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March 16, 2018

FEI 2017 LONG TERM GAS RESOURCE PLAN
EXHIBIT A-3

Sent via email

Ms. Diane Roy
Vice President, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
gas.regulatory.affairs@fortisbc.com

Re: FortisBC Energy Inc. 2017 Long Term Gas Resource Plan – Project Number 1598946 – Information Request No. 1

Dear Ms. Roy:

Further to your December 14, 2017 application of the FortisBC Energy Inc. 2017 Long Term Gas Resource Plan, enclosed please find Commission Information Request No. 1. Please file your responses electronically by May 3, 2018.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/yl

Enclosure

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FortisBC Energy Inc.
2017 Long Term Gas Resource Plan

INFORMATION REQUEST NO. 1 TO FORTISBC ENERGY INC.

Table of Contents **Page no.**

A. INTRODUCTION

1.0 **Reference: INTRODUCTION**
Exhibit B-1, Section 1, p. 1
Fort Nelson

In footnote 8 on page 1 of Exhibit B-1, FortisBC Energy Inc. (FEI) states:

> "Where applicable, FEI's LTGRP analysis includes data for Fort Nelson. FEI does not expect any system capacity constraints in Fort Nelson during the 2017 LTGRP forecast horizon. FEI's gas supply portfolio planning and DSM activities do include Fort Nelson customers."

1.1 Please confirm that the Application includes a long-term analysis of: (i) annual and peak demand forecasts for Fort Nelson; (ii) Demand Side Management (DSM) activities regarding Fort Nelson and their impact to Fort Nelson annual and peak demand; and (iii) system needs and alternatives for Fort Nelson.

1.1.1 If not confirmed, please provide any sections that were not included.

2.0 **Reference: INTRODUCTION**
Exhibit B-1, Section 1.2, Table 1-1, p. 3
FEI Service Statistics

In Table 1-1 of Exhibit B-1, FEI presents service statistics in a table for 2015 and 2016.

2.1 Please provide an updated version of this table which includes the figures for the service statistics for 2014 through to 2017 inclusive and which uses numbers for each of the years rounded to the nearest whole number.

3.0 **Reference: INTRODUCTION**
Exhibit B-1, Section 1.3, p. 5; Section 5.3.1, p. 137;
FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan, Exhibit B-1, pp. 8-9
FEI's Long Term Resource Planning Objectives

On page 5 of Exhibit B-1, FEI states:

> FEI's resource planning objectives form the basis for identifying and evaluating potential resources in the LTGRP, including major infrastructure projects, gas supply alternatives and demand side programs. These objectives reflect the Utility's commitment to providing customers with the highest level of quality energy services.

FEI then lists its key resource planning objectives as:

1. Ensure Cost Effective, Secure and Reliable Energy for Customers
2. Provide Cost Effective DSM [Demand-Side Management] Initiatives
3. Ensure Consistency with Provincial Energy Objectives

FEI lists the following resource planning objectives on pages 8 and 9 of the FEU 2014 Long Term Resource Plan:

1. Ensure a Safe, Reliable and Secure Energy Supply
2. Provide Innovative and Cost-Effective Energy Solutions
3. Provide Cost-Effective Energy Efficiency and Conservation Initiatives
4. Contribute to Provincial Energy Objectives and Emission Targets
5. Consider a Range of Possible Future Conditions.

3.1 Please provide a discussion that compares the FEI 2017 Long Term Gas Resource Plan (LTGRP) objectives with the FEU 2014 Long Term Resource Plan objectives. Please include in your discussion an explanation supporting any changes that were made to the objectives since the FEU 2014 Long Term Resource Plan.

On page 137 of Exhibit B-1, FEI states:

> Key objectives of the ACP [Annual Contracting Plan] are:
>
> 1) To contract for resources that appropriately balance cost minimization, security, diversity and reliability of gas supply in order to meet the Core customer forecast design peak day and annual requirements; and
>
> 2) To develop a gas supply portfolio mix, which incorporates flexibility in the contracting of resources based on short term and long term planning and evolving market dynamics.

3.2 Please provide a discussion that compares the FEI 2017 LTGRP objectives with the ACP objectives.

3.2.1 Please explain whether or not FEI considers that the ACP objectives should stem from the LTRP objectives.

B. PLANNING ENVIRONMENT

4.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.2.1, Figure 2-1, p. 18; Figure 2-2, p. 19
Natural Gas Prices

Figure 2-1 on page 18 of Exhibit B-1 contains a graph showing the Henry Hub historical natural gas spot prices, in USD$/MMBTU, from January 1, 2008 to approximately June 1, 2017 for the Henry Hub pricing point.

4.1 Please provide an updated version of this chart, to include historical natural gas spot prices from January 1, 2008 to January 31, 2018 in: (i) USD$/MMBTU; and (ii) CAD$/GJ. Please state the relevant conversion factors.

Figure 2-2 on page 19 of Exhibit B-1 contains a graph showing Wood Mackenzie's natural gas price forecast for the Henry Hub and for Alberta (AECO/NIT) in 2016 USD$ from 2017 through to 2036.

4.2 Please provide another version of the graph with the prices expressed in 2016 CAD$ per GJ. Please state the relevant conversion factors.

5.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.2.2.1, Figures 2-10 and 2-11, p. 27
Natural Gas and Electricity Rates

Figures 2-10 and 2-11 on page 27 of the Application provides a cost comparison, in $/kWh, between FEI's natural gas, FEI's 100 percent renewable natural gas and BC Hydro's electricity.

5.1 Please reproduce each graph (Figure 2-10 and Figure 2-11) using CAD$/GJ instead of $/kWh.

5.2 Please explain if Figures 2-10 and 2-11 contain fixed charges or delivery charges.

5.3 Please reproduce each graph (Figure 2-10 and Figure 2-11) to show the effective CAD$/GJ rate comparison based on the 2016 average annual consumption of a FEI Mainland residential, small commercial and large commercial customer with the fixed and delivery charges included.

6.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.3.4, p. 48
BC Energy Step Code

On page 48 of Exhibit B-1, FEI states:

> The BC Energy Step Code provides a consistent provincial standard for energy efficiency and replaces the various existing policies that various municipal governments had enacted previously. As such, the BC Energy Step Code poses a risk of downward pressure on natural gas demand but also provides an opportunity for FEI's C&EM [Conservation and Energy Management] programs.

6.1 Please elaborate on the opportunity for FEI's C&EM programs presented by the BC Energy Step Code.

7.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.3.3.1, p. 43
Energy and Emission Policy – BC Climate Leadership Plan

On page 43 of Exhibit B-1, FEI states:

> The CLP [BC Climate Leadership Plan] included 21 action items intended to help put BC on course to meet the target of an 80 percent reduction in GHG emissions from 2007 levels by 2050. The CLP stated that the carbon tax rate could be increased from the current level ($30 per tonne) in the future but only once other jurisdictions catch up.

On page 43 of Exhibit B-1, FEI also lists actions outlined in the CLP that FEI states: "if implemented, may impact FEI and provincial natural gas use patterns."

7.1 Please explain if and how the BC CLP's 21 action items and statement on carbon tax was incorporated into FEI's: (i) End-Use Annual Demand Reference case forecast; and (ii) Traditional Peak Demand Forecast used to inform system needs and alternatives.

7.1.1 If not, please explain how FEI accounted for the BC CLP's 21 action items and statement on carbon tax in FBC's long term resource planning.

8.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.3.3.5, pp. 46-47
Tilbury LNG Facility

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.

8.1 Please explain if and when FEI plans to: (i) begin construction; and (ii) put into service the Phase 1B expansion of the Tilbury LNG facility.

8.2 Please describe the factors that FEI monitored in order to determine whether or not to build Phase 1B expansions. For example this could include capacity on the CTS, NGT LNG demand, non-NGT LNG demand and other various factors.

9.0 **Reference: PLANNING ENVIRONMENT**
Exhibit B-1, Section 2.4.1, pp. 52-53
Marine Bunkering

On page 52 of Exhibit B-1, FEI states:

> … there are global environmental regulations that are scheduled to be implemented in the next couple of years that are expected to materially impact the current mix of fuels that have traditionally been consumed by the global marine market. Due to these tighter restrictions on marine vessel emissions, natural gas in the form of LNG is expected to emerge as a choice alternative fuel for vessel operators to comply with these tighter restrictions.

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

> Capitalizing on the LNG marine bunkering opportunity is a key part of FEI's strategy to leverage pre-existing Company-owned assets and operational expertise to drive growth in new markets. While the Tilbury LNG facility primarily serves as a winter peaking facility, over time, the facility has also evolved to serve a variety of new LNG markets.

9.1 Please confirm, or otherwise explain, that FEI's strategy involves capitalizing on LNG marine bunkering opportunities with organizations and companies that are not based in BC or do not have operations in BC.

9.2 Please explain the benefits for FEI's BC sales customers, of FEI pursuing this strategy.

9.3 Please explain: (i) the incremental costs; and (ii) the risks to FEI's BC Core customers of pursuing this strategy. Please provide calculations where necessary.

On page 53 of Exhibit B-1, FEI also 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. … FEI will continue to advance its interests in the LNG marine bunkering market as an LNG fuel and logistics provider.

9.4 Please explain if BC Ferries and Seaspan Ferries are/will be customers served under a negotiated contract with FEI or served under a rate schedule in the tariff.

9.4.1 If BC Ferries and Seaspan Ferries are served under a rate schedule in the tariff please identify the rate schedule.

9.5 Please state the: (i) aggregate annual demand; (ii) average daily demand; and (iii) peak day demand required to serve the five BC Ferries and two Seaspan Ferries vessels identified above.

