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July 31, 2014

<u>Via Email</u>
Original via Mail

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan (the Application)

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

On March 25, 2014, the FEU filed the Application as referenced above. In accordance with Commission Order G-56-14 setting out the Regulatory Timetable for the review of the Application, the FEU respectfully submit the attached response to BCUC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

Attachments

cc (e-mail only): Registered Parties

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[1] comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc.

1.0 Reference: COMPLETENESS OF FEU 2014 LONG TERM RESOURCE PLAN (2014 LTRP)

Exhibit B-2, BCUC IR 1.2.1, p. 6 and BCUC IR 1.2.3, p. 8;

Exhibit B-1, Application, Appendix C-2, p. 39;

FEI 2014-2018 PBR Application, Exhibit B-24, BCUC IR 2.364.3.3, p. 446

In response to British Columbia Utilities Commission (BCUC) IR 1.2.1, the FortisBC Energy Utilities (FEU) state: "For the FEU, demand and supply side resources are not directly comparable as they are for an integrated electric utility" and in response to BCUC IR 1.2.3 "The … EEC [Energy Efficiency and Conservation] Plan was also reviewed with the EEC Advisory Group who stated agreement that no major course correction in the Plan were needed." In Appendix C-2 of the Application, the 2010 Conservation Potential Review (CPR) states on page 39: "… even with declining load, there are significant potential cost effective natural gas efficiency improvements in the Industrial sector."

In response to BCUC 2.364.3.3 of the FortisBC Energy Inc. (FEI) 2014-2018 PBR Application (PBR Application), FEI stated: "By continuing with a previously-approved portfolio of activity and levels of expenditure a balance between rates and bills found to be acceptable by a previous Commission Panel will continue."

1.1 Please provide an *estimate* of the annual and cumulative effect over the planning period on FEU's revenue requirement, FEU residential rates, and BC GHG emissions if the EEC annual budget was (i) $25 million, (ii) $35 million and (ii) $45 million. Please assume the same average level of cost effectiveness of all three EEC portfolios, and state all assumptions made.

<u>Response:</u>

The FEU would like to first point out that the different levels of funding that the Commission has requested do not represent different portfolios as suggested in the information request. Nor is there any relevance to the Commission's description of an assumption of, "the same level of cost effectiveness". The FEU have included all cost-effective measures in its estimation of long term energy savings from EEC measures using the only standards of cost-effectiveness and the only market data available to them at the time of the analysis. The Commission's request, rather, is asking the FEU to analyze differing levels of funding for the same portfolio, assuming there is no limitation on the market's ability to take up EEC measures. As such, the FEU do not believe that the results provided for the higher spending levels have any relevance or that the results of this analysis provide any additional completeness to the LTRP.

If the Commission wishes to vary the actual portfolio of EEC measures, the FEU suggest that it would need to identify to the FEU which cost effective measures it would like to see removed from the portfolio in the lower funding case and identify any hypothetical measures it would like to see added to the portfolio in the higher funding case, along with the assumptions for the costs and energy savings of those hypothetical measures. However, the FEU do not believe that the hypothetical nature of such an analysis would add any value or completeness to the LTRP.

That said, the requested analysis is provided to the best ability of the FEU below. In completing the analysis, the FEU assume that the Commission is requesting a comparison to the information presented in Section 8.9, pages 160 to 162 of the LTRP (Exhibit B-1) and more specifically in Figure 8-3 regarding directional rate impacts, and to Figure 4-7 on page 89 regarding GHG emissions. Since the data used to create Figure 8-3 excludes gas costs which are independent of any EEC activities by the FEU, the analysis presented below also excludes gas costs and instead reports the directional impact on the FEU's delivery margin for the three spending scenarios. The reference case demand and reference case EEC energy savings scenarios are used as the starting point for this analysis.

Delivery Rate and Delivery Margin Variations

The impact on revenue requirements and rates across all rate classes is provided in Table A below[1]. As stated on page 160 of the LTRP, this discussion represents a directional look at the potential impact of long term demand on delivery margin and customer rates. Using approved rates and actual volumes from 2011, the stated figures include the cost of service for major capital items plus an escalation of the cost of service by a growth factor of 2% per year, divided by delivery volumes in each scenario. The figures do not consider future rate design changes and are not indicative of a detailed rate forecast—they provide simply a directional, 20-year view of FEI's delivery rates over time.

[1] The same annual rate change is applied to all non-bypass (and non-special contract) Rate Schedules. That is, generally speaking, the % delivery rate impact for all customers is the same as the % delivery rate impact to Residential customer delivery rates.

Table A: Annual and Cumulative Impact of Varying Levels of EEC Funding on FEU Delivery Margin and Rates Assuming a Linear Relationship Between EEC Spending Level and Energy Savings at All Spending Levels – All Customers, Reference Case Scenario.

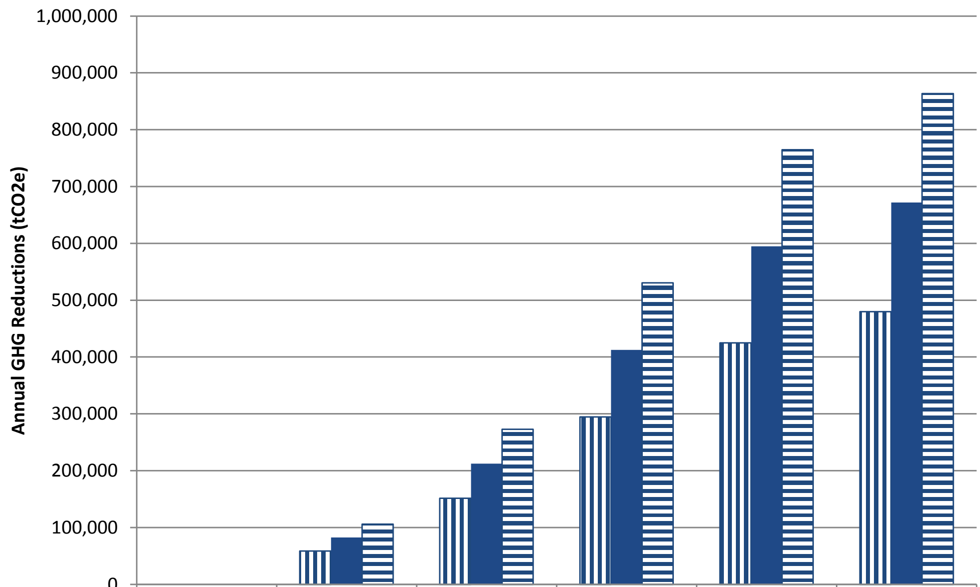
Line No.	Case	% Annual Compound Delivery Rate Change	% Cumulative Delivery Rate Change	$000 Average Annual Delivery Margin Requirement	$000 Cumulative Annual Delivery Margin Requirement
		(1)	(2)	(3)	(4)
1	Reference	2.20%	62%	$736,918	$16,212,199
2	Reference + EEC Mid ($35 MM per year spending)	2.80%	84%	$38,713	$851,691
3	Reference + EEC Mid ($25 MM per year spending)	2.70%	78%	$31,733	$698,137
4	Reference + EEC Mid ($45 MM per year spending)	3.00%	90%	$45,693	$1,005,245

