Diane Roy
Vice President, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

June 22, 2018

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598946

2017 Long Term Gas Resource Plan (LTGRP) (the Application)

Response to the British Columbia Utilities Commission (BCUC or the Commission) Information Request (IR) No. 2

On December 14, 2017, FEI filed the Application referenced above. In accordance with Commission Order G-33-18 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 2.

If further information is required, please contact Ken Ross at (604) 576-7343.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. PLANNING ENVIRONMENT 2
B. ANNUAL ENERGY DEMAND FORECASTING 11
C. DEMAND SIDE RESOURCES 52
D. GAS SUPPLY PORTFOLIO PLANNING 77
E. PRICE RISK MANAGEMENT 81
F. SYSTEM RESOURCE NEEDS AND ALTERNATIVES 90
G. 20-YEAR VISION FOR FEI 97

A. PLANNING ENVIRONMENT

47.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 1.5, p. 14; Exhibit B-2, BCUC IR 4.1, pp. 7-8

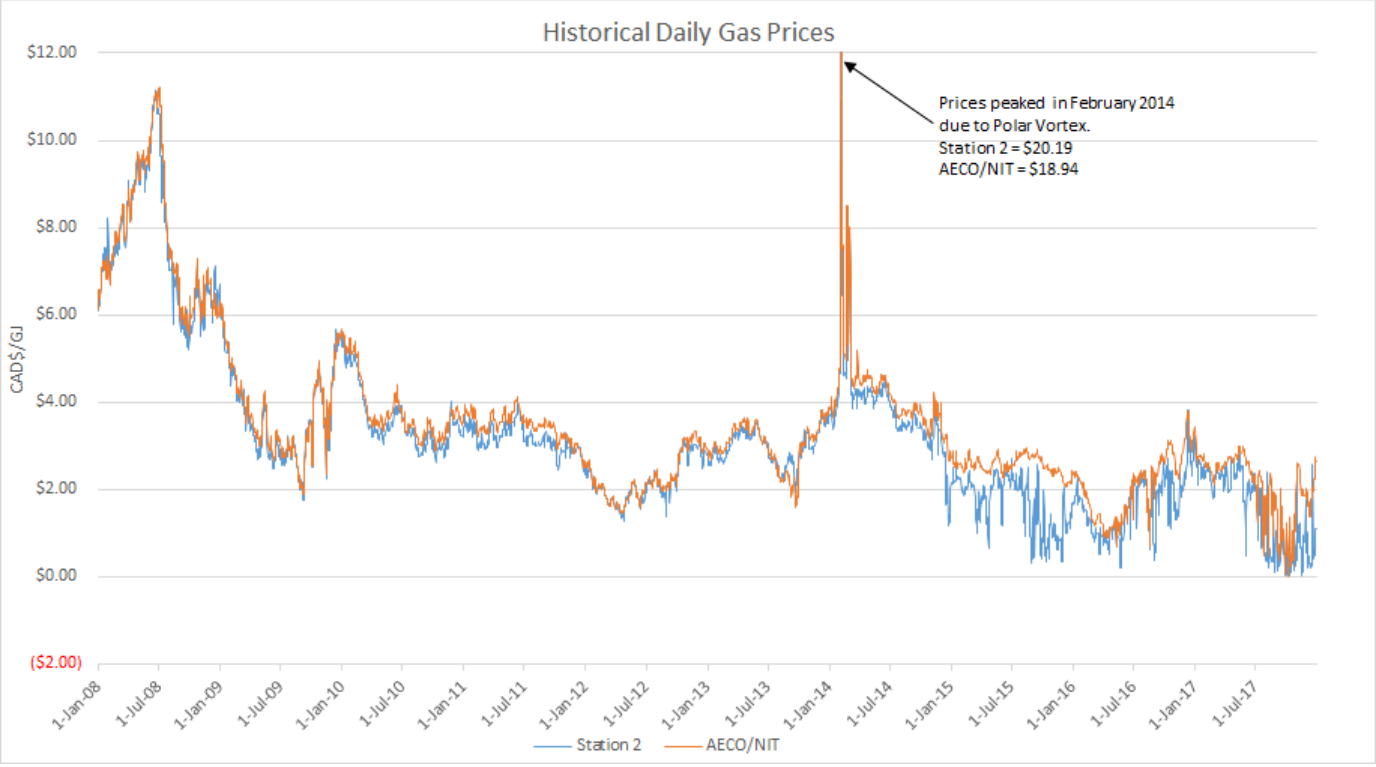
Natural Gas Prices

In response to BCUC IR 4.1, FortisBC Energy Inc. (FEI) provided updated charts showing the Henry Hub historical natural gas spot prices.

47.1 Please provide a chart using CAD$/GJ that shows historical natural gas prices using: (i) the Alberta (AECO/NIT) daily index; and (ii) Station 2 daily from 2008 through to 2017 inclusive.

Response:

The following chart shows historical daily natural gas prices for AECO/NIT and Station 2 hubs from 2008 to 2017 in CAD$ per GJ.



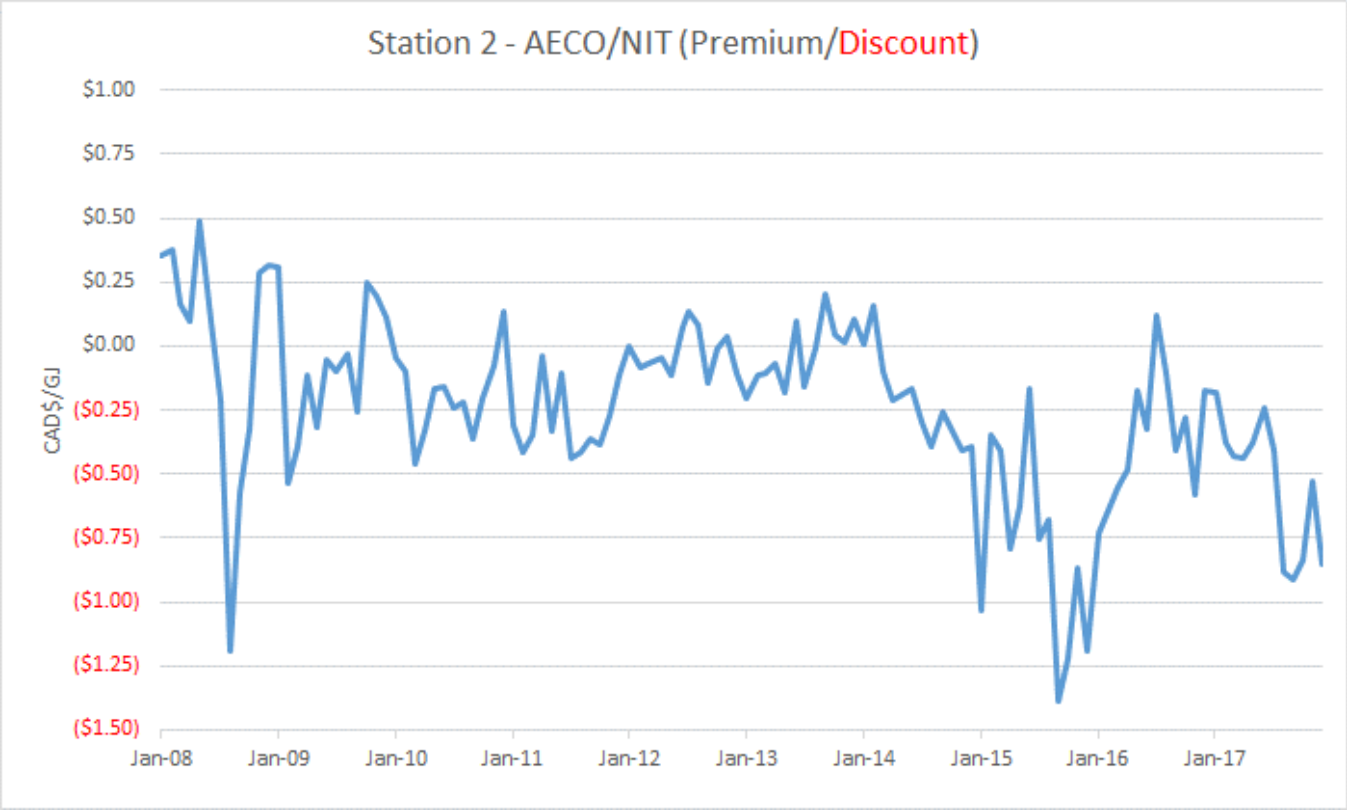
On page 14 of Exhibit B-1, FEI states:

> FEI has begun to secure the basis differential between the Station 2 and AECO/NIT price for term supply delivered at Station 2, for a period not exceeding three years, and within a confidential target pricing level. FEI's strategy to layer in its monthly indexed gas over a period of time is important because the Station 2 to AECO/NIT monthly discount/premium can change significantly over the course of a few months, which is reflective of ongoing changes in the marketplace.

47.2 Please provide a chart that shows the historical Station 2 to AECO/NIT monthly discount/premium for natural gas from 2008 through to 2017 inclusive.

Response:

The following chart shows historical Station 2 to AECO/NIT monthly premium/discount for natural gas from 2008 to 2017 in CAD$ per GJ.



48.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.3.3.5, p. 46;

Exhibit B-2, BCUC IR 9.1, p 19; BCUC IR 9.5.1, p. 22

RS 46 customers and Marine Bunkering

On page 46 of Exhibit B-1, FEI states:

> OIC 749 permitted additional expenditures, exempt from CPCN review by the BCUC, of up to $400 million for Phase 1B expansions of the Tilbury LNG facility subject to overall contracting levels averaging 70 percent of the facilities production capacity over a period of 15 years. … Subsequently, on March 21, 2017, the BC Government further amended Direction No. 5 through OIC 162/2017. The key amendments under OIC 162 were an increase to the Tilbury Phase 1A capital expenditure limit from $400 million to $425 million, removing the 70 percent average contracting requirement over 15 years pertaining to the Phase 1B expansion facility and removing the two lower priced tiers from Rate Schedule 46.

In response to BCUC IR 9.1, FEI states:

> FEI currently has customers under contract under Rate Schedule 46 (RS46) that are not based in BC that use LNG not only for marine bunkering, but for a variety of end uses in other parts of Western North America and in Asia.
>
> FEI provides LNG through RS46 to customers that satisfy the contracting requirements as outlined in RS46. This means that customers that are eligible to receive LNG dispensing service under RS46 may or may not be based in BC. FEI does not differentiate between BC based companies and those based outside of BC in terms of LNG supply under RS46.

48.1 Taking into account the deliverability of FEI's Liquefied Natural Gas (LNG) storage facilities and FEI's existing distribution system, please discuss the possibility of a scenario arising where the combined natural gas and LNG demand on a day for both BC based customers and customers based outside of BC, exceeds FEI's distribution capabilities.

Response:

In referring to "distribution capabilities" FEI assumes the Commission is referring to the ability of the Coastal Transmission System (CTS) to continue to provide supply to the Tilbury LNG

facilities as well as meet the peak demand requirements of all customers served by and through the CTS.

The CTS currently has the capacity to permit liquefaction year round at the volumes contemplated for Tilbury Phase 1A including under peak conditions and to continue to meet the peak demand requirements of the customers served by the CTS and Vancouver Island transmission system (VITS). As a result, there is a low probability of a scenario arising where all system demands could not be met for the current expansion's capacity.

Under the High Growth Scenario, LNG demand is forecast to grow dramatically over the planning horizon. In this scenario, future LNG demand requirements from the Tilbury LNG facilities, combined with demand to serve FEI's non-LNG customers, would likely exceed FEI's current overall distribution capabilities. If this demand scenario were to materialize, FEI would seek the necessary approvals to expand the CTS system in lockstep with the phases of the liquefaction capacity/storage facilities installed to meet this demand to ensure adequate capacity is always available to serve all of FEI's demand requirements.

As the CTS can be expanded when and as required to provide the necessary capacity to supply the installed liquefaction at the Tilbury site, the probability of such a shortfall event occurring and impacting the ability of the CTS to meet demand will remain low.

48.1.1 Is the occurrence of this scenario a low/medium/high probability? Please explain your response.

Response:

Please refer to the response to BCUC IR 2.48.1.

48.1.2 Please explain how FEI plans to prevent this scenario from occurring.

Response:

Please refer to the response to BCUC IR 2.48.1.

48.1.3 Please explain how FEI would address this scenario if it occurs.

Response:

Please refer to the response to BCUC IR 2.48.1.

49.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.4.1, p. 53; Section 3.4.3, pp. 67-68;

Exhibit B-2, BCUC IR 9.5.1, p. 22

RS 46 customers and Marine Bunkering

On page 53 of Exhibit B-1, FEI states:

> LNG supply and delivery contracts are in place for three BC Ferries and two Seaspan Ferries vessels, with two more BC Ferries Spirit-class vessels expected to begin operational service, beginning mid-2018 for the first vessel and mid-2019 for the second vessel.

In response to BCUC IR 9.5.1, FEI states:

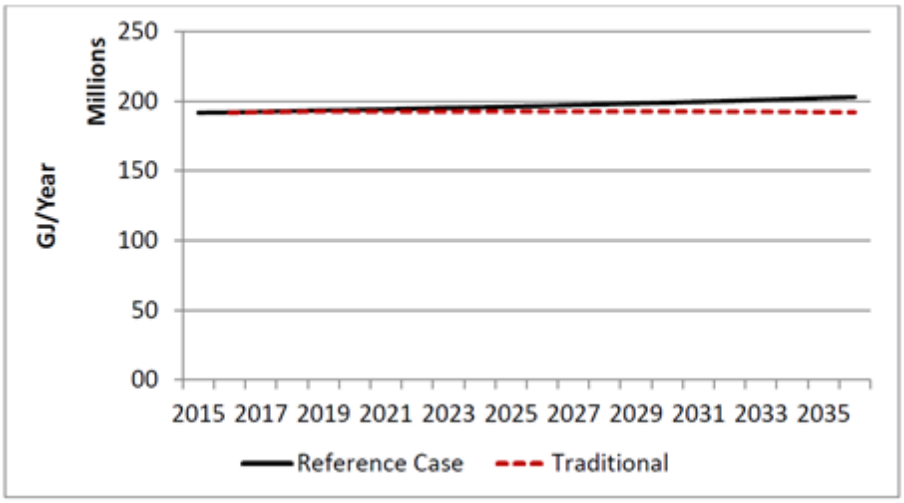
> FEI confirms that the End-use Method annual demand forecast Reference Case includes forecast demands for BC Ferries and Seaspan Ferries. … FEI6 notes that the Traditional Annual Method does not contain forecast demands for BC Ferries and Seaspan Ferries because the Traditional Annual Method simply extends FEI's short-term forecast method across the 20-year planning horizon. … FEI emphasizes that the 2017 LTGRP plans to the End-Use Method annual demand Reference Case and the Traditional Peak Demand Method.

On page 67 of Exhibit B-1, FEI states:

> Comparing the end-use method Reference Case results with the results of the Traditional Annual Method grounds the results of the end-use method before FEI proceeds to use this method for examining the impact on annual demand of alternate future scenarios … Figure 3-6 below compares the annual demand results of the Traditional Annual Method with the results of the end-use method Reference Case. By the end of the planning period the two forecast methods differ by less than six percent. This variance is due to the various differences between the two methods.

Figure 3-6 on page 68 of Exhibit B-1 is copied below:

Figure 3-6: Comparison of Annual Demand Forecasts



49.1 Please update Figure 3-6 from the Application to include a Traditional Annual Method forecast demand that includes forecast demands for BC Ferries and Seaspan Ferries.

Response:

FEI interprets this question to request total annual demand including BC Ferries and Seaspan Ferries for forecasts based on both the Traditional Annual Method and the end-use annual method. For clarification, Figure 3-6 of the Application shows both the Traditional Annual Method and the end-use annual demand method forecast results without NGT annual demand.

As stated in the preamble "the Traditional Annual Method does not contain forecast demands for BC Ferries and Seaspan Ferries"; FEI traditional forecast methods are time series based and therefore a traditional annual demand forecast is unavailable for BC Ferries and Seaspan Ferries. The forecast annual demand for the ferries is 1,177,000 GJ annually, as identified in the response to BCUC IR 1.9.5, and this amount would have to be added to both the Traditional Annual Method and the end-use annual demand method results in Figure 3-6 to attain a like-to-like comparison. The variance between the two forecasts would be the same as the variance shown in Figure 3-6. (Section 3.4.3 of the Application comments on how the results differ across the two forecast methods displayed in Figure 3-6.)

49.1.1 Please state the difference in: (i) GJ/year; and (ii) percentage between the two forecast methods, in the updated Figure 3-6, for each year of the planning period.

Response:

Please refer to the response to BCUC IR 2.49.1 which explains that the difference between these two forecasts is the same with and without including the BC Ferries and Seaspan Ferries demand since there is no separate traditional forecast just for ferries (e.g., there is no history of ferries demand to draw on to create a traditional forecast), rather there is only the end-use forecast. As such the comparison presented in this response is based on the original Figure 3-6.

The difference in GJs and percentage per year between the end-use method Reference Case and Traditional method in the original Figure 3-6 is shown below. As discussed in the response to BCUC IR 2.49.1, NGT is not included in the forecasts as shown in Figure 3-6.

Table 1: Difference in GJs and Percentage per Year between the end-use method Reference Case and Traditional Method

Year	Difference in GJ/year	Percentage Between the Two Forecast Methods
2016	-238,098	-0.1%
2017	-286,783	-0.1%
2018	87,281	0.0%
2019	107,412	0.1%
2020	829,339	0.4%
2021	1,317,548	0.7%
2022	1,777,374	0.9%
2023	2,135,056	1.1%
2024	2,491,573	1.3%
2025	2,901,795	1.5%
2026	3,423,701	1.7%
2027	3,949,334	2.0%
2028	4,515,011	2.3%
2029	5,105,707	2.6%
2030	5,749,354	2.9%
2031	6,462,629	3.2%
2032	7,181,217	3.6%
2033	7,949,211	4.0%
2034	8,754,322	4.4%
2035	9,598,977	4.8%
2036	10,455,404	5.2%

49.1.2 Please discuss the difference between the two forecast methods by the end of the planning period.

Response:

Please refer to the response to BCUC IR 2.49.1. As noted in Section 3.4.3 of the Application, the two forecasts differ by less than six percent by the end of the planning horizon. Section 3.4.3 of the Application provides further detail on this variance.

B. ANNUAL ENERGY DEMAND FORECASTING

50.0 Reference: ANNUAL ENERGY DEMAND FORECASTING
Exhibit B-1, Section 3.1, p. 59; Exhibit B-2, BCUC IR 10.2, p. 25-27;
Exhibit B-4, CEC IR 1.2, pp. 4-9
Customer Additions Forecast - Residential

In response to BCUC IR 10.2, FEI states: "The split between single and multi-family premises is based on historical percentages from internal FEI data."