9.5.1 Please confirm that the forecast demands for BC Ferries and Seaspan Ferries were incorporated into the Reference Case forecast developed using the: (i) End-Use Method; (ii) Traditional Demand Method; and (iii) the Traditional Peak Demand Method.

9.5.1.1 If not, please update the Reference Case forecasts listed in the question above with the forecast demands for BC Ferries and Seaspan Ferries.

9.6 Please explain FEI's role as a "logistics provider" as quoted from the statement in the preamble.

9.7 Which of FEI's LNG facilities (Mt. Hayes and Tilbury) will serve marine vessel customers?

C. ANNUAL ENERGY DEMAND FORECASTING

10.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.1, p. 59; Section 3.3, pp. 60-61
Customer Additions Forecast – Residential

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.

10.1 Please confirm, or otherwise explain 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.

10.1.1 If confirmed, please explain if the differences between the annual results of the traditional annual demand forecast method and the end-use annual demand method are attributable to the use-per-customer.

On pages 60 and 61 of Exhibit B-1, FEI states:

> FEI uses a well-established method to forecast customer additions that remains consistent with previous LTRP filings. The forecast of residential customer additions is grounded in the Conference Board of Canada housing starts forecast for BC.

10.2 Please provide a detailed explanation of the methodology used to forecast residential customer additions based on the Conference Board of Canada housing starts forecast.

11.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.3, p. 61
Customer Additions Forecast – Commercial

On page 61 of Exhibit B-1, FEI states: "Recent trends in commercial customer additions are used to forecast future additions. The net customer additions are estimated based on actual additions in the latest three years."

11.1 Please provide a detailed explanation of the methodology, with calculations where relevant, used to forecast customer commercial additions for each of the service regions.

11.2 Please explain how a three year observation period accurately reflects growth over the long term forecast period. Please include in your response a discussion of the extent that the three year observation period accurately captures the effects of exogenous factors, including but not limited to long term economic cycles.

12.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.3.1.3, p. 62
Customer Additions Forecast – Industrial

On page 62 of Exhibit B-1, FEI states:

> The Company had 979 industrial customers in 2015. At the time the long term forecast was prepared, there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no material growth or decline in industrial customers has been forecasted.

12.1 Please confirm that this remains true. If not confirmed, please provide updates to the relevant sections of the Application that would occur as a result.

13.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Appendix B-4, p. 1
End-use Model Use per Customer Forecast – Residential

On page 1 of Appendix B-4 of Exhibit B-1, FEI presents the customer additions, use per customer and annual demand forecasts broken down by rate schedule. The data shows that the use per customer for the residential rate class (Rate 1) is forecasted to decrease from 83.7 GJ per year in 2015 to 70.8 GJ per year in 2036.

13.1 Please state which service areas are included in the forecasts on page 1 of Appendix B-4.

13.2 Please explain, with rationale, what is contributing to the forecast reduction in the residential use per customer as seen in Appendix B-4.

14.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Appendix B-3, p. 1
Traditional Model Use per Customer Forecast – Residential

On Page 1 of Appendix B-3 in Exhibit B-1, FEI states:

> The Company's Traditional Annual Method for forecasting residential and commercial demand involved determining a forecast natural gas Use per Customer (UPC) and multiplying it by the number of customers forecasted for each year of the study period. … The analysis was conducted for each residential and commercial rate class, based on the most recent three years of data. The trends were then extended into the next 20 years for the purposes of providing a long term forecast.

14.1 Please 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.

14.2 Have there been any significant changes observed in historical UPC trends more recently that caused FEI to use a 3 year observation period?

15.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1; Section 3.4.1, p. 64; Appendix B-1, Section 1.2.1.4.2, p.12
End-use Reference Case forecast

On page 64 of Exhibit B-1, FEI states: "The end-use forecast process starts with developing a Reference Case forecast. The Reference Case is based on end-use patterns observed in the base year and keeps these patterns constant throughout the planning period."

On page 12 of Appendix B-1, FEI states that:

> The Reference Case assumes that currently mandatory or legally enshrined appliance standards continue across the entire planning period. The Reference Case also accounts for some natural change in average appliance efficiencies across the planning period, such as commercial domestic hot water tanks changing from 0.75 Thermal Efficiency (TE) to 0.80 TE as they are replaced.

15.1 Please explain what FEI means by "end-use patterns" as referenced above.

15.1.1 Please explain how and why end-use patterns observed in the base year are kept constant throughout the planning period.

15.2 Please explain how the end-use Reference Case accounts for natural change in average appliance efficiencies across the planning period while "end-use patterns" are kept constant throughout the planning period?

16.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 1.4.3.2, p. 12; Section 3.4.1, pp. 63-64
Developing the end-use Reference Case demand forecast

On page 12 of Exhibit B-1, FEI states that the Commission Panel directed the FEU to file their next long term resource plan on or before June 30, 2017 and that this filing date was extended to November 30, 2017 through Order G-99-17.

On pages 63-64 of Exhibit B-1, FEI states:

> To prepare the 2017 LTGRP end-use forecast, the Company used the following data sources to calibrate the forecast model to FEI's 2015 base year actuals and to identify Reference Case end-use changes across the forecast horizon:
>
> - The BC Conservation Potential Review (BC CPR) which represents a collaborative provincial forecast (sponsored by FEI, FBC, BC Hydro, and Pacific Northern Gas) of energy conservation potential and thus benefits from data supplied by all sponsors as well as the rigour of multiple entities acting as reviewers;
> - FEI's 2012 Residential End-use Survey (REUS); FEI's 2017 REUS is not complete at the time of filing the 2017 LTGRP;
> - FEI's 2015 Commercial End-use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
> - Research and data analysis from the 2014 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2014 LTRP.

16.1 Please state the purpose(s) for which FEI commissioned the Residential and Commercial End-use Surveys.

16.1.1 Please discuss the reason(s) why FEI's 2017 REUS was not complete at the time of filing the 2017 LTGRP.

16.2 Please explain how often FEI intends to have End-use Surveys conducted.

16.3 Please state the amount of time required to perform: (i) a residential end-use survey; and (ii) a commercial end-use survey.

16.4 Please provide an estimated cost of conducting the 2017 REUS.

16.4.1 Please compare this estimate to the cost of the 2012 REUS.

16.5 Please complete the tables below to provide residential and commercial survey information for each of the regions associated with the end-use demand forecast.

Residential End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total			

Commercial End-Use Surveys			
Region	**Number Targeted**	**Number of Responses**	**Response Rate (%)**
Lower Mainland			
Vancouver Island			
Whistler			
Southern Interior			
Northern Interior			
Total			

16.6 Please explain if and how the 2012 REUS accurately captures changes in customer end-uses and appliance efficiencies that occurred between 2012 and 2017.

16.6.1 Please explain how changes in customer end-uses and appliance efficiency that occurred between 2012 and 2017 could directionally impact the annual demand reference case.

17.0 **Reference:** **ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.4.2, Figure 3-4, p. 66; Appendix B-3, p. 2; Appendix B-4, p. 1
Comparison of the end-use and traditional method Reference Case forecasts

Figure 3-4 on page 66 of Exhibit B-1 presents FEI's end-use Reference Case annual demand forecast broken down into customer groups. Figure 3-4, copied below, shows the residential annual demand increasing steadily over the 20 year planning period while the industrial demand decreases.

Figure 1: FEI's End-Use Reference Case Annual Demand (Figure 3-4 in Exhibit B-1)

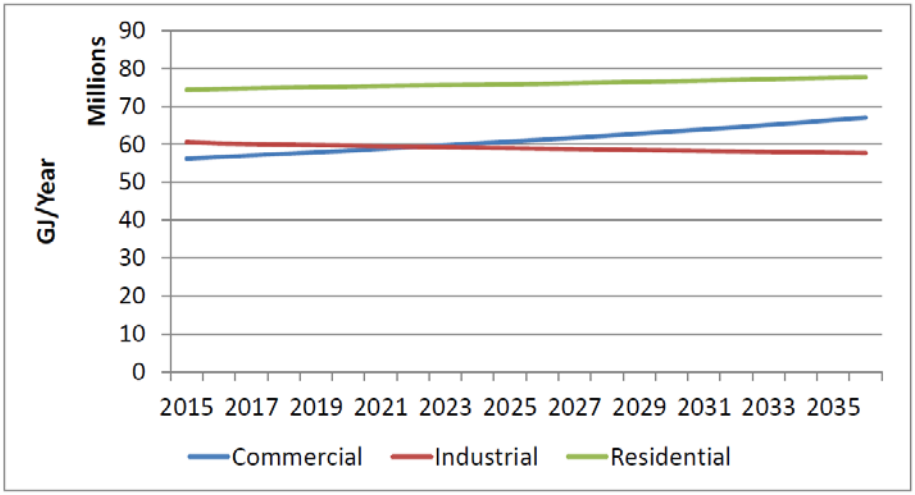
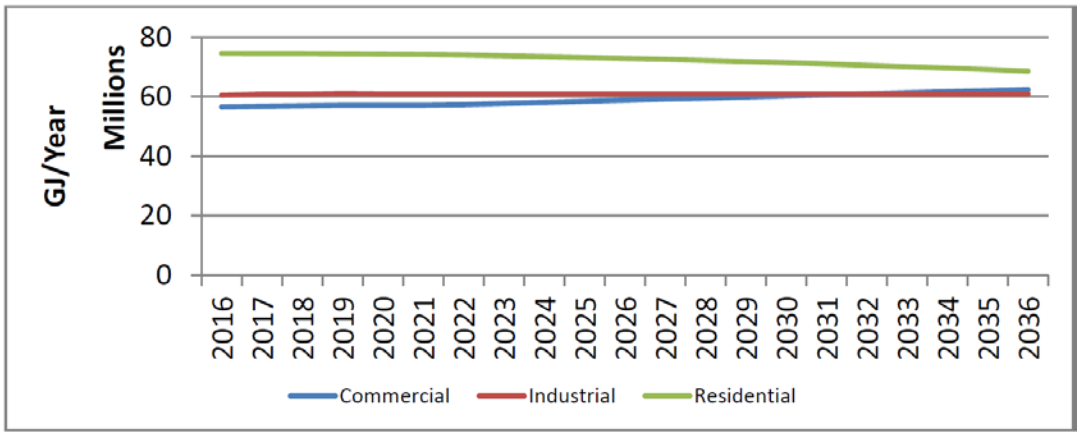


Figure B3-1 on page 2 of Appendix B-3 presents FEI's traditional Reference Case annual demand forecast broken down into customer group. Figure B3-1, copied below, shows the residential annual demand declining steadily over the 20-year planning period, while the industrial demand remains flat.