Columns 1 and 2 of Table A show the annual compound delivery rate change and cumulative delivery rate change over the planning period for all customers. Columns 3 and 4 of the table show the average annual and cumulative annual revenue requirement caused by the various levels of EEC spending over the planning period. Line 1 is the reference case without any EEC spending. Lines 2 through 4 show the added rate change and delivery margin for each of the spending scenarios requested. Line 2 shows the $35 million per year EEC spending and is the original analysis included in the LTRP in Figure 8-3.

<u>GHG Emission Variations</u>

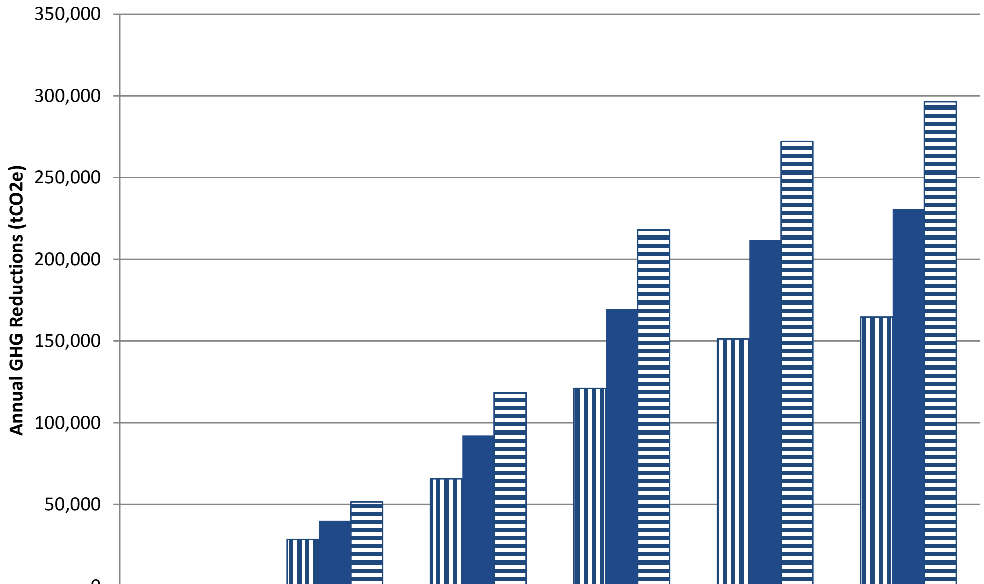
Since the GHG emission analysis conducted for the 2014 LTRP was separate from the rate impact analysis and is available specifically for residential customers, the FEU have provided the requested GHG emission variation results for all customers as well as the GHG emission variation results for residential customers only. Assuming the same linear relationship between EEC spending and energy savings requested by the Commission, Figure 1 shows the GHG emission variations for all customers for annual EEC spending of $25 million, $35 million and $45 million across all customer classes and Figure 2 shows the results of the same analysis for just residential customers. The results of the $35 million annual spend coincide with those presented in the 2014 LTRP in Figure 4-7.

Figure 1: Estimated Annual GHG Emission Reductions from EEC Measures under a Range of EEC Spending Levels Assuming a Linear Relationship between EEC Spending and Energy Savings at All Spending Levels – <u>All Customers</u>, Reference Case Scenario



	2011	2016	2021	2026	2031	2033
$25M	0	58,832	151,783	294,791	424,876	479,933
$35M	0	82,365	212,497	412,708	594,826	671,907
$45M	0	105,898	273,210	530,624	764,776	863,880

Figure 2: Estimated Annual GHG Emission Reductions from EEC Measures under a Range of EEC Spending Levels Assuming a Linear Relationship between EEC Spending and Energy Savings at All Spending Levels – <u>Residential Customers</u>, Reference Case Scenario



	2011	2016	2021	2026	2031	2033
$25M	0	28,655	65,819	121,119	151,239	164,732
$35M	0	40,117	92,147	169,567	211,735	230,625
$45M	0	51,579	118,474	218,015	272,231	296,518

1.2 Please explain why FEU has not targeted the 'most likely achievable' EEC option included in the 2010 CPR.

<u>Response:</u>

It is important to note again that the estimation of energy savings from EEC activities in the 2014 LTRP is not a "targeting" exercise in the same way that the development of the 2014-2018 EEC Plan in the FEU's PBR application has "targeted" program level savings and expenditures. Rather, the 2014 LTRP provides a long range estimate of energy savings that can be achieved over the planning horizon from all cost effective EEC measures established from the 2010 CPR results and based on a reasonable assumption of "achievable" EEC savings – it is a long term planning document. In the same way, the 'most likely achievable' estimate from the 2010 CPR was not an "option" that was at that time available for the FEU to "choose", but was rather a planning estimate of savings that could be achieved under a certain set of circumstances described within the CPR.

That said, the 2014 LTRP does in essence present a 'most likely achievable' estimate of energy savings over the planning period. However, since a number of things have changed since the CPR was prepared, such as the avoided cost of gas, the BC Demand-side Measures Regulation, the FEU's improved knowledge and experience in getting EEC measures into the market and the effect of running several years of EEC programs since the data for the 2010 CPR was acquired, the 'most likely achievable' estimate from the CPR no longer exists. The knowledge of potential measures and their cost effectiveness in today's environment, however, does exist. With this knowledge, and since the long term EEC planning exercise in the 2014 LTRP did not involve a complete new CPR, the methodology for estimating energy savings was refined to meet the needs of the LTRP as described in Section 4.2.2.1. As a result, the term 'most likely achievable' is not an appropriate descriptor of the savings estimate in the 2014 LTRP, in part since the FEU felt it was likely to be misinterpreted to be synonymous with the 'most likely achievable' savings estimate contained in the CPR, and in part because of the refinements made to determining the savings estimate.

