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October 9, 2015

Via Email
Original via Mail

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
1958 Parkside Lane
North Vancouver, B.C. V7G 1X5

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Energy Inc. (FEI)

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

Response to the B.C. Sustainable Energy Association and Sierra Club of British Columbia (BCSEA) 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 BCSEA 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: Commission Secretary
Registered Parties (e-mail only)

1.0 Topic: Transmission Reportable Incidents

Reference: Exhibit B-1, section 13.2.3; FEI 2015 Rates and Annual Report, Exhibit B-4, Response to BCSEA-SCBC IR 1.1, 1.1.1

1.1 The Transmission Reportable Incident metric is intended to be an indicator of the integrity of the transmission system. Does FEI confirm that one of the purposes of the integrity of the transmission system is to prevent methane emissions?

Response:

Yes.

1.2 Does FEI confirm that the Transmission Reportable Incident metric serves as an indicator of the ability of the transmission system to prevent methane emissions; noting that not all incidents result in a release of methane emissions?

Response:

The Transmission Reportable Incident metric is an indicator of the integrity of the transmission system, and can also serve as an indicator of the ability of the transmission system to prevent methane emissions, although not all incidents result in a release of methane.

2.0 Topic: Transmission Reportable Incidents

Reference: Exhibit B-1, section 13.2.3; FEI 2015 Rates and Annual Report, Exhibit B-4, Response to BCSEA-SCBC IR 2.2

"The first Level 1 incident occurred in May 2015 at a residence in Surrey when a third party's excavator pulled and damaged a high pressure gas service impacting 20 customers. An FEI crew subsequently reinstated the service.

The second Level 1 incident occurred in June 2015 at the compressor station in Warfield when an equipment failure (faulty diaphragm in pilot regulator) resulted in a leak at the valve station. The regulator was replaced." [p.134]

The following excerpt from FEI's responses to BCSEA-SCBC's information requests in the 2015 Rates and Annual Review proceeding is provided as an example of the desired format of the response.

2.2 Please provide the estimated GHG Emissions (indicating the GWP) associated with the two Transmission Reportable Incidents reported for 2014.

Response

The table below provides the available GHG emission estimates associated with the two incidents reported to the OGC for 2014.

Incident	Volume of Gas (Standard Cubic Metre)	GHG Emission (tCO_2e)[2]
Charles Park	Not Calculated[1]	Not Available[1]
Lumby	104,000	1664

[1] *Due to the nature of the leak (i.e., slow release), the volume of gas release was not determined as part of the OGC Incident report. The GHG emission from this source will be included in aggregate using company activity data and industry emission factor, in accordance with WCI350 methodology as referenced in BC Ministry of Environment GHG reporting regulation.*

[2] *A global warming potential of 25 was used for methane.*

2.1 Please provide the estimated GHG Emissions (indicating the GWP) associated with the two Transmission Reportable Incidents reported for 2015.

Response:

The table below provides the available GHG emission estimates associated with the two reportable incidents in 2015:

Incident	Volume of Gas (Standard Cubic Metre)	GHG Emission (tCO_2e)
Surrey - IP Service Line Hit, May 9, 2015	1,200	Not Available[1]
Warfield Compressor Station, June 5, 2015	1,700	Not Available[1]

[1] *As part of FEI's GHG reporting requirements, the gas composition analysis provided by upstream gas suppliers is averaged over the duration of the entire reporting period in order to determine fugitive gas loss. As a result, final GHG emission values are not available at this time.*

3.0 Topic: Transmission Reportable Incidents

Reference: Exhibit B-1, section 13.2.3, Table 13-14, Table 13-15

"The Transmission Reportable Incidents metric, an informational indicator as approved by the Commission, measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

The June 2015 year-to-date result is two reported incidents."

Table 13-14: Transmission Incidents by Severity Level

OGC Severity Level	Reportable Incidents to June 30 2015
Level 1 (moderate)	2
Level 2 (major)	0
Level 3 (serious)	0

Table 13-15: Historical Transmission Reportable Incidents

2009	2010	2011	2012	2013	2014
n/a	n/a	n/a	n/a	n/a	2

3.1 Please complete and provide a table with columns for 2009 to 2014 and 2015 to June 30, and rows for OGC Severity Level. It is understood that the values for 2009 to 2013 will be "n/a". The table will enable a comparison of 2015 results to 2014 results broken down by OGC Severity Level.

Response:

The requested table is provided below. Because the effective date of the OGC change in reporting requirements was October 1, 2014, the data is presented in a quarterly format for 2014 and 2015 for comparative purposes.