Figure 2: FEI's Traditional Reference Case Annual Demand (Figure B3-1 in Exhibit B-1)



17.1 In the same manner as was presented in Appendix B-4 for the End-use Annual Method, please provide tables showing for the Traditional Annual Method reference case the:

i. Year End Customers by Rate Schedule;

ii. Annual Use Rate per Customer by Rate Schedule (GJ);

iii. Annual Demand by Rate Schedule (GJ).

17.2 Please explain differences in long term demand forecast trends between the End-use Annual Method results and the Traditional Annual Method results for: (i) residential; and (ii) industrial customers.

On page 2 of Appendix B3-1, FEI states:

> Declining residential UPC in the FEI service territories is resulting in an overall decline in residential annual demand, even though the Company continues to add residential customers through the forecast period. This decline in residential UPC is now a common occurrence affecting mature natural gas utilities across North America.

17.2.1 Please explain why the declining residential UPC in the Traditional Annual Method reference case results in an overall decline in the Traditional Annual Method residential demand forecast, whereas the End-use Annual Method forecasts an increase in residential reference case demand despite a declining residential UPC.

17.2.2 Please explain if and how the reference case End-use demand forecast captures the decline in residential UPC as referenced in the preamble.

17.3 Please provide graphs showing annual actual residential and commercial UPC for the 20 years preceding 2017.

17.3.1 Please provide tables containing the data used in the graphs.

18.0 **Reference: ANNUAL DEMAND FORECASTING**
Exhibit B-1, Section 3.4.3, p. 67; Appendix B-3, p.3
Annual end-use demand forecast comparison

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

> FEI's end-use method differs in a number of ways from its time-series based Traditional Annual Method. 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. If the results of the Traditional Annual Method demand forecast and the end-use method Reference Case annual demand are reasonably aligned, then the end-use method provides a reasonable basis for developing alternate future scenarios.

18.1 Please explain what FEI considers "reasonably aligned" and against what parameters is the alignment assessed?

18.1.1 How were these parameters defined?

18.2 How does the variance between FEI's Traditional Annual Method and the end-use Reference Case forecast compare to other utilities?

19.0 **Reference: ANNUAL DEMAND FORECASTING**
Exhibit B-1, Section 3.4.6, p. 80; Figure 3-14, p. 81
Renewable Natural Gas (RNG) Demand

On page 80 of Exhibit B-1, FEI states:

> The links between the core end-use forecast and the RNG annual demand forecast are qualitative only because RNG represents an emerging market. FEI provided the core end-use forecast scenario parameters to its RNG program team and requested this team to prepare three forecast trajectories (Reference Case, Low, High) based on these scenario parameters.

19.1 Please explain with calculations where relevant, the method used to calculate the reference case RNG annual demand forecast.

19.2 Please elaborate on the parameters that were provided to the RNG program team.

19.3 Please provide in a table format the reference case RNG annual demand forecast in GJ for each year from 2017 through to 2036.

19.4 Please explain why the: (i) Upper Bound; (ii) Local Growth & Constricted Supply; and (iii) Global Growth & Green Step Change scenarios shown in Figure 3-14 experience a steep increase in annual demand from 2016 until approximately 2025, after which the demand flattens to approximately 2.75 million GJ/Year.

On page 80 of Exhibit B-1, FEI states: "FEI is aware that pilot projects exist for proving the commercial scalability of RNG from wood waste. If such cellulosic biogas does become available at reasonable prices, it could dramatically increase RNG supply and thus potentially enable FEI to substantially increase RNG annual demand via its RNG program."

19.5 Please describe the effects, if any, fuel switching from conventional gas to RNG has on the Reference Case Annual Demand forecast.

19.6 Please provide a chart, and accompanying data table, forecasting the potential effects cellulosic biogas could have on RNG demand. Please explain the assumptions used to calculate this forecast.

20.0 **Reference: ANNUAL DEMAND FORECASTING**
Exhibit B-1, Section 3.4.7, pp. 82-83
Compressed Natural Gas (CNG) Demand

On page 82 of Exhibit B-1, FEI states: "CNG is positioned as a fuel for on-road transport applications such as transit buses, waste haulers and heavy duty on-road trucks."

20.1 Please discuss the possibility of all-electric vehicles, specifically all-electric trucks having an impact on FEI's CNG demand over the 20-year planning period.

20.1.1 Please state if FEI has performed any analysis on how this technology could impact the Reference Case CNG demand forecast.

On page 83 of Exhibit B-1, FEI states: "FEI has assumed an annual growth in vehicles of about 85 additional CNG vehicles to the road per year. These additional CNG vehicles translate to an approximate net incremental growth of 100 thousand GJ per year."

20.2 Please provide details on how FEI forecasted annual growth of 85 additional CNG vehicles (100,000 GJ) per year in the CNG base scenario demand forecast.

20.3 Please provide details of the core end-use forecast scenario parameters FEI provided to its NGT programs department and the methodology used to obtain the base, high and low forecast demand trajectories.

21.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.4.7.2 p. 85; Section 2.4.1.2, pp. 53-54;
BCUC 2014 LTRP Decision, Section 3.1.2.3, p. 18
LNG Demand Forecast

On page 85 of Exhibit B-1, FEI states:

> The key markets that have emerged over the past number of years as consumers of LNG fuel have been high horsepower applications such as marine vessels, mine haul trucks, locomotives, and remote industrial power and heat generation applications. Similar to CNG demand forecasts, FEI formulated the LNG demand forecasts by accounting for commitments that have been made by customers to take LNG supply under RS46, then applying inflation and forecasting the impacts of a variety of factors.

21.1 Please explain how FEI uses inflation to develop LNG demand forecasts.

21.2 Please provide a graph detailing historic demand of LNG, grouped by each market.

21.3 In the LNG base scenario demand forecast, please explain how FEI calculated an annual growth rate of about 5 percent per year beyond 2028?

21.3.1 Please explain the assumptions that FEI uses in the base scenario prior to 2028?

On pages 53 and 54 of Exhibit B-1, FEI states:

> The International Maritime Organization (IMO) is scheduled to implement a global cap on sulfur emissions from the shipping industry to take effect on January 1, 2020. … The global cap on sulfur in marine fuels is expected to have a material impact on marine vessel operators as they must weigh a number of options in order to comply with these emission limits.

On page 85 of Exhibit B-1, FEI states that: "[t]hrough market intelligence and industry research, FEI has identified a certain segment of the trans-Pacific marine segment (international car and vehicle carriers) that would be ideal early adopters of LNG as a marine fuel."

21.4 Considering the LNG base case scenario demand forecast includes some capture rate of trans-Pacific marine vessels as LNG fuel early adopters, please explain why the base scenario forecast does not display accelerated LNG demand after the IMO sulfur cap is implemented in 2020?

21.4.1 Please update the following figures to account for a LNG base scenario forecast that contains accelerated LNG demand after the IMO sulfur cap is implemented in 2020:

i. Figure 3-16 on page 86 of Exhibit B-1;

ii. Figure 3-17 on page 87 of Exhibit B-1;

iii. Figure 3-19 on page 89 of Exhibit B-1.

On page 18 of the FEU 2014 Long Term Resource Plan (LTRP) Decision, the Commission "encourages the FEU in their next LTRP filing to provide a more complete and fulsome analysis of the potential for new Industrial LNG Demand over the entire forecast horizon."

21.5 Is FEI aware of other potential LNG developments, other than the Woodfibre LNG plant, that will impact annual demand from Industrial LNG customers over the next 20-year planning period?

21.6 Please describe the extent of FEI's discussions and activities to develop new and existing markets for LNG to be supplied by FEI.

22.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Appendix B-1, p. 5; Section 3.4.4, p. 70
End-use demand forecast scenario parameters

On page 5 of Appendix B-1, FEI states:

> FEI relies on simulation because its research does not suggest sufficient correlation between Gross Domestic Product (GDP) and natural gas consumption or customer counts. Moreover, relying on third party GDP growth forecast ranges introduces an additional source of potential forecast errors. … As an alternative to any strong direct correlation between GDP growth and customer numbers/natural gas consumption, the 2017 LTGRP relies on a statistical approach using Prediction Intervals (PI).

22.1 Please describe the statistical approach using Prediction Intervals (PI) the 2017 LTGRP relies upon.

22.1.1 Please explain how these PI were calculated.

22.1.2 Please explain how FEI uses these PI to calculate a High and Low customer forecast.

22.2 How does the above statement reflect how the economic growth critical uncertainty is implemented in each of the alternate future scenarios of the 2017 LTGRP?

22.3 Please explain how forecast variability in new customer additions incorporates different economic growth assumptions.

22.4 Please provide a summary of the existing research by FEI and Posterity that concludes a -0.2 long run price sensitivity value for residential customers is suitable for use in the 2017 LTGRP.

On page 70 of Exhibit B-1, FEI states:

> The extraneous variables of RNG demand, NGT demand, and demand from large industrial point loads (FEI's scenario analysis assumes that the RNG and NGT markets are still emerging and thus primarily depend on policy and stakeholder action rather than other macroeconomic factors).