1.3 Please confirm that NW Natural is a natural gas utility and that it ran a 'high' DSM sensitivity case in its 2013 Integrated Resource Plan.

Response:

Confirmed, NW Natural is a natural gas utility. In its 2013 Integrated Resource Plan, NW Natural ran a 'high' DSM sensitivity which appears to be similar to the way in which the FEU incorporated a range of natural gas cost assumptions in future EEC savings by scenario. NW Natural's "higher gas avoided cost scenario" does not examine the effect of expanding the DSM budget but rather estimates the impact that a higher cost of gas would have on NW Natural's cost-effective DSM potential. NW Natural also notes that it does not believe that either the "higher gas avoided cost scenario" or the "lower gas avoided cost scenario" are likely.

2.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Application, Section 2, p. 30; G-120-11 Reasons for Decision, p. 21;

Domestic consumption of gas for space and water heating

The FEU state on p. 30 of the Application: "Using the Government's rationale that natural gas can be used to reduce global GHG emissions, the Companies believe the efficient use of natural gas for heating applications in B.C. can provide a similar benefit …"

The Commission stated in G-120-11 Reasons for Decision: "... the Commission Panel bases its finding that the objective related to competitiveness of natural gas with other energy sources (principally electricity) is inappropriate for the following reasons: … promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate" (p. 21).

2.1 Does the FEU consider that options which focus on improving the competitive position of gas for BC space and water heating relative to other fuel sources (such as not increasing EEC spending or increased marketing of gas), should only be supported where it can be demonstrated that a shift towards natural gas for BC space/water heating is in the public interest? Please explain.

Response:

The FEU believe that the reference to the Panel Statement made in order G-120-11 Reasons for Decision is made out of context since the regulation cited in the Panel's statement has since been amended. The FEU provide additional context for this position later in this response.

The Companies do agree that improving the competitive position of gas for BC space and water heating relative to other fuel sources should be supported where it can be demonstrated that a shift towards natural gas for BC space/water heating is in the public interest.

The FEU are unclear as to how the Commission is inferring that "not increasing EEC spending" would improve the "competitive position of natural gas". However, the FEU have based the following discussion on the interpretation that not increasing EEC spending will result in not increasing rates and will therefore result in a better competitive position for natural gas. In this context, the Companies do not agree with the specific statement provided in the IR that, "improving the competitive position of gas for BC space and water heating relative to other fuel sources (***such as not increasing EEC spending or increased marketing of gas***), should ***only*** be supported where it can be demonstrated that a shift towards natural gas for BC space/water heating is in the public interest" (emphasis added). Firstly, the FEU operate a commercial business in a competitive marketplace for energy services and will therefore take steps to improve the competitive advantage of natural gas for BC space and water heating relative to other fuel sources. Secondly, the FEU note that "not increasing the level of EEC spending" is not used by the FEU as "an option (for) improving the competitive position of gas for BC space and water heating." As stated in BCUC IR 1.2.3, the level of EEC funding is set through analysis of the level of EEC the market will reasonably uptake. Thirdly, each FEU initiative must be evaluated individually to account for the fact that "the public interest" is a fluid, subjective, and contextual concept.

The Companies believe that there are many instances where improving the competitiveness of natural gas could be in the public interest. Using the Government's rationale that natural gas can be used to reduce global GHG emissions, the FEU believe the efficient use of natural gas for heating applications in BC can provide a similar benefit for global emissions when displaced electricity load results in clean electricity supply available for export to offset coal and gas fired generation in neighboring jurisdictions, or reduces the need to import electricity from neighboring jurisdictions. Such a use would be in the "public interest" in the sense that GHG emissions do not respect jurisdictional borders and it is therefore in the interest of British Columbians to reduce global emissions. Similarly, ensuring that natural gas service is available in those areas not currently served by natural gas could also be in the public interest as it provides customers with energy choice, can reduce emissions (if the alternate fuel is oil), and can reduce heating costs (if the alternate fuel is tier two electricity).

Commission Decision G-120-11 with regards to the objective of competitiveness was in direct reference to the objectives of FEU's 2010-2014 Price Risk Management Plans. In determining the merits of an objective related to the competition with electricity, the Commission Panel believed it appropriate to consider British Columbia's Energy Objectives as set out in the *CEA*, specifically objective (h) which is "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia," and objective (c), that states that "at least 93 percent of the electricity in British Columbia be generated from clean or renewable resources." This proceeding and the subsequent decision were <u>prior</u> to the *CEA* being amended by *British Columbia's Energy Objectives Regulation* so that the objective set out in section 2 (c) of the *CEA* is modified by adding ", other than electricity to serve demand from facilities that liquefy natural gas for export by ship," after "British Columbia".

The statement from Exhibit B-1, pg. 30 noted in this IR is in reference to using natural gas in direct-use applications in order to reduce GHG emissions from a multi-jurisdictional perspective—the very same rationale utilized by the Government to classify natural gas as a "clean" energy source for use in LNG production for export by ship in *British Columbia's Energy Objectives Regulation*. [2]

While statements made for the purposes of the 2010-14 Price Risk Management Plans and the 2014 LTRP are inherently different, the FEU submits that they are related through the reference to the statement from Commission Decision G-120-11, "promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate." The FEU would point out that the government policy objectives adopted by *British Columbia's Energy Objectives Regulation* are based on the justification that GHG reduction is a multi-jurisdictional issue and that displacing GHGs in other jurisdictions by substituting natural gas in place of more GHG intensive coal-fired energy production is a worthwhile exercise. The amendment adopts the view that promoting gas use over electricity consumption may in fact be an approach that meets government policy objectives and is therefore appropriate.

[2] In the March 14th 2012 news release from the Government of BC titled "Liquid Natural Gas (LNG) and the Green Economy," the Government stated that, "By exporting LNG, world-wide emissions will be lowered as B.C.'s natural gas increasingly displaces the use of other higher emission power sources, such as coal and diesel." On June 21, 2012 Christy Clark announced at a speech to the Business Council of B.C that the *Clean Energy Act* would be amended and justified the action with claims that included that creating LNG products for such markets as China will diminish their reliance on coal and other more emission intensive sources of energy. This amendment was put into effect July 24, 2012. On February 8, 2013, the BC Government realised its "Liquefied Natural Gas Strategy One Year Update" in which the Government stated, "Of course, the fight against climate change is a global issue. By exporting natural gas, B.C. will supply growing markets with a cleaner energy alternative compared to higher emission sources like coal and diesel. B.C.'s natural gas is also expected to replace the use of nuclear power in other areas of the world" (pg. 8).

