote 3 of Table 3-2 on page 31 of the Application).

Response:

Please see the table below for the historical FEI demand for each respective Industrial rate schedule.

FEI Actual Industrial Energy (Pjs) By Rate Schedule

FEI	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
Rate 5	6.4	6.0	5.6	5.2	4.7	4.2	4.3	4.0	3.8	3.4
Rate 6	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Rate 7	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0
Rate 22	37.0	32.8	35.4	32.0	26.3	30.1	34.9	38.0	36.4	36.0
Rate 25	15.1	15.7	15.3	14.4	13.1	12.8	13.2	12.9	13.1	13.4
Rate 27	6.1	5.6	5.5	5.5	5.8	6.0	6.6	6.4	7.5	6.6
FEVI Joint Venture	7.3	4.6	3.3	2.9	2.9	2.9	2.9	4.4	4.4	4.4
BCHydro Island Generation	16.4	16.4	16.4	16.4	18.3	18.3	16.4	14.6	14.6	14.6
Total FEI Industrial Demand (Pjs)	**88.9**	**81.4**	**81.8**	**76.6**	**71.4**	**74.4**	**78.8**	**80.6**	**80.1**	**78.6**
Rate 6P	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 16/46	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.5
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3
Total FEI NGT (Pjs)	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.1**	**0.2**	**0.3**	**0.8**
Burrard	2.5	3.0	7.1	1.3	3.3	2.9	0.0	0.4	0.5	1.1
Total FEI Industrial and NGT Demand (Pjs)	**91.4**	**84.4**	**88.9**	**77.9**	**74.7**	**77.3**	**78.9**	**81.2**	**80.9**	**80.5**

9.2 Please complete the worksheet titled "(1) Number of Customers" in the attached Microsoft Excel file to provide forecast, actuals and variances of the historical year-end number of customers for each industrial rate schedule.

Response:

Please see the table below for annual industrial customer count variances. This information is also provided in an Excel file in Attachment 9.2.

	FEI Amalgamated				
	Year-End Number of Customers				
	2010	2011	2012	2013	2014
Rate Schedule 5					
Forecast	326	328	283	284	265
Actual	280	271	264	264	265
Variance	46	57	19	20	0
Variance %	14%	17%	7%	7%	0%
Rate Schedule 7					
Forecast	2	2	4	4	3
Actual	3	2	3	3	3
Variance	-1	0	1	1	0
Variance %	-50%	0%	25%	25%	0%
Rate Schedule 22					
Forecast	45	45	43	43	45
Actual	43	43	46	45	44
Variance	2	2	-3	-2	1
Variance %	4%	4%	-7%	-5%	2%
Rate Schedule 25					
Forecast	580	580	557	557	499
Actual	557	510	514	550	548
Variance	23	70	43	7	-49
Variance %	4%	12%	8%	1%	-10%
Rate Schedule 27					
Forecast	98	98	101	101	95
Actual	101	98	98	103	101
Variance	-3	0	3	-2	-6
Variance %	-3%	0%	3%	-2%	-6%
TOTAL FORECAST	1,051	1,053	988	989	907
TOTAL ACTUAL	984	924	925	965	961
Variance	67	129	63	24	-54
TOTAL VARIANCE %	6%	12%	6%	2%	-6%

10.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-3, Gas Sales and Transportation Volumes

Demand Forecast Supplemental Data

In Exhibit B-3, FEI provides supplemental information in a table titled "Gas Sales and Transportation Volumes (TJ) for the year ending December 31, 2016."

10.1 Column 3 of the above referenced table is titled "2015 Projection." Please state the months of 2015, if any, for which actual data was included in the 2015 Projection figures.

Response:

There is no actual data embedded in Column 3, Exhibit B-3.

FEI notes that the label for column 3, Exhibit B-3 should more appropriately be labelled '2015 Seed' and not '2015 Projection' since it contains no actual data. To be clear, the volume in column 3, Exhibit B-3 is equal to the 2015 Seed year volume.

10.2 Please complete the worksheets titled "(2) Demand (2015 Seed Year)" and "(3) Demand (2015 Projection)" of the attached Microsoft Excel file to provide the following:

(i) A table similar to Exhibit B-3 with columns added for the number of customers and showing revenues and margins by rate class; and

(ii) An updated version of the previous table with a recalculated 2016 forecast demand using 2015 Projections for customer counts and energy demand instead of 2015 Seed Year figures.

Response:

The response for BCUC IR 1.10.2 (i) is included as Attachment 10.2. Since the Commission approves the average customer count, FEI has provided the average customer count in lieu of the end of year customer count. Average customers are better correlated to revenue (and volume) since revenues are collected based on the number of customers each month and not based on the end of year count. The actual data provided for 2014 (columns 2 & 3) in the attachment includes normalized volume and represents the data for FEI (pre-amalgamation) only; FEVI and FEW were separate utilities in 2014.

In response to BCUC IR 1.10.2 (ii), please refer to the response to BCUC IR 1.10.1. Since column 3, Exhibit B-3 is the 2015 seed year, there is no new data within column 3, Exhibit B-3 that would produce a 2016 forecast that is different from what FEI has already provided in the Application (Exhibit B-2, Schedule 18, Column 3, Line 6).

FEI notes that, since the time of filing, there have been two updates that affect the 2016 Forecast demand.

First, FEI has been notified that the Vancouver Island Gas Joint Venture (VIGJV) will increase its daily firm demand from 12,000 GJ/day to 13,000 GJ/day effective November 1, 2015. This change has not been reflected in any of the volumes or revenues in FEI's IR responses; however, it would result in a decrease of approximately $360 thousand to the 2016 forecast revenue deficiency.

Second, BC Hydro has exercised its right to terminate the Burrard Thermal Bypass Transportation Agreement (BTA) effective November 1, 2016 with the required minimum one year's notice. As part of the Letter Agreement with BC Hydro attached as an appendix to the Amendment to Direction 5, O.I.C. 749, dated December 19, 2014, upon the termination of the BTA the minimum contract demand for the Island Generation Transportation Service Agreement (IGTSA) will increase by 5 TJ/day from the current contract demand of 40 TJ/day to a minimum of 45 TJ/day effective November 1, 2016. As a result of the BTA terminating, other related agreements end and the toll for IGTSA also increases by $0.10 GJ from $0.858/GJ to $0.958/GJ effective November 1, 2016 to cover wheeling costs across the Coastal Transmission System.

FEI will update the financial schedules in Section 11 of the Application to reflect these two changes, as part of an Evidentiary Update to be filed before the Annual Review Workshop.

10.3 Please provide an explanation for the significant negative variance between the 2015 approved and 2015 projection interruptible demand seen in RS 7 and RS 22 Interruptible Service.

Response:

The variance in Rate Schedule 7 is positive (volumes have increased from 2015 Approved to 2015 Seed/Projection) primarily due to the addition of 2 customers.

Regarding Rate Schedule 22 Interruptible, FEI had incorrectly linked the data in Exhibit B-3, Lines 20 and 21, although the totals were correct. Attachment 10.3 contains a corrected version of Exhibit B-3. The variance in Rate Schedule 22 Interruptible demand between 2015 Approved and 2015 Seed/Projection in the revised Exhibit B-3 is no longer significant.

11.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.3, p. 19; Section 3.6.3, Figure 3-11, p. 29

Seed Year

On page 19 of the Application, FEI states: "The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available."

11.1 Please confirm, or explain otherwise, that the 2015 Seed Year forecast does not incorporate any 2015 actual data.

Response:

Confirmed for residential and commercial customers. For industrial customers, some 2015 actual data is included, as discussed in the response to BCUC IR 1.11.2.

11.1.1 If confirmed, please discuss the feasibility of using projected year-end figures, which contains actuals for some months and forecasts for other months, to represent the year preceding the forecast period in future filings.

Response:

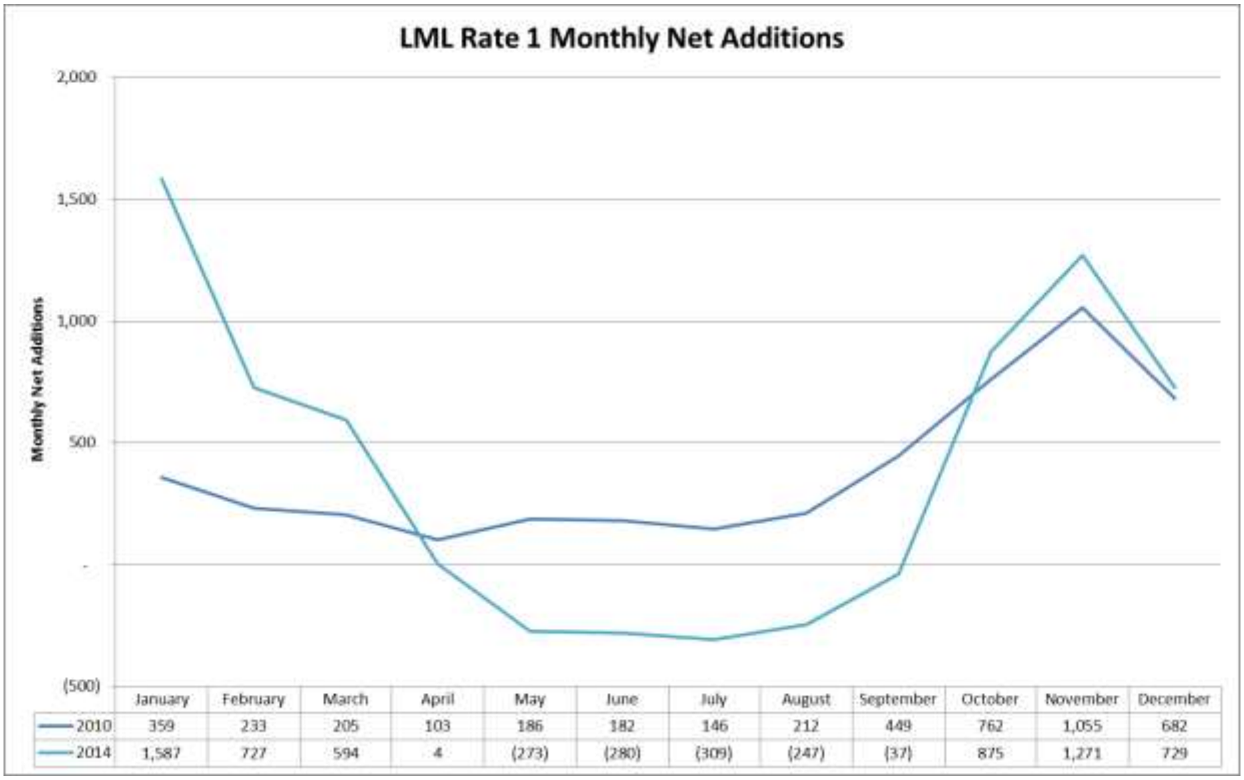
Projections, including some actual data, are not used because of the variations in the seasonality of customer additions and use rates. Further, using projections which include actual data would not improve the precision of the forecast year.