Table 1: Transmission Incidents by Severity Level

OCG Severity Level	2009	2010	2011	2012	2013	2014				2015			
						Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Level 1 (moderate)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2	0	2		
Level 2 (major)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0	0		
Level 3 (serious)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0	0	0		

3.2 Does FEI agree that the type of table in the previous information request is a useful way to present the key figures regarding the Transmission Reportable Incidents performance measure in a single table? If so, would FEI use this method in future PBR annual reviews? If not, why not?

Response:

FEI agrees that a single table as provided in the response to BCSEA IR 1.3.1 is a useful way to present the key figures regarding the Transmission Reportable Incidents performance measure. FEI will use this method in future PBR annual reviews.

4.0 Topic: Leaks per KM of Distribution System Mains

Reference: Exhibit B-1, section 13.2.3; FEI 2015 Rates and Annual Report, Exhibit B-4, Response to BCSEA-SCBC IR 4.1

4.1 Does FEI confirm that the Leaks per KM of Distribution System Mains metric is an indicator of the ability of the distribution system to prevent fugitive methane emissions?

Response:

Confirmed.

5.0 Topic: Leaks per KM of Distribution System Mains

Reference: Exhibit B-1, section 13.2.3, p.135

For the Leaks per KM of Distribution System Mains metric, "the June 2015 year-to-date result is 0.0026 which is based on 58 leaks detected year-to-date as compared to 74 in 2014 and 72 in 2013 for the same time period."

5.1 Is the June 2015 year-to-date result of 0.0026 based on a full-year, or one-half year, of KM of distribution system mains surveyed (or to be surveyed)?

Response:

The June 2015 year-to-date result of 0.0026 is based on the total km of distribution system mains, not the distribution system mains surveyed.

5.2 In Table 13-16, for July – December 2010 (6 months) the metric is 0.0042. Is this is based on a full-year, or one-half year, of KM of distribution system mains surveyed (or to be surveyed)?

Response:

The July - December 2010 result of 0.0042 is based on the number of leaks in the last six months of the year, divided by the total km of distribution system mains, not the distribution system mains surveyed.

6.0 Topic: Leaks per KM of Distribution System Mains

Reference: Exhibit B-1, section 13.2.3

Table 13-17: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2009	2010	2011	2012	2013	2014
Leaks	122	140	166	169	143	114
Total km	18,760	18,895	18,974	19,040	19,098	19,172
Leaks per km	0.0065	0.0074	0.0087	0.0089	0.0075	0.0059
5 year average	0.0062	0.0064	0.0067	0.0075	0.0078	0.0077

Table 13-16, indicates a June 2015 Year-to-Date Five Year Rolling Average of 0.0076.

6.1 Does FEI consider that the 2009 to 2015 YTD series of five-year rolling averages for Leaks per KM of Distribution System Mains shows a trend? If so, what is the explanation? If not, why not?

Response:

The five year average trend in Table 13-17 is roughly flat for 2009-2011 with an increase in 2012 and then flattening afterward. The increase in the five year average in 2012, 2013 and 2014 is attributable to the annual results from 2011 and 2012 which were higher owing to the areas being surveyed in those years. Fluctuations in the annual results of leaks per km of distribution main metric are expected owing to different geographical areas with different pipe and soil attributes being surveyed every year on primarily a five year cycle.

7.0 Topic: Annual GHG Emissions

Reference: Exhibit B-1, section 13.3; FEU 2014 LTRP Proceeding, Exhibit B-4, BCSEA 1.18.4

"On March 31, 2015 FEI reported to the BC Ministry of Environment its 2014 GHG emissions of 140,507 tCO2e. The 2013 reported value was 127,940 tCO2e." [p.136]

In the 2014 LTRP proceeding, the FEU provided the following table showing historical estimated GHG emissions related to operational activities:

	Estimated GHG Emission (tCO2e)
2009	171,312
2010	156,467
2011	137,059
2012	134,303

Note: GWP values for CH_4 and N_2O of 21 and 310, respectively.

7.1 Please confirm, or otherwise explain, that the 2014 and 2013 annual GHG emissions figures in tCO2e that FEI reported to the BC Ministry of Environment are comparable to the 2009 to 2012 figures shown in the table in FEU 2014 LTRP Proceeding, Exhibit B-4, BCSEA 1.18.4.

Response:

The 2014 and 2013 annual GHG emissions figures in tCO2e that FEI reported to the BC Ministry of Environment are not comparable to the 2009 to 2012 figures shown in the table in the FEU 2014 LTRP Proceeding, Exhibit B-4, Response to BCSEA IR 1.18.4.