3.0 Reference: PLANNING ENVIRONMENT

FEU 2013 Annual Report, p. 52; Exhibit B-5, CEC 1.25.1, p. 68;

Declining throughput

The FEU state on page 52 of the 2013 Annual Report: "In the future, if natural gas becomes less competitive … in an extreme case, could ultimately lead to an inability of the FortisBC Energy companies to fully recover COS [cost of service] in rates charged to customers." The FEU state in CEC 1.25.1: "The conserved clean electricity [from using natural gas instead of electricity] would then be available for higher and better uses both in BC and in neighbouring jurisdictions."

3.1 Please explain what measures, if any, the FEU considers would be appropriate to mitigate the effect of increasing delivery rates, resulting from declining throughput, for ratepayers, in particular for low income consumers.

Response:

FEU wish to clarify that the reference quoted in the preamble to this information request is from the 2013 Fortis Inc. Annual Report and is attributable to Fortis Inc.

To mitigate the effect of increasing delivery rates for all customers, including low-income customers, resulting from declining throughput, the FEU consider it both appropriate and necessary to grow the customer base and increase throughput on the system. As noted in Sections 2.3 and 2.4 of the 2014 LTRP, the FEU plan to achieve this through activities such as the Companies' NGT initiatives, outreach to key influencers such as builders, developers, architects, engineers, contractors, manufacturers, dealers and homeowners, the Renewable Natural Gas and Switch 'n Shrink programs and also by adding new industrial customers and markets for natural gas demand. The FEU continue to look at programs to encourage the addition of new efficient space and water heating customers as well.

Further, to mitigate the effect of increasing delivery rates for low-income customers in particular, the FEU offer EEC programs for low-income customers to reduce their energy costs such as the Energy Conservation Assistance Program (ECAP), which helps low-income households save energy and money with a free home energy evaluation, products and advice. In addition, low-income residential customers are also eligible to receive a free energy saving kit which provides easy-to-install household devices to save energy and lower energy costs.

3.2 Please explain what the FEU means by 'higher and better use' for electricity. Specifically, is this driven by a concern that BC will be unable to meet forecast demand for electricity space and water heating, such that it should be reserved only for some uses and not for others?

Response:

The term "higher and better uses" as stated in the response to CEC IR 1.25.1 refers to using electricity in applications where it is efficient and practical such as in lighting or electronic applications, but not for uses for which there are cost-effective and efficient alternatives such as for space heating and hot water where access to natural gas exists. This is driven by a concern that the direct use of natural gas is more efficient in space and water heating applications from a site-to-source or energy system perspective. At the same time, there is upward pressure on electricity rates in B.C. due to a need to invest in B.C.'s hydroelectric system (as noted in BC Hydro's 2013 Integrated Resource Plan) and the efficient use of natural gas in space and water heating applications could mitigate this upward pressure on B.C.'s electricity rates. In addition, the FEU believe that there is value in having diversity of energy supply to serve B.C.'s energy needs and express concern regarding initiatives that drive B.C. toward relying on the electric system to meet all or most of the Province's energy needs.

4.0 Reference: RESOURCE PLAN OVERVIEW

Exhibit B-2, BCUC IR 1.4.0, pp. 12-13;

Staff Resources to Improve the Long Term Resource Planning

In the response to BCUC IR 1.4.0, the FEU state: "…the FEU have utilized the approved additional funding [$400,000 in 2012 and $600,000 in 2013] to advance a number of improvements to the LTRP in the areas of stakeholder engagement, analyzing the planning environment, future scenario development, long term annual demand forecasting, long term EEC analysis and alternative forecast impact analysis."

4.1 Please provide more specific detail as to how this additional funding was utilized. For example, please identify how much, if any, was spent on additional staff, external consultants, stakeholder engagement and other 'areas' listed in the preamble above.

Response:

This response also addresses the response to BCUC IR 2.4.1.1.

The table below shows the expenditures for external consultants' to complete the end-use forecasting work for the LTRP and the expenditure for the Stakeholder Engagement. End-use forecasting work includes, among other items, future scenario development, long term annual demand forecasting, long term EEC forecasting and alternative forecast impact analysis. It should be noted that this estimate does not include costs associated with the completion of the Conservation Potential Review, which is an essential input to the end-use forecasting model. Stakeholder activities include expenditure for the Resource Planning Advisory Group (RPAG) meetings and Community Consultation workshops. The table below reflects an estimate of these amounts.

Item	2012 ($000's)	2013 ($000's)
End-use forecasting work performed by third parties	$155	$203
Stakeholder Engagement – including Resource Planning Advisory Group (RPAG) meetings and Community Consultation workshops	$61	$19
Total for End-Use Forecasting (Consultants) and Stakeholder Engagement	**$216**	**$222**

LTRP expenditures form a part of the Market Development group budget and this group's activities are managed as a whole and as such it is not possible to separate and itemize the remaining costs strictly related to the LTRP. However within that group, two additional staff were hired in 2012/3 whose efforts are largely focused on the LTRP. Additionally, in order to maximize the skill set of the group, there are a number of individuals within the Market Development group who undertake activities related to the LTRP as either their primary activity or as part of a number of other activities they undertake through the course of a year including the Forecasting, Energy Products and Services and Business Performance groups.

4.1.1 Please provide a table that shows the line item amounts with totals for each year (2012 and 2013) on how the additional funds were spent.

Response:

Please refer to the response to BCUC IR 2.4.1.

5.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.16.3, p. 48;

Commercial Customer Additions Forecast

In the response to BCUC IR 1.16.3, the FEU state: "The FEU believe there is no single numerical method that can provide accurate long term insight into the future commercial additions due to the volatility and multiple factors involved. Additionally, the FEU do not attempt to forecast economic cycles. … In the absence of a better alternative, the FEU used a simple three year average approach with the goal to update the forecast on a regular basis to capture any deviations from the existing trend."

5.1 If commercial additions are volatile as indicated in the above response, would it be more appropriate to use a longer trend period (between 5 and 20 years) to reduce the impact of volatility in the historic data? If not, why not?

Response:

While possibly damping the true volatility present in the actual data, longer trend periods do not accurately reflect what is really happening. If the recent data is volatile then it is volatile and using a long trend period to mask the volatility may not produce a better forecast. It may produce a less volatile forecast but the resulting forecast does not represent what is really happening. The FEU believe it is prudent to use three year trending periods while reforecasting on a regular basis.