For example, in preparation of a September filing, the forecast process generally begins in the late spring of that year. At that time, FEI has actual net customer additions data available from approximately January through May. However, net monthly and annual customer additions can vary widely from one year to another, including variations in the seasonality of the additions. As a result, using the monthly data available as of May to project the annual total is not practical.

For example, the following charts are typical of all regions and show net customer additions for the Lower Mainland for 2010 and 2014. The first chart shows the actual net additions through May of each respective year.

As shown, the patterns are very different and make it difficult to predict the final year-end total. In 2010, FEI had added 1,086 customers through the end of May. In 2014, FEI had added 2,639 customers through the end of May. Additionally, in 2010, the May additions were 186 while for the same month in 2014 the additions were -273.

While these two sample years started off very differently and the shape of the seasonality curves were very different, the annual net customer additions were very similar as shown in the chart below. For 2010, the total net residential customer additions for the Lower Mainland were 4,574 while, for 2014, the total additions were just 67 more at 4,641. To summarize, the January-May data would not have predicted that the annual totals would be so similar.



The seasonality changes from year to year and depends on many factors such as the timing of new residential developments obtaining occupancy permits.

A similar variation in seasonality exists for use rates.

Individual industrial customers also exhibit variations in seasonality from one year to the next and an attempt at projecting their year-end demand based on mid-year actuals is equally as difficult.

In summary, the seasonal variability makes projections using partial year actuals highly prone to error and, as a result, FEI uses the seed method.

11.1.2 Please explain whether incorporating actual data from the current year (i.e. 2015 in the current Application) could improve the precision of the forecast year (i.e. 2016 in the current Application).

Response:

Please refer to the response to BCUC IR 1.11.1.1.

Figure 3-11 on page 29 of the Application shows the historical industrial demand, the 2015 Seed Year industrial demand and the 2016 industrial demand forecast.

11.2 Please explain how the 2015 Seed Year is calculated for industrial demand.

Response:

The Seed Year for industrial customers is developed on a customer by customer basis. The 2015 Seed Year is developed using monthly 2015 actuals from January through March and monthly 2014 actuals from April through December. If there is no customer response to the industrial survey, then the 2015 Seed Year will be used as the 2016 Forecast.

11.3 Please explain how the 2015 Seed Year data is used to produce the 2016 industrial demand forecast.

Response:

Please refer to the response to BCUC IR 1.11.2.

12.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A3, Figure A3-4, p. 22

Residential Use Rate Methodology

Figure A3-4 on page 22 of Appendix A3, shows that the first step of developing the rate schedule 1 use rate is to "Collect 4 years monthly use rates by region and rate."

12.1 Please state the number of meter readings each year for each FEI residential customer.

Response:

Meters for typical FEI residential customers are read 12 times a year. Most customers have their meters read on the same day each month.

12.1.1 If meters are not read each month, please explain how monthly use rates are determined for months when actual consumption data was not obtained.

Response:

Monthly use rates are drawn from historical billed consumption aggregated data. All gas meters are scheduled to be read and billed every month. In the case of meters that did not receive an actual meter read for that month, an estimated consumption read is used to bill the customer.

Figure A3-4 on page 22 of Appendix A3 explains when the regression method is used and when the three-year average method is used to produce the residential and commercial use rate forecast.

12.2 Please produce a summary table showing whether a three-year average or a regression equation is used to produce the UPC forecast for each rate schedule in each region.

Response:

The requested table is provided below for each sub-region.

Region	Rate Schedule	Method Applied
LowerMainland	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Inland	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Columbia	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	3 Year Average Model
Revelstoke	RS 1	Regression Model
	RS 2	Regression Model
	RS 3	Regression Model
Vancouver Island	RS 1	Regression Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model
	RS23	New Rate Class
Whistler	RS 1	3 Year Average Model
	RS 2	3 Year Average Model
	RS 3	3 Year Average Model

13.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A2, Section 5.2, p. 12

Net Customer Additions

Section 5.2 of Appendix A2 in the Application shows the 2014 amalgamated RS 1 net customer additions forecast to be 6,647 and the corresponding actual customer additions to be 10,472. This results in a percentage variance of -57.5%.

13.1 Please explain why this variance is significantly larger than years 2005 through 2013 as presented in the table for RS 1 amalgamated net customer additions.

Response:

The larger than forecast increase in 2014 actual additions is likely due to a combination of factors. While it is not feasible for FEI to identify all the reasons for the variance in customer additions, please refer to the response to BCUC IR 1.6.2 for a list of factors that likely contributed to the increase in service line additions.

FEI notes that the variance of 3,825 customers has an immaterial impact on the overall demand forecast as it represents only 0.4 percent of the total residential customer count.

13.2 Please discuss the possibility that a similar variance could reoccur for 2015 based on the 2015 amalgamated RS 1 forecast and current 2015 year-end projections for amalgamated RS 1.

Response:

FEI believes that the likelihood of a similar variance in 2015 is low based on the fact that the average annual variance for the period from 2005 through 2013 for the Rate Schedule 1 customer additions forecast was 7.5 percent.

However, as discussed in the response to BCUC IR 1.11.1.1, FEI does not develop projection forecasts due to the volatility in seasonality. As a result, FEI cannot predict the likelihood of a similar variance based on a projection of customer additions for 2015.

14.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Appendix A1, Table A1-3, p. 3; Appendix A3, Table A3-10, p. 11;

FEI 2014-2018 Multi-Year PBR Plan Application, Exhibit B-1, Table C4-10, p. 227

Conference Board of Canada (CBOC) Housing Starts Forecast

Table A1-3, titled "BC Housing Starts Embedded in Initial Forecast as Filed," is found on page 3 of Appendix A1 in the Application.

Footnote 1 on page 3 of Appendix A1 states:

> The forecasted percentage changes are not calculated based on the previous year forecast in this table [table A1-3]; rather, they are calculated based on the previous year projected housing starts identified in each respective filing. For example, the 2014 percentage changes can be found in Table C4-10 of Exhibit B-1 of the 2014-2018 Multi-Year PBR Plan Application, p. 227.

Table A3-10 in the Application is titled "CBOC Housing Starts Forecast" and is found on page 11 of Appendix A3 in the Application.

The following information was extracted from the three tables for the year 2014.

British Columbia	Table A1-3	Table C4-10	Table A3-10
	2014	2014	2014
Forecasted Single-Detached Housing Starts (Units)	8,415	8,415	9,080
Forecasted Multi-Family Housing Starts (Units)	19,586	19,586	19,176
Total	28,001	28,001	28,256

14.1 Please explain the difference between the housing starts forecasts in Tables A1-3 and A3-10 for year 2014. Do the 2014 figures in Table A3-10 represent actual housing starts?

Response:

The data in Table A3-10 is an updated 2014 forecast and does not represent actual housing starts.

As noted in the table heading for Table A1-3, the amounts shown are the same amounts provided in the initial forecasts as filed in the respective applications for each year. As a result, the 2014 column in Table A1-3 matches Table C4-10 in the 2014-2018 Multi-Year PBR Plan Application. In the time since the forecast for the 2014-2018 Multi-Year PBR Plan Application was prepared, the CBOC has developed new forecasts. The CBOC forecast used for the current filing was published in November of 2014, the details of which are provided below, and is shown in Table A3-10.

Source:

Conference Board of Canada (CBOC)
November 24, 2014
Provincial Medium Term
Forecast: 15 Run: 15
Table 156: Housing Starts: Single Detached (Units)
Table 157: Housing Starts: Multi Family (Units)

14.2 Please state the source of the housing starts forecast in Table A3-10.

Response:

Please refer to the response to BCUC IR 1.14.1.

15.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.6.3, p. 28; Appendix A3, pp. 41, 47 and 49

Industrial Survey

Figure A3-15 on page 41 of Appendix A3 in the Application shows that FEI sends out industrial surveys to customers in RS 5, 7, 22, 25 and 27.

On page 49 of Appendix A3 in the Application, FEI states: "Once the target response rate has been achieved the survey is closed and no further responses are solicited."

On page 28 of the Application, FEI indicates that 44% of industrial customers representing 86% of industrial demand completed the 2015 Industrial Survey.

15.1 Please submit a table providing the target response rate for each of the rate classes in the Industrial Survey.

Response:

Response rate targets are not set at the rate class level. A single overall response rate target is used for the entire survey. The survey remains open until surveys have been received from all Rate Schedule 22 customers and the overall response rate target is met.

Item	Target	2015 Survey
Response rate by volume, all customers	80%	86%

Prior to the implementation of the Industrial Survey web site, response rates were approximately 80% but did not include customers in Rate Schedule 5.

Note that as discussed in Section 8.6 of Appendix A-3, FEI now includes all industrial customers in the denominator of the response rate calculation and not just those with valid email addresses. This calculation change has the effect of lowering the response rate scores.

15.2 Please confirm that the survey remains open until each rate class has achieved its target response rate.

Response:

Please refer to the response to BCUC IR 1.15.1.

15.2.1 If not, please explain how FEI forecasts demand for industrial customers in rate classes that do not achieve the industrial survey target response rate.

Response:

FEI does not set response rate targets by rate class. Customers that do not reply to the survey are assigned their seed year demand for 2016. Please refer to the response to BCUC IR 1.11.2 for more information.

15.3 Please explain how FEI intends to reduce the percentage of (i) surveys that were delivered but not completed; and (ii) undeliverable surveys.

Response:

FEI intends to meet or exceed the target response rate of 80% of industrial demand each year. Once surveys have been received from all Rate Schedule 22 customers and the overall response rate target is achieved, FEI believes that spending additional staff resources on customers that either refuse to respond (after receiving an introduction, the survey, and then three follow up email messages) or on smaller customers with outdated email addresses is unlikely to materially increase the response rate. As large volume customers have more potential to affect the overall forecast, these customers are contacted directly by FEI staff if they fail to respond after the standard set of automated messages.

15.4 Please provide industrial survey response data broken down into the relevant rate classes using the template below. The column titled “Number of Customers” represents the number of customers in the database at the time the survey was issued.

	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
Row 1		2015 Industrial Survey Response (Actual)						
Row 2			Completed		Delivered but not completed		Undeliverable	
Row 3		Number of Customers	% Customers	% 2015 Demand	% Customers	% 2015 Demand	% Customers	% 2015 Demand
Row 4	Rate Schedule 5							
Row 5	Rate Schedule 7							
Row 6	Rate Schedule 22							
Row 7	Rate Schedule 25							
Row 8	Rate Schedule 27							
Row 9	Total							

Response:

The information is provided in the requested format below.