22.5 Please explain why extraneous variables primarily depend on policy and stakeholder action rather than other economic factors.

22.6 Please provide an update to, "Table 3-1: Alternate Future Scenario Summary" explicitly discussing the impact on NGT, LNG and RNG for each scenario. Please differentiate between LNG for NGT and non-NGT LNG in your discussion.

23.0 **Reference: ANNUAL ENERGY DEMAND FORECASTING**
Exhibit B-1, Section 3.4, pp. 62-63
Development of the end-use demand forecasts

23.1 Please provide a detailed analysis of the costs of producing the reference and scenario forecasts using the end-use methodology.

23.1.1 Please compare these costs to the costs associated with producing demand forecasts based on the traditional method?

23.1.2 How has the cost of the end-use method varied between the FEU 2014 LTRP and the FEI 2017 LTGRP?

23.1.3 Is it likely the cost of the end-use method will remain constant or increase/decrease over time? Please explain your response.

D. DEMAND SIDE RESOURCES

24.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, Section 4.2.1.1, p. 95; Section 4.2.1.2, pp. 96 to 97; Section 4.2.3, p. 102;
Demand-Side Measures Regulation B.C. Reg. 326/2008, Section 3
Adequacy Measures

Table 4-2 of Exhibit B-1 outlines the adequacy requirements of a plan portfolio, pursuant to Section 3 of the Demand-Side Measures Regulation (DSM Regulation), that must be included to be considered adequate for the purposes of section 44.1 (8)(c) of the *Utilities Commission Act* (UCA).

On pages 96 to 97 of Exhibit B-1, FEI states:

> The 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. The 2017 LTGRP C&EM analysis contains measures that are included in FEI's existing portfolio but also adds new measures. In general, many measures are applicable to adequacy situations but their adequacy implications depend on their specific program packaging and delivery (including marketing) which is determined during program design.

On page 102 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis results are informed by both the BC CPR and existing program experience. The results maintain the BC CPR's segmentation into residential, commercial, and industrial program areas. These do not break out individual adequacy programs specifically (this breakdown will occur in the forthcoming 2018 and future C&EM expenditure schedule submissions)

24.1 Please confirm if all scenarios presented in the 2017 LTGRP C&EM analysis contain all adequacy measures required under section 3 of the DSM Regulation including amendments up to BC Reg. 117/2017, March 24, 2017.

24.1.1 If not confirmed, please explain why the adequacy measures are not included in the 2017 LTGRP C&EM analysis.

24.2 Please confirm, or explain otherwise, that adequacy measures required under section 3 of the DSM Regulation have not been included as standalone measures in the LTGRP C&EM analysis.

24.2.1 For each of the adequacy requirements in Table 4-2, please outline which C&EM measures contained in the 2017 LTGRP C&EM analysis are "applicable to adequacy situations", and where appropriate please briefly describe the activities that will be undertaken to meet the adequacy requirement.

Section 3(e) of the DSM Regulation requires that a portfolio plan include:

> 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;

24.3 Please indicate the forecasted expenditure on section 3(e) measure(s) for the planning horizon of the 2017 LTGRP, as either the average percentage of overall plan expenditures, or dollar per year average, for all C&EM scenarios.

25.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, Section 4.2.2, p. 99 to 100; Section 4.2.2.2; p. 102;
Section 4.2.3, p. 102; Section 4.2.3.4, p. 119
C&EM scenarios

On page 99 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis displays results for the Reference Case, Upper Bound and Lower Bound scenarios presented in Section 3. The C&EM analysis selected these scenarios to display the impact of forecast C&EM activity on the Reference Case but to also illustrate the potential range of this impact across the Upper Bound and Lower Bound scenarios which resulted in the lowest and highest forecast of annual demand for natural gas.

Table 4-3 of Exhibit B-1 summarizes the input settings (economic growth, natural gas price, carbon price and non-price carbon policy action) for the Reference Case and Lower and Upper Bound scenarios, and the impact upon potential savings from C&EM is described in section 4.2.2.2 of Exhibit B-1.

On page 102 of Exhibit B-1, FEI states:

> The C&EM analysis results indicate the outcome of pursuing all cost effective energy savings potential.

On page 119 of Exhibit B-1, FEI states:

> FEI's forthcoming 2018 and future C&EM expenditure schedules will be informed by the measure data from the 2017 LTGRP's C&EM analysis and will make program design and delivery decisions in accordance with changing customer needs, regulatory requirements and technology evolution.

25.1 Please confirm whether FEI is seeking acceptance of the C&EM element of the LTGRP with respect to the Reference Case only, all scenarios, or otherwise, as part of its 2017 LTGRP Application.

25.1.1 Please confirm that all scenarios (Reference Case, Upper Bound and Lower Bound) include all C&EM measures that are cost-effective for the respective scenario.

25.1.1.1 If not confirmed, please explain.

25.2 Please discuss whether there is a combination of input settings (economic growth, natural gas price, carbon price and non-price carbon policy action) that would generate forecasted C&EM energy savings on a portfolio basis at a level that is:

a) higher than the forecasted C&EM energy savings under the Upper Bound scenario;
b) lower than the forecasted C&EM energy under the Lower Bound scenario.

25.2.1 If yes, please provide a comparison of energy savings with the Upper Bound and/or Lower Bound scenarios.

25.3 Please confirm the key outputs of the 2017 LTGRP C&EM analysis that will be used to inform FEI's future C&EM expenditure schedules to be filed with the Commission.

25.3.1 Please discuss the extent that the C&EM analysis under the Reference Case, Upper Bound scenario and Lower Bound scenario, respectively, will be used by FEI as inputs or guidance to future C&EM expenditure schedules.

25.3.1.1 Please discuss whether FEI considers that the Reference Case represents a "preferred portfolio" for informing future C&EM expenditure schedules.

On page 102 of Exhibit B-1, FEI states:

> Although customer demand is price inelastic over the short term, higher gas pricing over the long term, while holding all other variables constant, may cause some customers to switch away from natural gas for certain end uses… Higher economic growth tends to increase the potential for savings due to its impact on the customer forecast; lower economic growth tends to decrease it.

25.4 Please discuss whether FEI believes that persistent high gas prices, all other variables being constant, could increase customer awareness of C&EM programs and participation rates. Please discuss if this effect is modelled in the 2017 LTGRP C&EM analysis.

25.5 Please discuss whether FEI believes that changing customer spending power as a result of economic growth contributes to C&EM participation rates. Please discuss if this effect is modelled in the 2017 LTGRP C&EM analysis.

26.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, Section 4.2.1.1, p. 96; Section 4.2.2.1, p. 101; Section 4.2.2.2, p. 102; Section 4.2.3.2, p. 111; Section 4.2.3.3, p. 115; Appendix C-1, pp. 2, 5
Cost effectiveness tests

On page 96 of Exhibit B-1, FEI states:

> Effective March 24, 2017, BC Reg. 117/2017 increased from 33 to 40 percent the cap on the ratio of public utility DSM portfolios that may rely on the MTRC [Modified Total Resource Cost] for cost effectiveness testing …

On page 102 of Exhibit B-1, FEI states:

> Following the BC CPR's [Conservation Potential Review] approach, the 2017 LTGRP C&EM analysis applies the TRC [Total Resource Cost] test to commercial and industrial program areas but the MTRC test to the residential program area to simulate the current DSM landscape.

The Conservation Potential Review appended to the Application, on page 5 states:

> To date, FortisBC Gas's experience is that, typically, most programs in the residential sector require the mTRC.

26.1 Please explain why FEI applies the MTRC to the entire residential program area, rather than only applying the MTRC to measures that are not cost-effective under the TRC.

26.1.1 Please explain whether only applying the MTRC to measures that are not cost-effective under the TRC would result in the C&EM portfolios containing additional C&EM measures compared to the analysis in the 2017 LTGRP.

26.1.2 Please explain why most programs in the residential sector require the MTRC to be cost-effective.

26.2 Please confirm for each C&EM scenario the percentage of the portfolio where the MTRC has been applied.

26.2.1 If below the 40 percent cap, please explain why FEI did not apply the MTRC to additional measures that are not cost-effective under the TRC test.

On page 115 of Exhibit B-1, FEI states:

> In general, Upper Bound cost effectiveness test ratios are lower than Lower Bound ratios because the low natural gas cost and carbon cost parameters in this scenario depress the avoided cost of gas which reduces the benefits from energy efficiency measures. The MTRC represents an exception to this as this test relies on the ZEEA [Zero Emissions Energy Alternative] for its avoided cost of gas. In the 2017 LTGRP, the ZEEA is not impacted by the natural gas and carbon cost critical uncertainties.

26.3 Please confirm the values assumed for the avoided cost of gas under the TRC test for each C&EM scenario, in $/GJ.

26.3.1 Please explain the methodology and key assumptions behind the calculation of the avoided cost of gas for the purposes of the TRC test.

26.4 Please confirm and briefly explain the calculation of ZEEA value (in $/GJ equivalent) that FEI has assumed for the MTRC in its 2017 LTGRP C&EM analysis.

26.5 Please summarize the analysis undertaken by FEI to conclude that the ZEEA does not fluctuate in response the 2017 LTGRP scenario parameters.

26.5.1 Please confirm that FEI considers that the ZEEA will be unaffected by changes in economic growth, natural gas price, carbon price and/or non-price carbon policy action.

26.6 Please explain the consequences of any changes to the ZEEA value in the next five years with regards to FEI's planned C&EM portfolio.

26.6.1 Please explain the main factors that contribute to fluctuations in the ZEEA.

26.6.1.1 Please explain whether FEI has undertaken sensitivity analysis to model the effect of changes to the ZEEA upon the 2017 LTGRP C&EM analysis.