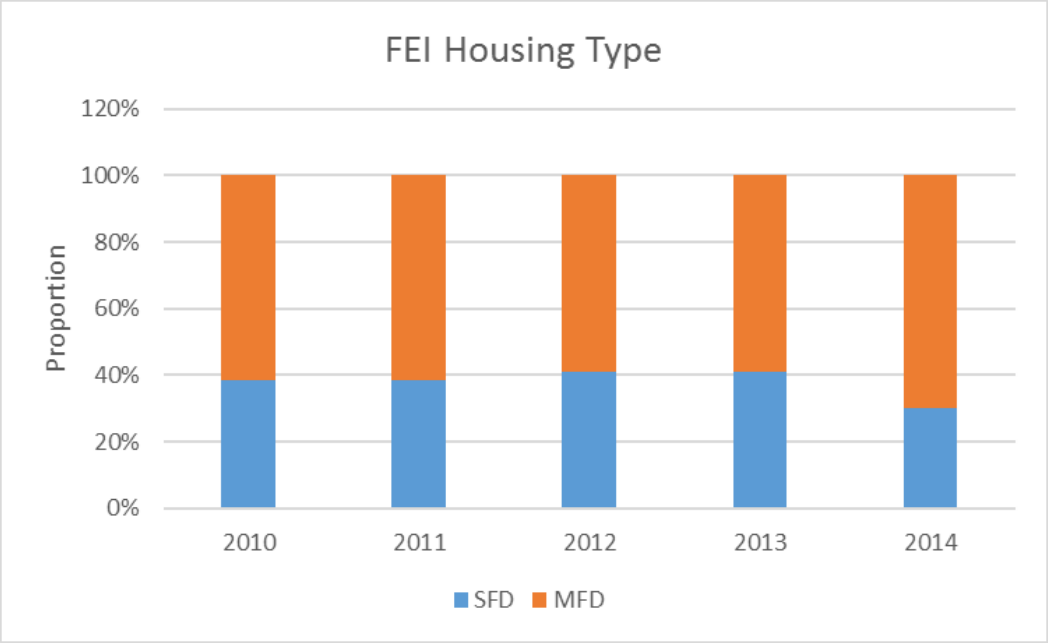
50.1 Please provide, in a table format, the historical split between single and multi-family premises for the five years preceding 2015.

Response:

The following table shows the SFD/MFD splits applied to FEI residential customer additions for the five years preceding 2015 (2010-2014). The splits for the five years preceding 2015 were taken from CBOC reports. From 2015 onwards, FEI has relied on proportional data from internal systems.

Housing Type	SFD	MFD
2010	39%	61%
2011	39%	61%
2012	41%	59%
2013	41%	59%
2014	30%	70%

The following figure uses the data from the table above:



The splits from 2010-2013 were consistent and indicate that approximately 40 percent of the FEI net additions were SFDs. In 2014, the proportion of SFD net additions fell to 30 percent.

50.1.1 Please discuss any identifiable trends in the data.

Response:

Please refer to the response to BCUC IR 2.50.1.

50.2 Please explain how the percentage split between single and multi-family premises is calculated.

Response:

The calculation is a simple ratio of dwelling type to total additions.

As shown in the response to BCUC IR 1.10.2, the 2015 SFD additions were 2,333. The 2015 MFD additions were 2,942. The percentage split for SFD is calculated as follows:

$$2015\ SFD\ percentage = \frac{2{,}333}{(2{,}333 + 2{,}942)} = \frac{2{,}333}{5{,}275} = 44.236\%$$

The MFD percentage is the remainder and calculated as follows:

$$2015\ MFD\ percentage = 100\% - 44{,}263\% = 55.764\%$$

50.2.1 Over what period does FEI use historic data to calculate these percentages and how have they changed over time? Please explain.

Response:

FEI has internal historic data in its work order system for single and multi-family premises beginning in 2015 (the estimated percentages for 2010 to 2015 provided in the response to BCUC IR 2.50.1 are based on CBOC percentages). As shown in the response to BCUC IR 1.10.2, FEI used 2015 customer additions and the 2015 split between single and multi-family premises (illustrated in the response to BCUC IR 2.50.2) to develop the customer additions forecasts. At the time the forecast were prepared, 2015 was the most recent full year of data available. The following figure shows that the proportions have remained relatively constant. In 2015 and 2016, the SFD portion was 44 percent and 45 percent respectively. In 2017, the SFD portion declined slightly to 41 percent.

50.3 Please explain what impact, if any, the change in percentage split between single family and multi-family premises would have on: (i) the residential demand forecast; and (ii) the aggregate demand forecast.

Response:

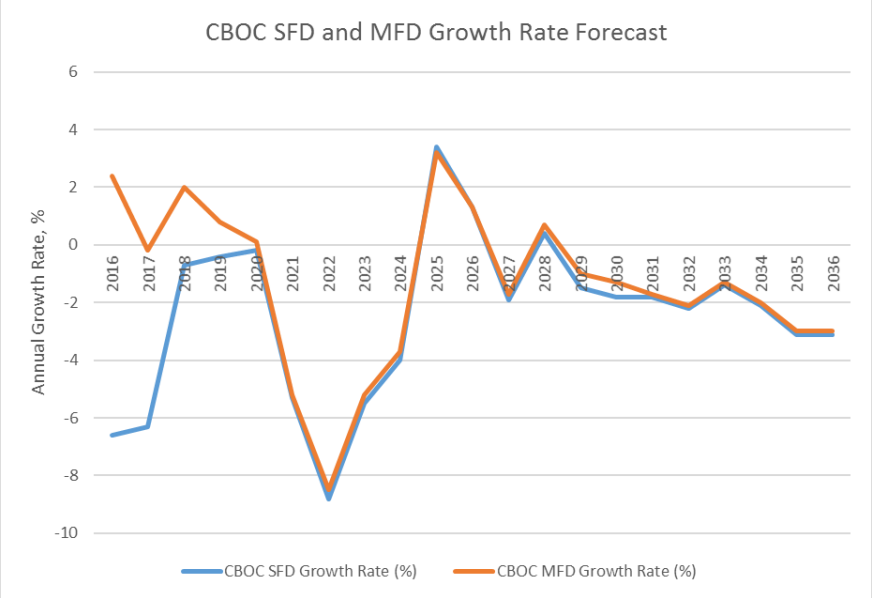
FEI consulted with Posterity Group Consulting Inc. (Posterity) to provide the following response.

The 2017 LTGRP end-use method forecast model assumes that attached/row housing is growing at a faster rate than single detached housing. This is based on historical housing starts data for the province. Apartment and strata units are subject to the assumed growth rates for the commercial rate schedules. In the model, apartment and strata units are also assumed to grow at a faster rate than single detached housing. Attached/row housing has a lower assumed UPC than single detached housing for several reasons: somewhat smaller average floor area, smaller average occupancy, shared walls that reduce space heating load, and somewhat smaller natural gas share for some end uses. UPC for individual apartment units is not an explicit assumption in the model (because apartment buildings are modeled as commercial customers and are therefore analyzed based on energy use per unit of floor area), but an average apartment unit has an even lower UPC than row houses, for the same reasons. As the ratio of single to multi-family premises decreases, therefore, both the residential and aggregate demand in the model would also decrease.

50.3.1 What factors account for the large negative growth rates observed between 2021 and 2023 for both single and multi-family dwellings? Please discuss.

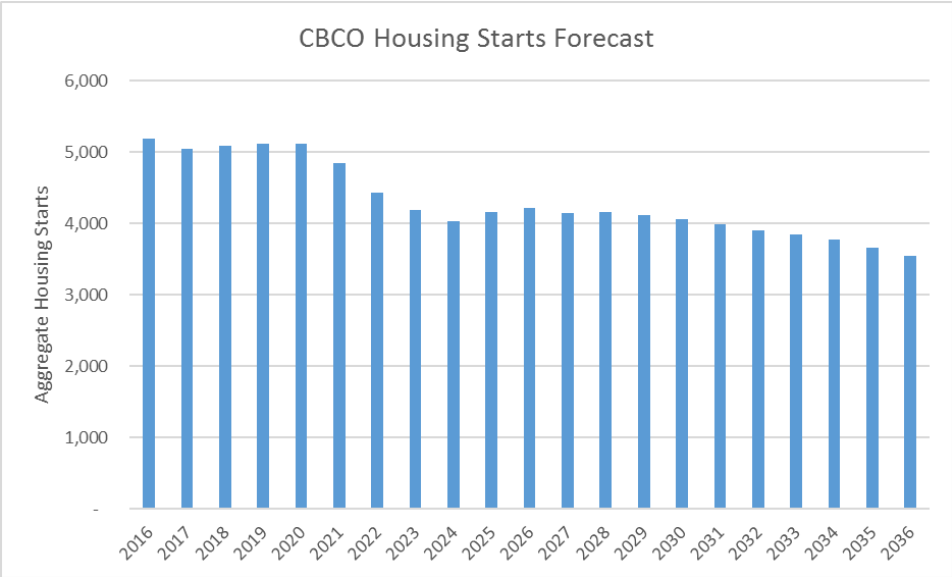
Response:

Consistent with past practice FEI uses the long-term CBOC forecast of single and multi-family housing starts. The forecast used in the preparation of the 2017 LTGRP filing is shown below:



The CBOC is forecasting a decline in housing starts between 2021 and 2023 compared to prior years. The CBOC does not publish factors that impact their forecast.

It should be noted that the housing starts are forecast to remain above 4,000 units through the period in question as shown in the following figure:



Housing starts are not forecast to drop below 4,000 units per year until 2031.

50.4 Please discuss if and how FEI's customer addition methodology accounts for new customers that are fuel switching from electricity, or other sources including propane, to natural gas.

Response:

FEI consulted with Posterity to provide the following response.

FEI provided Posterity an estimate of residential conversions over five years, by region, and as a percentage of customer additions. The 2017 LTGRP end-use annual demand forecast includes these percentages in the assumptions about how many new residential customers in each region are the result of new construction and how many are conversions of existing dwellings. Conversions are assumed to be distributed proportionally among the different vintages of existing dwellings, with appropriate building envelope characteristics, but with new gas-fired equipment for the gas end uses they begin using. Customer additions from new construction all belong to the newest vintage of homes.

In the end-use method scenarios that vary fuel share assumptions in response to a critical uncertainty (which are identified in Section 3.4.4 of the LTGRP), the share of new customers assumed to heat with natural gas also varies. New customer additions change independently of heating fuel share (as a different critical uncertainty), but the customers that are added, whether

as conversions or as new construction, will be either more or less likely (depending on the scenario) to use natural gas as their fuel choice in response to critical uncertainties that impact fuel share.

The building envelope and most other characteristics of conversion customers are assumed to be similar to other homes of the appropriate vintage. The only major change is that the equipment for any gas end uses that these conversion customers adopt is assumed to be new and therefore to have up-to-date efficiency ratings.

50.4.1 Please explain the impact of taking into account new customers that are fuel switching to natural gas on the customer additions forecast.

Response:

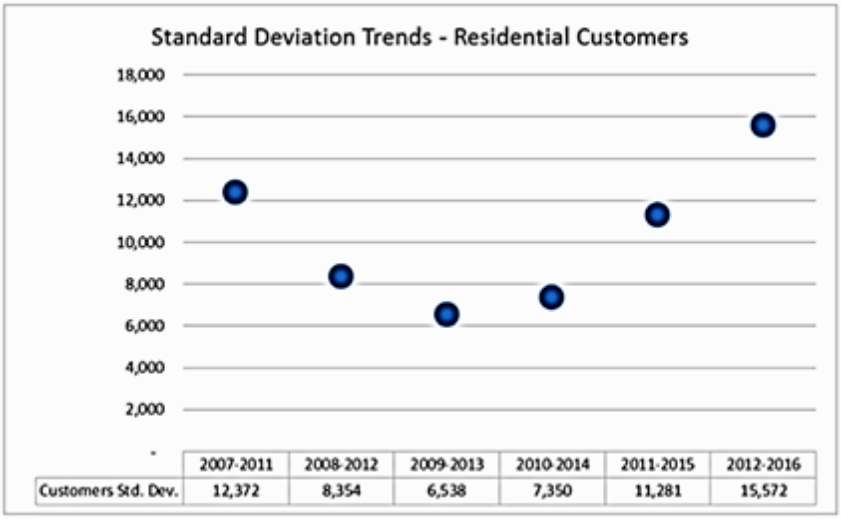
FEI consulted with Posterity to provide the following response.

The 2017 LTGRP end-use annual demand forecast method simply represents residential customers that are assumed to convert to natural gas from another fuel type as a subset of forecast customer additions. Please refer to the response to BCUC IR 2.50.4 for an explanation of how this impacts the dwelling and appliance characteristics of these customers.

In response to CEC IR 1.2, FEI provides graphs showing standard deviations for five year rolling periods for residential and commercial customers.

FEI further states: “Residential customer totals have become more volatile in recent years. The increased volatility may be due to increased customer additions following the post-recession slowdown.”

Figure 1



50.5 Please provide a graph displaying the volatility of residential customer totals in percentage terms.

Response:

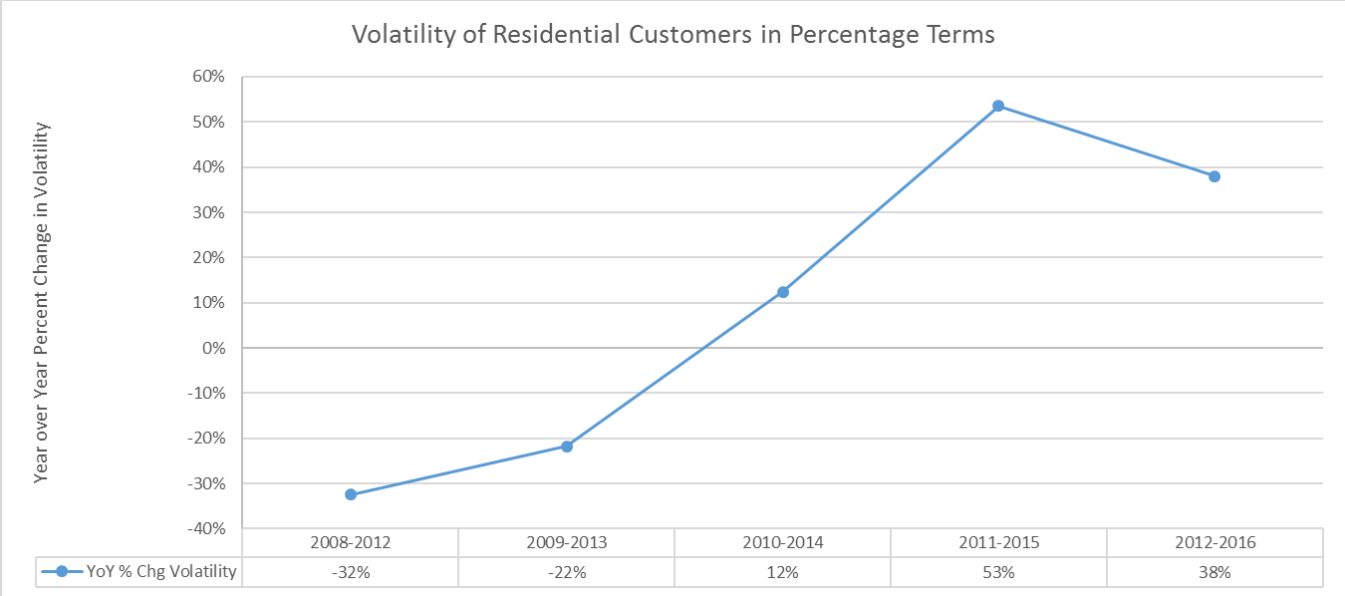
Please see the graph below, displaying the volatility of residential customer totals in percentage terms.

To develop the following figure, FEI calculated the percent change between the data points shown in the figure using the data provided in the figure developed in response to CEC IR 1.1.2 and reproduced in the preamble to this question.

For example the value of -32 percent is calculated as:

$$Volatility\ as\ Percent = \left(\frac{8{,}354}{12{,}372}\right) - 1 = -32\%$$

Figure 1: Volatility of Residential Customers in Percentage Terms



50.6 Please discuss the effects, if any, fuel switching from electricity to gas could have on the increased volatility in residential customer totals.

Response:

The measure of volatility FEI used in response to CEC IR 1.1.2 was the standard deviation. The standard deviation is the collective measure of how far a particular set of data points is from the mean.

FEI does not have any empirical data on which to analyze the impacts of actual fuel switching; however, if, in a particular year, the customer additions were lower than the average, then the addition of customers switching from electricity to natural gas would close the gap and reduce the volatility.

On the other hand, if the customer additions were already above average, then the addition of customers switching from electricity to natural gas would tend to increase the volatility as the gap between the average and the additions for the year widened.

50.7 What are other possible causes that could result in increased volatility? Please discuss.

Response:

For volatility to increase, customer additions need to deviate (positively or negatively) from the average number of additions. FEI does not maintain or have a detailed list of the reasons related to why customers might choose to join or leave the system. Examples of some reasons that might cause more volatility could be volatility in the cost of alternative fuels, changing lifestyle preferences (for example, patio heaters, fireplaces, cooktops), varying levels of promotional activities for natural gas and for alternative fuels, and rapidly changing technologies that might impact consumer energy choices.

51.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.3, p. 61; Exhibit B-2, BCUC IR 11.1, pp. 28-35; Exhibit B-4, CEC IRs 1.2 and 2.5, pp. 4-10 and p. 12 respectively

Customer Additions Forecast - Commercial

In BCUC IR 11.1, FEI states:

> The FEI commercial customer forecast method starts with the growth rates from the BC STATS HHF [Household Formations forecast] forecast to establish the commercial customer forecast for the period from 2016 to 2036. BC STATS publishes the growth rates in the HHF forecast for each Local Health Area. FEI groups customers similarly, and then applies the growth rates… All commercial rate schedules use these same growth rates.
>
> The HHF forecast is predicting household formations while the purpose of the commercial forecast is to predict net commercial customer additions. The growth trends (slopes) are expected to be similar but the starting point is lower because fewer commercial customers attach than households are formed.

51.1 Please confirm or otherwise explain that the HHF forecast only includes customers that FEI would class as residential customers.

Response:

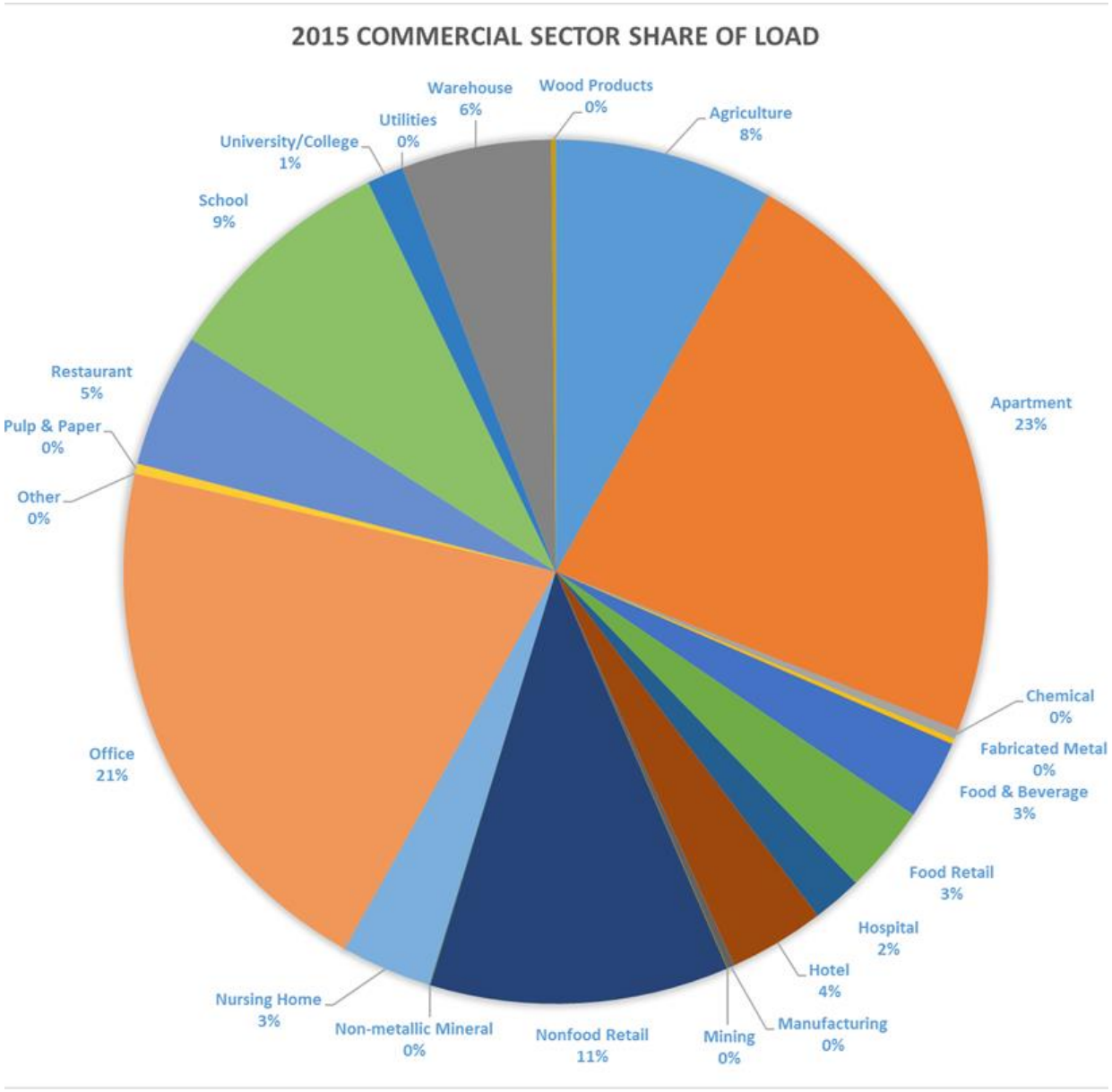
This response also addresses BCUC IRs 2.51.2, 2.51.4, and 2.51.5.