		Completed		Delivered but not completed		Undeliverable	
	Number of Customers	% Rate Sched. Customers	% 2015 Demand	% Rate Sched. Customers	% 2015 Demand	% Rate Sched. Customers	% 2015 Demand
Rate Schedule 5	230	14.0%	0.5%	43.8%	1.7%	42.1%	1.5%
Rate Schedule 7	5	40.0%	0.2%	20.0%	0.1%	40.0%	0.0%
Rate Schedule 22	47	100.0%	62.4%	0.0%	0.0%	0.0%	0.0%
Rate Schedule 25	559	46.3%	14.0%	49.9%	8.0%	3.7%	0.3%
Rate Schedule 27	108	71.1%	9.3%	27.2%	1.9%	1.8%	0.1%
Total	949		86.4%		11.7%		1.9%

On page 47 of Appendix A3 in the Application FEI states: "The response rate is measured by counting the number of responses vs the number of customers in the survey."

15.5 Please explain if the number of customers in the survey, as described in the preamble, includes the number of customers for which the survey was undeliverable.

Response:

The number of customers in the survey now includes all customers including those for which the survey was undeliverable. This change increases the denominator of the response rate calculation, which lowers the response rate. Even with this change, the response rate by volume still exceeded the target in 2015.

16.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.6.3, pp. 27, 28; Appendix A3, p. 41

Industrial Demand

On page 27 of the Application, FEI states: "The demand for the majority of industrial customers is forecast using the Industrial Survey … the forecast demand for Burrard Thermal, Vancouver Island Joint Venture, and BC Hydro Island Cogeneration Project is set at the contract demand for each customer and these customers are not surveyed."

Figure A3-15 on page 41 of Appendix A3 in the Application shows that FEI sends out industrial surveys to customers in RS 5, 7, 22, 25 and 27.

16.1 Please explain how energy demand is forecasted for RS 4.

Response:

Rate Schedule 4 is the seasonal rate class and use rates for these customers peak in the summer. Currently there are only Rate Schedule 4 customers in the Inland and Lower Mainland sub-regions. Rate Schedule 4 is an industrial rate class so no customer additions are forecast unless FEI is aware of new customers that will be joining the system. For 2015 and 2016 no new customers were forecast. Use rates for this group of customers are forecast at zero for November through February. Consistent with past practice, the use rates for all other months are set to the same as the previous year.

The total 2016 demand from Rate Schedule 4 is 0.17 percent of the total industrial demand forecasted.

On page 28 of the Application, FEI states: "The forecast of demand for all customers that either chose not to reply to the survey or could not be contacted … was set to 2014 actual consumption."

16.2 Please discuss the feasibility of using the average forecast growth of customers that responded to the survey to forecast the average growth of the customers that provided no response.

Response:

While it is feasible to apply the growth rates from responding customers to customers that do not respond, the method is not likely to provide satisfactory results. The survey covers customers in a wide variety of industry segments, from coal mines to refineries, to condominiums and many others. For example, if a high percentage of the responders were coal mines and refineries then the average growth rate from their forecasts would be applied to all non-responding condominium customers. However the condominium customers are more likely to use the same volume as the previous year because they have no opportunity to grow.

16.3 Please discuss the feasibility of using 2015 year-end projected figures to set the 2016 forecast industrial demand for the customers that provided no response.

Response:

The forecast is prepared in May and, at that time, FEI has actual consumption records through March. FEI does not believe that a method that uses three months of actual values to develop a new forecast for the following nine months would provide better results than the current method that uses the most recent 12 months, ending in March. Please refer to the response to BCUC IR 1.11.1.1 for further discussion of why projections are not used for forecasting.

17.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2, Appendix A4: Section 2, pp. 2-12; Section 4, p. 16

Demand Forecast Methodology for Rate Schedule 22

17.1 Please provide the following information for RS 22 by completing the table below.

	Column 1	*Column 2*	*Column 3*	*Column 4*	*Column 5*	*Column 6*	*Column 7*	*Column 8*
	FEI RS22 Energy Demand	**2010**	**2011**	**2012**	**2013**	**2014**	**2015[1]**	**2016**
		Normalized						
Row 1	Forecast Total Energy Demand (TJ)							
Row 2	Approved Total Energy Demand (TJ)							
Row 3	Actual Total Energy Demand (TJ)							
Row 4	Forecast Variance (TJ)[2]							
Row 5	Forecast Variance (%)[3]							

Notes

1 - Use the most recent 2015 year-end projected demand to represent 2015 Actual Total Energy Demand (TJ)

2 - Forecast Variance (TJ) = Row 1 - Row 3

3 - Variance (%) = Row 4 / Row 1

Response:

Please see the table below for Rate Schedule 22 Energy Demand. Please note that FEI has amended the 2014 approved total demand to the final amount (approved through BCUC Order G-164-14) of 43,245 TJs. This change does not impact any calculations contained within the Application related to the 2016 rates, but is for informational purposes only as tables contained in Appendix A2 used an incorrect demand of 41,200 TJs. All IR responses related to 2014 approved Rate Schedule 22 volumes reflect the correct approved amount of 43,245 TJs.

FEI Rate Schedule 22 Energy Demand

	FEI RS22 Energy Demand	2010	2011	2012	2013	2014	2015	2016
Row 1	Forecast Total Demand (Tjs)	27,117	27,117	29,675	29,620	35,740	33,340	36,266
Row 2	Approved Total Demand (Tjs)	27,117	27,117	29,675	29,620	43,245	33,340	
Row 3	Actual Total Demand (Tjs)	30,050	34,943	38,038	36,401	35,956	34,735	
Row 4	Forecast Variance (Row 1-Row 3)	-2,933	-7,827	-8,363	-6,781	-215	-1,395	
Row 5	Forecast Variance % (Row 4/Row 1)	-11%	-29%	-28%	-23%	-1%	-4%	

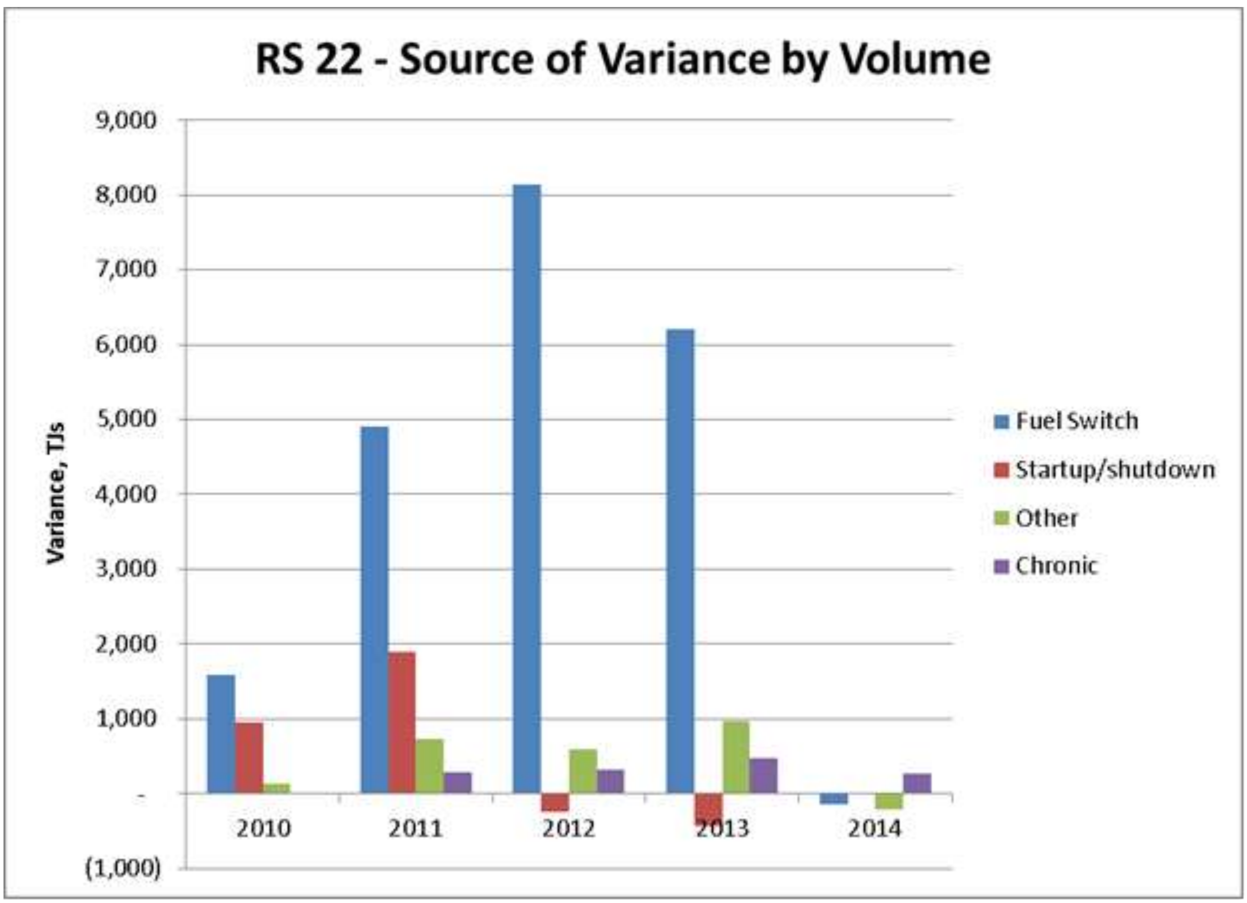
Please note that FEI does not have 2015 year-end projected demand for Rate Schedule 22 as discussed in the response to BCUC IR 1.11.1.1. Instead, FEI has completed the table using the 2015 Seed value for Row 3.

On page 2 of Appendix A4 in the Application, FEI lists potential sources of historical variance between actual and forecast demand for RS 22. FEI outlines that the primary reasons for material variances from forecast figures have been as a result of fuel switching, business start-up and chronic forecast variance by individual customers.