26.7 Please confirm the discount rate used for the TRC/MTRC calculation.

On page 101 of Exhibit B-1, FEI states:

> The 2017 LTGRP's C&EM analysis requires each measure to meet the cost effectiveness test threshold and does not package measures into programs (where individual non-cost effective measures could be rendered cost effective by other measures). This approach for pursuing all cost effective DSM is consistent with the analysis in the BC CPR. The 2017 LTGRP's C&EM analysis represents a long term directional forecast of addressable

C&EM initiatives; FEI's C&EM expenditure schedules bundle measures into specific programs, consider operational program deployment factors, and request BCUC permission for specific DSM expenditures.

The Conservation Potential Review appended to the Application, on page 2 states:

> This study models energy efficiency measures independently. As a result, the total aggregated energy efficiency potential estimates may be different from the actual potential available if a customer installs multiple measures in their home or business.

26.8 Please confirm whether FEI's C&EM expenditure schedules will consider measures that are not cost-effective on a standalone basis as part of "bundled" programs, where the bundled program is cost-effective.

26.8.1 If confirmed, please discuss whether FEI considers the bundling of measures, all other factors being equal, would increase or decrease:

a) overall energy savings, compared to the 2017 LTGRP C&EM analysis;
b) cost-effectiveness values, compared to the 2017 LTGRP C&EM analysis.

26.9 Please explain whether FEI will consider pursuing measures that are not cost-effective (within an overall portfolio that is cost-effective) in its forthcoming C&EM expenditure schedules.

26.9.1 If confirmed, please explain the difference in approach with the 2017 LTGRP.

27.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, Section 2.3.2.2, pp. 35 - 36; Section 4.2.3.1, pp. 103 to 106; Section 4.2.3.2, p. 107; Section 4.2.3.3, pp. 116 to 119; Section 8.6, pp. 210 to 215; Appendix C-2 pp. 3 - 4; Application for Acceptance of the 2014 Long Term Resource Plan Decision, Order G-189-14, Section 4.3, p. 27
C&EM Analysis

Figures 4-1 to 4-4 illustrates natural gas demand before and after estimated C&EM savings (excluding NGT) for all sectors, and by each customer program area.

On page 103 of Exhibit B-1, FEI states:

> Forecast 2036 Reference Case energy savings account for 7.89 percent of projected sales. This ratio changes to 6.79 percent and 5.92 percent for the Upper and Lower Bound scenarios, respectively.

On pages 35 to 36 of Exhibit B-1, FEI states:

> Energy Efficiency Resource Standards (EERS) aim to increase utility investment in energy efficiency measures to meet a share of their total load. Under an EERS, electric and gas utilities are regulated to demonstrate annual energy savings as a percentage of their total load. These savings are achieved through investment in utility energy efficiency programs. Annual savings targets range from 0.5 percent to 3 percent of total utility sales depending on the state. …
>
> Averaged over all state programs, EERS are saving an estimated 1.2 percent of utility load. However, should this annual savings rate persist, it would lead to a 15 percent reduction in utility energy demand by 2030, all else remaining equal.

27.1 Please reproduce Figures 4-1 to 4-4 in table form.

27.2 Please express energy savings (as a percentage of projected sales) as an annual average across the 20 years covered by the LTGRP for each C&EM scenario.

27.3 Please compare FEI's expected energy savings to the annual savings targets and 2030 reduction in energy demand summarized for EERS states. Please discuss the differences.

Table 4-4 of Exhibit B-1 displays estimated annual C&EM expenditures for all program areas. FBC submits estimated expenditures are expected to almost double from 2016 levels by 2023, and gradually decline after this year towards the end of the planning horizon as available energy savings opportunities are depleted. Figure 4-9 shows the estimated TRC results by scenario for all program areas, indicating that the TRC values level off around halfway through the planning horizon covered by the 2017 LTGRP.

Figures C2-1 to C2-3 of Appendix C-2 in Exhibit B-1, illustrate cost-effectiveness results for the residential program area.

27.4 Please explain if annual energy savings for all program areas also gradually decline from 2023 towards the end of the planning horizon.

27.5 Please explain why the cost-effectiveness values for the residential program area begin to increase at around 2031.

Table 4-8 of Exhibit B-1 summarizes the Reference Case cost effectiveness test results for all program areas, while Figures 4-9, 4-10, 4-11 and 4-12 illustrate how cost effectiveness test results vary across scenarios for the TRC, MTRC, Utility Cost Test (UCT) and Cost of Conserved Energy (CCE) respectively.

On page 116 of Exhibit B-1, FEI states:

> The 2017 LTGRP C&EM cost effectiveness test results also display the Cost of Conserved Energy (CCE) in dollars per GJ. The CCE is an industry standard method for expressing the TRC results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express Utility Cost Test (UCT) results in dollars per GJ by applying the UCT benefit and cost inputs. CCE results increase over time …

Figure 8-8 of Exhibit B-1, displays delivery rate direction for all rate schedules with C&EM (without NGT). Table 8-2 Exhibit B-1 provides a summary and comparison of average projected delivery rate changes. Figures 8-10 to 8-12 show the estimated total bill impact of projected C&EM activity on residential customers for each C&EM scenario. Table 8-3 shows the estimated total bill impact of projected C&EM activity on commercial and industrial customers.

The FortisBC Energy Utilities (FEU) 2014 Long Term Resource Plan (LTRP) Decision on page 27 states:

> The Panel therefore considers that in order for the Commission to evaluate the FEU's LTRP against BC's energy objectives, the FEU LTRP should include a broader analysis of the BC costs and benefits of different levels of DSM funding. The Panel is satisfied that, given that the FEU is not a traditional vertically integrated utility, this information should also satisfy the requirements of section 44.1(2)(f) as it relates to the FEU's own planned energy purchases and the DSM scenario analysis related requirements from the 2010 LTRP Decision.
>
> The Panel therefore directs the FEU to include, in its next LTRP, the following information:
>
> - The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario;

- Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low income, commercial etc.), including:
    - Total Resource Cost/modified Total Resource Cost test results;
    - Utility Cost Test result, expressed as a ratio and $/GJ;
    - Delivery rate impact;
    - Estimated total bill impact (including delivery and commodity), $ and %, with residential split between high and low use gas customers; and
    - Estimated gas (GJ) and GHG emission reductions.

27.6 Please confirm if the values in the TRC column of Table 4-8 and Figure 4-9 are calculated using the MTRC test for the residential program area.

27.6.1 If not confirmed, please add a column to Table 4-8 and reproduce Figure 4-9 using the MTRC for the residential program area and TRC for the commercial and industrial program areas.

27.6.2 Please confirm if FEI's low income program area is included in the analysis for the residential program area.

27.7 Please explain why in Figure 4-10 there is little variation in MTRC values between scenarios.

27.8 Please provide analysis in table format of the UCT expressed as the CCE ($/GJ) for each C&EM scenario, at a portfolio level and at residential, commercial and industrial program area level, for each year of the planning horizon covered by the 2017 LTGRP.

27.8.1 Please explain why the CCE results increase over time.

27.9 Please reproduce Table 8-2 to include a column which shows the compound annual delivery rate change and cumulative rate change for C&EM programs only. Please also provide separate tables that perform this analysis at a residential, commercial and industrial program area level, for each C&EM scenario.

27.9.1 Please briefly describe any significant differences between program areas.

27.10 Please explain why the annualized percentage compound 2015-2036 bill impacts of C&EM activity for residential customers, peaks at around consumption levels of 75 GJ/ year.

27.11 Please explain why the annualized percentage compound 2015-2036 bill impacts of C&EM activity for Rate Schedule 22 are significantly lower than for other rate classes.

28.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, 4.2.1.3, p. 99; Section 4.2.2.1, p. 101; Section 4.2.3.5, p. 121;
Appendix C-1, p. 3
Conservation Potential Review

On page 101 of Exhibit B-1, FEI states:

> FEI applied the C&EM potential to its multi-scenario end-use forecast via the following steps:
>
> 1. In the 2017 LTGRP forecast model, construct a separate Reference Case which matches as closely as possible the BC CPR's Reference Case;
> 2. Import the CPR measure assumptions into this 2017 LTGRP CPR Reference Case …;
>
> 7. Apply the 2017 LTGRP Reference Case and produce the market potential energy savings, benefit-cost, and expenditure results.

On page 121 of Exhibit B-1, FEI states:

> FEI instructed the consultant that prepared the BC CPR to use the BC CPR's Bass Diffusion model to explore how different levels of incentive value impact projected energy savings and estimated C&EM expenditures. While the BC CPR model is separate from FEI's 2017 LTGRP forecast model and the 2017 LTGRP Reference Case differs from the BC CPR, the BC CPR's results provide directional insight into this sensitivity.

28.1 Please confirm if the "2017 LTGRP CPR Reference Case" is the same as the "2017 LTGRP Reference Case."

28.1.1 Please describe the key differences between the 2017 LTGRP CPR Reference Case, 2017 LTGRP Reference Case and the BC CPR Reference Case.

28.1.1.1 Please explain the impact of these differences upon:

a) Estimated C&EM energy savings;
b) The sensitivity analysis of incentive value impact;
c) Estimated annual C &EM expenditures.

28.2 Please summarize how the sensitivity analysis of incentive value impact will be used by FEI in the development of future C&EM expenditure schedules.

On page 99 of Exhibit B-1, FEI states:

> The BC CPR summary report does not recommend specific programs or targets to be implemented. However, the report does identify technology and market opportunities as well as the scope of market energy savings potential across the study period. The range of potential C&EM measures from the BC CPR results informs the 2017 LTGRP C&EM forecast.