6.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.2, p. 42; Section 3.3.1 p. 44;

BC Hydro November 2013 Integrated Resource Plan (2013 IRP), Appendix 2A – 2012 Electric Load Forecast, p. 19;[3] Chapter 2, Section 2.2.2.3, p. 2-8;[4]

Industrial Annual Demand Forecast

On page 42 of the Application, the FEU state: "… there were no firm commitments for new industrial customers to take natural gas service or for existing customers to close their accounts. Hence, no growth or decline in industrial customers has been forecasted."

On page 44 of the Application, the FEU state: "The FEU utilized the results of the annual industrial customer survey to identify expected changes in industrial customer demand. The survey was conducted as part of the FEU's short term demand forecasting process used for gas supply planning, revenue requirements and other BCUC submissions. The intentions of industrial customers over the next five years were held constant over the LTRP planning horizon as this represents the best available information using the traditional methodology."

On page 19 of Appendix 2A of BC Hydro's 2013 IRP, BC Hydro utilizes billing data, provincial GDP forecasts and production forecasts in order to develop industrial demand forecasts. On page 2-8 of BC Hydro's 2013 IRP, BC Hydro states: "Without LNG, industrial sales are expected to grow by 1.2 per cent per year to F2033 before DSM. The industrial sector is expected to see the most growth of the key sectors in the next 10 years …, due to growth in mining and oil and gas activity."

6.1 Please confirm that for the Traditional Industrial Demand forecast the intentions of industrial customers were held constant for the last 15 years of the 20 year planning period.

Response:

Confirmed.

6.1.1 Please discuss the assumptions made that resulted in the Traditional Industrial Demand being held constant over the LTRP planning horizon.

[3] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0200a-nov-2013-irp-appx-2a.pdf

[4] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0002-nov-2013-irp-chap-2.pdf

Response:

Please refer to the response to CEC IR 1.34.1.

6.1.2 Were any proxies such as GDP growth forecasts or population growth forecasts used to produce the Traditional Industrial Demand forecasts? Please elaborate.

Response:

Proxy forecasts were not used in the preparation of the Traditional Industrial Demand forecast.

Internal research completed in 2012 using data from 2005 through 2011 revealed that of 36 industrial sub-sectors 18 were correlated only to weather. Of the remaining 18 sub sectors only 1 (pulp and paper manufacturing) correlated to GDP. As a result the FEU do not adjust our customers own forecasts with proxies such as GDP.

Using a GDP growth forecast in the Traditional Industrial Demand forecast would not be appropriate and all else being equal could be expected to produce a less accurate forecast. The Total Traditional Annual Demand Reference case would be equally affected. Comparing the End Use Forecast to the inappropriately adjusted traditional forecast would then be invalid and inconclusive.

6.1.2.1 If not, please discuss how the utilization of GDP growth forecasts in the Traditional Industrial Demand forecasts could affect the Total Traditional Annual Demand Reference case and thus the comparison between the Traditional Annual Demand Reference case and the End-Use Annual Demand Reference Case forecasts.

Response:

Please refer to the response to BCUC IR 2.6.1.2.

7.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IRs 1.19.3 and 1.19.4, pp. 58-61;

Patterns, Assumptions and Variables

The FEU's response to BCUC IR 1.19.3 describes what is meant by a "pattern" in the context of the forecast reference case; and states that the term describes "…the current blend of end uses and associated use rates being installed across the system." The FEU then gives some examples of patterns.

The FEU's response to BCUC IR 1.19.4 on pages 59 through 61 provides a table to show an example of the assumptions and variables underpinning the reference case forecast to demonstrate the level of detail in the models. The FEU state that they are unable to provide a complete listing of all information for all variables and assumptions within the response time frame, stating that: "… Such a response would result in over 4,000 pages of information ... However, the forecast model has been designed in such a way that individual assumptions and variables can be examined fairly readily by the FEU."

7.1 With the large number of patterns, assumptions and variables that make up the model, what methods can be used to ensure that the Commission and Interveners are able to observe and confirm the validity of the model and the consistence of patterns, assumptions and variables from application to application?

Response:

The End Use model was developed in conjunction with ICF/Marbek, a highly respected consultant in this field. The FEU believe one of the strengths of this approach is that the assumptions are explicit in the model and can be reviewed. The challenge, as indicated in the response to BCUC IR 1.19.4, is that the model is large and detailed. A complete listing of all the assumptions in the most disaggregated form is therefore very bulky. The FEU recognize the Commission's concerns, and note that this is part of the reason that the FEU spent time over the last two years reviewing the model with the RPAG stakeholder group.

However, now that the proceeding is underway, the FEU see the additional value of external review of the assumptions, both in providing BCUC and interveners greater confidence in the results and also in providing the opportunity for ongoing improvement of the assumptions and results. The FEU are therefore interested in finding an efficient and workable approach to enabling this external review if required. The following table provides several options, with estimates of their costs to the FEU and the level of training and effort required of the external reviewers.

Among these options, the FEU recommend the one-day workshop as the most preferred option to provide a mechanism for interveners to vet and better understand the model, should the Commission believe that such a review is warranted.

Option	Description	Estimated Effort	Reviewer Effort
Formatted tables as shown in the response to BCUC IR 1.19.4	Over 4,000 pages of tables. Much of the material would be generated by a customized macro to pull values from the model and assemble them into tables, but the notes fields would be a more manual task.	Approximately 2 person-months.	Reviewers would not require training to read the tables, but time commitment would be very large. Cross-comparisons would be manual and time-consuming.
Granular Excel tables directly copied from the model	90 workbooks (3 sectors x 5 scenarios x 6 regions) containing 18 worksheets each: • Building population • Tertiary load • Efficiency x 5 fuels • Unit energy consumption x 5 fuels • End use saturation • Fuel share x 5 fuels Each worksheet would have values for all building types, end uses, and milestone years	Approximately 10 person-days.	Reviewers should expect to participate in two to three webinars to get training on how to read the tables. Cross-comparisons would be easier than the above, but would require some expertise in Excel.
Excel tables subset	Any subset of the above collection of workbooks could be produced	One sector would be 5 person-days. Natural gas only would be 5 person-days. One scenario would be 3 person-days. One region would be 3 person-days.	Same type of reviewer commitment as above.
Workshop	One full-day workshop to explore the input assumptions and familiarize BCUC staff and interveners with the details of the model	Approximately 2 person-weeks.	Reviewers would spend one full day in the workshop.