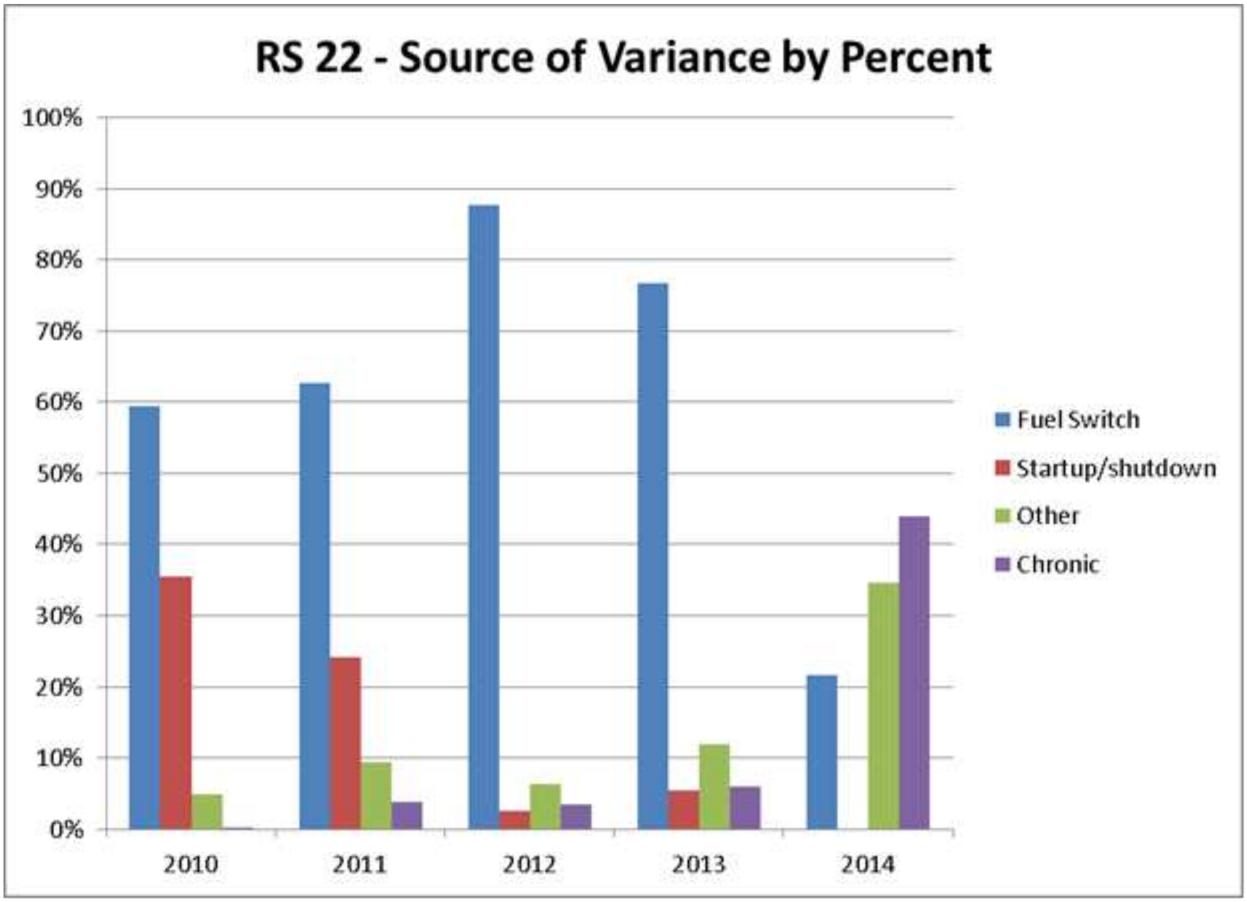
17.2 Please provide the percentage breakdown of the variance by volume that each of the following contributed to: (i) fuel switching; (ii) business start-up; (iii) chronic forecast variance by individual customers; and (iv) other causes.

Response:

The following chart shows the respective sources of the variances:



The following chart shows the same data in terms of percentage of absolute values:



On page 16 of Appendix A4 of the Application, FEI states that it conducted "an informal discussion with several other Canadian gas utilities, including Gaz Metro, Manitoba Hydro, Enbridge and Union Gas, in an attempt to determine if there was a significantly different method in use." FEI further states that in "all four cases, direct customer-by-customer communication was used to forecast [industrial] demand, through the use of a survey, email or discussions between account managers and large customers."

17.3 Please state the average percentage variance for industrial demand, over 5 years from 2010 to 2014, for each of the Canadian gas utilities listed above.

Response:

The informal discussions with each of the gas utilities listed above were only about the general method used to forecast industrial demand, and FEI did not collect variance information.

FEI notes that Section 3 in Appendix A2 of the Application contains an industrial forecast benchmark from the utilities surveyed by Itron.

FEI also intends to survey both Canadian and Pacific Northwest utilities during the fall of 2015 to establish a set of forecasting benchmarks. At that time, the utilities previously contacted by FEI will be solicited for variance information. The variance benchmarks will form part of the report to be filed in with the Commission in response to Directives 6, 7 and 8 from Order G-86-15.

18.0 Reference: DEMAND FORECAST AND REVENUE AT EXISTING RATES

Exhibit B-2: Section 3.6.4, pp. 29; Appendix B, p. 9

Natural Gas for Transportation (NGT) and LNG Demand

On page 29 of the Application, FEI states: “The following table shows the 2011 to 2014 Actual, 2015 Projected and 2016 Forecast annual demand for CNG and LNG for Rates Schedules 16/46 (LNG) and Rate Schedule 25 (CNG).”

18.1 Please state if the 2015 Projected figures contain any months of actual data and if so, please indicate how many months of actual data have been included in the projection.

Response:

The 2015 Projected annual demand contains six months of actual data, from January 1, 2015 to June 30, 2015. For contracts with an in-service date subsequent to June 30, 2015, the 2015 Forecast volumes for these contracts were used in the 2015 Projection.

On page 9 of Appendix B in the Application, FEI states:

> For the spot volumes related to the power generation customers FEI contacted the customers directly and received information on how much LNG would be required. Then, to be conservative in forecasting the resulting demand and supporting O&M, FEI reduced the demand by applying a percentage based on the 2015 projected as compared to the original forecast for these customers. A similar process was undertaken for the third-party fueling station demand forecasts.

18.2 Please explain if this approach could be used to address chronic forecast variance by individual RS 22 customers.

Response:

While the approach of contacting customers described in the preamble is similar to that used in determining the RS 22 demand forecast, FEI does not believe that applying an adjustment such as the one detailed in the preamble above would address the forecast variance in individual RS 22 customers. FEI believes that using the knowledge of account managers and direct feedback from the customers provides a more informed approach to determining the RS 22 demand forecast. Only through discussions with the customer will FEI learn the reasons for historical variances and be able to better assess if the variance is likely to continue. Identifying what may appear to be under-forecasters by analyzing past data provides information about the customers that should be contacted, but may not provide accurate information about how much of a post-survey adjustment should be made.

FEI notes that there is an error in Appendix A4 of the Application, where FEI stated: "The key account managers will review the forecast with each Rate Schedule 22 customer and discuss any risks such as fuel switching and chronic under-and over-forecasting." To clarify, all surveys will be reviewed by key account managers and FEI will contact those customers that are at risk of fuel switching or under-and over-forecasting, as well as those that submit surveys that do not appear correct. FEI does not intend to contact customers that are not at risk of fuel switching or under-and over-forecasting and that have submitted what appear to be reasonable surveys.

18.3 Please provide (i) the 2016 NGT and LNG demand forecast; (ii) the 2016 total energy demand forecast; and (iii) the 2016 revenue deficiency forecast if the original LNG spot volume forecasts were not adjusted based on the 2015 projected figures.

Response:

FEI interprets "2016 total energy demand forecast" to be referring to the total 2016 CNG and LNG demand forecast if volumes are not adjusted. Please refer to the tables below:

Table (i): Demand Forecast in the Application

2016 Forecast Demand (GJ)			
	CNG	LNG	Total
NGT	586,224	1,559,902	2,146,126
Non-NGT	-	106,904	106,904
Total	586,224	1,666,806	2,253,030

Table (ii): Demand Forecast without Adjustment

2016 Forecast Demand (GJ) (No Adjustment)			
	CNG	LNG	Total
NGT	586,224	1,743,758	2,329,983
Non-NGT	-	296,000	296,000
Total	586,224	2,039,758	2,625,983

Using the total volumes provided in Table (ii) rather than the volumes as forecast in the application (i.e. Table (i)) would reduce the revenue deficiency by approximately $1.7 million, or an approximate 0.2% reduction to delivery rates.

FEI has recently been made aware of an update that needs to be made to the LNG demand and associated spot volumes. Due to recent developments which are described in the response to BCUC IR 1.18.4, the 2016 LNG demand and associated spot volumes will be significantly reduced from the forecast FEI had filed. FEI will update its financial schedules and rate calculations in an Evidentiary Update prior to the Annual Review Workshop.

As a result of changes to the LNG demand, the difference in adjusted and non-adjusted spot volumes will be reduced. Table (iii) below shows the updated LNG demand that is expected to be filed in the Evidentiary Update. Table (iv) shows the demand without adjustments.

Table (iii): Revised Demand Forecast

2016 Forecast Demand (GJ)			
	CNG	LNG	Total
NGT	586,224	561,824	1,148,049
Non-NGT	-	106,904	106,904
Total	586,224	668,729	1,254,953

Table (iv): Revised Demand Forecast without Adjustment

2016 Forecast Demand (GJ) (No Adjustment)			
	CNG	LNG	Total
NGT	586,224	561,824	1,148,049
Non-NGT	-	296,000	296,000
Total	586,224	857,824	1,444,049

Using the total unadjusted volumes provided in Table (iv) rather than the volumes as forecast in Table (iii) would reduce the revenue deficiency by approximately $0.870 million, or an approximate 0.12% reduction to delivery rates.

On page 9 of Appendix B in the Application, FEI states:

> In 2016, a significant portion of the total incremental increase in the total LNG demand is related to 998,077 GJs in new demand attributable to an agreement with Puget Sound Energy (PSE) to provide LNG to one shipping vessel that will be operated by Totem Ocean Trailer (TOTE). This Rate Schedule 46 contract is between FEI and PSE, with PSE then providing the LNG to TOTE in the Port of Tacoma. The expected in service date of TOTE's marine vessel is April 1, 2016.

18.4 Please discuss the possibility of PSE sourcing the LNG for TOTE from an alternate supplier in the near future.

Response:

On October 1, 2015, FEI was informed by TOTE of a delay in putting the first LNG vessel into service in 2016 in Tacoma. The delay is a direct result of the sinking of TOTE's relief vessel in the Caribbean, the El Faro, which occurred on October 1, 2015.[6] The El Faro was a relief vessel that TOTE was going to deploy to Tacoma to relieve the MV Midnight Sun to allow for the conversion of this first TOTE vessel to LNG engines.

As a result of these developments, TOTE has delayed the conversion of the first vessel to LNG by at least one year and will revisit this project with FEI and PSE over the coming months. At the present time, FEI assesses that it is unlikely that it will be providing LNG to PSE for the TOTE vessels in 2016. This will have a significant effect on the 2016 LNG demand forecast. FEI will update the financial schedules in an Evidentiary Update prior to the Annual Review Workshop.

18.5 Please discuss the potential for other RS 46 agreements to supply LNG to PSE in the near future.

Response:

FEI is supplying LNG to PSE for their Gig Harbor LNG peaking facility on a spot basis. LNG is purchased on an as-required basis with little predictability. In January 2015 approximately 5,100 GJs was purchased by PSE for Gig Harbour. In addition, PSE has taken approximately

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[6] http://www.nytimes.com/2015/10/08/us/coast-guard-to-suspend-search-for-survivors-of-el-faro.html?_r=0

2,000 GJ for Gig Harbour in October 2015. As a result of the delay of the conversion of TOTE's first vessel to LNG as discussed in response to BCUC IR 1.18.4, FEI does not foresee any other supply of LNG to PSE, other than the supply for Gig Harbor.