The most significant difference between GHG values reported to the BC Ministry of Environment in 2013 and 2014 versus previous years' reporting is the change in global warming potential (GWP) as required by the reporting regulation. GWP for methane was revised from 21 to 25 while GWP for N_2O was revised from 310 to 298. In addition, updated emission factors were developed in 2013 and 2014 resulting in decreases in GHG estimates. Due to these changes, annual GHG emission values for 2013 and 2014 are not comparable to values reported from 2009 through 2012.

FEI estimates that it would require extensive work and approximately 2 months to restate the 2009 to 2012 figures to be comparable to the 2013 and 2014 figures.

8.0 Topic: Service Quality Indicators, Presentation of Data

Reference: Exhibit B-1, section 13

Table 13-1, Approved SQI, Benchmarks and Actual Performance, shows the Benchmark, Threshold and June 2015 YTD Results for each Performance Measure. It does not show historical results for each Performance Measure. In the subsequent sections discussing each of the Performance Measures there is a table showing Historical Results from 2009 to 2014 (for example, Table 13-2, Historical Emergency Response Time). These tables do not show June 2015 YTD Results, nor do they show the Benchmark and Threshold figures.

Comment: In order to compare the June 2015 YTD results for a particular Performance Measure with the Historical results and the Benchmark and Threshold figures one has to flip back and forth between the Historical table and Table 13-1.

8.1 As an example, please provide a table for the Emergency Response Time performance measure that has columns for the years 2009 to 2014 and June 2015 YTD and rows showing Results, Benchmark and Threshold. (It is recognized that values for Benchmark and Threshold may not be applicable for years prior to the PBR period.)

Response:

Provided below is the requested information for the Emergency Response Time performance measure.

Description	2009	2010	2011	2012	2013	2014	June 2015 YTD
Results	97.7%	97.7%	97.9%	97.4%	97.4%	96.7%	97.5%
Benchmark	n/a	n/a	n/a	n/a	n/a	97.7%	97.7%
Threshold	n/a	n/a	n/a	n/a	n/a	96.2%	96.2%

8.2 Does FEI agree that the type of table in the previous information request would be a useful way to present the key figures regarding each Performance Measure in a single table? If so, would FEI use this method in future PBR annual reviews? If not, why not?

Response:

FEI agrees that providing the requested information in the format suggested allows for a more convenient way to compare the historical performance of the indicator.

FEI will provide the SQI performance data in such a format in future PBR annual reviews.

9.0 Topic: Savings Initiatives

Reference: Exhibit B-1, section 1.4.3, Major Initiatives Undertaken; Appendix 3C, Table D-3, Review of Technical and Infrastructure Support Provider

"3. ***Review of Technical and Infrastructure Support Provider*** is an initiative to review the existing agreement with the Company's technical and infrastructure service provider responsible for providing Information Systems (IS) Customer and Infrastructure Services to FEI. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. In 2015, FEI replaced its existing technical and infrastructure support provider through an RFP process with a new service provider, Compugen. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. 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. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements. The 2015 O&M savings projected for the Information Systems department compared to 2013 actuals are approximately $1.8 million." [p.6, underline added]

Preamble: At the time of writing, a Commission decision is awaited in "FortisBC Energy Utilities Application for Removal of the Restriction on the Location of Data and Servers Providing Service to the FEU, currently Restricted to Canada, Project No.3698799."

9.1 To what extent, if any, are the 2015 O&M savings projected for the Information Systems department dependent on the outcome of FEI's application for removal of the Data Restriction?

Response:

None of the 2015 O&M savings projected for the Information Systems department are dependent on the outcome of FEI's application for Removal of the Data Restriction.

9.2 In the sentence "The 2015 O&M savings projected for the Information Systems department compared to 2013 actuals are approximately $1.8 million" [underline added], should "2013" read "2014"? Alternatively, please explain why the comparison was made with 2013 instead of 2014.

Response:

For consistency with how sections 1.4.1 Overview of O&M Savings and 1.4.2 Staffing Levels in the Application are presented, FEI provided the comparison to 2013 instead of 2014. In the two sections, FEI provided an overall projection for 2015 O&M savings along with an explanation of how changes in staffing (i.e. labour) levels from 2013 to 2015 have contributed to the O&M savings projected. For consistency and clarity, the explanation for the O&M savings related to the new technical and infrastructure service support provider is based on a similar reference point (i.e. 2013).