Not confirmed.

The HHF forecast also accounts for a portion of the customers in the commercial classes.

FEI rate schedules are based on the volume of gas consumed, not what it is consumed for. For example many residential premises are in multi-family dwellings where there is a shared boiler. The shared boiler results in a load large enough for the apartment complex to be in a commercial rate schedule.

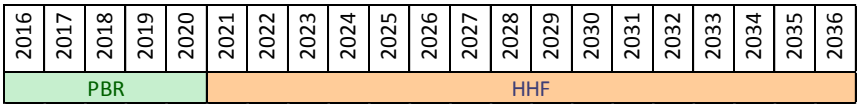
The following figure shows the distribution by sector for the commercial rate schedules:



Twenty three percent of the demand flowing to customers in the commercial rate schedules is actually serving apartments. FEI believes it is reasonable to assume that schools and hospitals are also built to serve regional populations. When taken together apartments, schools and hospitals directly account for more than 1/3rd of the commercial demand. FEI also believes it is reasonable to assume that a portion of sectors such as offices, restaurants and retail establishments also develop in relation to household formations.

FEI believes that, for the period over which the HHF method is used, it is reasonable to assume that, on the Local Health Area and aggregate basis, the same factors affect the bulk of the customers in the commercial sectors equally. The HHF method is only used for the latter

portion of the forecast, as shown below, and described in Step III of the response to BCUC IR 1.11.1:



FEI believes using the HHF forecast for this purpose is reasonable because of the mix of residential and commercial uses. FEI believes the lack of correlation between GDP and commercial use rates is related to this issue (for example residential customers would not be expected to change their end-use patterns based on the performance of the economy). Due to the appropriateness of the HHF method, FEI has not tested any alternative methods.

As a result, FEI believes that the HHF forecast is appropriate to use for forecasting the final 15 years of the 20-year forecast period and has used it for this purpose since 2004.

51.2 Please explain why FEI uses the growth rates from BC STATS HHF to establish the commercial customer forecast?

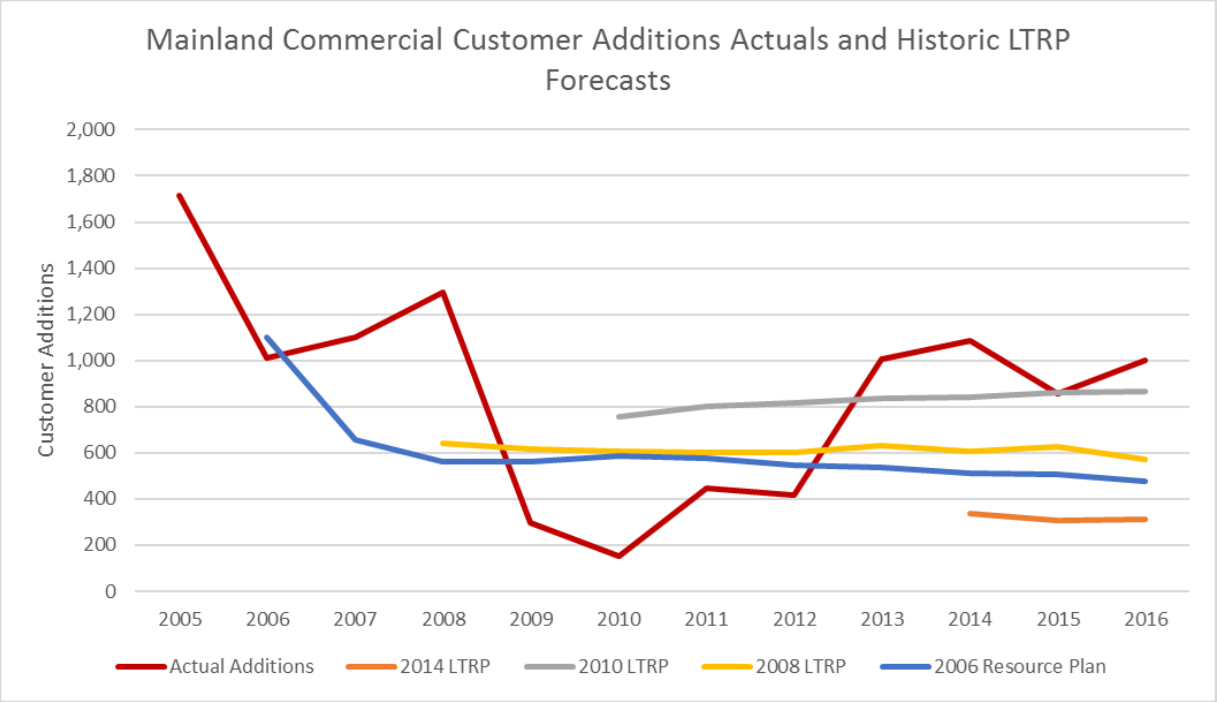
Response:

Please refer to the response to BCUC IR 2.51.1.

51.3 Please explain how commercial customer additions are correlated with HHF. Please provide FEI's regression analysis to support these assumptions.

Response:

For clarity the figure prepared for the response to BCUC IR 2.51.8 is repeated here.



The figure shows multiple LTRP forecasts of commercial additions along with the actual recorded additions. FEI notes that, between 2010 and 2016, commercial additions have ranged from approximately 200 to 1,100 additions per year. FEI also notes that all forecasts that cover this timeframe have been well within this range. The HHF portion of the customer additions forecast does not start until the sixth year of the forecast so FEI believes these results are reasonable.

FEI has used the HHF method since 2004 and consequently a regression analysis has not been prepared and is not available for these results.

51.4 Has FEI explored any alternative forecasts that could be more appropriate to forecast commercial customers? Please discuss.

Response:

Please refer to the response to BCUC IR 2.51.1.

51.5 To what extent does the use of HHF when forecasting commercial customers, account for the differences in growth rates between residential and commercial customers, when each customer group or subset may be affected by numerous exogenous factors differently? Please provide an explanation both on a Local Health Area and aggregate basis.

Response:

Please refer to the response to BCUC IR 2.51.1.

51.6 Please explain FEI's use of the three year average additions method to reconcile the first five years of the HHF forecast with the first five years of the Short Term forecast?

Response:

The use of the most recent PBR forecast (which uses a three-year average for commercial customer additions forecasting) is described in detail in the response to BCUC IR 1.11.1 and includes worked mathematical examples. FEI believes that response (refer to Step III) addresses this request and is uncertain what additional information the Commission is seeking.

51.6.1 Please explain why FEI fixes a three year historical average of customer additions for the first five years?

Response:

Please refer to the response to BCUC IR 2.51.6.

51.7 How does the use of HHF account for the variances in growth rates between region and commercial sectors if FEI applies the same method to all commercial rate schedules and regions? Please explain your response.

Response:

FEI consulted with Posterity to provide the following response.

The BC Stats HHF forecast is prepared for approximately 90 different local health areas. FEI believes this regional granularity is sufficient to model the commercial customer growth in years six through 20 of the forecast.

FEI is not aware of a forecast method that would provide both the regional granularity of the HHF forecast as well as providing both accurate and meaningful differences between the commercial rate schedules six to 20 years into the future.

Note that, consistent with all commercial customer use rate and demand forecasting, FEI applies the same methods regardless of the region or rate schedule being forecast.

FEI provides the following table in response to CEC IR 2.5:

Table 1: Historical Commercial Customer Additions.

Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
FEI Commercial Additions (Incl. FTN)	1,910	944	1,231	1,508	454	232	551	557	1,255	1,201	1,789	1,002

51.8 Please provide a graph comparing prior Long Term Gas Resource Plane (LTGRP) commercial customer addition forecasts to actual commercial customer additions from 2005 shown in Table 1 above.

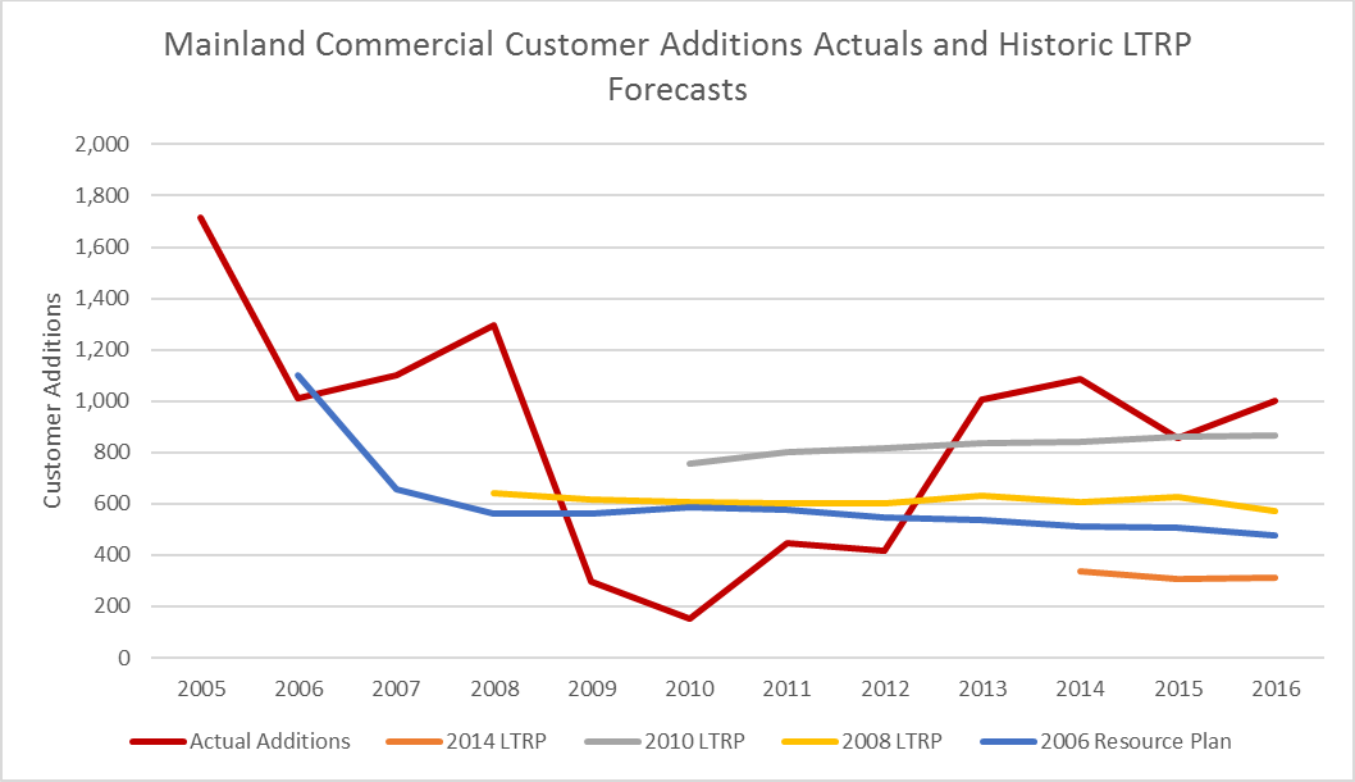
Response:

A chart comparing prior LTGRP commercial customer addition forecasts to actual commercial customer additions from 2005 is shown below. FEI was unable to isolate commercial customer additions data for the 2004 Resource Plan at the required level of granularity[1]. In addition, only Mainland additions are shown as VI and WH were not yet amalgamated and used separate rate

[1] The 2004 Resource Plan only shows additions for rate schedules 1,2,3 and 23 together in a chart and did not forecast at the granularity of more recent forecasts.

schedule classifications. As a result of these limitations, the data points used for the "Actual Additions" line in the following figure do not match the table in the preamble.

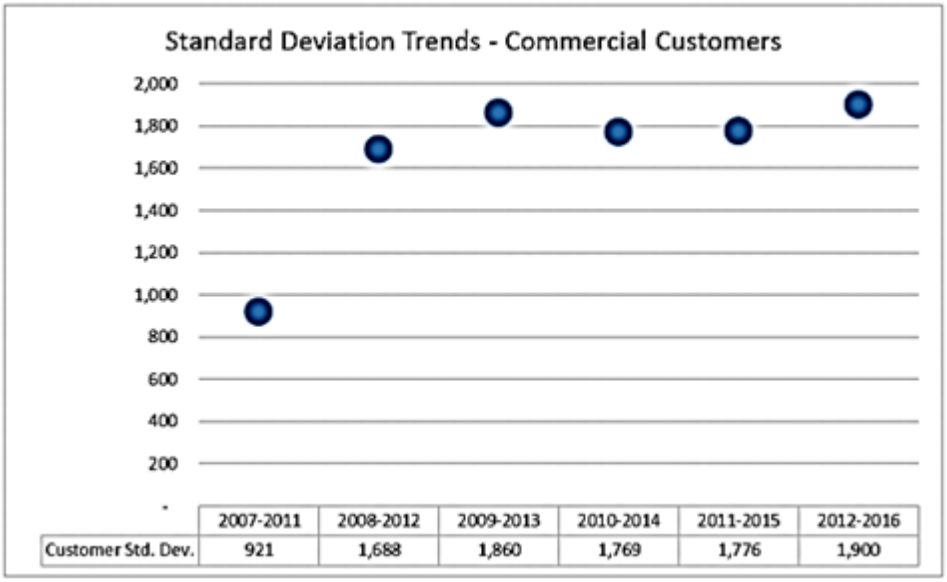
Figure 1: Prior LTGRP commercial customer addition forecasts to actual commercial customer additions from 2005[2]



[2] The 2014 LTRP additions are adjusted for SAP.

In CEC IR 1.2, FEI provides the following graph showing standard deviations for five year rolling periods for commercial customers.

Figure 3



51.9 Please provide a graph displaying the volatility of commercial customer totals in percentage terms.

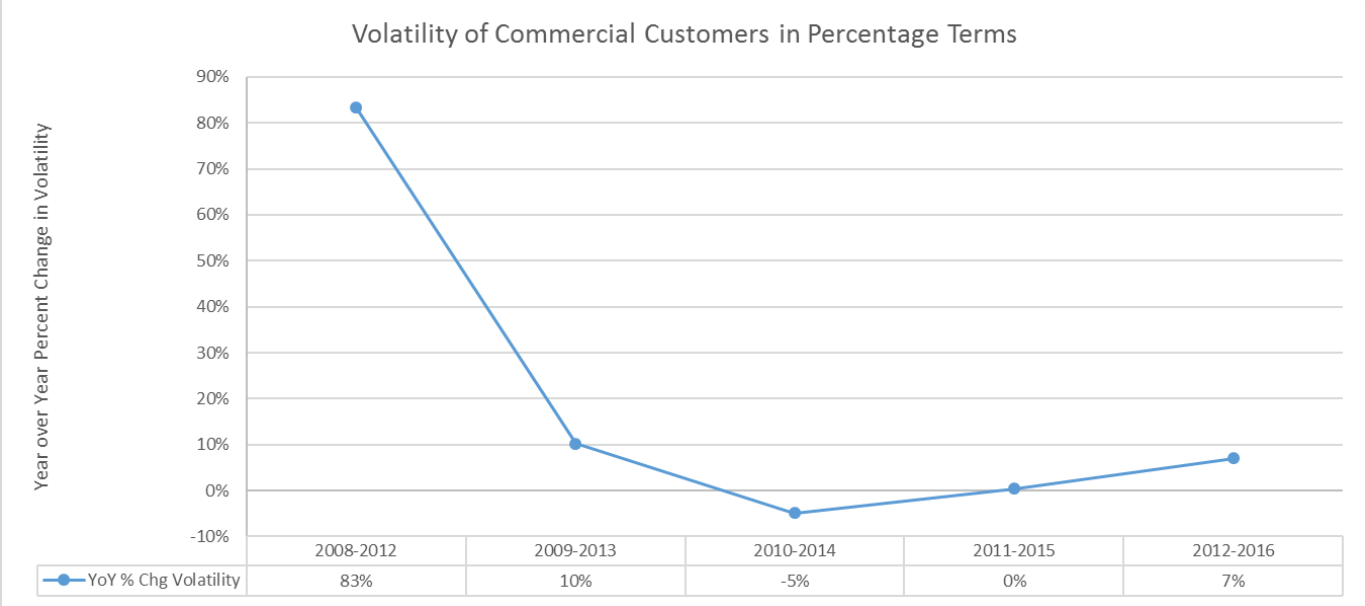
Response:

To develop the following figure, FEI calculated the percent change using the data provided in the figure developed in response to CEC IR 1.1.2 and reproduced in the preamble to this question.

For example the value of 83 percent is calculated as:

$$Volatility\ as\ Percent = \left(\frac{1{,}688}{921}\right) - 1 = 83\%$$

Figure 1: Volatility of Commercial Customers in Percentage Terms



51.9.1 What are the main reasons why the volatility in commercial customer totals has remained relatively consistent from the 2009-2013 period? Please explain.

Response:

The measure of volatility in the response to CEC IR 1.1.2 is based on five-year rolling periods. For each point in the graph, one year is removed from the dataset and one year is added. The standard deviation is a measure of the dispersion of a dataset relative to its mean. Since commercial customer additions tend to be small relative to the total, it is reasonable to expect that dropping one year and adding one year would not change the dispersion of the dataset relative to the mean by a large amount. As a result, the rolling volatility shown in the response to CEC IR 1.1.2 is consistent for the latter five data points.

52.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 1.4.3.2, p. 12; Section 3.4.1, pp. 63–64;

Exhibit B-2, BCUC IRs 16.3-16.6, pp. 47–50

Developing the end use Reference Case demand forecast

In BCUC IR 16.5, FEI provides the following tables related to the 2012 Residential and Commercial End-Use Surveys:

Residential End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland	6,250	793	12.7%
Vancouver Island	3,704	752	20.3%
Whistler	1,650	85	5.2%
Southern Interior	13,465 [2, 3]	1,065	13.5% [1, 2, 3]
Northern Interior		749	
Total	25,069	3,444	13.7%

Commercial End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total [4]	10,000	866	8.7 [5]

52.1 Please explain how FEI ensures: (i) the number of End-Use surveys targeted by region; and (ii) the customers FEI targets to participate in the end-use surveys appropriately capture a suitable sample distribution.

Response:

In designing the 2012 REUS sample frame FEI was mindful of the need to obtain adequate samples from each of the regions to allow for region-based analysis. A complicating factor was that the survey was sent to both FortisBC natural gas and electric customers in the shared service territory and the data would be used by both entities. To meet those goals the sample size was increased to 25,000 from 11,260 in 2008.