D. OTHER REVENUE

19.0 Reference: OTHER REVENUE

Exhibit B-2, Section 5.2.5, pp. 35, 37-38, Table 5-1; FEI Annual Review of 2015 Delivery Rates, Exhibit B-2, BCUC IR 1.12.1

Biomethane Other Revenue

Table 5-1 of the Application provides the following amounts for Biomethane Other Revenue: Approved 2015 - $(0.070) million; Projected 2015 - $(0.215) million; Forecast 2016 - $0.250 million.

In response to BCUC IR 1.12.1 in the 2015 Annual Review proceeding, FEI provided the following information regarding the 2014 and 2015 Biomethane cost of service of the Biomethane capital assets:

Biomethane Cost of Service ($ Thousands)

	2014				2015			
Particulars	Salmon Arm Landfill	Kelowna Landfill	General Costs	Total	Salmon Arm Landfill	Kelowna Landfill	General Costs	Total
O & M Expenditure	92	30	300	422	80	208	306	594
Property Taxes	2	-	3	5	2	2	9	13
Depreciation	133	154	-	287	144	307	-	451
Subtotal	227	184	303	714	226	517	315	1,058
Income Tax	(201)	(300)	-	(500)	(91)	(411)	-	(502)
Earned Return	137	165	-	302	131	301	-	432
Subtotal - Other Revenue	(64)	(135)	-	(199)	40	(110)	-	(70)
Total Cost of Service	$ 163	$ 49	$ 303	$ 515	$ 267	$ 407	$ 315	$ 988

Response:

The requested Projected 2015 and Forecast 2016 information is provided below. FEI also provides a summary of where each of the 2016 cost of service items are transferred to the BVA in the financial schedules in Section 11:

- The O&M of $959 thousand is shown on Schedule 21 Line 29 Column 4.
- The Property Tax of $7 thousand was not removed from the total property tax on Schedule 23 but should have been. FEI will correct the financial schedules for this oversight in an Evidentiary Update prior to the Annual Review Workshop.

- The Depreciation of $372 thousand is composed of depreciation expense of $400 thousand less amortization of CIAC of $28 thousand. These amounts do not agree to the financial schedules which show $383 thousand of depreciation being transferred to the BVA on Schedule 7.2 Line 40 Column 6 and no amortization of CIAC being transferred. FEI will correct the financial schedules for this oversight in an Evidentiary Update prior to the Annual Review Workshop.
- The Other Revenue of $252 thousand does not agree to the amount shown on Schedule 20 Line 8 Column 3 of $250 thousand. FEI will correct the financial schedules for this oversight in an Evidentiary Update prior to the Annual Review Workshop.

Biomethane Cost of Service ($,000)

	2015 Projected				2016 Forecast				
Particulars	Salmon Arm Landfill	Kelowna Landfill	General Costs	Total	Salmon Arm Landfill	Kelowna Landfill	General Costs	Surrey Costs	Total
O & M	189	109	320	618	125	306	453	75	959
Property Tax	2	2	-	4	4	-	3	-	7
Depreciation	133	-	-	133	114	258	-	-	372
Subtotal	324	111	320	755	243	564	455	75	1,337
Income Tax	(102)	(599)	-	(701)	(24)	(247)	-	(4)	(275)
Earned Return	145	340	-	485	136	360	-	31	527
Subtotal - Other Revenue	43	(259)	-	(216)	113	113	-	27	252
Total Cost of Service	367	(148)	320	538	356	677	455	102	1,590

The net decrease of approximately $449 thousand in the cost of service between the 2015 Forecast and the current 2015 Projection is attributable to the delay in the Kelowna Landfill project which is partly offset by higher than forecast O&M costs for the Salmon Arm project. All variances for the Biomethane Cost of Service items above flow through the BVA and do not affect delivery rates.

E. RATE BASE

20.0 Reference: PLANT IN SERVICE

Exhibit B-2, Section 11, Schedule 6.2, Line 19

Account 483-10 GP Computer Hardware

Line 19 in Schedule 6.2 of Section 11 of the Application shows a forecast 2015 retirement of $10,421 thousand in Account 483-10 (General Plant Computer Hardware).

20.1 Please discuss the cause of this large asset retirement.

<u>Response:</u>

FEI notes that the reference to "…. forecast 2015 retirement of $10,421 thousand…" in the question is incorrect. The correct reference should be to 2016.

Asset class 483-10 (General Plant Computer Hardware - includes assets such as laptops, desktops, monitors, hard drives, servers, etc.) is subject to amortization accounting whereby the account is amortized over a fixed period of time (5 years). This is outlined on page III-3 of FEI's 2014 Depreciation Study. As a result, when the assets within this asset class reach zero net book value, they are retired from plant in service.

The $10,421 thousand amount will be fully amortized by the end of 2016 and thus will be retired in 2016 with no gain/loss recorded. This retirement is attributable to computer hardware acquired in 2011 as part of specific IT projects. The largest contributor to additions to the account in 2011 was the hardware acquired as part of the Disaster Recovery project at $3.2 million. The remainder of the assets were for various smaller projects.

20.2 Please explain whether asset retirements of this magnitude are common in this asset class.

<u>Response:</u>

The forecast retirement of $10,421 thousand for Account 483-10 is higher than any of the years from 2010 to 2014, which had annual retirements ranging from $0.2 to $8.4 million. However, for the period 2017 to 2019 the forecast retirements are expected to be in the range of $8 to $10 million per year.

As this asset class is subject to amortization accounting with a five year amortization period, the magnitude of the asset retirements in a given year depends on the amount of capital additions that occurred five years prior, which will fluctuate depending on specific projects in that year.

21.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedules 11, 11.1 and 12, pp. 92-94

Unamortized deferred charges and amortization (Rate Base and Non-Rate Base)

21.1 In the same format as is provided in Schedules 11, 11.1 and 12 in Section 11 of the Application, please provide the previous years' information by starting with the Actual 2014 ending deferral account balances and including Projected 2015 deferral account additions and Projected 2015 amortization.

Response:

Please refer to Attachment 21.1 for the requested schedules. The Earnings Sharing Mechanism Projected amounts in the attachment have been updated for the change discussed in response to CEC IR 1.33.3.

22.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 7.5.1.1, pp. 56-57

New Accounts - 2015 System Extension Application

22.1 Please provide a breakdown of the forecast $325 thousand application costs into the following categories: consulting costs, legal fees, intervener and participant funding costs, Commission costs, and miscellaneous costs.

Response:

The requested breakdown of the $325 thousand forecast application costs is provided below.

Category		Amount
Consulting Costs	$	144,500
Legal Fees		57,000
Intervener and Participant Funding Costs		50,000
Commission Costs		60,000
Miscellaneous Costs		13,500
TOTAL	**$**	**325,000**

22.2 Please provide a comparison of the rate impact for 2016 if the 2015 System Extension Application deferral account was amortized over one year as opposed to the proposed two years.

Response:

The rate impacts are shown in the table provided below. The proposed two-year amortization period results in a delivery rate impact of approximately 0.02 percent. Reducing the amortization period to one year would result in an increased revenue requirement of approximately $158 thousand in 2016, or an additional 0.02 percent increase in the delivery rate increase compared to a two-year amortization period.

FEI Delivery Rate Impact	2016
2 year amortization	0.02%
1 year amortization	0.04%

23.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2: Appendix C2, Table 1, p. 10; Section 3.2, pp. 17-18

New Accounts – 2017 Long-Term Resource Plan Application

FEI states on page 17 of the Application: "Pursuant to the extension approved by Commission Letter L-30-15, FEI will provide alternatives to existing forecast methodologies with recommendations to improve residential and commercial UPC forecasts and commercial net customer additions forecasts in its Annual Review of 2017 delivery rates."

Table 1 on page 10 of Appendix C2 provides a summary of anticipated long-term resource plan (LTRP) activities and expenditures, including such activities as "Alternative residential and commercial customer additions forecast."

23.1 Is there any overlap in activities and resources between FEI's load forecasting methodologies analyses and the preparation of the 2017 LTRP?

Response:

The following discussion addresses BCUC IRs 1.23.1, 1.23.1.1, 1.23.1.2, 1.23.2 and 1.23.3.

Section 3.2 and Appendix A3 of the Application describe FEI's short-term demand forecast methodology used for revenue requirement forecasting purposes typically for a test period of 1 to 2 years, whereas the forecasting methodologies discussed in Appendix C2 of the Application are for FEI's long-term demand forecasting for the purpose of FEI's Long Term Resource Plan which has a planning horizon of 20 years. Given the different time horizons, the methodology used for forecasting demand over the short term (1-2 years) is separate and distinct from the methodology used to forecast demand over the long term (20 years).

As such, the overlap between the short term demand forecasting analyses for revenue requirements purposes and long term demand forecasting analyses for the Long Term Resource Plan will be minimal or non-existent. For instance, it is possible that there may be some insights into the study of alternative short term customer addition forecasts for commercial and industrial sectors that could aid in the development of the alternatives for long term customer additions forecasts; however, FEI will not be able to determine if such insights will provide any efficiencies or cost savings until the work is underway.

It may be possible for FEI to utilize the same consultant for some aspects of the work related to the short term and long term demand forecasting analyses. However, FEI will not be able to confirm this until it is in formal discussion with potential project consultants on scope and costs for the methodology review work. If the same consultant is able to undertake portions of the work needed for both the short term and long term forecasting tasks, then some cost efficiencies might be realized, in the form of fewer meetings and the need to provide project background details to only one consultant.

FEI intends to find any cost efficiencies that it can related to the tasks identified in Appendix C2 of the Application. The extent to which FEI can find such efficiencies, they will be reflected in the actual amounts charged to the proposed deferral account.

23.1.1 If yes, please describe the areas of overlap and whether FEI expects to achieve efficiencies and cost savings as a result of the overlap

Response:

Please refer to the response to BCUC IR 1.23.1.

23.1.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.23.1.

23.2 Will FEI be able to utilize the same external consultants to perform the load forecasting methodology analyses and the 2017 LTRP preparation activities? Please discuss.

Response:

Please refer to the response to BCUC IR 1.23.1.

23.3 Will FEI be able to utilize some or all of the alternative load forecasting methodology analyses in its preparation of the 2017 LTRP? Please discuss.

Response:

Please refer to the response to BCUC IR 1.23.1.

On page 6 of Appendix C2, FEI outlines the Commission's directives from the 2014 LTRP Decision, which included the following: "A detailed analysis of the relative benefits/shortcoming of their [FEI] particular End-Use Method as compared to other end-use methods."

Based on the information provided in Table 1 on page 10 of Appendix C2, FEI forecasts total expenditures of $180,000 for End-Use Demand Forecast (Activity #4 in Table 1).

FEI provides the following description for the End-Use Demand Forecast activity on page 15 of Appendix C2: "This activity is to develop an end-use based long-term residential, commercial and industrial customer forecast of demand for the LTRP. The long-term, end-use demand forecast was first undertaken in the 2014 LTRP…"

23.4 Please confirm, or explain otherwise, that as part of the 2014 LTRP FEI developed an end-use method for demand forecasting.