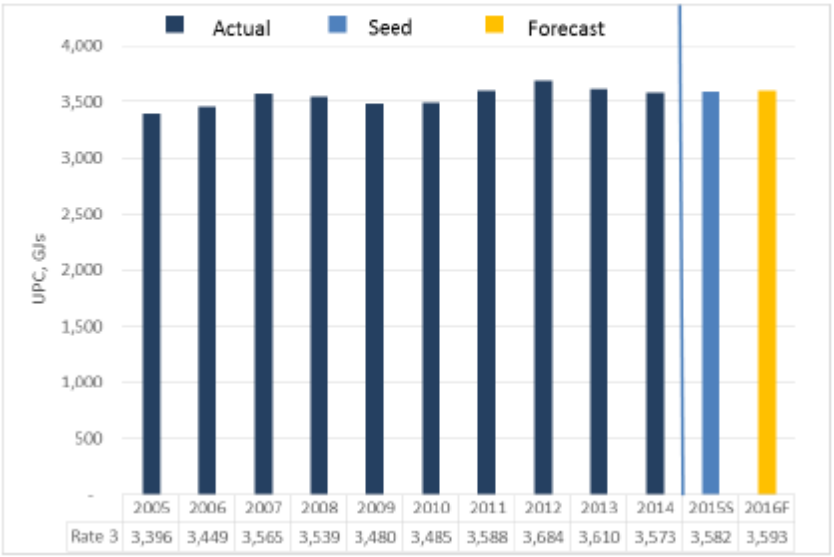
In this particular situation with the new service provider, the description and explanation would not have changed if the comparison were instead made to 2014 as the changeover did not occur until the beginning of 2015, and O&M costs in both 2013 and 2014 included the costs of the previous outsource provider.

10.0 Topic: Large Commercial Use Per Customer

Reference: Exhibit B-1

As shown in Figure 3-3, the upward trend in Large Commercial (Rate Schedule 3) UPC has been consistent and this trend is forecast to continue. The Rate Schedule 3 UPC is forecast to increase by 11 GJ (0.3 percent) in 2016.

Figure 3-3: Rate Schedule 3 UPC Trend Consistent with Prior Years



10.1 Please explain why FEI characterizes Large Commercial (Rate Schedule 3) UPC as an "upward trend."

Response:

The Rate Schedule 3 UPC in 2005 was 3,396 GJs and generally increased through 2016F where the UPC forecast is 3,593 GJs. From Figure 3-3 it is clear that the UPC has declined in some years, but overall the UPC is forecast to be almost 200 GJs higher in 2016 compared to 2005. Generally speaking the UPC since 2005 has been increasing and is therefore described as exhibiting an "upward trend".

11.0 Topic: Unaccounted For Gas

Reference: Exhibit B-1, section 4, Cost of Gas, p.34

"UAF [unaccounted for gas] refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (gas lost as a result of utility and third party activities, including gas theft), and measurement inaccuracies. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered from core customers16 via the gas cost0 rates, whereas the cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates to facilitate recovery of UAF costs from Transportation Service customers, as they do not pay midstream charges."

11.1 Please provide an estimate of the amount of unaccounted for gas, in volume, as a percentage of throughput, and in financial terms, for 2015 YTD and for five preceding years. Please provide a breakdown by system leakage, lost gas, measurement inaccuracies and other.

Response:

UAF is calculated as the difference between the measured quantity of gas receipts and the quantity of gas deliveries, including FEI company use gas. The various components comprising UAF are discussed below but the amount of UAF attributable to each component cannot be quantified. The actual, annual UAF amounts for the years 2010-2014 and the preliminary 2015 YTD (January to August) UAF amounts are provided in Table 1.

Table 1: Total UAF for Amalgamated FEI (Mainland, Vancouver Island, and Whistler)

		2010	2011	2012	2013	2014	Jan - Aug 2015
Total Receipts [1]	(TJ)	194,525	205,673	202,242	200,737	196,933	114,455
Total UAF	(TJ)	587	1,574	828	1,441	1,925	427
UAF (as % of receipts)	(%)	0.30%	0.77%	0.41%	0.72%	0.98%	0.37%
UAF Valuation [2]	($000)	$ 2,533	$ 5,328	$ 2,075	$ 4,431	$ 8,245	$ 1,153

Notes:

(1) Total metered natural gas receipts from pipelines for the amalgamated FEI, including Mainland, Vancouver Island, and Whistler service areas.

(2) For the purpose of this IR response, the annual quantities of UAF have been valued at the respective annual average cost of commodity purchases within the midstream portfolio.

A description of unaccounted for natural gas in a utility system described by the American Gas Association (AGA) can be found in Attachment 11.1(a). Different jurisdictions refer to UAF using different terms and describe the various components of UAF in different ways.