While the sample distribution did not reflect the overall distribution of the FEI customer base, where results were shown on total sample basis in the report, the data was weighted to reflect the distribution of customers and therefore avoid any possible skewing of data due to the overrepresentation of a geographical area.

As not all homes have natural gas, it is not possible to compare the demographic data obtained in the REUS to census data to verify that underlying population. However, from a statistical

perspective, we can calculate the possibility that the data reflects the underlying population. For the Lower Mainland, Interior and Vancouver Island at the 95 percent confidence level, the margin of error (MoE) for any given question ranged from plus/minus 1.4 percent to 3.5 percent. The MoE for the total sample ranged from 1.4 percent to 2.3 percent.

The sample frame for the 2015 CEUS was randomly selected from the overall customer base. Regional weights were applied to the response data to ensure that it reflected the overall distribution of customers. Again, from a statistical perspective we can calculate the possibility that the data reflects the underlying population. At the 95 percent confidence level, the MoE for any question ranges from plus/minus 3.4 percent to plus/minus 9.8 percent where the sample size is between 100 and 866.

52.2 Has FEI identified methods to increase end-use survey response rates to obtain a larger sample of data? Please discuss.

Response:

For the 2017 REUS, FEI assessed why the response rate for the 2012 REUS was lower than anticipated. It was determined that two factors played a significant role:

- The timing of the survey mailing (December); and
- The sample preparation.

To address this issue, it was decided that the survey should be mailed out no later than the first week of November. If that target could not be met, FEI would postpone the survey until February 2018.

A more rigorous approach was taken to the sample preparation. This entailed a line-by-line review of the data to look for address anomalies (missing unit numbers, misspelt street names, discrepancies between mailing and billing addresses) and to remove non-residential properties (garages, workshops, pool etc.). As a result, the number of non-deliverable surveys dropped from approximately 3500 in 2012 to 300 in 2017. The 2017 REUS had a sample size of 26,000 and yielded 5827 responses for a response rate of 23 percent. The same approach will be taken with future End Use studies.

52.2.1 What effect, if any, would an increase in response rates have on the survey cost? Please explain.

Response:

An increase in the response rate can impact survey costs several ways:

- An increase return post costs;
- Additional data entry costs; and
- Additional data cleaning and data analysis costs.

However, the impact on the overall budget is dependent both on the number of responses and the ratio of responses that are mailed in as compared to completed online. In the 2017 REUS pricing was based on 25,000 surveys, a response rate of 19 percent and with 40 percent completed online. The final response rate was 23 percent with 49 percent completed online. The cost of the higher response rate was therefore partially offset by the higher number of online completions.

In response to BCUC IR 16.6, FEI states:

> Looking at the trends noted in the 2012 REUS it was possible to deduce what changes occurred in the following years due to natural attrition and energy regulations. This insight combined with other information from the Conservation Potential Review and an analysis of actual consumption in the 2015 base year provides an indication of what changes were occurring between 2012 and 2017.

52.3 Please explain how FEI was able to attribute changes to natural attrition and energy regulations.

Response:

FEI consulted with Posterity to provide the following response.

The response to BCUC IR 1.16.6.1 provided some detail on how natural attrition and energy regulations can be expected to influence energy consumption. FEI used natural gas furnaces as a concrete example, because the efficiency of new installations or replacements is clearly influenced by a regulated mandatory minimum efficiency. FEI estimated the average efficiency of existing furnaces in 2012 based on information in the 2012 REUS, estimated the number of furnaces that would reach their end of life between 2012 and 2017, and calculated the new average efficiency for 2017 with the new, more efficient furnaces. FEI used the same approach to extrapolate the continued improvement in average furnace efficiency to future years. Year by year, a percentage of furnaces can be expected to reach end of life and get replaced with new furnaces that meet the new regulations. There is an eventual leveling off after virtually all of the old furnaces have been replaced.

Energy regulations are not the only driver of end-use changes. For example, energy use for domestic hot water is driven partly by the average efficiency of the water heater itself, but also by changing hot water requirements in the household (e.g., changing number of occupants due to changing housing uses). The average hot water use for both dishwashers and clothes washers is decreasing as these appliances age and are replaced. The average efficiency of new models of both these appliances has improved dramatically. While there are energy efficiency standards setting minimum performance standards for both, programs such as ENERGY STAR® result in average performance substantially better than the minimum. FEI used NRCan's regularly published summary of average appliance efficiency, *Energy Consumption of Major Household Appliances Shipped in Canada*, to estimate the average efficiency of both the new appliance and the one being replaced.

FEI assumed a rate of replacement for both appliances based on their average life expectancy, assumed the replacement appliances would be at the average new efficiency (not the regulated minimum), and estimated the reduction in the hot water they would demand from the water heater. At the same time, water heaters will be reaching the end of their lives and will be replaced by water heaters that meet or exceed new energy regulations. FEI combined both factors to estimate the change in energy consumption for water heating over time.

These examples from the residential sector illustrate FEI's general approach, but similar estimates were also developed for evolving energy end uses in the commercial and industrial sectors.

53.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 17.3, p. 62

Residential UPC Forecast Trend

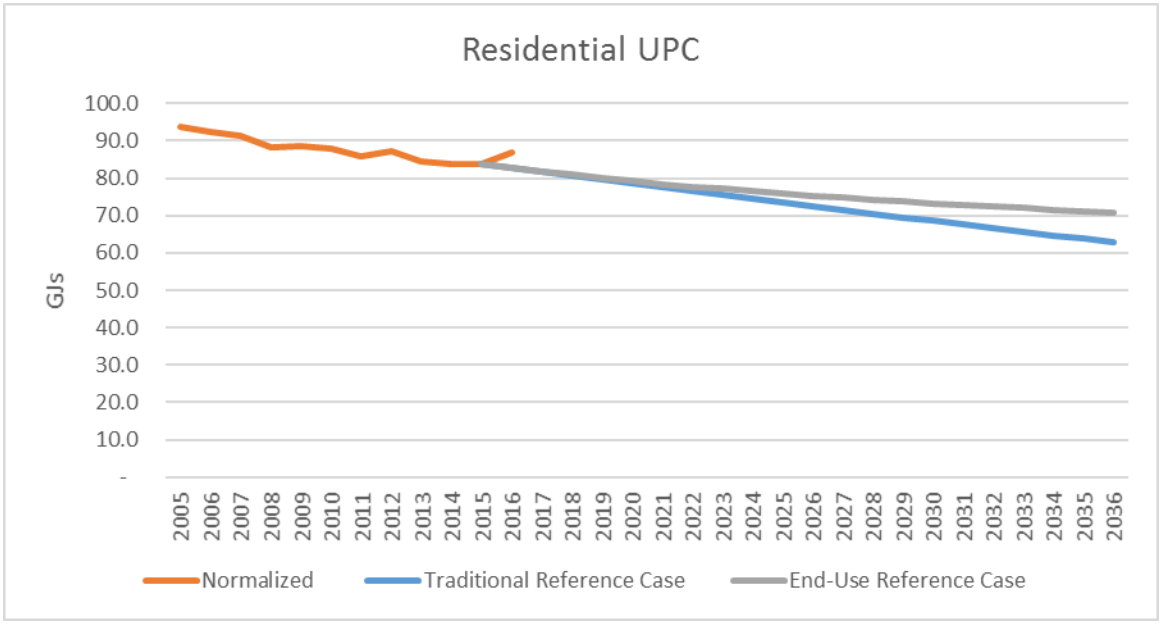
In response to BCUC IR 17.3, FEI provided graphs showing annual actual residential and commercial Use per Customer (UPC) from 2005 through to 2016.

53.1 On the same chart please provide the following graphs: (i) the normalized actual annual residential UPC from 2005 through to 2016; (ii) the Traditional method reference case UPC forecast from 2017 to 2036; and (iii) the End-Use method reference case UPC forecast from 2017 through to 2036.

Response:

Provided below is the same residential chart as used in the response to BCUC IR 1.17.3 which provided (i) the normalized actual residential UPC from 2005 to 2016, with the following added: (ii) the Traditional method reference case UPC forecast from 2017 to 2036; and (iii) the End-Use method reference case UPC forecast from 2017 through to 2036.

Figure 1: Normalized, Traditional and End-Use Reference Case Residential UPC 2005-2036



54.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Appendix B-3, p. 1; Exhibit B-2, BCUC IR 14.1, p. 43

Traditional Model Use per Customer Forecast - Residential

In BCUC IR 14.1, FEI was asked to "explain the pros and cons of using 3 years of historical data to forecast 20 years, when compared to using more years of historical data (for example 5 or 10 years) to forecast 20 years.

FEI responded by stating:

> Consistent with past practice, FEI uses the results from the most recent short-term use rate forecast for the start of the long-term forecast. This is the only way to ensure consistency between short and long-term filings so that use rate predictions for future years match. If FEI were to use different methods for the short and long-term forecasts then multiple use rate forecasts would exist for the same year, regions and rate schedules.
>
> Using different inputs to the time series methods will certainly result in different forecasts (for example using 10 years of historic data instead of three years) but it is not clear that a different result would also be a more accurate result.
>
> The traditional forecast presented in the LTRP is intended to provide a check on the end-use forecast results. If FEI were to start using untested methods (such as a 10 year time series) then it is not clear if the results would form a reliable check on the end-use method.

54.1 Please summarize in a table format the pros and cons of using (i) 3 years of historical data to forecast 20 years; versus (ii) more years of historical data (for example 5 or 10 years) to forecast 20 years.

Response:

	Pros	Cons
Three Years	Consistent with past practice Only way to ensure consistency between the short and long-term forecasts. Demonstrated reliability and accuracy.	FEI is not aware of any cons to the current Traditional three-year method.

	Pros	Cons
More Years	FEI is not aware of any pros to using an untested number of historic years to prepare a forecast with which to validate the End-Use forecast. To provide value as a validation tool the "Traditional" forecast has to use a proven method.	Would result in different forecasts for all years, including the early years of the long-term forecast where there is overlap with the short-term forecast. For example, if different terms were used, then it is probable that two different forecasts would exist for 2017. The Traditional Forecast is known to perform well and therefore is useful as a check against the newer End-Use forecast. If FEI were to change the method to use an untested number of historic years (such as five or ten), then the new method would essentially be an unproven third variant and comparing it to the End-Use forecast would not be meaningful.

1

55.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.1, p. 59; Exhibit B-2, BCUC IRs 10.1 and 10.1.1, p. 24

Difference between Traditional method and End-Use Method

On page 59 of Exhibit B-1, FEI states:

> Sections 3.2 and 3.3 set the stage by outlining FEI's base year customer distribution and annual demand and by discussing FEI's customer forecast which serves as the basis for both of the 2017 LTGRP's two annual demand forecast methods.

In response to BCUC IR 10.1, FEI confirms that FEI's traditional annual demand forecast method and FEI's end-use annual demand forecast method both utilize the same year end customer forecasts for residential, commercial and industrial customers.

In response to BCUC IR 10.1.1, FEI states:

> Each method uses a different approach for deriving its UPC and combining it with the customer forecast. As such, the root cause of the difference between the two forecast methods extends beyond UPC only.

55.1 Please explain the different approaches for how UPC is combined with the year-end customer forecast for: (i) residential; (ii) commercial; and (iii) industrial.

Response:

FEI consulted with Posterity to provide the following response.

As stated in the response to BCUC IR 1.10.1.1 both the Traditional and End Use methods combine the customer forecast with the UPC forecast to derive the annual forecast. By "combine" FEI means "multiply".

To clarify the response to BCUC IR 1.10.1.1 FEI:

1) Uses a different method to derive the UPC forecast for the Traditional and End Use methods;

2) Uses multiplication in both forecast methods to combine the residential and commercial use rate forecasts with the matching customer forecasts; and

3) Notes that differences in the resulting demand forecast are due to differences between the end use forecast UPC and the Traditional Forecast UPC. The method of combining the use rate and customer forecasts (multiplication) does not itself contribute to differing forecast results.

The following table shows how demand is calculated for each sector:

Method	Residential Demand	Commercial Demand	Industrial Demand
Traditional	Average UPC X Customers	Average UPC X Customers	Survey
End Use	Sum of End Use UPC X Customers	Sum of End Use UPC X Customers	Sum of End Use UPC X Customers

For the End Use method, UPC is a summation of annual energy consumption per customer for each energy end use. The end use values are developed from the REUS, NRCan data, the BC CPR, and other sources. To the extent information is available, they vary by region, dwelling type, and age of dwelling.

For the Traditional method the average UPC, derived using historic time series data is used for the residential and commercial forecasts. The industrial forecast is developed using a survey of industrial customers.

55.2 Please explain how the root cause of the difference between the two forecast methods “extends beyond UPC only”?

Response:

FEI consulted with Posterity to provide the following response.

The other key difference between the two approaches is that the 2017 LTGRP end-use annual demand forecast model operates at a higher degree of granularity than the traditional method. In the traditional method, that year’s average UPC for the rate class and region is multiplied by the year-end customers forecast to obtain overall annual demand. In the LTGRP model, the UPC is divided into consumption per customer for each energy end use, usually with different values for each customer segment, region, and rate class, each of which is changing each year. These individual end use consumption values are multiplied by the subset of the customer forecast for that customer segment, region, and rate class. The full level of detail is maintained throughout the calculations and it is only at the end that the values are rolled up for presentation purposes. The model is designed to present average values in convenient summary formats, but the underlying granularity is always available when more detail is needed.

56.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 16.2, p. 47; BCUC IRs 16.4 and 16.4.1, p. 48

Developing the End-use surveys

In response to BCUC IR 16.2, FEI states:

> FEI intends to conduct End-use Surveys every two to three years. The Residential End-use study takes approximately 30 months from start to finish, while the Commercial End-use study takes approximately 24 months. Projects typically span two to three calendar years depending upon project start date.

56.1 Please state when FEI intends to finish the next End-use Surveys that follow the 2017 Residential End-use Survey (REUS).

Response:

The next CEUS will be undertaken in 2019 and the next REUS will be undertaken in 2021. The 2021 REUS data will likely not be available until 2022.

In response to BCUC IR 16.4, FEI states: "The estimated final cost of the 2017 REUS is $325,000. This includes costs attributable to both FEI ($275,000) and FBC ($50,000). The final amount is still subject to change, as the project is still in progress."

In response to BCUC IR 16.4.1, FEI states: "The 2012 REUS cost $330,000, which includes $72,000 charged to FBC."

56.2 Please provide a table showing a breakdown of the costs for: (i) the 2012 REUS; and (ii) the 2017 REUS.

Response:

The following table provides the requested information.

REUS Budget	2012	2017*
Management & Planning		
Project Management	$13,090	$9,900
Client Meetings	$6,545	$2,450
Workplan Finalization	$4,085	$1,100
Needs Assessment Workshop	$5,745	$0

REUS Budget	2012	2017*
Preparation of Sample Plan and Sample	$6,393	$4,775
Survey Implementation		
Development of Questionnaires	$11,160	$7,575
Survey Fielding + Tabs	$77,870	$78,500
Mailing Costs	$59,500	$78,900
Incentives	$4,000	$4,000
Conditional Demand Analysis		
Data preparation	$7,410	$8,700
Data Analysis: Gas	$26,130	$24,900
Data Analysis: Electric	$16,130	$0
Comparison with Previous CDA Results	$3,660	$3,600
Reports	$17,140	8,700
REUS Reports		
Analysis of Survey Data	$23,200	$26,000
Trend Analysis	$7,120	$0
Change in Use Rates	$3,480	$0
Draft Reports - REUS	$23,400	$38,400
Final Reports - REUS	$3,480	$8,700
Presentation of Results	$6,755	$6,300
REUS Dataset Workshop	$2,328	$0
Subtotal	**$328,620**	**$312,500**

**The 2017 figure is still subject to change.*

Overall, the costs of the 2012 REUS and the anticipated final 2017 REUS are similar; however, within the budgets there are some variations.

- Management and Planning costs were lower in 2016. This is due to using the same research vendor for both studies and therefore being able to use the 2012 work plan as the basis of the 2016 study.

- Survey Implementation costs were similar in 2012 and 2017. The lower cost of development of the questionnaire were offset by a larger sample size ($26 thousand versus $25 thousand) and a higher number of responses. Mailing costs were also driven by higher postage rates and the inclusion of the cost of printing the reminder card in the Mailing Costs line for 2017.

- The Conditional Demand Analysis (CDA) costs are lower as there will be no FBC CDA at present.

- The REUS Report costs are similar to those in 2012. The 2012 study was the first combined (FEI and FBC) REUS. In pricing the study, the vendor underestimated the cost of producing two separate reports. The higher report costs in 2017 reflect the true cost of doing so. These increases have been offset by dropping the Trend Analysis and Change of Rate sections of the REUS report.

56.2.1 Please provide a discussion of any significant changes in line item costs between the 2012 REUS and the 2017 REUS.

Response:

Please refer to the response to BCUC IR 2.56.2.

57.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.4.6, p. 80; Figure 3-14, p. 81;

Exhibit B-2, BCUC IR 19.2-19.4, pp. 66-69

Renewable Natural Gas (RNG) Demand

In BCUC IR 19.1 FEI states:

> For residential and commercial customers, FEI uses historical participation to project future participation and combines that with calculated RNG use per customer. FEI then identifies specific prospective RNG customers that represent significant loads – such as the University of British Columbia - and adds those customers to the total.

In BCUC IR 19.3 FEI provides the following RNG reference case annual demand table:

Forecast Year	Reference Case RNG Annual Demand Forecast (GJ)
2017	238,016
2018	338,135
2019	502,948
2020	572,956
2021	628,180
2022	633,538
2023	638,960
2024	644,439
2025	649,991
2026	655,629
2027	661,340
2028	666,797
2029	671,568
2030	675,960
2031	680,366
2032	684,774
2033	689,184
2034	693,596
2035	698,011
2036	702,426

In BCUC 19.4 FEI states:

> There has been a sharp increase in interest from large, sophisticated customers over the past year. FEI believes that this is due to awareness,

ease of adoption, government policy and the current price. In addition we have seen a steady increase in residential and small commercial demand since the price of RNG dropped and the marketing efforts were increased.

57.1 Please confirm, or otherwise explain, that FEI has accounted for the increase in interest and potential demand from large, sophisticated customers described in FEI's response to BCUC IR 19.4 in its forecast of significant prospective RNG loads in response to BCUC IR 19.1.

Response:

Not confirmed. The forecast of RNG demand provided in the 2017 LTGRP and shown in table format in response to BCUC IR 1.19.3 included information pertaining to the increase in interest from large sophisticated customers as it was understood at the time that the RNG analysis was completed for the 2017 LTGRP. The response to BCUC IR 1.19.4 is referring to additional interest that FEI became aware of after the LTGRP analysis on RNG was completed. Please also refer to the response to BCUC IR 2.57.1.2.

FEI continues to update short-term forecasts for the purpose of ongoing management of the RNG program. These shorter-term forecasts that will more accurately account for demand within a one to two-year window are filed separately as part of the regular reporting for the RNG program. FEI also updates its LTGRP at regular intervals and considers the most recent practically available information when preparing forecasts for each iteration of the LTGRP.

57.1.1 Is this customer demand included in the annual demand table in FEI's response to BCUC IR 19.3? Please explain.

Response:

No. Please refer to the response BCUC IR 2.57.1. The data provided in response to BCUC IR 1.19.3 presents the Reference Case RNG demand as included in the LTGRP. FEI became aware of the increased interest cited in response to BCUC IR 1.19.4 after the RNG analysis for the 2017 LTGRP was completed. Also, refer to the response to BCUC IR 2.57.1.2.