Option	Description	Estimated Effort	Reviewer Effort
Consulting retainer	BCUC staff or interveners would submit specific requests. FEU would estimate costs and timing and manage the fulfilling of requests by consultant.	Reasonable cost and scope limitations would need to be set. It would be hoped that time and effort requirements would diminish as the Commission and interveners develop a better understanding of the model.	Reviewers would not require special training.
Assumptions Dataset	Assumptions dataset in similar format to the results dataset, with columns for tertiary load, efficiency, unit energy consumption, saturation, and fuel share. Users would be able to use the pivot table and charting systems in Excel to develop summaries and weighted averages of these values.	Approximately 2 person-months. Subsequent updates for future LTRP filings would be significantly less expensive.	Reviewers should expect to participate in two to three webinars to get training on how to use the input dataset tool. Cross-comparisons would be relatively easy compared to the other options. Comparing assumptions between filings would be possible.

8.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.2, p. 45; Section 3.3.6, pp. 55-56; Figure 3-12, p. 56;

Exhibit B-1, Terasen Utilities 2010 Resource Plan, Section 4.2.5, pp. 87-90;

Comparing the range of scenarios for the Traditional and End-Use Methodologies

The Application on page 45 states: "Using historical trend data to forecast future consumption is a common and accepted industry practice, particularly for short-term analysis or decision making where historical data is used to forecast a few years into the future." (Exhibit B-1, p. 45)

8.1 Please indicate, with an explanation, which methodology (Traditional or End-Use) the FEU intends to use for energy demand forecasting in the annual Revenue Requirements Application.

Response:

The FEU intend to continue using the FIS model for its annual Revenue Requirement Applications, which applies short term forecasting. The FIS model is based on the traditional methodology.

The end use method is appropriate for long term forecasting because it incorporates the effects of changes in appliance saturation and efficiency levels, even when those changes are not present in the historic data.

The traditional time series method, on the other hand, cannot model how efficiency improvements affect sales when those efficiencies remain unchanged during the estimation period. As a result the traditional time series method works fine in the short term but should be replaced with an end use model for long term forecasting.

This issue was discussed in detail in a series of round one IRs from the CEC. Please refer to the responses to CEC IRs 1.38.1, 1.41.1, 1.42.1, and 1.46.2.

8.2 In a manner consistent with Section 4.2.5 of the Terasen Utilities 2010 Resource Plan, please produce High and Low Annual Demand Forecasts, with respect to the Traditional reference case developed in the Application. Please provide this data <u>for each of the years in the planning period</u> (not milestone years) in a functional Microsoft Excel workbook containing tables of customer year end account forecasts, average use per customer forecasts and annual demand forecasts. The data should be separated by service region (FEVI, FEW, FEI – Coastal Region and FEI – Interior), and each service region should be broken down into all relevant customer rate classes. Data for the FEU totals broken down by major customer class (Residential, Commercial and Industrial) should also be included.

Response:

As described in Section 4.2.5 of the Terasen Utilities 2010 Resource Plan, high and low annual demand forecasts were developed to illustrate the upper and lower range of annual demand based on a set of reasonable assumptions. At the time of the 2010 filing many of the assumptions considered the potential rate of recovery of the then recent economic downturn.

It is not reasonable to apply the same assumptions to the Traditional reference case developed for the current application because the factors that were considered in 2010 are no longer relevant.

Instead, the Company completed analyses to produce a high and low forecast of demand based on maintaining the degree of variation between high and low cases relative to the base case in the 2010 Resource Plan. The degree of variation was then applied to the current base forecast (Traditional method) in order to accomplish this task in the permitted time.

Please refer to Attachment 8.2 for the live excel spreadsheet.

8.2.1 Please elaborate on the reference case input assumptions that were varied in order to produce these high and low Traditional Annual Demand forecasts.

Response:

Please refer to the response to BCUC IR 2.8.2.

8.2.2 Please provide a functional Microsoft Excel workbook with Figure 3-12 on page 56 of the Application updated to include the Traditional High and Low Annual Demand Forecasts.

Response:

Please refer to Attachment 8.2.2 which contains the functional excel workbook.

8.2.3 Does the Traditional High Annual Demand forecast fall outside of the range of End-Use Annual Demand Forecast scenarios seen in Figure 3-12?

Response:

The traditional high annual demand forecast does fall outside the range of the end use annual demand forecast based upon the adjusted methodology as noted in response to BCUC IR 2.8.2. The table below compares the maximum magnitude of the two high cases relative to the base for the traditional and end use forecasts. The end use high case (Scenario C) shows less variance to the base case (8 percent as opposed to 19 percent) compared to the traditional forecast. This improved precision is expected due to the inclusion of more sophisticated and detailed input data from sources such as Conservation Potential Review (CPR) into the End Use Model.

FEU	Traditional High Relative to Base as a %	End Use High Relative to Base as a %
Residential	3%	1%
Commercial	32%	12%
Industrial	18%	12%
Overall	**19%**	**8%**

The FEU believe it is reasonable to expect that the traditional base case would fall within the bounds of the end use model. There are no scenario decisions or interpretation on the base cases so it is an “apples to apples” comparison. At the same time the FEU are not surprised that the use of less sophisticated data and methods in the traditional model, particularly in the more volatile commercial and industrial sectors, produced a high case significantly higher than the better informed end use model.

It must also be noted that the high and low cases are scenarios and the results are fully subject to the designs of those scenarios. The differences in the intentions and assumptions used in the development of the traditional high scenario and the various end use scenarios mean that the resulting forecasts are not comparable on an “apples to apples” basis.

8.2.3.1 If yes, please explain why the Traditional High Scenario is higher than the End-Use High Scenario.

<u>Response:</u>

Please refer to the response to BCUC IR 2.8.2.3.

8.2.3.2 If yes, how could the End-Use methodology be adjusted to ensure that this additional range of possible energy demand is considered during planning?

<u>Response:</u>

While an artificially high scenario could be created in the End Use Model, the FEU believe there would be no merit in developing such a scenario solely for the purpose of exceeding the traditional high case. Scenarios need to be plausible and should not be developed with a specific end result in mind.

The FEU do not believe it is necessary to make the results line up. The End Use Model is informed by newer and more sophisticated data. The magnitude of the datasets required to contain the two models is an example of the increased detail available in the end use model.

9.0 Reference: ENERGY DEMAND FORECASTING

Swan, Lukas G. and V. Ismet Ugursal, 2009, Modeling of end-use energy consumption in the residential sector: A review of modeling techniques, Renewable and Sustainable Energy Reviews 13 (8): 1819-35;

Exhibit B-2, BCUC IR 1.19.10, pp. 68-72;

Modelling Residential Energy Consumption

The referenced article presents the figure below which categorizes various techniques used for modelling residential energy consumption in to "top-down" and "bottom-up" approaches.