The various components, consistent with how FEI has broken down UAF the past number of years, and the programs in place which can influence the amount of UAF, are described below.

System Leakage

The natural gas system is not 100% hermetically sealed and some leakage occurs. The system leakage is associated with both transmission and distribution systems.

While system leakage cannot be directly controlled or quantified by FEI, FEI has a leak survey program in place whereby it conducts regular leak surveys; leak survey programs help to reduce the amount of system leakage by allowing leaks to be detected at an early stage and the necessary repairs to be completed.

Lost Gas

Lost Gas is a result of utility and third party activities, including gas theft. This lost gas is associated with both transmission and distribution systems and includes gas lost as a result of hits to the gas system, as well as gas lost through system venting (such as intentional operational activities or unintentional relief valve releases). To date, some lost gas related to known incidents of gas theft has occurred on the distribution system.

While lost gas cannot be directly controlled or quantified by FEI, FEI's active participation in the BC One Call program and "Call Before You Dig" communications help to reduce the third party system damage. Also, since mid-2012, FEI has had a Revenue Protection Program focused on detecting and deterring gas theft.

Measurement Inaccuracies

Measurement inaccuracies relate to volumetric variances attributable to differences in the measurement data obtained from transmission system take-off points (typically custody transfer meters located at third party pipeline custody transfer points) and the measurement data obtained from end point meters at customer locations, exclusive of any other sources of UAF, such as those mentioned above. The type of measurement used at the transmission system take-off point (e.g. turbine, orifice, or ultrasonic meters) can differ depending upon the pipeline operator and it is believed that measurement error is a significant component of UAF. Measurement inaccuracies occur across the transmission and distribution systems.

While measurement inaccuracies are considered to be the most significant contributor to UAF, measurement inaccuracies cannot be fully controlled or quantified by FEI.

Further, measurement inaccuracies can be broken into two sub-components. First, accurate measurement of gas is a function of the accuracy of the volume registered by the meter and the accuracy of the auxiliary devices and factors that are used to adjust the measured volume in order to correct the volume for the effect of temperature, pressure and the heating value (energy

content) of the gas. FEI calibrates and maintains its meters and auxiliary devices to industry standards where the accuracies are within Measurement Canada's mandated tolerances. Measurement Canada's accuracy tolerance for a gas meter is +/- 1%. The total error allowable by Measurement Canada for devices utilized in the measurement of natural gas, which includes the inaccuracy of the volumes registered by the meter and the inaccuracy of the auxiliary devices that are used to correct the volume for the effect of pressure and temperature and the energy value of the gas, is +/- 3% of the total energy sold. Errors that are within the allowable tolerance can account for differences in the volume of gas measured coming into the distribution system and the measured gas going out of the same system. It is inevitable that measurement imbalance will exist in a system since meters are not capable of registering zero absolute error in actual operating conditions.

Second, billing estimation, prior period adjustments and variations between mass market meter reading billing cycles and calendar month financial reporting (accruals) also account for the variability of reported UAF from year to year. These variations make it difficult to accurately monitor UAF levels on a year to year basis.

An American Gas Association study (AGA UAF Study – Lost and Unaccounted For Gas) from 2013, which provided a range of UAF percentages (5.95% to -7.5%) experienced by natural gas distribution utilities and also showed an average UAF of 0.9%. FEI's total UAF is well within the range. The AGA UAF study for 2014 had an average range by year from 2010 to 2012 of 0.87% to 1.29%.

In comparison, Table 1 – Total UAF for Amalgamated FEI (Mainland, Vancouver Island, and Whistler) above, shows that the Company's annual UAF fell within a range of 0.30% to 0.98% for the 2010-2015 YTD period which is, on average, lower than the 0.9% average of the comparable 2013 AGA UAF Study and has a lower range than the 2014 AGA UAF Study provided in Appendix 2. FEI's UAF compares favorably to the AGA UAF results shown in the reports provided in Attachment 11.1(b); FEI believes its UAF is not outside acceptable thresholds and that the data shows no obvious trends that would warrant further mitigation strategies.

11.2 Does FEI observe a trend in the amount of unaccounted for gas or in any of the types of unaccounted for gas?

Response:

Please refer to the response to BCSEA IR 1.11.1.

11.3 Please provide an estimate of how much, or what percentage, of unaccounted for gas is vented as opposed to combusted.

Response:

Please refer to the response to BCSEA IR 1.11.1.

11.4 Does FEI consider the amount of unaccounted for gas, in total or by type, to be satisfactory, or a problem?

Response:

Please refer to the response to BCSEA IR 1.11.1.