57.1.2 If not confirmed, please discuss the effects, if any, the referenced increase in interest from customers over the past year would have on FEI's three forecast RNG trajectories? Please provide updated forecast RNG trajectories and accompanying data where relevant.

Response:

FEI updates its LTGRP at regular intervals and considers the most recent practically available information when preparing forecasts for each iteration of the LTGRP. By virtue of having to meet specific submission dates, each iteration of the LTGRP necessarily needs to represent inputs that capture a certain snapshot in time rather than a continuously updated stream of input data. While the LTGRP examines long-term demand, FEI provides short-term forecasts in due course as part of the annual reporting process established for the RNG program. As such, FEI provides in this response directional indications only of how the recent referenced increase in customer interest may affect future demand. FEI expects demand that will exceed the original forecast, at least in the near future (two-year timeframe). If the shape of future demand is similar to the shape modeled for the 2017 LTGRP, the recent increase in interest would have the effect of shifting the entire demand curve up by a fixed amount and could cause demand to increase somewhat more steeply due to the effect of residential customer growth.

In BCUC 19.4 FEI further states:

> In 2016 the Commission approved a new lower price for RNG…Since the time of the price change, FEI has seen a steady increase in the overall number of RNG customers. This suggests to FEI that price was a factor in the slowing uptake. FEI believes that the demand will more likely continue upward rather that flatten in the future but demand may be constrained by supply.

57.2 Has FEI performed any price elasticity analysis in relation to RNG demand? Please discuss.

Response:

FEI has performed a price elasticity analysis in relation to RNG demand. Per the response to BCUC IR 1.23.1 in the FEI 2015 Application for Approval of Biomethane Energy Recovery Charge (BERC) Rate Methodology proceeding (Project No. 3698850) (Exhibit B-5)[3]:

[3] http://www.bcuc.com/Documents/Proceedings/2015/DOC_45000_B-5_FEI-BCUC-IR-1-Response.pdf.

Using 2014 and 2015 data and multinomial regression, FEI has been able to estimate a demand curve for RNG for residential customers, and has also been able to determine an estimate of the elasticity of demand based on the relative probability of selecting a certain blend level at varying levels of RNG price premiums. Only residential data were analyzed as it was the only class that had adequate data points to meet the minimum degree of freedom to allow a statistical assessment of demand elasticity.

The analysis found that the elasticity is not constant across the various values of RNG premiums; additional details may be found in the referenced IR response. FEI has not performed any further investigation into the price elasticity of demand for its RNG product.

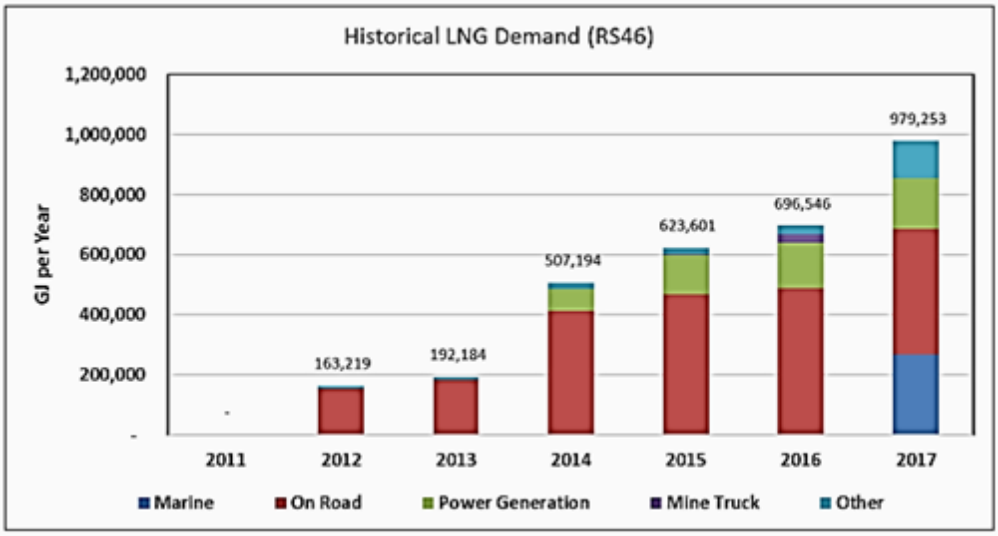
58.0 Reference: ANNUAL ENERGY DEMAND FORECASTING

Exhibit B-1, Section 3.4.7.2, p. 85; Section 2.4.1.2, pp. 53-54;

Exhibit B-2, BCUC IR 21.2, pp. 24-25; Exhibit B-4, CEC IRs 18.1-18.2, pp. 56-57

LNG Demand Forecast

In BCUC IR 21.2, FEI provides the following graph, illustrating historic LNG demand grouped by each market since 2011:



58.1 Please confirm, or otherwise explain, that the LNG marine demand is as a result of three BC Ferries and two Seaspan Ferries vessels.

Response:

Confirmed.

58.2 Please provide examples of industries or customers that would fall into the 'other' category.

Response:

The 'Other' category generally includes LNG demand for end uses that do not fit into the other categories. For example, 'Other' includes demand for LNG:

- exported to customers via ISO-containers;
- for R&D testing purposes;
- for peak shaving purposes; and
- other end uses that do not traditionally fit into the market segments specifically identified in the graph (marine, on road, power generation, mine truck).

FEI occasionally provides LNG to some utilities located in the Pacific Northwest for their own peak shaving requirements, and this demand is captured in the 'Other' category. FEI also provides LNG supply to other market area LNG suppliers located in Alberta and northeast BC during times LNG supply is required by these customers. This demand is also captured in the 'Other' category.

58.2.1 What are the main drivers behind the 'other' category seeing a significant increase in demand between 2016 and 2017?

Response:

Generally speaking, FEI supplied LNG to some customers that required supply due to outages they experienced at their own LNG production facilities, mainly in Alberta and northeast BC.

Additionally, FEI exported its first shipment of LNG to a customer in China via ISO-container in the latter half of 2017, which did not occur at all in 2016. Finally, FEI supplied LNG to a customer that was delivering it to different end uses in Washington State. As FEI did not know for certain the destination of the end-use application, this demand was captured in the 'Other' category.

58.2.2 Please explain why demand was relatively flat for the 3 preceding years.

Response:

Demand was relatively flat for the three preceding years primarily due to limited growth in the on-road LNG market and the cessation of Teck's pilot program for LNG mine haul trucks, which was halted in 2016. Demand flat-lined in the on-road market because there is currently a lack of a higher horsepower engine for the heavy duty on-road market suitable for operating conditions in our market in BC.

During this time, FEI was also developing the LNG market for the marine sector (with Seaspan and BC Ferries) that positively impacted LNG demand in 2017.

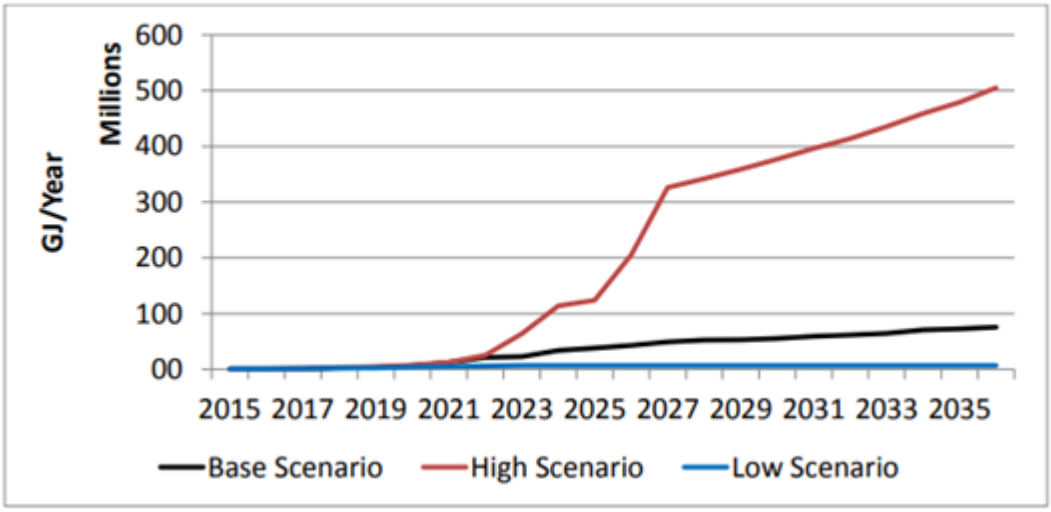
In CEC IR 18.1, FEI states:

> Although the International Maritime Organization will impose a sulphur emissions limit on *all* maritime traffic beginning in 2020, there is currently a sulphur emissions limit on all maritime traffic that specifically operate in designated Emissions Control Areas (ECAs). It is these coastal freight vessels, in addition to the short sea segment which is already adopting LNG that FEI is projecting to adopt LNG in the Low Scenario. A combination of stricter emissions limits and lower fueling costs versus current emission compliant fuels are expected to result in increased LNG adoption for these two (short sea and coastal freight) market segments before adoption is expected to occur for the trans-Pacific segment.

In CEC 18.2, FEI states:

> …the forecast capture rate includes a combination of existing LNG supply agreements that FEI currently has contractually in place with various customers, plus agreements that FEI expects to execute with customers with a high degree of certainty, plus a forecast of markets that could adopt LNG as a fuel over the planning horizon… At a high level has identified all potential adopters of LNG as a fuel based on discussions and engagement with these customers across all market segments. Based on this information, FEI then applied probabilities of each customer adopting LNG over the planning horizon.

Figure 3-16: Forecast Annual Demand from Long Term LNG Adoption Scenarios (2017-2036)



58.3 Please explain how the 2020 sulphur emissions limit on all maritime traffic will be imposed (for example, phasing by vessel size/vessel weight etc.)?

Response:

FEI's knowledge of how the sulphur emissions limits will be imposed is based on discussions with various regulatory agencies, such as Transport Canada, and various maritime classification societies. FEI's understanding of how emissions limits will be imposed is summarized below.

The International Maritime Organization (IMO) establishes the international rules and standards for the safety, security and environmental performance of international shipping. The signatories (state parties/ports) of the United Nations Convention on the Law of the Sea (UNCLOS) have rights and obligations in various maritime zones that must be exercised and fulfilled through the IMO. Basically, the Port State Control agencies, which are in charge of the inspection of foreign ships in national ports, verify that the condition of the ship and its equipment comply with the requirements of international regulations and that the ship is manned and operated in compliance with these rules.[4]

Flag States (in the case of Canada, the agency responsible is Transport Canada) cannot police themselves. Therefore, there are memoranda of understanding agreements (MOUs) to establish a control regime that guarantees minimum standards are met. Each Port State Control agency has a requirement to inspect the documents of at least 25 percent of the ships calling to a specific port. To identify the 25 percent to be inspected, the ports download the ship's record to assess the risk associated with the ship, and identify whether an inspection is warranted.

[4] http://www.imo.org/en/OurWork/MSAS/Pages/PortStateControl.aspx.

Specifically to impose the sulphur emissions cap, ships will be required to maintain fueling and fuel switch logs and a technical book of records. Fueling logs would show what the ship received; fuel switch logs are to record when the ship switches from high sulphur fuel oil (HSFO) to ultra low sulphur diesel (ULSD) or LNG to run in the emission control areas (ECA); and the technical book contains the maintenance logs and technical specifications of the engine and fuel on board the vessel. All three can be audited and can be used to monitor the implementation of the emissions cap.

Also, FEI understands that the IMO will engage in Focus Campaigns where the IMO will visit ports and inspectors and review the procedures to ensure continuity as each port will have their own procedure.

58.4 As the International Maritime Organization (IMO) will impose a sulphur emissions limits on all traffic beginning 2020, does FEI anticipate long term LNG adoption, 2036 and onwards, to be closer to the high scenario? Please explain.

Response:

FEI expects LNG demand to grow substantially on a global scale in response to the IMO's sulfur cap in 2020; however, the demand scenarios shown in the figure above represents LNG demand from marine vessels in the Pacific Northwest region.

As there remains uncertainty at this time in terms of how customers will comply with the stricter emissions limits, FEI has chosen to model the level of demand arising from the IMO sulphur cap in the High case rather than the Base case at this time. Since FEI prepares and submits LTGRPs on a regular basis, should FEI see this future scenario begin to unfold, it may be more appropriate to incorporate additional demand from international shipping in the Base case in the next or future LTGRPs.

58.5 Have the number of agreements and associated volumes FEI expects to execute changed as a result of the IMO emissions limit applying to all traffic? Please discuss.

Response:

The IMO announced its intention to impose a global sulfur limit on all maritime traffic as far back as 2008.[5] According to the IMO, "The date of 1 January 2020 was set in the regulations adopted in 2008. However, a provision was adopted, requiring IMO to review the availability of low sulphur fuel oil for use by ships, to help Member States determine whether the new lower global cap on sulphur emissions from international shipping shall come into effect on 1 January 2020 or be deferred until 1 January 2025. IMO's Marine Environment Protection Committee (MEPC 70), in October 2016, decided that the 0.50% limit should apply from 1 January 2020."

As a result of the timing of these IMO announcements, FEI has not experienced a change in the number of agreements and associated volumes as a result of the IMO emissions limit that was announced with certainty in 2016. However, FEI has experienced a marked increase in customer interest and inquiries in the past six months or so as crude oil prices have begun to increase. This increase in crude oil prices has also impacted prices for marine fuels around the world, thus explaining customer interest in lower priced fuel options such as LNG. To FEI's knowledge, there are only three pathways to comply with the emissions limit: (1) consume low sulphur marine fuel (e.g., diesel); (2) install exhaust scrubbers to strip out sulphur content from the flue exhaust; or (3) adopt natural gas in the form of LNG.

58.6 Please explain, with calculations where relevant, how FEI calculated the probabilities of LNG adoption for each potential customer.

Response:

The reference made to applying probabilities is based on a subjective measure of the engagement and discussions that FEI has had with various potential LNG customers. For example, FEI is currently engaged in discussions with two potential LNG adopters for their coastal freight marine vessels. However, although each of these two customers have expressed interest in adopting LNG, one of these two customers is further along in terms of already starting discussions with potential shipyard companies, marine engine providers and other providers of infrastructure that would be required for this customer to adopt LNG. This customer would be viewed as more likely to convert to LNG than the other customer who has not advanced to the same stage, but has shown interest in converting their vessels.

[5] http://www.imo.org/en/MediaCentre/HotTopics/GHG/Documents/FAQ_2020_English.pdf.

C. DEMAND SIDE RESOURCES

59.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, pp. 108 to 109

Exhibit B-2, BCUC IR 1.24.1

Demand-Side Measures Regulation B.C. Reg. 326/2008 (DSM Regulation), Section 3

Adequacy Measures

In its response to BCUC IR 1.24.1, FEI states:

> The table below contains no specific measures addressed at educating students enrolled in schools or post-secondary institutions in FEI's service area or financial or other resources provided to standards-making, regulatory or government bodies (requirements 3(1)(c), (d) and (e), respectively, of the DSM Regulation). This is due to the 2017 LTGRP C&EM [Conservation and Energy Management] energy savings forecast and expenditure estimates specifically excluding non-incentive expenditures that support or enable C&EM programs at the portfolio level, such as Enabling Activities (which includes resources provided to standards-making, regulatory or government bodies) and Conservation Education Outreach expenditures.

Section 3(1)(e) of the DSM Regulation states that a plan portfolio is adequate for the purposes of UCA section 44.1(8)(c) if it includes:

> one or more demand-side measures to provide resources as set out in paragraph (e) of the definition of "specified demand-side measure", representing no less than
>
> (i) an average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or
>
> (ii) an average of $2 million per year over the portfolio's period of expenditures

Table 4-4 of Exhibit B-1 shows the estimated reference case annual expenditures for all program areas, and Figure 4-5 illustrates estimated annual C&EM expenditures across all scenarios for all program areas.

59.1 Please explain what average annual expenditure levels have been assumed for measure(s) required under DSM Regulation subsection 3(1)(e) for the duration of

the 2017 LTGRP, and as applicable, compare to the expenditure levels outlined in DSM Regulation subsection 3(1)(e)(i) or 3(1)(e)(ii).

Response:

FEI consulted with Posterity to provide the following response. This response also addresses BCUC IRs 2.59.2 and 2.59.2.1.

Section 44.1(8)(c) of the UCA states that "*in determining under subsection (6) whether to accept a long-term resource plan, […] the commission must consider whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures* [emphasis added]". In the 2017 LTRGP FEI states in Section 4.2.1.2 (p. 96) that "*new adequacy requirements that are not met within the existing portfolio will be addressed in the upcoming expenditure schedule application to be filed after the 2017 LTGRP".* In Section 4.2.4 of the 2017 LTGRP FEI further states that "*FEI projects that it will continue to perform residential, commercial, industrial, low income, innovative technologies, conservation education and outreach as well as enabling C&EM activities. […] FEI will operationalize these activities via successive C&EM expenditure schedules. […] FEI's specific program offers will likely change to suit the evolving marketplace, legislative provisions (including future adequacy requirements), end-use technologies and FEI customer needs* [emphasis added]." As such, it is FEI's view that the 2017 LTGRP shows that FEI *intends* to pursue adequate, cost-effective demand-side measures as contemplated under section 44.1(8)(c) of the UCA.

As noted in the response to BCUC IR 1.24.1, the quantitative 2017 LTGRP C&EM analysis, in accordance with the BC CPR and the 2017 LTGRP C&EM analysis approaches, does not forecast education programs for school and post-secondary students and financial or other resources provided to standards-making, regulatory or government bodies (DSM Regulation requirements 3(1)(c), (d) and (e), respectively). These items are not calculated since they represent non-incentive expenditures that support or enable C&EM programs at the portfolio level without resulting in direct and specific energy savings.

It is theoretically possible to make an exception to this analysis approach in order to include forecast values for items 3(1)(c), (d) and (e) but this would cause additional costs (e.g., up to $8 thousand of estimated Posterity consulting time) while providing limited additional insight. In order to implement such an exception, FEI would first have to forecast the level of expenditures associated with items 3(1)(c), (d) and (e). Since the evolution of such expenditures is closely related to regulatory and policy requirements across the forecast horizon (which could change dramatically across 20 years), FEI would have limited factual basis for its forecast. FEI would subsequently import these forecast expenditures into the C&EM analysis module of its forecast model. Here, these additional expenditures would directionally increase total forecast C&EM expenditures and tend to decrease TRC cost effectiveness test results. Depending on the level of forecast expenditures, this may cause the forecast C&EM portfolio to fail cost effectiveness test requirements in certain forecast years and under certain conditions. In such a case, FEI

would have to manually remove marginal C&EM measures in order to raise portfolio cost effectiveness test results. Such an activity is more akin to program design rather than long-term forecasting. FEI believes that such detailed trade-offs between individual energy conservation measures and adequacy requirements are best performed during program design or when preparing a C&EM expenditure schedule in order to avoid in advance limiting the addressable C&EM potential that program managers consider when designing their programs and preparing expenditure schedules.

59.2 Please discuss the feasibility and impact of an exception to FEI's approach of excluding non-incentive activities from the 2017 LTGRP C&EM Analysis, to include measure(s) that address requirements 3(1)(c), (d) and (e) of the DSM Regulation.

Response:

Please refer to the response to BCUC IR 2.59.1.

59.2.1 Please provide further explanation as to why, in the view of FEI, the 2017 LTGRP should be deemed adequate for the purposes of section 44.1(8)(c) of the UCA, in the absence of forecasted expenditures and energy savings for these measures in the 2017 LTGRP C&EM Analysis.

Response:

Please refer to the response to BCUC IR 2.59.1.