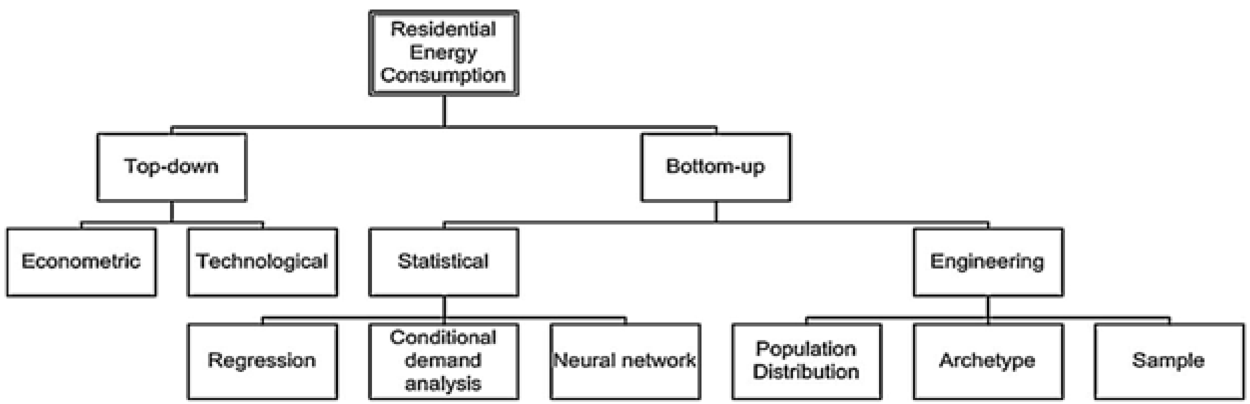


Fig. 2: Top-down and bottom-up modeling techniques for estimating the regional or national residential energy consumption

Source: L.G. Swan, V.I. Ugursal, Modeling of end-use energy consumption in the residential sector: A review of modeling techniques, p. 1822.

The article states on page 1824: "The SM [Statistical Method] utilizes dwelling energy consumption values from a sample of houses and one of a variety of techniques to regress the relationships between the end-uses and the energy consumption. SM models can utilize macroeconomic, energy price and income, and other regional or national indicators, thereby gaining the strengths of the top-down approach. The EM [Engineering Method] relies on information of the dwelling characteristics and end-uses themselves to calculate the energy consumption based on power ratings and use characteristics and/or heat transfer and thermodynamic principles."[5]

The authors provide an explanation of the three SM modeling techniques and EM modeling techniques on pages 1825 and 1828 respectively. On page 1833 the authors

[5] L.G. Swan, V.I. Ugursal, Modeling of end-use energy consumption in the residential sector: A review of modeling techniques.

present Table 3, shown below, which summarizes their findings on the strengths and weaknesses of the top-down and bottom-up approaches.

Table 3
Positive and negative attributes of the three major residential energy modeling approaches.

	Top-down	Bottom-up statistical	Bottom-up engineering
Positive attributes	• Long term forecasting in the absence of any discontinuity	• Encompasses occupant behaviour	• Model new technologies
	• Inclusion of macroeconomic and socioeconomic effects	• Determination of typical end-use energy contribution	• "Ground-up" energy estimation
	• Simple input information	• Inclusion of macroeconomic and socioeconomic effects	• Determination of each end-use energy consumption by type, rating, etc.
	• Encompasses trends	• Uses billing data and simple survey information	• Determination of end-use qualities based on simulation
Negative attributes	• Reliance on historical consumption information	• Multicollinearity	• Assumption of occupant behaviour and unspecified end-uses
	• No explicit representation of end-uses	• Reliance on historical consumption information	• Detailed input information
	• Coarse analysis	• Large survey sample to exploit variety	• Computationally intensive • No economic factors

Source: L.G. Swan, V.I. Ugursal, Modeling of end-use energy consumption in the residential sector: A review of modeling techniques, p. 1833.

The authors submit that all three modeling approaches are useful and outline the applicability of the models, based on their strengths and weaknesses, as follows:

- "Top-down approaches are used for supply analysis based on long-term projections of energy demand by accounting for historic response.
- Bottom-up statistical techniques are used to determine the energy demand contribution of end-uses inclusive of behavioural aspects based on data obtained from energy bills and simple surveys.
- Bottom-up engineering techniques are used to explicitly calculate energy consumption of end-uses based on detailed descriptions of a representative set of houses, and these techniques have the capability of determining the impact of new technologies." (p. 1833)

9.1 Which of the bottom-up models, at the lowest hierarchical level, in Fig. 2 from the article best represents the End-Use methodology in the FEU 2014 LTRP (e.g. Regression, Conditional Demand Analysis, …, Sample)? Please explain the selection.

Response:

The FEU End Use model most closely resembles the bottom-up engineering method, but calibrated in the base year to actual sales, including elements of the sub-types shown under the engineering method. The REUS adds elements of the bottom-up statistical method to the approach. Elements of the top-down approach are included, because the macroeconomic effects are incorporated into the different scenarios.

The FEU's response to BCUC 1.19.10 indicates, when summed, that for the 2011 base year space heating, domestic hot water and fireplace account for at least 94 percent of residential demand for each of the service regions. Similarly, for the 2011 base year, space heating and domestic hot water account for at least 77 percent of commercial demand for each of the service regions.

9.2 Please confirm the calculations of 94 percent and 77 percent for the 2011 base year.

Response:

Confirmed

9.3 Does the FEU anticipate any significant changes in technology for residential or commercial space heating and domestic hot water and residential fireplaces during the planning period? If so, please elaborate.

Response:

The changes in technology in the case of space heating, DHW and fireplaces are, in all three cases, incremental changes towards technologies that are already present in the marketplace, at the rate of retirement of old equipment. There are no game-changing technologies in the model with respect to trends for those end uses.

9.4 Does the FEU anticipate any significant shift in the proportion of annual end-use demand from the current major sources of residential and commercial end-use demand (space heating, domestic hot water and fireplaces) to other natural gas end-uses during the planning period? If so, please elaborate.

Response:

The end-use demand forecast suggests a shift in the proportion of the annual residential end-use demand between the fireplace load and domestic hot water load. Figure 3-10: Reference Case Demand for Three Largest Residential End-Uses by Consumption – All Regions of the 2014 LTRP submission illustrates how the domestic hot water load which currently ranks as the second largest residential load would become the third largest load sometime between 2026 and 2031.