11.5 Presumably FEI takes many types of measures to reduce the amount of each of the types of unaccounted for gas. Are there any specific or notable measures FEI is taking in 2015 to reduce the amount of unaccounted for gas?

Response:

Please refer to the response to BCSEA IR 1.11.1.

11.6 Please further explain “lost gas (gas lost as a result of utility and third party activities, including gas theft).”

Response:

Lost gas includes gas lost as a result of third party activities (e.g. hit lines), as well as due to utility activities which can include venting, purging, and sampling of gas. Gas losses may also result from the theft of gas whereby the gas consumed by the end-user is unmetered (either due to a tampered meter index or diversion of the gas around the meter) and is therefore unaccounted for.

As discussed in the response to BCSEA IR 1.11.1, the portion of UAF attributable to lost gas cannot be quantified.

11.6.1 How common is gas theft?

Response:

It is difficult to determine the extent of gas theft within FEI's service territory as gas theft is typically covert in nature and not readily detectable by the utility, particularly since the majority of FEI assets are underground. Beginning in mid-2012, FEI instituted a Revenue Protection Program focused on detecting and deterring gas theft. The table provided below details the number of gas thefts discovered by year since the inception of the program.

	2012 (August – December)	2013	2014	2015 (to August)
Gas Thefts Sites	5	15	21	15
Estimated Annual GJ Impact	22,240	8,410	6,752	6,214

11.6.2 To what extent is gas theft associated with marijuana grow operations?

Response:

Approximately 25 percent of the gas thefts discovered by FEI since the inception of FEI's Revenue Protection Program have been either confirmed as, or are suspected of being associated with, marijuana grow operations.

11.6.3 Does FEI foresee an increase in gas theft due to electricity theft reduction measures being undertaken by BC Hydro and FortisBC Inc.?

Response:

It is difficult for FEI to foresee whether there will be a possible increase in gas theft due to the electricity theft reduction measures being undertaken by BC Hydro and FBC, particularly considering the evolving and uncertain nature of the current regulatory framework for the production and distribution of medical marijuana.

12.0 Topic: New Deferral Accounts

Reference: Exhibit B-1, section 7.5.1; Appendix C2 Long-Term Resource Plan Deferral Account

"FEI is proposing to create three new deferral accounts to address the costs of applications related to the 2015 System Extension review, the BERC Rate Methodology and the Long Term Resource Plan (LTRP)." [p.56]

"In light of the Commission's statement concerning restricting eligible deferral costs to *external resources*, and given the history of regulatory process around the incremental LTRP activities and costs, FEI is proposing to limit deferral account spending for the next LTRP to external resources utilized for completing incremental LTRP activities. Ongoing regular activities, as well as any incremental LTRP requirements that have not been identified in this appendix as requiring incremental funding, will be completed within the existing Base O&M." [Appendix C2, p.1]

"Table 1 [of Appendix C2] provides a summary of those tasks and activities that are incremental activities and for which FEI is requesting that costs be captured in the proposed deferral account."

"*Breakdowns of internal versus external resource budgets*: All of the incremental activities for which FEI is requesting deferral account treatment for the costs are expected to be completed by external resources. FEI expects that it will be able to manage the hiring and contracting of this work, as well as the integration of this work into the LTRP, within the current Base O&M such that the cost estimates provided are entirely for external resources." [Appendix C2, p.11]

"As discussed above, none of the incremental activities identified in Table 1 were included, or required to be included, within the 2010 or earlier LTRPs. The costs to complete the incremental activities required by the 2010 LTRP Decision were explicitly excluded from FEI's Base O&M, while the more recent incremental activities directed by the Commission in the 2014 LTRP Decision were determined after FEI's Base O&M was set..." [Appendix C2, p.11]

"FEI does not anticipate hiring additional permanent employees in 2016 or 2017 to perform LTRP-related work." [Appendix C2, p.26]

12.1 Does FEI's use of external rather than internal resources to complete the LTRP reduce the quality of the LTRP?

Response:

No, the quality of the LTRP will not be reduced by the use of external resources.

12.2 Are external and internal resources for completing the LTRP equivalent in terms of cost-effectiveness?

Response:

FEI has not conducted a full analysis comparing the two options, but believes using external resources is cost effective for the incremental LTRP activities given that they are one-time or intermittent activities and FEI does not have all of the necessary expertise within its internal staff. FEI will reevaluate the mix of external and internal staff following the completion of the 2017 LTRP and after considering any further direction from the Commission with respect to the content and frequency of future LTRPs.

12.3 The "2016 Potential Cost Estimate" range and "External Consulting Hours" do not appear to be based on consistent 'dollars per hour' figure, both regarding the two figures in the cost estimate range and regarding the different line items. Please explain how the 2016 Potential Cost Estimate figures were derived.