The Conservation Potential Review appended to the Application, on page 3 states:

> Navigant and BC Utilities agreed to show savings from this study at the gross level, whereby natural change and free ridership, as it relates to program implementation, are not included in the savings estimates but rather are estimated separately.

28.3 Please confirm and explain if the 2017 LTGRP C&EM analysis includes the effects of free-riders and spillover, where these effects are applicable.

28.4 Please discuss whether the 2017 LTGRP C&EM analysis accounts for lost opportunities that would be more expensive to address at a later time.

29.0 **Reference: DEMAND SIDE RESOURCES**
Exhibit B-1, Section 4.3, p. 124; Section 6.3, pp. 155 to 188;
FEU Application for Acceptance of the 2014 Long Term Resource Plan Decision, Order G-189-14, Section 4.4; p. 28
C&EM and peak demand

In the FEU Application for Acceptance of the 2014 Long Term Resource Plan Decision (2014 LTRP Decision), p. 28, the Commission stated:

> The Commission Panel agrees with the interveners that future filings would benefit from additional analysis focused on identifying potential DSM strategies that could favourably affect peak demand. Accordingly, in the next LTRP the FEU are directed to provide a more fulsome analysis of opportunities for DSM to be cost-effectively used to replace or defer infrastructure investments.

On page 124 of Exhibit B-1, FEI states:

> Load Management: Programs that may either reduce peak demand or shift demand from peak to non-peak periods. Since the largest portion of natural gas demand in BC is for space and water heating which are more difficult to shift, and because the natural gas system acts to store energy allowing it to be drawn down over a longer period of time than with electricity, programs that reduce or shift peak demand for natural gas are more challenging in BC.

On page 154 of Exhibit B-1, FEI states:

> FEI has since commissioned Posterity, a consultant, to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. At this point, the exercise is theoretical in nature and unsupported by direct measurement.

Section 6.3 of Exhibit B-1 describes FEI's Regional Transmission System Capacity Plans, which includes analysis of the impact of FEI's planned C&EM activity upon peak demand, and the potential impact on infrastructure expansion requirements.

29.1 Please confirm, or explain otherwise, that the 2017 LTGRP does not include any C&EM programs/measures that specifically target peak demand (as opposed to targeting annual energy reductions).

29.1.1 If confirmed, please summarize analysis of any load management measures that were considered for the 2017 LTGRP, and explain why these measures were ultimately not included in the 2017 LTGRP.

29.1.2 Please discuss whether FEI has plans to include load management programs in forthcoming expenditure schedules submitted during the period covered by the 2017 LTGRP.

29.2 Please explain why natural gas demand for space and water heating is "more difficult to shift."

29.2.1 Please summarize any programs in other jurisdictions that FEI is aware of that aim to reduce and/or shift peak natural gas demand for space and water heating.

29.2.1.1 Please explain whether similar programs could be applicable in BC in future.

29.3 Please identify and describe the limitations of the "theoretical nature" of the peak demand analysis with respect to the impact of DSM initiatives upon peak demand.

29.3.1 Please confirm if the analysis considers regional effects.

29.3.2 Please discuss if FEI plans to undertake direct measurement in future to support the exploratory analysis.

29.4 Please comment and explain the extent to which, in the view of FEI, the C&EM measures contained in the 2017 LTGRP analysis can be considered "firm" in the context of resource planning for the reduction of peak demand.

30.0 **Reference:** **DEMAND SIDE RESOURCES**
Exhibit B-1, Section 4.3, p. 124
Load building measures

On page 124 of Exhibit B-1, FEI states:

> Load Building: Programs that increase the annual consumption of electricity or natural gas by increasing sales of electricity, natural gas or both. In the broader context of DSM, FEI's fuel switching program and NGT initiatives are also examples of load building demand side activities in that they increase the annual use of natural gas.

30.1 Excluding fuel switching and NGT, please identify any measures included in the 2017 LTGRP C&EM analysis that could be classified as load building.

E. GAS SUPPLY PORTFOLIO PLANNING

31.0 **Reference:** **GAS SUPPLY PORTFOLIO PLANNING**
Exhibit B-1, Section 5, Table 5-1, p. 130
Rate Schedules included in Gas Supply Planning

Table 5-1 on page 130 of Exhibit B-1 shows the rate schedules included in or excluded from FEI's gas supply portfolio planning and FEI's system capacity planning.

In the cell that represents Firm Transportation Rate Schedules FEI states: "Contracted firm delivery component of 22 (including 22A and 22B) and other special Rate Schedules." In row 3 of the same table FEI also uses the term "special Rate Schedules."

31.1 Please list the "special Rate Schedules" which: (i) is relevant to Firm Transportation in row 2; and (ii) is included in row 3 regarding interruptible customers.

31.2 Please state whether: (i) rate schedule 22A has a firm delivery component; and (ii) rate schedule 22B has a firm delivery component.

31.3 Please confirm, or otherwise explain, that Rate Schedule 46 demand is included in: (i) Gas Supply Portfolio Planning; and (ii) System Capacity Planning.

32.0 **Reference:** **GAS SUPPLY PORTFOLIO PLANNING**
Exhibit B-1, Section 4.2.3.6, p. 123; Section 5.3.1, p. 137
Demand Forecasts used for Gas Supply Portfolio Planning

On page 123 of Exhibit B-1, FEI states:

> FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end-use scenarios used in the annual demand forecasts. Section 6.2.1.3 further discusses this process. Overall, Posterity's approach suggests that the 2017 LTGRP's C&EM forecast decreases peak demand. Section 6 discusses in detail how this may impact infrastructure expansion requirements across FEI's regional transmission systems. FEI emphasizes that Posterity's approach currently is theoretical in nature and unsupported by direct measurement. Thus FEI's infrastructure planning continues to rely on FEI's traditional peak demand forecast method (Traditional Peak Method).

32.1 Does FEI agree with Posterity that the 2017 C&EM forecast decreases peak demand? Please explain your response.

32.2 Please explain if, and how, FEI has accounted for the impact of its 2017 LTGRP C&EM reference case forecast in its peak demand forecast associated with Gas Supply Portfolio Planning.

32.2.1 If not, please explain why.

On page 137 of Exhibit B-1, FEI states:

> FEI's portfolio is designed to provide secure and reliable daily gas supply to Core customers so that system-wide forecasted normal, design and peak design day demand is met.

32.3 Please use the following template to produce tables showing the forecast peak day demand and forecast annual normal demand for each year of the planning period before and after the impacts of FEI's 2017 LTGRP C&EM reference case forecast.

Service Regions	Forecast Peak Day Demand used for Gas Supply Portfolio Planning (TJ/d) (before C&EM)				
	2017	2018	...	2035	2036
Columbia					
Lower Mainland					
Inland					
Whistler					
Vancouver Island					
Sub-total Peak Day Demand (A)					
Ft. Nelson (B)					
Total Peak Day Demand (A + B)					
System-wide	**Forecast Annual Normal Demand used for Gas Supply Portfolio Planning (PJ/yr) (before C&EM)**				
	2017	**2018**	**...**	**2035**	**2036**
Annual Normal Load (PJ/yr) - FEI					
Annual Normal Load (PJ/yr) - Fort Nelson					

Service Regions	Forecast Peak Day Demand used for Gas Supply Portfolio Planning (TJ/d) (after C&EM)				
	2017	2018	...	2035	2036
Total Peak Day Demand (TJ/d)					
System-wide	**Forecast Annual Normal Demand used for Gas Supply Portfolio Planning (PJ/yr) (after C&EM)**				
	2017	**2018**	**...**	**2035**	**2036**
Annual Normal Load (PJ/yr) - FEI					
Annual Normal Load (PJ/yr) - Fort Nelson					

32.3.1 Please produce graphs with the forecasts before C&EM for: (i) Sub-total Peak Day Demand; (ii) Total Peak Day Demand; and (iii) Annual Normal Load for FEI for the 20-year planning period.

32.3.1.1 Please discuss possible reasons for any significant trends identified.

32.3.2 Please produce graphs with the forecasts after C&EM for: (i) Sub-total Peak Day Demand; (ii) Total Peak Day Demand; and (iii) Annual Normal Load for FEI for the 20-year planning period.

32.3.2.1 Please discuss possible reasons for any significant trends identified.

32.3.3 Please list all rate schedules whose demand was included in response to the above questions.

32.4 Please explain if a reduction in peak demand due to FEI's 2017 LTGRP C&EM could impact the resources required for FEI's Gas Supply Portfolio Planning.

32.4.1 Using FEI's 2017 LTGRP C&EM Reference Case forecast and FEI's peak demand forecast used for Gas Supply Portfolio Planning please calculate and explain any impacts to the following forecast resources:

(i) commodity supply (baseload, seasonal and winter);

(ii) storage capacity (market area and on-system storage); and

(iii) transportation capacity.

32.5 Please discuss the flexibility of FEI's gas supply resources identified in Figure 5-3 of Exhibit B-1, to respond to a possible reduction to the peak demand and normal demand due to the impacts of FEI's C&EM.

33.0 **Reference: GAS SUPPLY PORTFOLIO PLANNING**
Exhibit B-1, Section 5, p. 135; NW Natural 2016 Integrated Resource Plan, p. 8.1
Mist contracts for market area storage

On page 135 of Exhibit B-1, FEI states that one of the major market factors that may affect FEI's gas supply planning over the long term includes the risk of "FEI's shorter duration market storage assets, specifically Mist, being recalled by approximately 2021/22."

In a footnote on page 135 of Exhibit B-1, FEI provides a hyperlink to the NW Natural 2016 Integrated Resource Plan. Page 8.1 of NW Natural 2016 Integrated Resource Plan states: "Mist Recall is the primary resource addition to meet growing peak loads. The next Mist Recall is projected to be for 30,000 Dth/day for the 2019-2020 gas year."