Response:

Confirmed.

23.4.1 If confirmed, please confirm or explain otherwise that it is FEI's intention as part of the 2017 LTRP preparation to identify and develop a different end-use demand forecast model than the one presented in the 2014 LTRP Application.

Response:

Not confirmed.

FEI does not now know whether it will in fact identify and develop a different end-use demand forecast model or methodology than that used for the 2014 LTRP. The Commission's directive to compare the methodology used by FEI for the 2014 LTRP with other end-use methodologies (Activity #2 in Table 1 of Appendix C2 in the Application) may indeed result in a different methodology being found that is preferable to that used by FEI for the 2014 LTRP.

If the existing methodology is used for the 2017 LTRP and the same consultant is contracted to do this work as that used for the 2014 LTRP, then FEI anticipates that a substantial portion of the base work for the 2014 LTRP will be able to be re-used for the 2017 LTRP. In this event, however, there will still be costs associated with this incremental activity for updating the model, updating the base year information, bringing forward the updated information from the CPR work currently underway and rerunning the model. FEI has not sought a cost estimate from the consultant who undertook the end-use demand forecast modelling work used in the 2014 LTRP for completing Activity #4, as doing so in advance of the methodology review (Activity #2) would be premature. FEI's current best estimate of costs for Activity #4 if the same consultant and same methodology are used is between $80 and $100 thousand.

Only the actual cost for external consultants to complete the modelling portion of the end use demand forecast will be captured in the deferral account.

23.5 Please explain why FEI has interpreted the Commission's directive in the 2014 LTRP Decision to perform "a detailed analysis of the relative benefits/shortcomings of their particular End-Use Method as compared to other end-use methods" as requiring FEI to develop a new End-Use demand forecast model, as opposed to providing analyses of the benefits and shortcomings of its already developed end-use demand model.

Response:

FEI has not interpreted the Commission's directive in the way described in this request. FEI believes that the directive to review end-use forecasting methodologies is a separate and distinct task from the incremental activity of completing an end use, annual demand forecast. Reviewing methodologies is Activity # 2 in Table 1, while completing the end use methodology is Activity #4 in the same table. The incremental activity of completing an end use annual demand forecast, however, must be completed regardless of whether the same methodology is used or a new preferred methodology is identified. Please also refer to the response to BCUC IR 1.23.4.1. For clarity, completing the end use methodology is an incremental item that is carried over from the 2014 LTRP to the 2017 LTRP and, hence, is an incremental activity for which incremental costs will be incurred regardless of the methodology used.

23.6 If FEI did not develop a new end-use demand forecast model as part of the 2017 LTRP preparation, and instead provided the detailed analysis on its existing end-use model, as requested by the Commission in the 2014 LTRP Decision (and quoted in the above preamble), how would this change FEI's forecast expenditures for the 2017 LTRP Application?

Response:

For the reasons discussed in response to BCUC IR 1.23.5, this would not change FEI's forecast expenditures for Activity #2. As discussed in the response to BCUC IR 1.23.4.1, FEI's current best estimate of costs for Activity #4 if the same consultant and existing methodology are used is between $80 and $100 thousand.

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23.6.1 In this scenario, would Activity #4 in Table 1 of Appendix C2 be eliminated entirely? Please discuss.

Response:

No. If FEI did not develop a new end-use demand forecast model as part of the 2017 LTRP preparation, Activity #4 would not be eliminated because FEI would still have to prepare its end use demand forecast using the existing model. As stated in page 15 of Appendix C2, the long-term, end-use demand forecast was first undertaken in the 2014 LTRP in order to meet Commission directives from the 2010 LTRP Decision. This work is therefore an incremental activity for which FEI has no funding in Base O&M.

24.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1, Line 18; FEI 2014-2018 Multi-Year PBR Plan Application, Exhibit B-1, Section 4.3.3, Table D4-3, p. 301

Other Deferral Accounts – Gas Asset Records Project

On page 301 of the FEI 2014-2018 Multi-Year PBR Plan Application, FEI states: "The completion of this [Gas Asset Records] project is expected to extend from 2015 to 2017; however, the forecasted overall budget of $7.8 million remains the same as the previous amount included in the 2012-2013 RRA."

24.1 Please provide an update on the progress of the Gas Asset Records Project, including the expected timeline for completion, the total amount spent to date, and the revised forecast total budget for the project.

Response:

The Gas Asset Records Project is making good progress. More records than expected are being analyzed and secured. Industry pipeline integrity and record keeping practices continue to evolve, which is adding to the scope of the Gas Asset Records Project. This additional scope is expected to extend the timeline for the project to 2018. Robust processes are in place to secure records as current gas asset projects are completed and closed out. Work to improve drawing management and control systems is proceeding on the revised schedule.

The total amount spent as of August 2015 is $3.1 million and the forecast total budget for the project remains at $7.8 million.

FEI provided the following table on page 301 of the PBR Application:

Table D4-3: FEU Gas Assets Records Project Costs ($ thousands)

	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	800	800	800	800	300	3,780
Project 'B' – Implement improved drawing management & control systems		70	150	150			370
Project 'C' - Review & analyze historical drawings	30	220	300	650	1050	1,400	3,650
Total	310	1,090	1,250	1,600	1,850	1,700	7,800

24.2 Please revise the above table to include Actual expenditures for 2013 and 2014, Projected expenditures for 2015, and updated forecasts for 2016 and 2017.

<u>Response:</u>

	2012 Actual	2013 Actual	2014 Actual	2015 Projected	2016 Forecast	2017 Forecast	2018 Forecast	Total
Project 'A' - Consolidate & scan critical Gas System Asset Records into Filenet	280	570	772	852	1,100	1,100	546	5,220
Project 'B' - Implement improved drawing management & control systems	-	20	155	170	170	100	-	615
Project 'C' - Review & analyze historical drawings	30	245	140	250	500	500	300	1,965
Total	310	835	1,067	1,272	1,770	1,700	846	7,800

24.2.1 Please provide explanations for variances between forecast and actual/projected results for the years 2013 through 2015.

Response:

The Gas Asset Records Project is managing costs to the approved $7.8 million. The project is using resources well and the actual/projected costs for 2013 through 2015 are consistently tracking below the original forecast. The favourable variance in 2013 is the result of a delayed approval of the project, ramp-up time, and challenges recruiting the appropriate skills. FEI has been challenged to keep the project staffed with the appropriate skills resulting in a continued favourable variance in 2014 and 2015. These staffing challenges and additional scope have resulted in the revised annual forecasts for 2016 through 2018 (see BCUC IR 1.24.2) and extended the expected duration of the project.

As noted in the response to BCUC IR 1.24.1, evolving pipeline integrity and records keeping practices are adding to the scope of Project ‘A‘ and Project ‘B’, and reducing the scope of Project ‘C’. Project ‘A’ is finding more critical records than anticipated needing to be analyzed, sorted, and secured. Project ‘B’ has put in place robust processes for securing records as current gas asset projects are complete and is finding more work needs to be done to develop and implement a drawing management system to comply with APEGBC Quality Management Guidelines. As a result of early improvements to the gas asset project completion and close out process, Project ‘C’ costs are reduced.

25.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 11, Schedule 11.1, Line 19; FEI 2014-2018 Multi-Year PBR Plan Application, Exhibit B-1, Section 4.3.4, Table D4-4, pp. 301-302

Other Deferral Accounts – BC OneCall Project

25.1 Please provide an update on the progress of the BC OneCall Project, including the expected timeline for completion, the total amount spent to date, and the revised forecast total budget for the project.

Response:

The BC One Call Project is progressing with the cleanup of data integrity issues. The project is challenged by the complexity and high degree of analysis required to resolve many of the historical records issues. Some of the issues cannot be resolved by a paper review of the record provenance and must be field verified. The additional complexity is increasing the forecast total budget to $2.868 million compared to the original forecast amount of $2.3 million but the timeline for completion remains 2017. The total amount spent as of August 2015 is $2.3 million.

FEI provided the following table on page 302 of the PBR Application:

Table D4-4: FEU BCOneCall Ticket Process Improvement Project Costs ($ thousands)

Stream	2012 Actual	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	Total
Data Consistency Stream	20	380	450	150	150	120	1,270
Conflation Stream	130	700	200				1,030
Total	**150**	**1080**	**650**	**150**	**150**	**120**	**2,300**

25.2 Please revise the above table to include Actual expenditures for 2013 and 2014, Projected expenditures for 2015, and updated forecasts for 2016 and 2017.

Response:

The requested table is provided below. FEI notes that the 2012 actual amount for the conflation stream in the 2014-2018 PBR Application was rounded to the nearest $10 thousand whereas the amount below is rounded to the nearest thousand.

FEI also notes that it had forecast no additions in 2016 to the BC OneCall Project deferral account shown in the financial schedules provided in Section 11, Schedule 11.1, Line 19. This was based on an earlier forecast, and does not reflect the forecast provided below based on the most recent information available. FEI will update its revenue requirements as part of the Evidentiary Update to be filed prior to the Annual Review Workshop.

Stream	2012 Actual	2013 Actual	2014 Actual	2015 Projected	2016 Forecast	2017 Forecast	Total
Data Consistency Stream	20	285	847	450	350	100	2,052
Conflation Stream	126	590	100	-	-	-	816
Total	146	875	947	450	350	100	2,868

25.2.1 Please provide explanations for variances between forecast and actual/projected results for the years 2013 through 2015.

Response:

The actuals for 2013 are lower than the forecast due to a longer ramp-up time for the Data Consistency Stream and lower Conflation Stream costs. The longer ramp-up time for the Data Consistency Stream was required to enable the simple data updates to get underway and to coordinate with the business to access resources with the skills to analyze the more complex records issues and complete the corrections.

The actuals/projected costs for 2014 through 2015 exceed the forecast due to a higher level of expertise and more effort required to analyze the records than was originally contemplated. The higher level of expertise was more costly than originally budgeted and more time was required to analyze the records than initially forecast. While semi-automated processes are used for simple data updates, the exceptions need to be dealt with manually. Complex data integrity exceptions were encountered that required significant effort to resolve and, in some cases, required field verification.

F. EARNINGS SHARING AND RATE RIDERS

26.0 Reference: DEFERRAL ACCOUNTS

Exhibit B-2, Section 10.2.3, Table 10-10, p. 76

RSAM Rate Riders

Table 10-10 on page 76 of the Application shows a 2015 Revenue Stabilization Adjustment Mechanism (RSAM) closing balance (including interest) of $36,191,000.

26.1 Please discuss the factors which contributed to such a large 2015 closing balance in the RSAM account.

Response:

The RSAM account captures variances in use rates as compared to forecast for residential and commercial customers. As forecasts of use rates are developed assuming normal weather, the largest driver of variances in use rates is warmer or colder weather.