60.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-2, BCUC IR 1.25.3

Future Filings

In its response to BCUC IR 1.25.3, FEI states:

> FEI has also used the 2017 LTGRP C&EM analysis as a "reasonableness check" in its development of the 2019-2022 Demand Side Management Expenditures Plan (DSM Plan). FEI builds its DSM Plans from the measure level and program level up and then compares the results of this process to the LTGRP results to see if there are any significant inconsistencies. Any inconsistencies identified then prompt a further review of DSM Plan data inputs to determine if adjustments are required. Future LTGRPs will include new C&EM analyses that will inform future expenditure schedule applications. Ideally, a new LTGRP will be submitted to the Commission prior to submitting each successive C&EM expenditure application; however, many factors influence the timing of each submission and it is not always possible to line up all the studies that inform each application so that this sequence of filing can always be achieved. FEI DSM Plans do not incorporate scenarios hence they use the Reference Case as the key directional guidance.

60.1 Please clarify the role of the Upper and Lower Bound scenarios with respect to the development of expenditure schedules.

Response:

As stated in FEI's response to BCUC IR 1.25.3, FEI uses the LTGRP C&EM analysis as a 'reasonableness check' in its development of expenditure schedules. This reasonableness check considers all scenarios developed. For instance, if a forecast in the DSM Plan falls outside the Upper and Lower Bound scenarios of the LTGRP C&EM analysis, FEI further reviews the applicable DSM Plan data inputs to determine if adjustments are required. It is important to note that FEI does not purposefully constrain its DSM Plan forecast by the LTGRP Upper and Lower Bound scenarios as new data inputs, market data and policy direction changes throughout the DSM Plan development process may result in different forecasts.

60.2 Please summarize the key studies that will be required to feed into FEI's next LTGRP, and the estimated duration to complete these studies.

Response:

FEI interprets this request to refer to studies that need to be completed by or with significant involvement from external third parties (consultants) rather than those regular studies completed by FEI staff from time to time as regular inputs into the LTGRP. FEI anticipates that the following studies will provide input into the next LTGRP:

- REUS - FEI plans to undertake the next REUS in 2021 and expects to have results available in 2022.
- CEUS – FEI plans to undertake the next CEUS in 2019 and expects to have results available in 2020.
- CPR – FEI anticipates that this study will take place in 2020 and 2021 and is estimated take 12 to 24 months to complete. The next CPR will likely use the 2017 REUS findings since results from the next REUS (noted above) will likely not be ready in time for this next CPR.
- End-Use Annual Demand Forecast Analysis – This work will require inputs from the REUS and CEUS studies as well as the CPR and is estimated to take between 6 and 10 months.
- LTGRP Demand-side Management Analysis – This work will require inputs from the End-use Forecast results and the CPR.
- Continued exploration of the End-use Peak Demand modelling – this work will require inputs from the End-use Forecast and the CPR.
- Other studies not yet determined that might be required to meet Commission Directives and for which FEI is currently unable to provide timing estimates.

FEI also anticipates that it may need to conduct some additional studies or investigations in order to gain further insights into changes in the planning environment between now and the preparation of the next LTGRP. FEI is unable to fully define the scope or duration of such work at this time.

61.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-2, BCUC IR 1.26.2

Modified Total Resource Cost Test

In its response to BCUC IR 1.26.2, FEI submits the following table:

Scenario	Percentage of The Estimated C&EM Portfolio where the MTRC Has Been Applied				
	2017	2020	2025	2030	2036
Reference Case	10%	20%	31%	41%	36%
Upper Bound	14%	23%	52%	52%	48%
Lower Bound	0%	24%	25%	35%	4%

61.1 Please discuss the feasibility of including a 40 percent Modified Total Resource Cost (MTRC) cap in the 2017 LTGRP C&EM analysis.

Response:

This response also addresses BCUC IRs 2.61.1.1 and 2.61.1.1.1. FEI consulted with Posterity to provide the following response.

In theory, the C&EM analysis module of the 2017 LTGRP forecast model could implement a 40 percent MTRC cap for the 2017 LTGRP C&EM analysis but this would require manually iterating individual measures which, as noted in FEI's response to BCUC IR 1.26.1, is labor intensive and more akin to program design than long-term forecasting. For this reason, the BC CPR elected to apply the MTRC to the residential sector only and the 2017 LTGRP C&EM analysis is informed by the BC CPR approach. As noted in Section 4.2.4 of the Application, FEI will operationalize its C&EM activities throughout the planning horizon via successive C&EM expenditure schedules that will suit the evolving marketplace, legislative provisions, end-use technologies, and FEI customer needs.

The manual and iterative process would require two steps:

1. Run the C&EM analysis module with [Pass TRC] [OR] [Pass MTRC] as the passing criterion for every measure in all sectors; and

2. Iteratively reset the passing threshold for the MTRC cost effectiveness test until the percentage of savings attributable to measures that pass the MTRC but not the TRC is equal to 40 percent.

The Step 2 percentage would vary by year. The C&EM module is the most complex part of the 2017 LTGRP forecast model and would take several hours to run each iteration of the scenarios

for all three customer sectors. Depending on how quickly these iterations converge to the 40 percent target for each year and scenario, this may take up to four person-weeks of Posterity consulting time, a value of approximately $24,000.

FEI is unable to provide a full quantitative analysis of the impact of assuming a 40 percent MTRC cap on the C&EM portfolio for all years and all scenarios without performing the iterative process described above. Directionally, applying this assumption would slightly increase the forecast C&EM energy savings and expenditures in the Reference Case. Average TRC benefit/cost ratios for measures included in the portfolio would be expected to drop slightly. In the Upper Bound scenario, applying the 40 percent MTRC cap across the entire C&EM portfolio would decrease forecast C&EM energy savings and expenditures in most years. Average TRC benefit/cost ratios for measures included in the portfolio would be expected to increase. In the Lower Bound scenario, applying the 40 percent MTRC cap across the entire C&EM portfolio would increase forecast C&EM energy savings and expenditures. Average TRC benefit/cost ratios for the measures included in the portfolio could be expected to decrease.

Applying a 40 percent MTRC cap to the C&EM portfolio would only be expected to remove C&EM measures in years where the MTRC percentage currently exceeds 40 percent. Please refer to the chart FEI provided in the response to BCUC IR 1.26.2, for guidance on when this would occur. For the most part, this is applicable to the Upper Bound scenario only.

61.1.1 Please provide analysis (quantified if possible) of the impact of assuming a 40 percent MTRC cap on the C&EM portfolio for all years and all scenarios, upon projected energy savings, expenditures, and overall TRC benefit/cost ratios.

Response:

Please refer to the response to BCUC IR 2.61.1.

61.1.1.1 Please confirm whether implementing a 40 percent cap would result in the removal of certain C&EM measures from the forecasted C&EM portfolios.

Response:

Please refer to the response to BCUC IR 2.61.1.

62.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-1, p. 100

Exhibit B-2, BCUC IRs 1.26.4 and 1.26.5

Exhibit B-3, BCSEA IR 1.25.3.1

Avoided Costs of DSM

On page 100 of Exhibit B-1, FEI summarizes the assumptions for the Lower Bound scenario, which includes accelerated non-price carbon policy action.

In its response to BCUC IR 1.26.4, FEI states:

> The ZEEA [Zero-Emission Energy Alternative] value used is $27.78 $/GJ. FEI used $100 per MWh, which was the published LRMC [Long Run Marginal Cost] value for BC Hydro at the time the analysis was conducted as the ZEEA value and applied a conversion ratio of $1 per MWh = $0.2778 per GJ.

In its response to BCUC IR 1.26.5, FEI states: "FEI's ZEEA is informed by BC Hydro's LRMC of procuring renewable electricity."

62.1 Does FEI consider that accelerated non-price carbon policy action could include support for clean or renewable electricity generation?

Response:

The Non-Price Carbon Policy Action critical uncertainty accounts for the impact of building codes (for new construction), appliance standards (for retrofits in existing buildings or appliance installations during new construction), and any other undetermined effects or policy actions that may result in customers switching away from natural gas to another end-use fuel type[6].

The 2017 LTGRP scenario analysis includes a mechanism that mandates minimum levels of fuel switching across the planning period for scenarios that are subject to the "Accelerated" outcome on the Non-Price Carbon Policy Action uncertainty. This refers to scenario variables such as the percentage of commercial buildings that connect to district energy systems, percentage of residential dwellings and apartment buildings that switch their space heating, etc. as a result of undetermined future policy actions that may compel customers to switch from natural gas to another fuel type. (Please refer to Appendix B-1: Section 1.2.1.4.3 "Other Policy Actions that May Result in Fuel Switching" of the Application for details). As such, it is reasonable to assume that an example of future policy action could include further support for clean or renewable electricity generation.

[6] Appendix B1. Section 1.2.1.4 Non-Price Carbon Policy Action.

62.1.1 If yes, please explain if FEI considers that this could lead to a reduction in BC Hydro's LRMC?

Response:

FEI is hesitant to speculate on impacts of non-price carbon policy action on BC Hydro's LRMC. In response to BCUC IR 1.26.5.1, FEI recognized it is possible that non-price carbon policy action might influence BC Hydro's LRMC value, however, FEI has no way of predicting how much, in which direction, or if/when such changes might occur.

62.2 For a comparison with the ZEEA value, please provide FEI's LRMC value for acquiring renewable natural gas resources.

Response:

When referring to renewable natural gas, FEI means a purified form of biogas, which is interchangeable with conventional natural gas. The most reasonable LRMC for acquiring renewable natural gas is the maximum acquisition price established by the BC Ministry of Energy and Mines. This value is $30 per GJ.

For clarity, biogas energy is generated from the decomposition of organic waste with the resulting methane gas captured and used as a fuel source. Sources of biogas energy include landfill sites, sewage treatment plants and anaerobic digestion organic waste processing facilities. This biogas can be used directly to run an engine and generator to produce electricity. In its 2016 Long Term Electric Resource Plan (LTERP), FBC identified biogas electricity generation resource options with a Unit Energy Cost (UEC) ranging from $77- $101 (2015$)[7] per MWh. The UEC is the annualized cost of generating a unit of electrical energy for a specific resource option, expressed in $ per MWh.

[7] FBC 2016 LTERP. Section 8: Resource Options. Table 8-4: Supply Side Resource Options Unit Cost Summary. Ex. B-1, filed November 30, 2016.

In its response to BCSEA IR 1.23.5.1, FEI states:

> FEI does include a distribution adder that represents avoided distribution system improvements in its assessment of DSM cost effectiveness; however, this value does not include deferral of transmission system capacity related infrastructure.

62.3 Please confirm the value of the distribution adder and briefly outline the assumptions underpinning this value.

Response:

The distribution adder included in the 2017 LTGRP C&EM analysis cost effectiveness tests is equivalent to the System Improvement (SI) charge as reported in the FEI's Main Extension Annual Report. The SI charge as reported in the 2017 Main Extension Annual Report (filed on March 28, 2018 for Year Ended 2017) is $0.21/GJ. The SI charge is a per gigajoule charge that represents a proxy for the incremental distribution system improvement costs associated with growth in volume not attributable to a specific customer. In the context of C&EM programs, this SI charge serves as an avoided system improvement cost associated with reduction in natural gas demand from C&EM activities, which is the opposite effect from growth.

The method for calculating the SI charge was originally approved in Commission Order G-152-07 and accompanying decision for FEI's (Terasen Gas at that time) System Extension and Customer Connection Policies Review in 2007. The methodology remains unchanged, and per Commission Letters L-67-11 and L-19-12, the SI charge is to be updated on an annual basis as part of FEI's Main Extension Annual Report. The SI charge is based on a five year forecast of system improvement costs and the growth in peak day demand over that period. The first step in the calculation is to divide all the system improvement costs by the growth in peak day to arrive at a cost per peak GJ added. The cost per peak GJ is then converted into a charge that is applied to all of the GJs consumed on an annual basis. The conversion from peak GJ to GJ consumed annually is carried out by converting the peak GJ figure into annual consumption by dividing the peak GJ by 365 days and the load factor. The capital carrying cost is used to arrive at a charge applied to all GJs consumed throughout the analysis period (currently 40 years)[8].

[8] Per Decision G-147-16 for FEI's 2015 System Extension Application, the analysis period is updated to 40 years from 20 years.

63.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-2, BCUC IRs 1.27.2, 1.27.3;

BCUC IRs 1.27.8, 1.27.8.1, 1.27.9 and 1.28.1

C&EM Analysis and Results

In its response to BCUC IR 1.28.1 FEI states:

> The 2017 LTGRP Reference Case holds fuel shares constant per building type and region, while the 2017 LTGRP CPR Reference Case assumes some fuel shares to change over time.

63.1 Please explain why the 2017 LTGRP Reference Case holds fuel shares constant per building type and region.

Response:

FEI consulted with Posterity to provide the following response.

The 2017 LTGRP end-use forecast method seeks to minimize uncertainty for the inputs of the Reference Case across the planning horizon. FEI expects that, across the planning horizon, fuel shares can be sensitive to multiple factors, such as energy and emissions policy, customer preferences and energy prices. As a result, the timing, direction and magnitude of fuel share changes is uncertain across the planning horizon. As such, FEI, after consultation with the Resource Planning Advisory Group, elected to hold fuel shares constant in the Reference Case in order to permit a cleaner analysis of fuel share changes motivated by the 2017 LTGRP's critical uncertainties throughout the 2017 LTGRP scenario analysis.

63.1.1 Does FEI forecast any changes to fuel shares over the planning horizon that would not be caused by the drivers assumed in the Upper and Lower Bound scenarios?

Response:

In the LTGRP annual demand forecast, FEI only adjusted fuel share changes caused by changes in commodity prices, carbon prices, non-price carbon policy action, RNG demand, CNG/LNG demand or industrial point loads (the drivers in the future scenario forecast analysis). However, it is possible that additional factors may influence fuel shares. Such factors may include naturally evolving customer preferences or technological change. Section 1.2.6 of Appendix E of the Application discusses some emerging technologies, such as end-use carbon

sequestration, that may significantly change the impact of energy and emissions policy on natural gas fuel shares.

FEI's response to BCUC IR 1.27.2 states:

> Expressing the forecast C&EM energy savings as a percentage of projected sales (noted on page 103 of Exhibit B-1) as annualized average across 20 years yields the following results: 0.36 percent for the Reference Case, 0.29 percent for the Upper Bound, and 0.26 percent for the Lower Bound. The data noted on page 103 of Exhibit B-1 but expressed for 2030 yields the following results: 5.39 percent for the Reference Case, 4.36 percent for the Upper Bound, and 5.07 percent for the Lower Bound.

FEI's response to BCUC IR 1.27.3 explains the differences in projected energy savings from FEI's approach to C&EM compared to jurisdictions that use Energy Efficiency Resource Standards.

63.2 Please provide a summary of any analysis undertaken by FEI regarding energy savings that are being contemplated in other jurisdictions that use a policy framework similar to FEI.

Response:

FEI has not conducted an analysis of energy savings approaches being contemplated in other jurisdictions. To assist with answering this question, FEI had E Source (an energy industry analytics consultancy) conduct an industry review. FEI interprets "policy framework" to be a very broad term and something which varies significantly across all jurisdictions. In the interest of being responsive to this question, FEI has narrowed this down to mean utilities that are required to report societal cost test results for DSM. This can be considered somewhat similar to the MTRC test results that FEI is required to report.

The table below displays E Source's findings (converted into percentage terms by FEI) for utilities that report on a societal cost test. E Source was only able to source forecast energy savings for the years 2018 through to 2020 and sales for 2016. As listed in the table, FEI's percentage of forecast energy savings to overall sales is smaller than that of most of the utilities with societal cost test reporting. A reason for this could be that these utilities have societal cost tests that enable natural gas DSM programs to be cost effective that would not be enabled to be cost effective under British Columbia's DSM Regulation hence enabling more energy savings compared to sales than would be possible for FEI. This reasoning is speculative, however, as

1 FEI has not had time to investigate all of the policy constructs associated with the utilities listed
2 in the table below.

Gas Utilities with SCT	2018 Forecast Energy Savings/2016 Sales	2019 Forecast Energy Savings/2016 Sales	2020 Forecast Energy Savings/2016 Sales	# of Customers
CenterPoint Energy - Minnesota	1.19%	1.24%	N/A	N/A
Central Hudson Gas & Electric	2.04%	2.04%	2.04%	261,411
Great Plains Natural Gas Company	7.52%	7.55%	N/A	N/A
MidAmerican Energy - IL	5.88%	N/A	N/A	84,901
Minnesota Energy Resources Corporation	6.51%	6.64%	N/A	235,000
National Fuel - NY	4.01%	4.01%	4.01%	740,000
National Grid - Brooklyn Union Gas	1.42%	1.38%	1.38%	1,017,000
National Grid - Key Span Gas East Co	0.77%	0.76%	0.76%	N/A
National Grid - Niagara Mohawk	3.23%	2.99%	2.99%	1,323,415
New York State Gas & Electric	1.68%	1.68%	1.68%	682,633
Orange & Rockland Utilities, Inc.	0.55%	0.55%	0.55%	144,686
Rochester Gas & Electric	2.64%	2.64%	2.64%	293,122
Southwest Gas Corporation - AZ	7.54%	N/A	N/A	2,000,000 (AZ, CA, NV)
Washington Gas - MD	7.27%	8.67%	9.74%	1,000,000
Xcel Energy - Minnesota	3.30%	3.29%	N/A	1,269,408
FortisBC Energy Inc.	0.52%	0.46%	0.46%	995,082

Notes:

"N/A" means insufficient data was available to complete the percentage calculation

All FEI data pertains to the 2017 LTGRP Reference Case

Energy savings are annual unless otherwise noted

63.2.1 Please describe any significant differences between FEI's forecasted energy savings in the 2017 LTGRP C&EM Analysis and energy savings projected in other jurisdictions.

Response:

Please refer to the response to BCUC IR 2.63.2.

BCUC IR 1.27.8 provides estimated Cost of Conserved Energy (CCE) results (in $/GJ) for each program area. BCUC IR 1.27.8.1 explains why the overall CCE values increase over time.

63.3 Please explain why CCE values decline over time in the residential program area.

Response:

FEI consulted with Posterity to provide the following response.

As noted in the response to BCUC IR 1.27.8.1, the 2017 LTGRP C&EM analysis calculates the average CCE for each scenario by the mixture of technical potential measures that pass the cost effectiveness test and thus result in participant uptake in each C&EM scenario. The increase in CCE for the total C&EM portfolio appears to be due to the mix of measures containing more measures with lower measure costs at the beginning of the planning horizon.

Likewise, the decline in CCE over time in the residential program area appears to be due to measures with lower costs relative to energy savings becoming more prevalent in the measure mixture over time. The following example illustrates this change in the Reference Case. In 2017, the following measures contribute most significantly to residential C&EM potential:

- Efficient Fireplaces, with CCE of $0.9/GJ, accounts for 33.5 percent of the 2017 residential market potential;

- Non-condensing Gas Storage Water Heaters, with CCE of $2.8/GJ, accounts for 14.3 percent of the 2017 residential market potential;
- Wall Insulation, with CCE of $5.1/GJ, accounts for 14.5 percent of the 2017 residential market potential;
- R-2000 Standard New Homes, with CCE of $5.3/GJ, accounts for 4.2 percent of the 2017 residential market potential; and
- Condensing Gas Tankless Water Heaters, with CCE of $21.8/GJ, accounts for 23.4 percent of 2017 residential market potential.

In contrast, the following measures contribute most significantly to residential C&EM potential in 2030. The largest difference between the two years is the decreased contribution from the Condensing Gas Tankless Water Heaters which exhibit a high CCE.