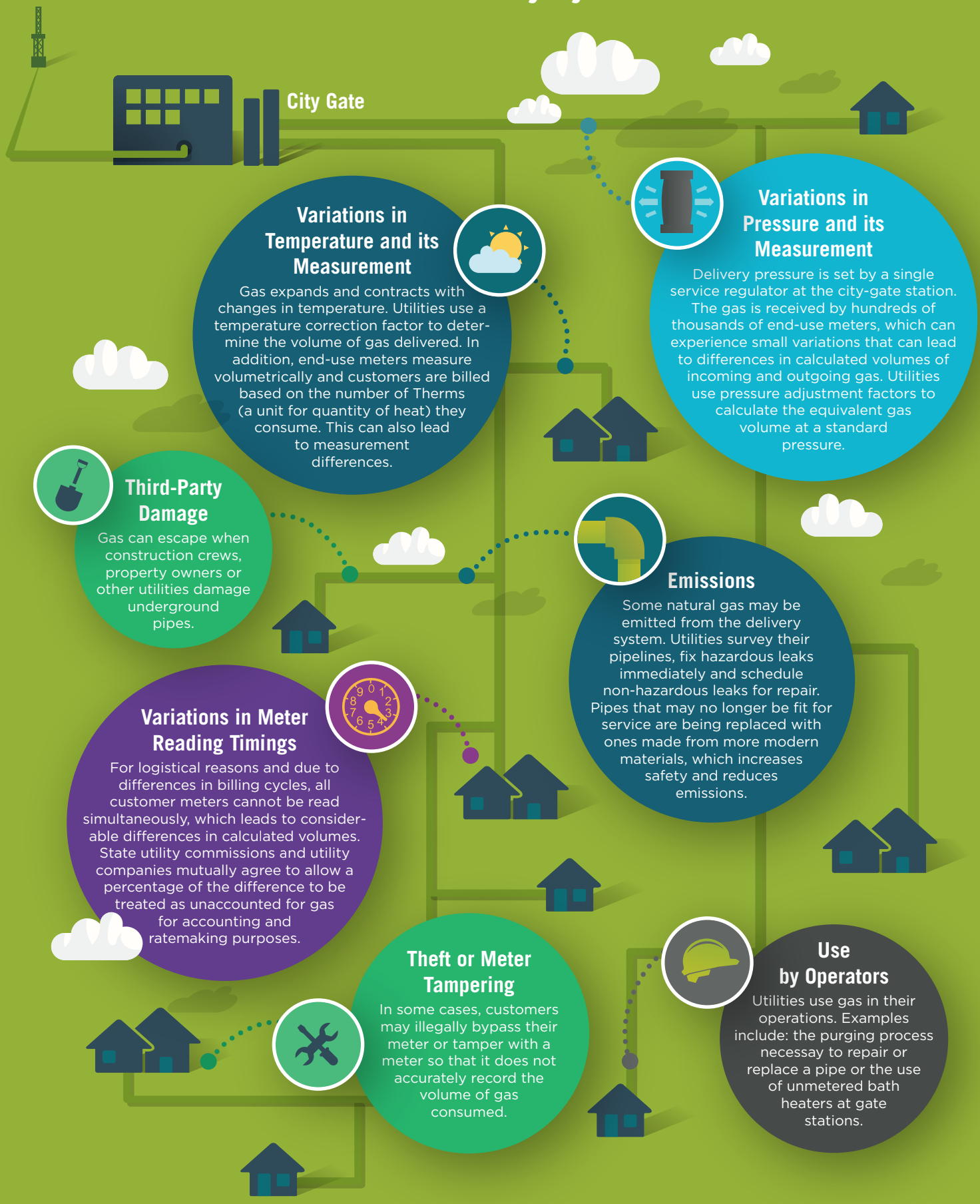
Response:

No single consultant can undertake all of the incremental tasks identified in Appendix C2. FEI has also not yet identified a specific consultant for each of the individual tasks discussed. As such, there will be a range of potential charge out rates (dollars per hour) possible for each task; hence, a range of consultant hours is provided. FEI developed the costs presented in Appendix C2 by examining other actual consultant costs or proposed costs for undertaking these activities or similar types of activities. In those cases where charge out rates were available to examine, FEI considered the reasonableness of those charge out rates and the estimated project scope provided in Appendix C2 to develop an approximate range of consulting hours that would be applied to each task.