The main reason for the projected 2015 RSAM closing balance of approximately $36.2 million is the significantly warmer than normal weather in 2015 causing less consumption of gas per customer compared to the forecast use per customer. For context, as of July 2015, it has been 17 percent warmer than normal.

G. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

27.0 Reference: DEPRECIATION STUDY

Exhibit B-2: Section 12.3.2.1, Table 12-2, pp. 113-116; Appendix D-1

Depreciation Rates

Table 12-2 on page 114 of the Application shows significant proposed decreases in depreciation rates for the following asset classes:

(i) 437-00 “Mtg. Gas Meas/Reg Equipment”

(ii) 466-00 “TP Compressor Equipment – Overhauls”

(iii) 467-10 “TP Meas/Reg Equipment”

(iv) 468-00 “TP Communications Equipment”

(v) 477-10 “DS Meas/Reg Additions”

(vi) 482-20 “GP (Masonry) Structures”

(vii) 484-00 “GP Vehicles”

(viii) 485-20 “GP Heavy Mobile Equipment”

27.1 Please confirm, or explain otherwise, that the impact of decreasing an asset class’s depreciation rate is that the asset class will be depreciated over a longer time period.

Response:

Gannett Fleming confirms that all else equal, the lower the depreciation rate is, the longer is the time period during which the assets are depreciated and recovered.

27.2 Please discuss whether increasing the length of an asset class’ depreciation period potentially increases the likelihood of early retirements in the asset class.

Response:

Gannett Fleming confirms that under the average service life methodology, increasing the expected (i.e. average) length of an asset class’ depreciation period does not potentially increase the likelihood of early retirements in an asset class.

As indicated in the Depreciation Study, the depreciation rates are determined by the straight line method using the average service life methodology. The average service life methodology recognizes that some assets in the classes will be retired later than the estimated average life and some will be retired earlier. Increasing the estimated life by itself does not potentially increase the likelihood of early retirements. Rather, as successive Depreciation Studies are undertaken and the experience of asset retirements is known, more early retirements than expected will decrease the depreciation period, or conversely, more later retirements than anticipated will increase the depreciation period.

27.3 For each of the asset classes listed above, please explain the rationale and drivers which resulted in the changes to the asset classes' depreciation rates.

Response:

Gannett Fleming confirms that changes to an asset class' depreciation rate recommended in a depreciation study are a function of the estimated life of the asset class and also true-up adjustments required to adjust for differences between the actual reserve booked (i.e. accumulated depreciation) compared to the calculated reserve. These differences can arise as a result of changes in the asset class' estimate life over time and the recovery of gains/losses on retirement of assets recorded in the reserve account.

Following is further discussion of the rationale behind the change in the depreciation rate for the specific asset classes identified.

437-00 Mtg. Gas Meas/Reg Equipment

Gannett Fleming recommends a 20 year service life which is consistent with the service life recommended in the previous study. In the 2009 depreciation study, this account was under accrued which resulted in an increased effect on the composite depreciation rate. A recent review of the 2010-2014 additions and retirements suggests that this account is now in an over accrued position. To adjust for this over the remaining life of the assets, the depreciation rate needs to be decreased.

466-00 TP Compressor Equipment – Overhauls

This account consists of individual assets with their own approved depreciation rate and is subject to amortization accounting. Each individual asset is amortized over a fixed period of time depending of the term of each individual overhaul. The stated depreciation rate of 10.19% is a calculated weighted average rate based on the remaining life of the current assets within the account. This rate is expected to change depending on the overhaul term of new asset additions and respective retirements.

467-10 TP Meas/Reg Equipment

Gannett Fleming recommends a 36 year life, an increase from the 27 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 36 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the assets by nine years results in a decrease of approximately 1.87 percent in the depreciation rate for this asset category.

468-00 TP Communications Equipment

Gannett Fleming recommends a 19 year life, an increase from the 12 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 19 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life by seven years results in a decrease of approximately 10.79 percent in the depreciation rate for this asset category.

477-10 DS Meas/Reg Additions

Gannett Fleming recommends a 30 year life, an increase from the 26 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 30 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the measurement/regulating addition assets by four years results in a decrease of approximately 1.66 percent in the depreciation rate for this asset category.

482-20 GP (Masonry) Structures

Gannett Fleming recommends a 50 year life, an increase from the 45 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 50 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the assets by five years results in a decrease of approximately 0.28 percent in the depreciation rate for this asset category.

484-00 GP Vehicles

Gannett Fleming recommends a 6 year life, an increase from the 5 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 6 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the GP Vehicles assets by one year results in a decrease of approximately 5.49 percent in the depreciation rate for this asset category.

485-20 GP Heavy Mobile Equipment

Gannett Fleming recommends an 8 year life, an increase from the 7 year service life recommended in the previous study. Review of retirement transactions suggests that an average service life of 8 years is more reflective of the historical retirement activity and falls within the typical range of lives used for this account. The recommended longer life of the assets by one year results in a decrease of approximately 6.59 percent in the depreciation rate for this asset category.

27.3.1 What precipitated the proposed decrease in depreciation rates for GP Vehicles (484-00) and GP Heavy Mobile Equipment (485-20) of 5.49% and 6.59%, respectively?

Response:

Please refer to the response BCUC IR 1.27.3.

In the 2012-2013 FortisBC Energy Utilities (FEU) RRA Decision, the Commission accepted Gannett Fleming's Depreciation Study and approved the changes in depreciation rates recommended by the study, which resulted in a general overall increase to depreciation rates.[7]

27.4 Please explain the reasons why the overall depreciation rates are proposed to decrease as a result of the current study when compared to the increase to depreciation rates resulting from the previous study.

[7] 2012-2013 FEU Revenue Requirement Application (RRA) Decision, pp. 79-80.

Response:

Gannett Fleming confirms that in comparison to the previous study, depreciation rates overall are declining due to increases in the estimated service lives of the assets. Please refer to the response to BCUC IR 1.27.2 and page 115 of Exhibit B-2 for explanations of the recommended changes in depreciation rates.

As the age profile of the assets can change over time due to retirements and additions, complete depreciation studies are recommended every three to five years to account for such changes and to adjust the annual depreciation accrual rates accordingly.

27.4.1 Is it common for utilities to experience a general depreciation rate decrease following a period of higher depreciation rates? Please discuss.

Response:

Gannett Fleming confirms that generally, it is not common for utilities to experience a general depreciation rate decrease followed by a period of depreciation rate increase.

The experience of FEI can be attributed to the relatively long time periods between the completion of depreciation studies. The last depreciation study was completed in 2009 and prior to that a study was completed in 2007. Prior to the 2007 depreciation study, a full study was last completed in 1998, so that there was a gap of nine years between studies. As a result of this, rates were increased significantly by the 2007 depreciation study to catch-up for the under depreciation of assets that had occurred over the nine year time period since the last study in 1998. Recent retirement data, however, shows that some of the assets are experiencing longer service lives, warranting downward revisions in the depreciation rates.

The changes in the depreciation rates are therefore magnified by the result of the longer time between when studies are completed. To minimize such volatility in the depreciation rates, Gannett Fleming recommends depreciation studies be completed every 3 to 5 years.

27.5 When did FEI file its depreciation study prior to the depreciation study filed as part of the 2012-2013 FEU RRA? Please also indicate if the previous study was filed during FEI's previous PBR term.

Response:

Prior to the 2009 Depreciation Study which was filed as part of the 2012-2013 RRA, FEI filed a depreciation study as part of its 2010-2011 RRA, which was prepared based on gas plant-in-service as of December 31, 2007 (the 2007 Depreciation Study). The depreciation rate changes requested in the 2007 Depreciation Study were implemented in 2010, which was after the prior PBR term. The last time depreciation rates had been changed prior to that was in 2004 (at the outset of the prior PBR term) when FEI sought and received Commission approval through Order G-51-03 to implement depreciation rate changes for some asset classes, specifically Meters, Meter Installations and Regulators, and Computer Software based on the results of the 1998 Depreciation Study.

27.5.1 As part of the depreciation study filed previous to the study in the 2012-2013 FEU RRA, did the study recommend a depreciation rate increase or decrease?

Response:

The 2007 Depreciation Study filed in the 2010-2011 RRA recommended an overall increase in depreciation rates, from 2.7 percent to 3.4 percent.

27.6 When does FEI propose to file its next depreciation study?

Response:

FEI will undertake its next depreciation study five years after the 2014 Depreciation study, or based on plant in service as of December 31, 2019. As this would be the end date of the current PBR term, FEI expects to file the 2019 Depreciation Study as part of its 2020 RRA.

28.0 Reference: DEPRECIATION STUDY AND RATES

Exhibit B-2: Section 12.3.2, Tables 12-1 and 12-3, pp. 113, 117; Appendix D-1, Appendix B, p. B-2

Net Salvage

Table 12-1 shows that the impact of implementing the depreciation study recommendations is an increase to net salvage of approximately $10.1 million.

On page B-2 of Appendix B of the Depreciation Study, the second step in the estimation of net salvage is described as follows: "A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year…"

28.1 Please confirm, or explain otherwise, that part of the driver of increased net salvage is higher asset retirement costs.

Response:

Confirmed. Consistent with other utilities in the Canadian natural gas utility industry, part of the driver of increased net salvage being observed is higher asset retirement costs in recent years.

In addition to the explanations provided on page 118 of the 2016 Annual Review, following are details for the noted asset classes that are driving the increase in net salvage of approximately $10 million.

442.01 to 467.00 Mt Hayes assets – increase $1 million in net salvage

For this group of assets related to the Mt Hayes facility, the increase in net salvage is the result of net salvage rates being introduced for the first time. No net salvage rates were initially set by the previous study as the Mt Hayes facility was not in-service yet at the time of the study.

465.00 Transmission Pipeline – increase of $3.2 million in net salvage

For this asset class, retirement costs are dependent on the specific requirements of particular projects. Since the last depreciation study in 2009, retirement costs have increased for the period 2010 – 2014 with notable increases experienced in 2011 and 2014 for specific projects (refer to page VI 13 of the 2014 depreciation study). For example, in 2014, retirement costs were higher caused by pipeline relocation activities requiring the removal of the old pipe. These historical costs and their trend provide a reasonable indication that the level of retirement costs in the future will be similar to that recently observed.

473.00 Distribution Services – increase of $5.2 million in net salvage

For this asset class, since the last depreciation study in 2009, retirement costs have increased (page VI-19) for the period 2010 – 2014 reflecting the Company's focus on retiring inactive services. Contributing to the increased costs for retiring service lines, which includes costs for road closings, paving, etc., was the practice of cutting the service line at the main for safety reasons instead of at the property line. Additionally, inflation is a contributing factor to the higher retirement costs.