33.1 Please explain the nature of Mist's ability to recall storage capacity. In addition to your explanation, please discuss:

i. Whether FEI has the option of negotiating the volume of the recall;
ii. How much notice in days/months/years would FEI get if NW Natural were to recall Mist storage contracted to FEI.

33.2 How likely is it for all or a significant portion of FEI's storage capacity at Mist to be recalled during the planning period (highly likely, somewhat likely, highly unlikely)? Please explain your response.

33.3 If all or a significant portion of FEI's storage capacity at Mist is recalled during the 4-year period covered by the Action Plan, please explain FEI's contingency plan for its Gas Supply Portfolio Plan in order to minimize both supply and price risk to ratepayers?

34.0 **Reference: GAS SUPPLY PORTFOLIO PLANNING**
Exhibit B-1, Section 5.4, p. 142
Excess resources

On page 142 of Exhibit B-1, FEI states:

> … FEI has also started to contract for some resources in excess of what Core customers are forecast to require in the short term. This approach is reasonable because the costs and ability to manage contract renewals within the portfolio of resources help to reduce the risk to Core customers.

34.1 Please calculate the cost to Core customers in 2017, if any, for <u>only</u> the excess gas supply portfolio resources contracted by FEI.

34.1.1 Please calculate what percentage of the cost for only the excess resources was mitigated throughout 2017.

F. PRICE RISK MANAGEMENT

35.0 **Reference: PRICE RISK MANAGEMENT**
Exhibit B-1, Section 5.5.1, p. 142, 143;
Decision on FortisBC Energy Utilities 2014 Long Term Resource Plan dated December 3, 2014 (FEU 2014 LTRP Decision), p. 37;
FEI 2017 Price Risk Management Plan (PRMP) proceeding, Exhibit B-1-2 (2018 PRMP Application), Section 2, p. 4
Price risk management objectives

Page 37 of the FEU 2014 LTRP Decision states:

> The Commission Panel considers that the LTRP should inform the PRMP on price risk management principles, and not vice versa. The UCA requires that, when considering utility filing of energy supply contracts under section 71 of the UCA, the Commission must consider the most recent LTRP filed by the utility. The Panel therefore directs the FEU to include in the next LTRP a description of its long-term vision for price risk management and provides broad principles, which can be used to inform the PRMP.

FEI states on page 142 of the Application:

> FEI has developed diversified procurement strategies and utilized [Price Risk Management Plans (PRMPs)] to manage commodity price risk and facilitate competitive and affordable natural gas rates" [emphasis added]. FEI further states on page 143 of the Application that "FEI's price risk management objectives include mitigating market price volatility to support rate stability and capturing favourable prices to provide customers with more affordable rates. [emphasis added]

FEI states on page 143 of the Application that: "the objectives for medium and longer term are the same, but the tools for managing price risk management are different."

On June 13, 2017, FEI filed its 2017 Price Risk Management Application. On January 5, 2018, FEI submitted its revised application titled 2018 Price Risk Management Plan Application (2018 PRMP Application). FEI states on page 4 of FEI's 2018 PRMP Application that: "FEI's objectives for its price risk management, which includes hedging, include the following:

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

35.1 Please reconcile the differences between the PRMP objectives stated in the LTGRP and in the 2018 PRMP Application, and clarify what are FEI's PRMP objectives.

35.2 In light of FEI's statement that: "the objectives for medium and longer term are the same," please explain whether FEI has one set of PRMP objectives that are consistently applied to inform its planning and operational decisions. If not, please explain why not.

35.2.1 Please confirm that FEI's responses to information requests filed in the FEI 2017 PRMP proceeding regarding price risk management objectives also speaks to the price risk management objectives contained in the 2017 LTGRP, and can be included as part of the evidentiary record on the 2017 LTGRP proceeding. If not confirmed, please elaborate.

35.3 Please provide FEI's views on the Commission's comment in the FEU 2014 LTRP Decision that the LTRP should inform the PRMP on price risk management principles, and not vice versa.

35.3.1 Going forward, does FEI consider that the review of the LTRP should conclude prior to FEI's filing of its PRMP, if possible? Please explain your response.

36.0 **Reference:** **PRICE RISK MANAGEMENT**
Exhibit B-1, Section 5.5.1, p. 143; FEI 2017 PRMP Application, Exhibit B-1-2 (FEI 2018 Application), p. 34
Volumetric Production Purchase (VPP)

On page 143 of Exhibit B-1, FEI states:

> FEI plans to continue to investigate longer term strategies such as VPPs and, if warranted, will bring forward any requests to the Commission for approval in the future." FEI further states that "the objectives for medium and longer term, are the same, but the tools for managing price risk management are different.

On page 34 of FEI's 2018 PRMP Application, FEI elaborates on the VPP under section 4.5.3. Specifically, FEI states that: "In this arrangement, the buyer pays an upfront lump sum payment to a gas producer in exchange for specific volumes delivered over the term of the agreement (up to twenty years)… the capital investment would be included in FEI's rate base and earn a rate of return for shareholders."

36.1 Please elaborate on FEI's investigation process into VPPs as a long term PRMP strategy, and provide the timing of when FEI will conclude its investigation.

36.2 Please elaborate on VPPs, including a discussion of the following:

- the requirements (e.g. market condition, financial commitment, counterparty financial standing) to execute VPP investments;
- whether additional resources (external or in-house) and costs is required to enter into and monitor VPPs;
- the risk exposures that VPPs are designed to reduce;
- any additional risks that FEI could be exposed to by entering into VPPs; and
- any other pros and cons of VPPs in meeting FEI's price risk management objectives relative to its existing tools.

37.0 **Reference:** **PRICE RISK MANAGEMENT**
Exhibit B-1, Section 5.5.2, pp. ES-7, 145;
FEI 2017 PRMP proceeding, Exhibit B-1-2, pp. 33-34
Investment in natural gas reserves

FEI states on page ES-7 of its Application:

> FEI plans to continue to investigate longer term strategies such as investing in reserves, and if warranted, will bring forward any requests to the Commission for approval in the future." FEI also states on page 145 of the Application that: "Other potential instruments or tools for managing longer-term market price volatility could include investment in natural gas reserves or long term fixed price contracts. Investment in natural gas reserves would provide even longer-term price protection.

On pages 33 to 34 of FEI's 2018 PRMP, FEI states:

> Managing the risk associated with reserves would be of paramount importance to FEI in a reserves arrangement. While it may seem that the risk associated with drilling, completing, and operating wells would differ from typical regulated utility assets, there may be ways to mitigate these risks through contractual arrangements and effective due diligence. One important feature of any deal would be the ability to transfer risks to producers that are appropriate for a producer to manage, such as drilling risks and most operating risk. However, this transfer of risks may not be acceptable to the producer or increase the capital investment required by the producer. Because of this, *FEI is not planning to explore this option further at this time*. [emphasis added]

37.1 Please reconcile FBC's statement contained in its Application and in its 2018 PRMP on whether FEI plans to further explore the option of investing in natural gas reserves.

G. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

38.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.2, p. 150
Projects to address system capacity constraints

On page 150 of Exhibit B-1, FEI states:

> Infrastructure projects on transmission systems to address system capacity constraints are often large and take many years to plan and execute. As a result, securing infrastructure resources is not as responsive as securing gas supply resources.

38.1 Using high-level estimates, please provide the various types of infrastructure projects for transmission systems meant to address system capacity constraints and the:

(i) time to plan the project;

(ii) time to execute the project; and

(iii) total time to plan and execute the project by bringing it into service.

Please use a table format for your response and please exclude the time required to obtain regulatory approvals from the relevant organizations.

39.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.2.1.3, p. 153; Section 6.1, p. 149
Peak demand forecast for system capacity planning

On page 153 of Exhibit B-1, FEI states:

> FEI's Traditional Peak Method forecast is built from a "load gather" process that determines unique daily and hourly UPC_{peak} values for each customer. Values for most customers are based on regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. … For customers where hourly consumption data is available (typically large commercial and industrial customers) UPC_{peak} is determined directly from that data. These unique hourly UPC_{peak} values for each customer are then grouped by rate and region to determine average hourly UPC_{peak} for each region and rate schedule that can then be applied to an account forecast to determine a peak demand forecast. A unique UPC_{peak} for residential, small commercial and large commercial rate schedules in 66 separate regions across the province is developed in FEI's Traditional Peak Method.

On page 149 of Exhibit B-1, FEI defines UPC_{peak} as "peak hour use per customer."

39.1 Please explain, with calculations and examples where relevant, how the UPC_{peak} is determined for residential, small commercial and large commercial customers whose consumption meters are read monthly.

39.2 Please state if FEI's system capacity planning approach is based on a coincident peak approach or a non-coincident peak approach for each system (Vancouver Island Transmission System (VITS), Coastal Transmission System (CTS) and Interior Transmission System (ITS)).

39.2.1 Please explain the reason for the approach chosen.

40.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 5, p. 130; Section 6.1, p. 149
Peak demand forecasts

On page 154 of Exhibit B-1, FEI states:

> UPC_{peak} values used in the Traditional Peak Method forecast are determined based on current measured consumption for customers. When applied to the 20-year account forecast to determine the peak demand forecast, <u>these values are assumed to remain unchanged over the planning horizon. As such, there is no explicit allowance for evolving customer utilization in this approach</u>. The estimates of UPC_{peak} are, however, refreshed annually so that assessments of future capacity constraints are always determined against current customer consumption patterns and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs. (Underline Emphasis Added)

40.1 For each of the: (i) VITS; (ii) CTS; and (iii) ITS, please provide a table that shows: (a) the UPC_{peak} for each rate schedule and applicable contract customer; and (b) the combined UPC_{peak} for the system for each of the 10 years from 2007 to 2016.