Attachment 11.1

Unaccounted for Natural Gas

in the Utility System



At a city gate, natural gas is transferred from an interstate or intrastate pipeline to a local natural gas utility. At that moment, some utilities measure the volume of gas using highly sophisticated technology that is able to quickly and precisely take into account a variety of factors, including temperature and pressure. The utility reports the volume of gas sold to customers as represented on their bills. The difference between the city-gate measurement and the volume of gas sold is treated as unaccounted for gas by regulators who build a form of reimbursement for this gas into the utility's rate structure.

Unaccounted for gas is the inevitable imbalance that exists at any given time between the measured gas coming into a utility distribution system and the measured gas going out of the same system.

For natural gas utilities and regulators, unaccounted for gas (sometimes called LUAF) is an accounting and ratemaking issue — not an operational issue. The cost of unaccounted for gas is recovered through accounting and ratemaking measures, and these measures differ from state to state. Under traditional ratemaking, natural gas distribution companies do not make a profit on the sale of the natural gas commodity that they acquire on behalf of their customers. Instead, utilities pass through the costs of natural gas supply, including those of unaccounted for gas, in base rates and/or through rate adjustments, which are set and approved by state utility commissions.

The U.S. Environmental Protection Agency also rejects the idea that unaccounted for gas could provide an indication of or could be used to formulate policy on fugitive methane emissions. In response to comments on its Mandatory GHG Reporting Rule it said, "EPA disagrees on the use of LUAF as a surrogate for greenhouse gas emissions data collection … there are other multiple factors associated with LUAF, such as inaccuracies of gas measurement, and thus would not provide the desired level of data accuracy and quality to achieve the objectives of [the reporting] rule. Most importantly, because LUAF would not identify the exact sources of the emissions, there would be further inadequacies for informing future policy. Finally, no current studies exist that accurately define the percentage of LUAF that is emissions from a system."

Representing America's Natural Gas Utilities

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Issue:

REVISION Lost And Unaccounted For Gas REVISION

- The percentage of natural gas lost and unaccounted for (LUAF) has decreased since 2009.
- The 2011measure of LUAF gas was only one-fourth of the 2009 value.
- Unaccounted for gas typically varied from the median values more than lost gas.

Gas Utility Lost And Unaccounted For Gas 2009 – 2011 – Weighted Average

	2009	2010	2011
Lost 1/	0.22%	0.49%	0.39%
Unaccounted For 2/	1.31%	0.68%	0.51%
Lost & Unaccounted for Gas	1.53%	1.18%	0.90%

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Gas Utility Lost And Unaccounted For Gas 2011 – Non Weighted

	Unaccounted For	Lost	Lost & Unaccounted For
Maximum	5.63%	3.59%	5.95%
3rd Quartile	1.04%	0.45%	1.64%
Median	0.00%	0.36%	0.42%
1st Quarter	-0.00%	0.13%	0.42%
Minimum	-7.89%	0.00%	-7.50%

Methodology

- Based on data from 161 companies.
- 1/ Losses from Leaks, Accidents, & Other Damage – Losses from leaks, migration, accidents, etc. Volume of loss may represent reporting entity's best estimate.
- 2/ Unaccounted for Gas Supply – Gas supply or disposition not accounted for. Positive number indicates unaccounted for supply. Negative number indicates unaccounted for disposition.
- Lost and unaccounted for non-weighted represents the combination of the two items on a company-by-company basis..

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Issue:
Lost and Unaccounted For Gas

173 Gas Utility Lost And Unaccounted For Gas 2010 – 2012 Volume (Mcf)

	2010	2011	2012
Lost Volume 1/	70,109,076	65,338,646	63,204,066
Total Disposition Volume	14,890,925,711	15,035,967,220	14,907,845,275
Unaccounted For 2/	97,968,233	65,438,609	67,419,607
Lost and Unaccounted For	168,077,309	130,777,255	130,623,673

173 Gas Utility Lost And Unaccounted For Gas 2010 – 2012 Percent of Total Volumes

	2010	2011	2012
Lost	0.471%	0.435%	0.424%
Unaccounted For	0.658%	0.435%	0.452%
Lost and Unaccounted For	1.129%	0.870%	0.876%

Source: Energy Information Administration, 176 Annual Report of Natural and Supplemental Gas Supplyand Disposition

Methodology

- Based on data from 173 companies.
- 1/ Losses from Leaks, Accidents, & Other Damage – Losses from leaks, migration, accidents, etc. Volume of loss may represent reporting entity's best estimate.
- 2/ Unaccounted for Gas Supply – Gas supply or disposition not accounted for. Positive number indicates unaccounted for supply. Negative number indicates unaccounted for disposition.

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