475.00 Distribution Mains – increase of $1.6 million in net salvage

For this asset class, retirement costs are dependent on the specific requirements of particular projects. Since the last depreciation study in 2009, retirement costs have increased for the period 2010 – 2014. Starting around 2010, the provincial government, municipalities, other utilities and FEI initiated significant projects and programs to upgrade infrastructure. For example, in the Lower Mainland, municipalities have increased their renewal of their roads and underground infrastructure. At the same time, FEI initiated a program to replace distribution mains having high relative risk of pipe failure. As a result of these activities, and the congested locations of many of the mains, higher retirement costs are being experienced by FEI in order to adjust its facilities to meet the requirements of others and to install its new distribution mains in permitted locations.

474.00/02 Meter/Regulators Installations including meters (478.10) – net decrease of $0.2 million in net salvage

On a combined basis, the net change in net salvage for the meter group of accounts is relatively minor. The reduction in net salvage for Meters 478.10 is the result of minimal retirement costs for the last number of years (refer to page VI 24 of the 2014 depreciation study). There have been minimal retirement costs which have been offset by the salvage proceeds from scrapped meters. This reduction in net salvage is offset by an increase in Meter / Regulator Installation retirement costs (refer to page VI-20 of the 2014 depreciation study) reflective of the increasing number of annual meter exchanges performed each year. Residential meter exchanges increased from approximately 40,000 in 2009 to close to 70,000 in 2014.

28.2 Please describe the causes of increased asset retirement costs.

<u>Response:</u>

Please refer to the response to BCUC IR 1.28.1.

Attachment 9.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 10.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 10.3

REFER TO LIVE SPREADSHEET MODEL

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Attachment 21.1

FORTISBC ENERGY INC.

Section 11

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

Schedule 11 (2015)

Line No.	Particulars	12/31/14	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/15	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ 441	$ -	$ (17,312)	$ 4,501	$ -	$ -	$ -	$ (12,370)	$ (5,964)	
3	Midstream Cost Reconciliation Account (MCRA)	(3,477)	-	(15,845)	4,120	-	7,046	(1,832)	(9,989)	(6,733)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	1,547	-	39,757	(10,337)	-	6,738	(1,752)	35,953	18,750	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,302)	-	(10)	3	295	20	(5)	(4,000)	(4,151)	
6	Revelstoke Propane Cost Deferral Account	24	-	(300)	78	-	-	-	(198)	(87)	
7	SCP Mitigation Revenues Variance Account	(962)	-	(783)	204	708	-	-	(834)	(898)	
8		$ (6,729)	$ -	$ 5,506	$ (1,431)	$ 1,002	$ 13,804	$ (3,589)	$ 8,563	$ 917	
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	$ 56,794	$ 185	$ 15,000	$ (3,900)	$ (6,310)	$ -	$ -	$ 61,769	$ 59,374	
11	NGV Conversion Grants	32	-	45	(12)	(9)	-	-	56	44	
12	Emissions Regulations	3	-	-	-	-	-	-	3	3	
13	NGT Incentives	12,780	-	5,809	(1,510)	(1,415)	-	-	15,664	14,222	
14	CNG and LNG Recoveries	(126)	-	(449)	117	126	-	-	(332)	(229)	
15		$ 69,483	$ 185	$ 20,405	$ (5,305)	$ (7,608)	$ -	$ -	$ 77,160	$ 73,414	
16	Non-Controllable Items Deferral Accounts										
17	Pension & OPEB Variance	$ 10,967	$ -	$ 1,999	$ -	$ (6,105)	$ -	$ -	$ 6,861	$ 8,914	
18	BCUC Levies Variance	302	-	571	(148)	(302)	-	-	423	362	
19	Customer Service Variance Account	(13,828)	-	-	-	3,456	-	-	(10,371)	(12,099)	
20	Pension & OPEB Funding	(176,449)	(37,416)	(451)	-	-	-	-	(214,316)	(214,090)	
21	US GAAP Pension & OPEB Funded Status	111,395	37,416	-	-	-	-	-	148,811	148,811	
22		$ (67,613)	$ -	$ 2,119	$ (148)	$ (2,950)	$ -	$ -	$ (68,592)	$ (68,102)	

FORTISBC ENERGY INC.

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

Line No.	Particulars	12/31/14	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/15	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2019 PBR Requirements	$ 1,063	$ -	$ 188	$ (49)	$ (213)	$ -	$ -	$ 990	$ 1,027	
3	2014 Long Term Resource Plan Application	86	-	67	(17)	(86)	-	-	50	68	
4	AES Inquiry Cost	386	-	-	-	(132)	-	-	254	320	
5	Generic Cost of Capital Application	836	-	-	-	(825)	-	-	11	423	
6	2016 Cost of Capital Application	-	9	300	(78)	-	-	-	231	120	
7	Amalgamation and Rate Design Application Costs	1,003	-	6	(2)	(486)	-	-	522	762	
8	2015-2019 Annual Review Costs	-	-	300	(78)	-	-	-	222	111	
9	2017 Rate Design Application	-	-	150	(39)	-	-	-	111	56	
10	2017 Long Term Resource Plan Application	-	-	-	-	-	-	-	-	-	
11	LMIPSU Application Costs	-	-	-	-	-	-	-	-	-	
12	Huntingdon CPCN Application Costs	-	29	-	-	(29)	-	-	-	15	
13	2015 System Extension Application	-	-	325	(85)	-	-	-	241	120	
14	BERC Rate Methodology Application	-	-	75	(20)	-	-	-	56	28	
15		$ 3,374	$ 38	$ 1,412	$ (367)	$ (1,770)	$ -	$ -	$ 2,687	$ 3,050	
16	Other Deferral Accounts										
17	Whistler Pipeline Conversion	$ 10,897	$ -	$ -	$ -	$ (745)	$ -	$ -	$ 10,151	$ 10,524	
18	2010-2011 Customer Service O&M and COS	17,811	-	-	-	(3,251)	-	-	14,560	16,185	
19	Gas Asset Records Project	624	-	1,272	(331)	(327)	-	-	1,237	930	
20	BC OneCall Project	799	-	450	(117)	(291)	-	-	840	820	
21	Gains and Losses on Asset Disposition	36,388	-	-	-	(3,986)	-	-	32,402	34,395	
22	Negative Salvage Provision/Cost	(31,518)	-	14,168	-	(21,240)	-	-	(38,589)	(35,053)	
23	TESDA Overhead Allocation Variance	174	-	400	(104)	(174)	-	-	296	235	
24	PCEC Start Up Costs	920	-	-	-	-	-	-	920	920	
25	Huntingdon CPCN Pre-Feasibility Costs	-	-	-	-	-	-	-	-	-	
26	LMIPSU Development Costs	-	-	-	-	-	-	-	-	-	
27		$ 36,094	$ -	$ 16,290	$ (552)	$ (30,015)	$ -	$ -	$ 21,818	$ 28,956	
28	Residual Deferred Accounts										
29	Depreciation Variance	$ (11)	$ -	$ -	$ -	$ 11	$ -	$ -	$ -	$ (5)	
30	BFI Costs and Recoveries	(165)	$ -	(38)	10	-	-	-	(193)	(179)	
31	Fuelling Stations Variance Account	106	-	-	-	(53)	-	-	53	79	
32	US GAAP Transitional Costs	(141)	-	-	-	70	-	-	(70)	(106)	
33	Residual Delivery Rate Riders	23	-	-	-	(23)	-	-	-	12	
34	Property Tax Deferral	(2,904)	-	-	-	1,448	-	-	(1,456)	(2,180)	
35	Interest Variance	(1,066)	-	-	-	728	-	-	(338)	(702)	
36	Interest Variance - Funding benefits via Customer Deposi	342	-	-	-	(302)	-	-	40	191	
37	Tax Variance Account	19	-	-	-	(19)	-	-	-	10	
38	NGV for Transportation Application	2	-	-	-	(2)	-	-	-	1	
39	Rate Schedule 16 Application Costs	21	-	-	-	(21)	-	-	-	11	
40	Gas Cost Variance Account (GCVA)	3,269	(3,269)	-	-	-	-	-	-	-	
41	FEW 2014 Revenue Surplus/Deficiency	18	-	-	-	(18)	-	-	-	9	
42	Capital Contribution to FEVI	13,002	(13,002)	-	-	-	-	-	-	-	
43	FEI 2014 Rates Deficiency	1,318	(1,318)	-	-	-	-	-	-	-	
44		$ 13,833	$ (17,589)	$ (38)	$ 10	$ 1,819	$ -	$ -	$ (1,965)	$ (2,860)	
45											
46	**Total**	$ 48,444	$ (17,366)	$ 45,693	$ (7,794)	$ (39,522)	$ 13,804	$ (3,589)	$ 39,671	$ 35,375	

FORTISBC ENERGY INC.

Section 11

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

Schedule 12 (2015)

Line No.	Particulars	12/31/14	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/15	Mid-Year Average	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Non-Rate Base										
2	Biomethane Variance Account	$ 1,364	$ -	$ -	$ -	$ (267)	$ -	$ -	$ 1,096	$ 1,230	
3	EEC Incentives for AES / TES	185	(185)	-	-	-	-	-	-	-	
4	KORP Feasibility Costs	109	-	500	(130)	-	-	-	479	294	
5	EEC-Incentives	9,083	-	550	-	-	-	-	9,633	9,358	
6	US GAAP Uncertain Tax Positions	466	-	-	-	-	-	-	466	466	
7	Mark to Market - Hedging Transactions	11,165	-	-	-	-	-	-	11,165	11,165	
8	Huntingdon CPCN Application Costs	29	(29)	-	-	-	-	-	-	-	
9	Huntingdon CPCN Pre-Feasibility Costs	339	-	21	-	-	-	-	360	349	
10	Amalgamation Regulatory Account	853	-	756	(194)	-	(613)	159	961	907	
11	2014-2019 Earning Sharing Account	(2,706)	-	(5,088)	1,236	-	3,341	(869)	(4,086)	(3,396)	
12	Flow-Through Account	(3,073)	-	(806)	-	3,166	-	-	(713)	(1,893)	
13	Phase-In-Rider Balancing Account	-	-	-	-	-	1,434	(373)	1,061	531	
14	2016 Cost of Capital Application	9	(9)	-	-	-	-	-	-	-	
15	LMIPSU Application Costs	130	-	1,212	(295)	-	-	-	1,047	589	
16	LMIPSU Development Costs	1,793	-	747	(158)	-	-	-	2,382	2,088	
17	PEC Pipeline Development Costs and Commitment Fees	7,994	-	484	-	-	-	-	8,479	8,237	
18	Rate Stabilization Deferral Account (RSDA)	(78,015)	4,587	(1,117)	290	-	38,902	(10,115)	(45,467)	(59,447)	
19	FEW Rider B Refund Deferral	7	-	1	(0)	-	-	-	8	8	
20	**Total Non Rate Base Deferral Accounts**	$ (50,267)	$ 4,364	$ (2,740)	$ 749	$ 2,899	$ 43,064	$ (11,197)	$ (13,128)	$ (29,516)	