- Efficient Fireplaces, with CCE of $0.9/GJ, accounts for 18.8 percent of the 2017 residential market potential;
- Smart Thermostats, with CCE of $4.0/GJ, accounts for 18.0 percent of the 2017 residential market potential;
- ENERGY STAR Home, with CCE of $4.8/GJ, accounts for 9.4 percent of the 2017 residential market potential;
- Furnace Early Retirement, with CCE of $6.9/GJ, accounts for 17.8 percent of the 2017 residential market potential; and
- Condensing Gas Tankless Water Heaters, with CCE of $21.8/GJ, accounts for 8.3 percent of 2017 residential market potential.

FEI's response to BCUC IR 1.27.9 illustrates the forecasted rate changes from FEI's C&EM activity.

63.4 Please briefly explain the differences in rate change between the Reference, Upper Bound and Lower Bound scenarios.

Response:

The differences in the forecast rate changes from C&EM activities between the three different scenarios (Reference Case, Upper Bound, and Lower Bound) are primarily due to the difference

in the amount of C&EM expenditures as well as the natural gas demand forecast over the planning horizon. FEI notes that increases in C&EM expenditures and decreases in natural gas demand will both put upward pressure on delivery rates.

Based on the estimated annual C&EM expenditures discussed in Section 4.2.3.2 and shown in Figure 4-5 of the Application, the C&EM expenditures for the Reference Case is the highest out of the three scenarios at approximately 6 percent more than the Upper Bound scenario and at approximately 33 percent more than the Lower Bound scenario. Over the same analysis period, as shown in Figure 4-1 of the Application, the natural gas demand forecast for the Reference Case remains relatively flat with a slight decrease of 2.4 percent from 2015 to 2036, as opposed to the 18.7 percent increase in natural gas demand for the Upper Bound scenario from 2015 to 2036, and the 46.9 percent decrease in natural gas demand for the Lower Bound scenario from 2015 to 2036. Combining the effect of the highest forecast C&EM expenditures and the relatively flat forecast natural gas demand over the analysis period, the Reference Case has both the highest cumulative and compound annual rate changes out of the three scenarios.

For comparison between the Lower Bound and Upper Bound scenarios, the Lower Bound scenario has the lowest compound annual rate changes for C&EM activities because of the lowest C&EM expenditures forecast out of the three scenarios; however, when combining this with the significant decreases in natural gas demand forecasted for the Lower Bound (a decrease of 46.9 percent for Lower Bound which puts upward pressure on rates versus an increase of 18.7 percent for the Upper Bound which puts downward pressure on rates), the net result is a higher cumulative rate increase at 17 percent over the planning horizon. This compares to a 12 percent increase estimated for the Upper Bound over the same analysis period.

63.5 Please discuss the extent to which FEI considered rate impacts in its development of the 2017 LTGRP C&EM Analysis.

Response:

As noted in the response to BCSEA IR 1.18.1, the 2017 LTGRP C&EM analysis incorporates all cost effective C&EM measure activity and its results indicate the outcome of pursuing all cost effective energy savings potential. This estimated outcome takes into account program experience and technology diffusion but does not take into account operational program delivery factors. As such and in order to avoid a priori limiting the analysis results, FEI did not consider rate impacts as an input into the 2017 LTGRP C&EM analysis; rather, rate impacts represent an output of the analysis. When considering these results, it is important to note that C&EM

program participants will tend to benefit from overall cost savings on the commodity, midstream, tax and delivery components of their total bill.

FEI notes that, as discussed in Section 8.6 of the Application, the 2017 LTGRP rate impact analysis is not indicative of a detailed rate forecast; rather it is simply a 20-year directional view of FEI's delivery rates over time due to FEI's forecast natural gas demand and potential activities. In addition to the analysis in Section 8.6 of the Application, Section 4.2.3.3 also provides UCT cost effectiveness test results which display an extra perspective on the utility cost of C&EM activity.

64.0 Reference: DEMAND SIDE RESOURCES

Exhibit B-2, BCUC IR 1.29.1; BCUC IR 1.29.2.1.1

Exhibit B-3, BCSEA IR 1.23.3.1

Peak Demand

In its response to BCUC IR 1.29.1, FEI states:

> FEI is conducting a pilot project on advanced meters for residential and commercial customers that could provide hourly or more frequent meter readings. As part of that pilot, FEI will be examining the ability of such meters to provide improved data for analyzing end use trends which might lead to a better understanding of the impacts of C&EM activities on peak demand.
>
> …
>
> FEI expects that this pilot will also provide insights into whether or not demand response programs (please also refer to the response to BCUC IR 1.29.1.1), other than industrial curtailment as noted above, would potentially be effective in reducing or shifting peak demand.

In its response to BCSEA IR 1.23.3.1, FEI states:

> FEI believes that many years will be required to establish the measurement solutions and develop the end-use method to a point where a reliable determination of the impacts of DSM on peak demand projections and capacity related infrastructure investments can be made.

64.1 Does FEI consider that improved understanding of the impacts of C&EM activities on peak demand is contingent on the success, or otherwise, of the pilot project on advanced meters?

Response:

FEI believes that having advanced meters in place will provide critical information needed to analyze peak demand trends based on better end-user consumption information. However, FEI would like to clarify that:

a) advanced metering will not provide all of the needed information for such peak demand analysis;

b) the current advanced metering pilot project is not designed to test this functionality specifically; and

c) there may be other ways to gather peak demand data that could be further explored and, if found appropriate, implemented.

These clarifications are further explained below.

a) Advanced metering, if implemented across a broad enough customer base to provide reliable data, should allow FEI to analyze customer usage trends associated with peak period events at a much more granular level than current infrastructure allows. However, FEI would still need some understanding of the energy equipment and consumption patterns beyond the customer meters in order to understand the impact of changing equipment technology on peak demand. This type of information might be gained through end use surveys of those customers for which AMI is deployed, through some sort of sub-metering program that would measure consumption at the end-use equipment, through sufficient pre and post measure installation monitoring of hourly load profiles, or some combination of these information sources.

b) The objectives of the current AMI pilot project are primarily focused on validating operational impacts and data collection performance as opposed to analyzing customer use trends. Thus, FEI's view of the success of the pilot study will be based on these objectives rather than on its usefulness in analyzing peak demand trends. However, the pilot is expected to confirm that more granular consumption data can be captured and provides the opportunity to assess how useful the information can be (for example, how the hourly data compares to the peak hour estimates generated from monthly consumption data).

c) An example of another method to gain a more accurate understanding of customer demand during peak period events could be to install metering and data collection equipment at the end-use equipment on an adequate sampling of customer premises. Although FEI has done a preliminary survey of potential technologies, it has not conducted a full assessment of the practicality and costs of this type of study.

64.1.1 If successful, does FEI plan to undertake further pilots or scaled up projects? Please summarize potential timelines for implementing further projects.

Response:

Please refer to the response to BCUC IR 2.64.1 regarding the measuring of success of the AMI pilot study. At this time a decision has not been made with regard to additional studies or an application for implementation of a full AMI project. FEI estimates that if a full AMI project is pursued, the earliest the utility would be able to begin acquiring consumption data useful in the analysis of peak demand trends would be five years from the decision to proceed. If additional studies or limited project scale-ups are pursued, this timing would be extended.

64.1.1.1 What other activities, besides advanced metering projects, does FEI anticipate could be required to achieve a better understanding of the impacts of C&EM activities on peak demand, and the potential for demand response programs? Please summarize which activities could be feasible ahead of FEI's next LTGRP.

Response:

Additional activities that could help in better understanding the impacts of C&EM activities on peak demand include:

- Refining hourly load profiles of natural gas end-use equipment where possible within FEI and to the extent possible with available metered data from jurisdictions where advanced metering or end-use measurement is available;
- Improving understanding of new commercial and near commercial gas end-use equipment technologies to inform future annual and peak demand forecasts;
- Explore marketplace options for cost effective technology for measuring appliance level demand trends;
- Improving understanding of the impact of potential electrification programs being planned or proposed by BC Hydro if such information can be obtained;
- Analyzing the results of UPC_{peak} determined in future base years against the estimates projected from the end-use peak demand forecast method;
- Developing and Implementing customer surveys focused on understanding expected peak demand behavior or responses;

- Improving understanding and methods to examine, by customer segments, peak demand response to C&EM programs; and

- Improving understanding of programs that are most effective at targeting peak demand reductions.

FEI cannot confirm at this time if the information needed to complete all or any of these activities will be sufficiently available in time to fully inform the next LTGRP. FEI does believe that continued examination of the end-use peak demand forecast method is an important activity.

64.1.2 Is FEI aware of similar advanced metering programs undertaken in other jurisdictions? If yes, please briefly summarize and highlight any potentially useful findings for FEI.

Response:

Yes, FEI is aware of Advanced Metering Infrastructure (AMI) projects or programs in other jurisdictions.

Enbridge Gas Distribution and Union Gas in Ontario are exploring an advanced metering pilot project and SaskEnergy began mass deployment of AMI in late 2013 after prior system testing. Currently, most of that deployment is complete. PG&E in California completed a 6 year deployment of AMI technology for its approximately 4.5 million gas customers in 2012.

In addition to these, an industry review conducted by E Source (an energy industry analytics consultancy) identified another 10 utilities in the US that have deployed or are currently in the process of deploying smart meters for gas customers. Two of these utilities, SoCalGas in California and DTE Energy in Michigan, have documented some evaluation of their gas AMI programs. These organizations are finding:

- AMI is necessary for the detailed evaluation of DSM and DR programs; and

- Smart meter campaigns are effective at producing energy savings in the heating season through conservation programs; but

- Direct impacts on peak demand reduction due to some DR pilot programs conducted by SoCalGas have not yet produced statistically significant results.

PG&E's experience shared with FEI through presentations and industry papers has highlighted several useful findings. FEI has found that organizations widely deploying AMI such as PG&E are able to effectively provide aggregated accurate daily profiles for very specific groups of customers such as specific commercial sectors, specific premise types and that results based on hourly metering provided, in many cases, results that were quite different from those generated from monthly consumption data; in some cases higher. The findings confirm that better system knowledge can be obtained with such a program and applied effectively to capacity planning.

In its response to BCUC IR 1.29.2.1.1, FEI states:

> FEI is currently conducting a Smart Learning Thermostat (SLT) pilot through the C&EM Innovative Technologies program area. If the results from the pilot are positive, FEI anticipates offering Smart Learning Thermostats as an incented measure in the future. FEI cannot say at this time if a SLT program can have an impact on peak demand as there is some indication from work done for Enbridge Gas Distribution in Ontario that, although SLTs might reduce annual demand, they could result in an increase in peak demand.

64.2 Please briefly explain why SLTs may lead to an increase in peak demand.

Response:

According to the study report filed with the Ontario Energy Board[9], building modeling suggests that adaptive thermostats contribute to increased demand during winter peak hour periods. These periods of increased demand occur when heating systems are recovering from temperature setback. The results of the modelling conducted for Enbridge show that in both the residential and commercial applications, it can be seen that adaptive thermostats lead to increased demand during other non-setback hours during the winter peak day since it can take several hours to heat up a building's entire thermal mass. The results of that analysis suggest that where adaptive thermostats are deployed on a broad basis, their impacts on a natural gas distribution system would need to be closely monitored.

[9] The study completed by ICF Consultants for Enbridge Gas is included as Appendix D to the following document on file with the Ontario Energy Board – http://www.rds.oeb.ca/HPECMWebDrawer/Record?q=CaseNumber=EB-2017-0128&sortBy=recRegisteredOn-&pageSize=400, filename: EGDI_SUB_EB-2017-0128_20180115.

64.3 Does FEI consider that "positive" results from the SLT pilot would constitute a reduction in peak demand, or reduction in annual demand but with an increase in peak demand?

Response:

FEI considers a "positive" result to be an overall reduction in annual energy consumption that meets BC DSM Regulation requirements and customer acceptance scores that indicate satisfaction with the technology, irrespective of an increase or reduction in peak demand. FEI would also view a reduction in peak demand as a positive result, although as discussed in the response to BCUC IR 2.64.2 a contribution to peak demand reduction might not be achievable through an SLT program. FEI will be assessing the energy savings through conducting a billing analysis and customer acceptance rates through surveys.

D. GAS SUPPLY PORTFOLIO PLANNING

65.0 Reference: GAS SUPPLY PORTFOLIO PLANNING

Exhibit B-2, BCUC IR 19.3, p. 67; BCUC 19.4, pp. 68-69

Renewable Natural Gas

In response to BCUC IR 19.3, FEI forecasts an increase in Renewable Natural Gas (RNG) demand from 238,016 GJ in 2017 to 702,426 GJ in 2036.

In response to BCUC IR 19.4, FEI stated:

> There has been a sharp increase in interest from large, sophisticated customers over the past year. FEI believes that this is due to awareness, ease of adoption, government policy and the current price. In addition we have seen a steady increase in residential and small commercial demand since the price of RNG dropped and the marketing efforts were increased. … FEI believes that the demand will more likely continue upward rather than flatten in the future but demand may be constrained by supply.

65.1 Please explain each of the sources of supply for FEI's RNG program.

Response:

Currently, FEI has five operating supply projects, as outlined in the table below:

Supplier	Location	FortisBC owned upgrader?	Online
Fraser Valley Biogas	Abbotsford, BC	N	Oct 2010
Salmon Arm Landfill	Salmon Arm, BC	Y	Feb 2013
Glenmore Landfill (Kelowna)	Kelowna, BC	Y	Sep 2016
Seabreeze Farm	Delta, BC	N	Feb 2015
Surrey Biofuel	Surrey, BC	N	Jun 2018

65.1.1 Please explain the criteria that FEI considers when procuring supply for its RNG program.

Response:

FEI has developed the following criteria for procuring RNG supply:

- Project volume: annual RNG quantity;
- Cost per gigajoule: finished RNG cost (may be a levelized cost including raw gas, upgrading and injection costs);
- Speed to market: project and proponent readiness;
- Location: preference is for projects that can connect directly to FortisBC pipelines but projects that are competitive on the other criteria will be considered;
    - In British Columbia, projects will be preferred if they have nearby access to a FortisBC pipeline with the capacity to accept RNG;
    - Outside of British Columbia, preference will be based on geographic proximity to British Columbia with a further preference for Canadian projects;
- Partner suitability: a combination of factors including long-term financial stability, experience with biogas or similar industries, and technical expertise of the respondent's team;
- Technological feasibility: preference is given for the use of technologies that are already commercialized. Novel technologies may be considered if technological viability is proven;
- Carbon Intensity: how many kilograms of CO_2 equivalent will be produced per gigajoule of RNG; and
- Other environmental or social benefits: additional project elements could include management of other forms of pollution, partnerships with Indigenous communities, and implementation of best practice for digestate management.

65.1.2 Does FEI have a preference for procuring supply for its RNG program from within BC, as opposed to from outside of BC?

Response:

Yes. Please refer to the response to BCUC IR 2.65.1.1.

65.2 Taking into consideration the sharp increase in interest and the anticipated supply constraints, please explain FEI's plans to obtain supply to meet the long-term RNG demand forecast.

Response:

FEI is taking several steps to increase the acquisition of RNG Including:

- The addition of internal resources to support existing RNG operations, to actively engage with potential suppliers and to effectively evaluate and develop opportunities;
- Increased RNG awareness efforts. This includes improvements to the website, increased efforts to communicate interest in supply through existing relationships and active promotion at conferences. For example, FEI recently presented at the Solid Waste Association of North America BC & Yukon conference, where most of the landfills across BC were represented;
- Implementation of a supplier's guide to better support potential project developers; and
- An open call for new projects in the summer of 2018.

65.3 If FEI is unable to meet its forecast RNG demand due to constrained supply, please discuss the impact to: (i) FEI's RNG program; (ii) FEI's non-RNG customers; and (iii) FEI.

Response:

i) FEI's RNG Program:

The primary impact would be an inability to grow the service offering in line with demand. The program has three tools to address supply constraints:

- **Carbon Offsets:** FEI may use carbon offsets to serve customers on Rate Schedules 1B, 2B, 3B and 5B to smooth out fluctuations in LNG availability.
- **Enrollment Caps and Removal of Customers:** FEI can set customer enrollment caps for customers on Rate Schedules 1B, 2B, 3B and 5B. FEI may also remove some of these customers from the program.

- **Interruptible:** Rate Schedule 11B customers and customers with Long Term Biomethane Contracts receive RNG via a service that is interruptible, subject to the availability of adequate RNG supply.

The extent to which any or all of these tools may be used will be evaluated within the context of both the reason(s) for and magnitude/duration of any undersupply, with a goal of best serving RNG customers.

ii) FEI's non-RNG customers:

FEI expects no direct impact to its non-RNG customers. Indirectly, there could be some effect on the RNG supply cost, but as any such effect is distributed among FEI's total non-RNG customer base FEI expects that the effect would be virtually immaterial.

iii) FEI:

The primary impact to FEI would be a limitation on its ability to sign up new customers for its RNG service. There would also be a concomitant requirement to find new sources of RNG supply in order to satisfy the demand.

E. PRICE RISK MANAGEMENT

66.0 Reference: PRICE RISK MANAGEMENT

Exhibit B-2, BCUC IRs 35.1-35.3, pp. 157-159;

FEI 2017 Price Risk Management Plan (PRMP) proceeding, Exhibit B-5,

BCUC IR 1.4, pp. 4-5; BCUC IR 1.4.1.1, p. 14

Price risk management objectives

As stated in response to BCUC IR 35.1, FEI's PRMP objectives are as follows:

- Mitigate market price volatility to support rate stability, and
- Capture opportunities to maintain commodity rates at historically low levels.

FEI states in response to BCUC IR 35.1 that in FEI's current PRMP proceeding:

> … FEI has revised its second objective regarding capturing favourable prices to provide customers with more affordable rates to make it more specific and relevant to the current low market price environment rather than the affordability in rates. The affordability in rates can be somewhat subjective and difficult to measure as it will vary among different customers. Maintaining commodity rates at historically low levels is less subjective and easier to define since information regarding historical commodity rates is available and observable and can be used for comparison or as part of benchmarking in a hedging strategy. [Emphasis Added]

In response to BCUC IR 35.2, FEI states that:

> FEI has one set of PRMP objectives that are consistently applied to inform its planning and operational decisions. As discussed in Section 5.1.1 of the Application, however, each PRMP includes more detailed strategies and tactics for managing price risk and its impact on gas costs on customer rates.

In response to BCUC IR 35.3, FEI states that:

> …the LTGRP sets out gas supply contracting and price risk management principles within the context of a 20-year outlook while the ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of natural gas supply or the impact of gas costs on rates for core sales customers.

In response to BCUC IR 1.4 in the FEI 2017 PRMP proceeding, FEI states that:

> FEI discusses in the 2018 PRMP (page 5) that market price conditions could change in the future and FEI may no longer have the opportunity to capture opportunities to maintain low commodity rates for customers. Therefore, FEI notes that this objective is applicable in the current low market price environment. As FEI discusses on page 4 of the 2018 PRMP, the objective related to mitigating market price volatility is applicable in both high and the current low gas price environment as there can be market price volatility in either.

66.1 Please explain if there is a distinction between a price risk management principle and a price risk management objective. Please provide an example to support your response.

Response:

The principles for price risk management provide the long-term, high-level guidelines to help frame FEI's objectives for price risk management. The objectives are more specific so as to determine the specific price risk management strategies that will achieve the objectives. For example, the guiding principle of the reduction of market price risk is supported by the price risk management objectives of mitigating market price volatility to support rate stability for customers. The strategies change over time in response to the changing market conditions. Hedging up to 50 percent of the commodity portfolio with fixed price swaps for up to five years out in the current market price environment is the strategy that helps to meet this objective, at least for the medium term. If market conditions changed such that market prices were much higher than current levels, FEI would consider using other tools, like hedging options, to mitigate the market price volatility while balancing reducing potential hedging costs.