40.1.1 Please discuss any significant trends identified over the 10 years by rate schedule.

40.2 Please explain if FEI considers that holding the UPC_{peak} values constant for the 20 year planning period accurately reflects historical data.

40.3 Taking into consideration the planning environment, in particular FEI's discussion regarding energy and emissions policy in Section 2.3 of the Application, please discuss the likelihood of UPC_{peak} for residential, small commercial and large commercial customers remaining unchanged for the 20 years from 2017 to 2036.

40.4 Please explain if, and how, there is any risk to FEI or FEI ratepayers of actual UPC_{peak} increasing during the planning period while FEI's system capacity plans are made using a constant UPC_{peak} during the planning period.

40.5 Please explain if, and how, there is any risk to FEI or FEI ratepayers of actual UPC_{peak} decreasing during the planning period while FEI's system capacity plans are made using a constant UPC_{peak} during the planning period.

40.6 Please describe how FEI could mitigate the risks to both FEI and FEI's ratepayers identified in response to the above questions.

41.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.3.1, p. 158; Figure 6-2, p. 159
Vancouver Island (VI) demand and capacity balance

On page 158 of Exhibit B-1, FEI states:

> The Mt. Hayes facility has a storage capacity of 1.5 Bcf (approximately 1,614 TJ), a liquefaction capacity of 7.5 million standard cubic feet per day (MMscfd), and a send-out deliverability of 150 MMscfd (161 TJ/d).Traditionally, the capacity of the VITS is represented by allocating one third of the Mt. Hayes sendout capacity to the VITS, with the balance remaining available for the rest of the FEI system. The peak day capacity on the following figures reflects this arrangement.

41.1 Please provide the figure in TJ/d for the design day system capacity, identified by a red line in Figure 6-2 on page 159 of the Application.

41.2 Please provide an updated version of Figure 6-2 which shows any forecast demand above the VI design day system capacity line for each of the years from 2028 to 2036.

41.2.1 Please state the VI system capacity deficit (Demand minus Capacity) in TJ/d for each year from 2028 to 2036.

On page 158 of the application FEI states:

> Traditionally, the capacity of the VITS is represented by allocating one third of the Mt. Hayes send out capacity to the VITS, with the balance remaining available for the rest of the FEI system.

41.3 Please explain how flexible the Mt. Hayes storage facility is in its allocation of supply between VITS and the rest of the FEI system.

41.4 Please explain if the amount contributed to the rest of the FEI system is fixed or capped.

41.5 Is there availability to increase the allocation from Mt. Hayes to the VITS?

41.6 What is the maximum capacity that can be allocated from Mt. Hayes to VITS?

42.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.3.1, p. 158; pp. 162-163;
FEI 2016 Rate Design Application proceeding, Exhibit B-1-5, Section 9.8, p. 9-37;
Exhibit B-5, BCUC IR 34.7.1, p. 174; Exhibit B-7, BC Hydro IR 1.1, p. 1
BC Hydro Island Generation contract

On page 158 of Exhibit B-1, FEI states:

> Prior to installation of the Mt. Hayes LNG storage facility, the VITS was fully subscribed and relied upon a right to call back capacity from BC Hydro Island Generation during design weather events in order to serve its Core and Firm Transportation market design day (i.e. peak demand) requirements.

42.1 Does FEI still retain the right to call back capacity from BC Hydro Island Generation (IG) during design weather events?

42.1.1 If yes, please explain if FEI expects that it will retain this right for the duration of: (i) the period spanning FEI's Action Plan; and (ii) the 20-year LTGRP planning period.

42.1.2 If yes, please state the maximum capacity in TJ/d that FEI would be able to call back from BC Hydro IG during design weather events.

On pages 162 and 163 of Exhibit B-1, FEI discusses two options for addressing the identified capacity constraint on the VI system. FEI then notes that a key input is the renegotiation of the contract with BC Hydro IG. FEI states:

> Renegotiating the existing peaking agreement with BC Hydro in 2022 may allow curtailment of flows to IG to meet Core and Firm Transportation market requirements. Depending on the peaking agreement reached with IG, reduction of the peak day firm quantity has the potential to defer the capacity constraint within the planning horizon or move it beyond the 20-year forecast horizon altogether. The final agreement will be a key factor in determining the requirement and timing of the preferred option for capacity expansion.

In the FEI 2016 Rate Design Application proceeding, FEI proposes on page 9-37 of Exhibit B-1-5: "to create a firm rate for RS 22, VIGJV and BC Hydro IG based on a cost of service allocation from the COSA model." In response to BCUC IR 34.7.1, FEI stated:

> If BC Hydro elects not to become a RS 22 customer, BC Hydro could elect to become an RS 50 customer, if they meet the requirements of that rate schedule. BC Hydro could also elect to extend their current agreement, which would require negotiation of a rate that would need to be approved by the Commission.

42.2 Please explain and calculate the impact, if any, to the VI system capacity requirements and the identified capacity constraint for the VI system if BC Hydro IG becomes a RS 22 customer. Please include a discussion of FEI's ability for flow curtailment of BC Hydro IG's demand in this scenario.

42.3 Please explain and calculate the impact, if any, to the VI system capacity requirements and the identified capacity constraint for the VI system if BC Hydro IG becomes a RS 50 customer. Please include a discussion of FEI's ability for flow curtailment of BC Hydro IG's demand in this scenario.

In the FEI 2016 Rate Design Application proceeding, FEI confirmed on page 1 of Exhibit B-7 that BC Hydro's existing Transportation Service Agreement (TSA) contains a renewal term provision that allows BC Hydro to extend the existing TSA up to 2042. FEI further stated:

> The current renewal provision in the BC Hydro Transportation Service Agreement effective January 1, 2008 allows for a maximum term of 35 years. If BC Hydro chooses to extend the agreement beyond April 2022, the rates applicable to the extension need to be approved by the Commission.

42.4 Please explain if FEI has the option to renegotiate terms other than the rate, should BC Hydro choose to extend the current agreement through the renewal provision.

43.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.3.1, p. 164
Woodfibre LNG Limited

On page 164 of Exhibit B-1, FEI states:

> Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 236 MMscfd on the VITS. Should a final investment decision be made, the estimated in-service date of this facility is currently projected no earlier than 2021.

43.1 Please explain the timeframe associated with building Woodfibre LNG Limited's LNG plant, beginning with the planning stages and ending with the plant being put into service. Please use timeline diagrams where appropriate.

43.2 Please provide an estimate of the earliest in-service date of this facility if it is longer 2021.

43.3 Please reproduce Figure 6-3 and Figure 6-5 to show the impact of Woodfibre LNG Limited's facility entering into service in 2021.

On page 164 of Exhibit B-1, FEI states:

> To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year.

43.4 Please update Figure 6-1 to show where pipeline looping and added compression would be required in order to accommodate the addition of the Woodfibre LNG Limited's LNG plant.

43.4.1 Please provide a schematic diagram similar in nature to Figure 6-6 which shows where the pipeline looping and added compression would be required in order to accommodate the addition of the Woodfibre LNG Limited's LNG plant.

44.0 **Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES**
Exhibit B-1, Section 6.3.2, p. 170
Interior Transmission System Demand-Capacity Balance

Figures 6-15, 6-16 and 6-17 present the Interior Transmission System (ITS) demand-capacity balance using various peak demand forecasts. Figure 6-15 shows that the Traditional Case peak demand forecast for this region reveals a capacity constraint occurring in 2022. Figure 6-17 shows that the Traditional Case peak demand forecast for this region reveals a capacity constraint occurring in 2022 and includes end-use scenarios with DSM.

44.1 Please update Figure 6-15 to show the impact of DSM on the Traditional Case peak demand forecast.

44.1.1 Please provide a discussion regarding the timing of the capacity constraint on the ITS after taking into consideration the impact of DSM.

H. 20-YEAR VISION FOR FEI

45.0 **Reference: 20-YEAR VISION FOR FEI**
Exhibit B-1, Section 8.3.2, Table 8-1, p. 206
FEI's contributions to BC's Greenhouse Gas (GHG) Emissions Targets

On page 206 of Exhibit B-1, FEI states: "Table 8-1 below compares 2036 emissions reductions of FEI's initiatives with the calculated 2036 emissions reductions target. … Some forecast NGT emissions reductions are realized outside the current boundaries of the BC emissions inventory." Table 8-1 is reproduced below.

GHG Reductions Required to Meet the Calculated 2036 Target ($MtCO_2e$, 2014 Base)	Forecast Emissions Reductions in 2036 ($MtCO_2e$, 2015 Base)		
29.3	Reference Case	Upper Bound	Lower Bound
RNG	0.04	0.14	0.01
C&EM	0.8	0.8	0.3
NGT	2.3	14.9	0.2

45.1 Please provide a copy of Table 8-1 which excludes NGT emissions reductions that are realized outside the current boundaries of the BC emissions inventory.

46.0 **Reference: 20-YEAR VISION FOR FEI**
Exhibit B-1, Section 8.3.1, Figure 8-4, p. 201
Application for Acceptance of the 2014 Long Term Resource Plan Decision, Order G-189-14, Section 4.3, p. 27
GHG emission reductions

The FEU 2014 LTRP Decision on page 27 states:

> The Panel therefore directs the FEU to include, in its next LTRP, the following information: … Analysis of each DSM scenario, at a portfolio level and for each DSM category (residential, low income, commercial etc.), including: … Estimated gas (GJ) and GHG emission reductions.

46.1 Please explain why in Figure 8-4 the curve for the Lower Bound scenario trends upwards in the later years of the planning horizon.

46.2 Please provide analysis in table format of the estimated GHG emission reductions for each C&EM scenario by residential, commercial and industrial program area, for each year of the planning horizon covered by the 2017 LTGRP.

46.2.1 Please provide a brief explanation of the results.