66.2 Please explain whether the PRMP objective to "capture opportunities to maintain commodity rates at historically low level" being applicable "in the current low market price environment," is aligned with FEI's statement that "the LTGRP sets out… price risk management principles within the context of a 20-year outlook."

Response:

The PRMP objective to capture opportunities to maintain commodity rates at historically low levels in the current low market price environment is aligned with the LTGRP price risk

management principles within the context of a 20-year outlook. While the objective may not always be achievable throughout the entire 20-year planning horizon, as market conditions may change from time to time, it is still an important objective in that it supports the strategies that position FEI to capture low price opportunities if they do materialize over the 20 years.

66.2.1 Please explain if FEI expects the low market price environment to span the 20-year planning period.

Response:

Gas market prices have generally trended lower since the shale gas era began but are inherently volatile and can change due to many supply and demand factors, as well as other factors that impact price. As a result, FEI has no certainty on whether the current low market price environment will span the 20-year planning period. In addition, other factors besides market prices may increase the cost of natural gas for FEI's customers over the long term; one example being the BC carbon tax.

66.3 With reference to FEI's revised PRMP objective of "maintaining commodity rates at historically low levels," please elaborate on how the revised objective would facilitate "comparison or as part of benchmarking in a hedging strategy," and what the benchmarking review would entail.

Response:

Using the FEI commodity rate as a comparison or as part of benchmarking in a hedging strategy provides one metric to assess the effectiveness of the hedging strategy. FEI files a Price Risk Management Annual Report with the Commission which discusses the outcomes to date of the implemented tools and strategies approved within FEI's PRMP. The Annual Report includes a section that reviews the impacts on the commodity rate from the hedging strategy. A comparison to FEI's historical commodity rates is also provided.

In response to BCUC IR 4.1.1 in the FEI 2017 PRMP proceeding, FEI states that:

> AECO/NIT prices near or below about $2.00 per GJ with temporary spikes up to $5.00 per GJ and dips to or below $1.00 per GJ for a period of years would be considered a continuation of the low priced environment.

66.4 Please confirm, or explain otherwise, that "historically low levels" refers to AECO/NIT prices near or below about $2.00 per GJ with temporary spikes up to $5.00 per GJ and dips to or below $1.00 per GJ for a period of years, as explained in response to BCUC IR 1.4.1.1 in the FEI 2017 PRMP proceeding.

Response:

Confirmed.

66.4.1 Please explain if a price range specified within in its objective regarding "commodity rates at historically low levels" would further eliminate subjectivity and also provide clarity for comparison and benchmarking purposes.

Response:

The price risk management objectives are not designed to include specific metrics, such as market price or commodity rate ranges, as this would unnecessarily complicate the objectives, especially since the metrics may change over time. The hedging strategies, to meet the objectives, are the appropriate place to include specified market price ranges or targets so they can be responsive to changing market conditions. As discussed in the response to BCUC IR 2.66.4, the Price Risk Management Annual Report provides information that enables comparisons and benchmarking for the purposes of assessing the hedging strategies.

66.4.2 Please explain why FEI does not specify a price range for the objective regarding "commodity rates at historically low levels."

Response:

Please refer to the response to BCUC IR 2.66.4.1.

66.5 In consideration that the PRMP objectives to "capture opportunities to maintain commodity rates at historically low level" is only applicable in the current low market price environment, please explain how often does FEI intend to re-evaluate the PRMP objectives to determine whether they remain applicable based on the current market environment at the time.

Response:

FEI reviews and evaluates the price risk management objectives before filing each PRMP to determine the appropriate strategies to meet the objectives, which may not always be achievable in the market price environment at the time. For example, while mitigating market price volatility is applicable in both a low and high price market environment, capturing opportunities to maintain commodity rates at historically low levels may not be achievable in a high market price environment. Therefore, FEI would consider altering the hedging strategy, and not necessarily the objective, if market conditions changed. Please also refer to the response to BCUC IR 2.66.2.

66.5.1 If the need to re-evaluate the PRMP objectives is subject to certain criteria being met, please elaborate on the criteria used and the rationale for using the chosen criteria.

Response:

Please refer to the response to BCUC IR 2.66.5.

66.6 Please explain how a PRMP objective that is only applicable in the current low market price environment can be used to inform long term price risk

management strategies that have financial and supply portfolio impacts that may extend beyond the current market price environment.

Response:

Please refer to the response to BCUC IR 2.66.2.

66.6.1 Please discuss FEI's views on whether PRMP objectives included in the LTGRP should be established such that they remain relatively consistent over time in order to inform planning and operational decisions for the long-term horizon, despite changing market environments.

Response:

Please refer to response to BCUC IR 2.66.1.

66.7 If available, please provide how often other jurisdictions review and revise their PRMP objectives.

Response:

Generally speaking, to FEI's knowledge, the primary price risk management objective of natural gas utilities in other jurisdictions has been, and continues to be, managing rate volatility for customers. FEI does not know how often this objective is reviewed but it has remained consistent over time, at least among the regional utilities that FEI's monitors which includes Cascade Natural Gas, Puget Sound Energy, Avista Utilities and Northwest Natural Gas Company.

67.0 Reference: PRICE RISK MANAGEMENT

Exhibit B-2, BCUC IR 36.2, pp. 160-162; Exhibit B-4, CEC IRs 26.1 and 28.2, pp. 75-77, 80

Long term instruments

FEI states in response to BCUC IR 36.2 that:

> VPPs [Volumetric Production Payment] or other arrangements with gas producers, including prepayment options where FEI would provide an upfront lump sum payment to a gas producer for long-term (i.e. 10 to 20 years) cost based supply, would be favorable in the current gas market conditions" and that "Customers would not benefit, from a cost perspective, if market prices decrease below the long-term arrangement contract price/cost. They may still benefit from a security of supply perspective.

In response to CEC IR 26.1, FEI elaborates on a list of longer term instruments or tools that could improve long term cost certainty, including long term hedging, volumetric production payment, investing in natural gas reserves, and other long term supply arrangements.

In response to CEC IR 28.2, FEI states that:

> FEI does not expect that purchasing long term supply and/or ownership of gas field supply arrangements would alter transmission or storage resources as FEI would utilize existing infrastructure (e.g. Westcoast Pipeline) to move the supply to its customer load areas. These arrangements would merely reduce the amount of commodity supply FEI purchases in other deal structures.

67.1 Please explain whether FEI currently anticipates a security of supply issue in the long term and, if so, whether the issue is best mitigated by the use of long term commodity strategies as listed in response to CEC IR 26.1, among other existing and potential options besides long term instruments.

Response:

This response also addresses BCUC IRs 2.67.1.1, 2.67.2 and 2.67.3.

The main objectives for the long-term supply arrangements listed in the response to CEC IR 1.26.1 are to provide cost certainty and help achieve the objectives of the PRMP. Although it is not the primary reason, long-term supply arrangements would also help mitigate some of the security of supply risks, given that ongoing changes in the marketplace can create different types of security of supply risks. As discussed in the response to CEC IR 1.31.1, there is no

issue regarding the long-term availability of gas supply in Western Canada, however uncertainties exist as to whether such supply gets fully developed in the short and long term, and whether FEI can access this supply sufficiently and cost effectively. There are certain pricing signals in the market that can create security of supply issues. For producers to continue to invest and procure gas they must earn a reasonable rate of return. Given the low natural gas commodity future prices, FEI has had experiences where producers and counterparties were unwilling to transact term supply at Station 2, which can be viewed as a security of supply issue. Moreover, there are ongoing initiatives in terms of pipeline infrastructure that could potentially move gas from northeast BC to larger markets, potentially bypassing Station 2 to some degree. Long-term supply arrangements would help mitigate these risks by having supply committed to FEI on a long term basis.

Security of supply can also be viewed as capacity constraints in the region related to third-party infrastructure (storage and pipeline). Long-term supply arrangements discussed in the response to CEC IR 1.31.1 would not mitigate this risk, however FEI actively monitors and implements strategies to mitigate this risk through the Annual Contracting Plans. This is discussed in greater detail in Section 5.2 and 5.4 of the 2017 LTGRP.

67.1.1 If a security of supply issue were to arise in the long term, please discuss whether the issue would most likely be due to capacity constraints related to third-party infrastructure or availability of commodity from gas fields.

Response:

As discussed in the response to BCUC IR 2.67.1, there is long-term availability of supply in Western Canada, however the issues that will likely arise in the long term are the capacity constraints related to third-party infrastructure as well as how the supply is connected to the North American energy market.

67.2 Please discuss whether, and if so how, long term instruments address supply risks related to access to capacity to move the commodity supply to FEI's customer load areas.

Response:

Please refer to the response to BCUC IR 2.67.1.

67.3 Please explain whether the primary distinct purpose of potentially including VPPs in FEI's portfolio compared to FEI's other available price risk management options is to: i) provide security of supply, ii) provide cost certainty, iii) potentially realize gains from a cost perspective should the market price increase, or iv) other.

Response:

Please refer to the response to BCUC IR 2.67.1.

67.4 Please elaborate on the source of current commodity supply that will be reduced as a result of introducing long term instruments in FEI's portfolio.

Response:

The long-term arrangements, as listed in the response to CEC IR 1.26.1, would reduce FEI's monthly-priced supply requirements at the transacted market hub (e.g., Station 2 or AECO/NIT).

F. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

68.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-2, BCUC IR 39.2, p. 167

Peak demand forecast for system capacity planning

In response to BCUC IR 39.2, FEI states:

> FEI's system capacity planning approach is based on a coincident peak approach for the customers whose UPCpeak is determined from monthly consumption. The load gather process for these customers described in BCUC IR 1.39.1 is designed to derive the peak demand that coincides with the system peak. For customers where hourly billing is available the maximum observed peak hourly measured value for those customers is used even though the value used may be non-coincident with the system peak. This approach is taken unless there are requirements within the rate schedule or other documented reasons that prevent the customer from taking the observed consumption during the system peak.

68.1 Please explain if any of the customers with hourly billing available typically experience their peak demand coinciding with the system peak.

Response:

Many of the customers with hourly billing experience their peak demand coinciding with the system peak. While they currently represent a small proportion of the total customers served, there are a variety of customer segments in the population that currently have hourly metering installed. These customers are for the most part medium to large commercial or industrial customers that may operate gas fired equipment either steadily or intermittently during the business day or through multiple shifts around the clock. They may be entirely process loads or could also represent heat sensitive loads. Some, for example, represent strata developments with a daily gas profile similar but larger in magnitude than a typical residential customer demand profile. FEI's System Capacity Planning department reviews hourly measurement data for these customers as part of its annual load generation process and identifies hourly values from this data that are representative of the peak demand capabilities of the customers' connected appliances. As indicated in the response to BCUC IR 1.39.2, a portion of the values used do not coincide with the system peak on the occasion that the hourly consumption was recorded. However, when FEI in its annual assessment determines that it is reasonable to assume the customer could require that observed maximum flow during the system peak, the observed value is applied at the system peak hour. When FEI sees an indication in the hourly data that there is a significant change in the peak consumption pattern of the customer, System Capacity Planning will work with the Commercial/Industrial Account managers to investigate if the change should be reflected as a new peak hour value. Many of these customers are served

though FEI's distribution systems and often represent a significant load in the local area. To ensure the distribution system can safely and reliably maintain system pressure to serve the local area without interruption, FEI believes it is appropriate to consider the hourly maximum observed loads determined from the annual load generation assessment as coinciding with the system peak.

68.1.1 If so, please discuss the appropriateness of using the maximum observed peak hourly measured value for these customers, even though that value may be non-coincidental with the system peak.

Response:

Please refer to the response to BCUC IR 2.68.1.

69.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-2, BCUC IR 41.1, p. 178; BCUC IRs 41.3 and 41.6, pp. 180-181

Vancouver Island (VI) system capacity

In response to BCUC IR 41.1, FEI states that: "the capacity of the VITS, allocating one third of Mt. Hayes sendout capacity to the VI system, as 218 TJ/d."

When asked what "is the maximum capacity that can be allocated from Mt. Hayes to VITS?" in BCUC IR 41.6, FEI pointed the reader to the response to BCUC IR 41.3. FEI's response to BCUC IR 41.3 states:

> The Mt. Hayes storage facility has flexibility to reallocate supply between the VITS and the rest of the FEI system. The need for reallocation can be reasonably foreseen in the peak demand forecast and planned for years in advance so the allocation can be considered very flexible. Current gas supply strategy allocates a certain proportion of Mt. Hayes to the rest of the FEI system, however this allocation is not firmly fixed or capped. Capability is limited only by the peak vaporization capacity and the total tank volume at Mt. Hayes. There is availability to increase the allocation from Mt. Hayes to the VITS. As Mt. Hayes is located within the VITS its send out capability could be allocated solely to the VITS on a peak day and the entire tank volume reserved for support of the VITS during the winter.

69.1 Taking into consideration the peak vaporization capacity and the total tank volume at Mt. Hayes, please state in TJ/d the maximum capacity that can be allocated from Mt. Hayes to Vancouver Island Transmission System (VITS).

Response:

The Mt. Hayes facility can store up to 1,614 TJ of LNG and has the vapourization capacity to inject up to 161 TJ/day. This capacity could be allocated entirely to the VITS if required.

70.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 6.3.1, pp. 162-163; Exhibit B-2, BCUC IR 43.3, pp. 187-189

VI demand-capacity balance with Woodfibre LNG Limited

In response to BCUC IR 43.3, FEI presented revised versions of Figures 6-3 and 6-5 showing the VI system demand-capacity balance chart if Woodfibre LNG entered into service in 2022.

70.1 Please confirm, or otherwise explain, that in the traditional reference case without DSM the daily demand exceeds system capacity at some point in 2027.

Response:

By "traditional reference case without DSM" FEI assumes the Commission is referring to the Traditional peak demand forecast shown in the revised Figure 6-3. FEI can confirm that the revised Figure 6-3 shows that the Traditional peak demand forecast exceeds the defined system capacity after the winter of 2027-28. The Reference peak demand forecast was not shown on the revised Figure 6-3.

FEI would like to clarify that the Traditional peak demand forecast and the Reference peak demand forecast are different and there is no "traditional reference" forecast presented in the Application. The Traditional forecast holds UPC constant at current values through the planning period and reflects FEI's current peak demand forecast method. The Reference forecast applies the exploratory end-use method to change UPC through the forecast based on the inputs defined for the Reference Case scenario in the Application.

70.2 Please confirm, or otherwise explain, that in the traditional reference case with DSM the daily demand exceeds system capacity at some point in 2027.

Response:

FEI confirms that the revised Figure 6-5 shows that the Traditional peak demand forecast, which holds UPC constant through the forecast period, exceeds the defined system capacity after the winter of 2027-28. The Traditional peak demand forecast in revised Figure 6-3 is the same as the forecast presented in revised Figure 6-5 (which otherwise included end-use forecasts scenarios with DSM) as the Traditional peak demand method of holding UPC constant does not impart any load change due to DSM programs. The Traditional forecast was included in both Figures to provide a common basis for comparison. The Reference peak demand forecast with

DSM is also shown in the revised Figure 6-5. That forecast which uses the exploratory end-use method to change UPC through the forecast period, including the projected effects of DSM, exceeds the defined system capacity after the winter of 2033-34.

70.2.1 Please explain if FEI's VI system expansion alternatives, as described on pages 162 and 163 of Exhibit B-1, would remain the same if Woodfibre LNG entered into service in 2022.

Response:

With the exception of the upstream expansion requirements directly related to serving the Woodfibre LNG facility, the system expansion alternatives shown in Table 6-1 required to meet the forecasts presented in the 2017 LTGRP would still apply. As part of the proposed expansion to serve Woodfibre LNG, additional compression near Squamish would be installed. Where the expansion alternatives refer to Installation of the V2 Compressor (also projected to be in the Squamish area) a compressor facility would already be installed as part of the Woodfibre project (possibly at the proposed Mt. Mulligan site) with the required horsepower or with the ability to upgrade to the required horsepower.

70.2.1.1 If not, please identify and briefly discuss each VI system expansion alternative if Woodfibre LNG entered into service in 2022.

Response:

Please refer to the response to BCUC IR 2.70.2.1.

71.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-4, CEC IRs 52.1 and 52.2, p. 127

Infrastructure Project Sizes

In response to CEC IRs 52.1 and 52.2, FEI provides the dollar value and lead times needed for a small, medium and large infrastructure projects.

71.1 Please provide an example of a capacity driven infrastructure project that would qualify as: (i) small; (ii) medium; and (iii) large, based on FEI's responses to CEC IRs 52.1 and 52.2.

Response:

FEI provides the following examples of completed capacity-driven infrastructure projects that are representative of each of the categories:

(i) Small:

Project: David St to Begbie Street Intermediate Pressure gas pipe extension and new District Station (1700 Begbie), Victoria.

Description: 2160m of 219mm IP main and New District Station. Capacity Upgrade completed in Victoria in 2008 to improve distribution system capacity to the Oak Bay neighbourhood.

Cost: approximately $2,200,000

(ii) Medium:

Project: Nichol to Roebuck 1066mm (NPS 42) Transmission pipeline loop

Description: Part of the CTS Project completed in 2017 to improve system resiliency that additionally improves the capacity of the CTS capacity to serve core customers and new industrial demand.

Cost: approximately $30,300,000

(iii) Large:

Project: Mt. Hayes LNG Peak Shaving Facility, Vancouver Island

Description: Large LNG storage and peak shaving facility to provide peak day supply for the VITS to avoid pipeline looping or additional compression and Gas Supply capability for the Coastal region. The facility entered service in 2011.

Cost: approximately $190,000,000

72.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-4, CEC IR 63.1, p. 154

Revelstoke Propane System

In response to CEC IR 63.1, FEI states:

> At this time, converting Revelstoke's distribution system to piped natural gas and installing an LNG storage and vaporization plant in place of the propane plant is not being considered; therefore FEI cannot provide a date as to when a determination will be made for this project. At this time FEI is reviewing other alternatives.

72.1 Please explain the "other alternatives" FEI is reviewing for the Revelstoke Propane System.

Response:

FEI is considering an application to the Commission to amalgamate Revelstoke propane costs into the greater natural gas cost portfolio. Revelstoke customers would continue to pay a higher cost for the propane delivered, with the cost difference based on the relationship between the BC government's carbon pricing for propane and carbon pricing for natural gas. FEI anticipates filing an application within the next month or two. The application will be to the design of the rates, rather than having any associated capital or operational cost.

72.1.1 Please discuss the potential timing and costs associated with these "other alternatives."

Response:

Please refer to the response to CEC IR 2.72.1.

G. 20-YEAR VISION FOR FEI

73.0 Reference: 20-YEAR VISION FOR FEI

Exhibit B-2, BCUC IR 1.46.1

FEI's contributions to BC's Greenhouse Gas (GHG) Emissions Targets

In its response to BCUC IR 1.46.1, FEI states:

> The curve for the Lower Bound scenario trends upwards because this scenario experiences an erosion in the amount of C&EM savings towards the end of the forecast horizon. GHG reductions from C&EM follow the trend in the natural gas savings.

73.1 Please confirm if the explanation in the preamble should be interpreted to mean that towards the end of the forecast horizon, C&EM activities in the Lower Bound scenario lead to negative natural gas savings, compared to a situation where no C&EM activities had taken place.

Response:

This response also addresses BCUC IR 2.73.1.1. FEI consulted with Posterity to provide the following response.

Not confirmed; for greater certainty on FEI's response to BCUC IR 1.46.1, future conditions in the Lower Bound scenario cause a reduction in opportunities for C&EM activities, so that the savings from such C&EM activities are eroded. None of the 2017 LTGRP end-use annual demand scenarios involve a situation where C&EM activities cause negative savings, i.e., an increase in natural gas consumption. Savings may be larger or smaller in different scenarios, but they are always positive.

73.1.1 If confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.73.1.