No significant shift is forecast for the commercial end-use demand with each of the major end uses maintaining their current ranking throughout the forecasting horizon.

10.0 Reference: ENERGY DEMAND FORECASTING

BC Hydro November 2013 Integrated Resource Plan (2013 IRP), Section 2.4.1,

pp. 2-36 and 2-38;[6] Appendix 2A – 2012 Electric Load Forecast, Appendix 1, pp. 66-69;[7]

Exhibit B-1, Application, Section 3.1, p. 38;

Demand Forecasting using the Statistically Adjusted End-use Methodology

On page 66 of Appendix 2A in the 2013 IRP, BC Hydro states: "BC Hydro forecasts residential and commercial distribution sales by using the Statistically Adjusted End-Use (SAE) model. This model incorporates end-use information, economic data, weather data and market data to construct regional forecasts." BC Hydro then elaborates that the SAE model defines energy use using explanatory variables constructed from end-use information, economic drivers, dwelling data and weather data. Figures 2-6 and 2-7 in BC Hydro's 2013 IRP suggest that BC Hydro is able to calculate forecasts for each year from 2014 through 2033. Figure A1.1 on page 69 of Appendix 2A in the BC Hydro 2013 IRP summarizes the inputs used in the construction of the regression variables for the commercial sector.

On page 38 of the Application the FEU state: "The FEU's demand forecasts are used to ensure adequate system capacity, to plan gas supply resources, and also to provide a baseline against which to analyse the impact of proposed or potential future initiatives such as expanded energy efficiency and conservation activities or growth in natural gas sales for fuelling transportation."

10.1 Please compare and contrast the FEU's End-Use methodology with the SAE methodology utilized to forecast residential and commercial distribution demand in BC Hydro's 2013 IRP.

Response:

The FEU believe it is impractical to perform such an investigation for two reasons noted below.

First, the current FEU End Use model was developed cost effectively in response to recommendations and directions from BCUC Order No. G-14-11 and Order No. G- 44-12, by repurposing data already collected for different purposes (the Conservation Potential Review). The progress and results of that work were reported on regularly at the Resource Planning

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6 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0002-nov-2013-irp-chap-2.pdf

7 https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0200a-nov-2013-irp-appx-2a.pdf

Advisory Group meetings held in 2012 and 2013. At no time was there a suggestion during the RPAG sessions that additional modelling methodologies be investigated and compared. Additionally, Order No. G-14-11 did not contain a direction or recommendation to compare and contrast competing methodologies. The FEU did not therefore perform a compare and contrast exercise in preparation for this proceeding.

Second, the work to compare and contrast a particular methodology (whether from BC Hydro, PNG or PSE) to the current method would be time consuming due to the detailed investigations that must be completed. How a new model would make use of existing data, how new results would compare with old, how required features such as robust scenario modelling are implemented would all take time and resources to investigate, compare and report on. In addition practical considerations such as where and how to store the millions of data records and the methods to retrieve them need to be considered. All these considerations cost time and money to investigate, compare, contrast and report on. The time alone required to complete a thorough investigation of multiple competing methodologies would far exceed the response period allotted for this round of IRs.

However, notwithstanding the above, the FEU understand that the Statistically Adjusted End Use Model (SAE) used by BC Hydro is provided by a company named Itron from the United States. The SAE is therefore a term used to refer to the Itron model. Adopting an SAE model would require that the FEU become an Itron customer. At a high level, the FEU understand that the Itron model uses data from the US Energy Information Administration and this data forms the basis for the model. On the other hand the FEU End Use Model makes use of end use data already collected from our customers. The FEU believe it is better to use data collected from our customers than it is to use data collected in the United States. Further, it is unlikely that the development of a custom or proprietary SAE model would be cost effective.

10.2 Would the SAE methodology allow the FEU to calculate demand forecasts for each year in the planning period? Please elaborate.

Response:

The FEU believe that any method from SAE to CDA to any of the methods mentioned in Fig. 2 in the preamble to BCUC IR 2.9.1 can be reported at any level of granularity. For example in the short term FIS model used for RRA forecasts data is entered and can be reported at the monthly level. Conversely the peak forecast as reported in the Annual Contracting Plan includes load duration curves that can report at the daily level. The reporting period capability of any model is not normally a function of the model, as suggested in this question. The reporting period is a decision based on pragmatism, cost effectiveness and the maintenance of quality in the results. In the case of the End Use Model reporting at the annual level would have increased the cost of the forecast with absolutely no increase in forecast performance. The FEU believe that the same pragmatism would apply to an SAE (or any other) model. In long term forecasts the FEU consider linear interpolations between milestone years to be adequate and would likely use the same approach in any long term model. Simply put, as the duration of the forecast increases FEU believes it is practical and cost effective to increase the time between reporting periods while relying on simple linear interpolation to establish intervening values as needed.

Please refer to the response to BCUC IR 1.19.2.2.

10.3 Does the FEU see any value in utilizing SAE for demand forecasts? Please discuss the capability of the SAE to satisfy the use of the FEU's demand forecasts as outlined in the preamble.

Response:

Please refer to the response to BCUC IR 2.10.1.

10.4 Please compare the effort required, including technical ability and amount of time, by staff to produce annual demand forecasts using the SAE with the End-Use methodology.

Response:

As discussed in the response to BCUC IR 2.10.1 the level of effort to learn the Itron/SAE model, how the inputs need to be changed, what inputs are required, how to interpret the outputs etc. far exceeds the scope of a single information request response. Such a project would need to be funded and completed during the development of the next LTRP. As a result the FEU are not be in a position to provide a reasonable estimate of effort, technical ability or amount of time required to produce a long term forecast with the Itron/SAE model.

11.0 Reference: ENERGY DEMAND FORECASTING

Pacific Northern Gas Ltd. (PNG) 2014 Resource Plan, Exhibit B-1, Section 3, pp. 47-58;[8]

Comparison with PNG Residential Demand Forecast Methodology

On page 47 of their 2014 Resource Plan, PNG states: "The residential forecast is now based on an end-use methodology that determines the average residential use per account based on a number of influencing factors including dwelling type, construction, the numbers and types of natural gas appliances in the home, and the behaviour of residents. The relationship between each of the influencing factors and the residential use per account was determined through a Conditional Demand Analysis (CDA) with data acquired through a REUS [Residential End-Use Survey]. A complete description of the CDA is found in APPENDIX B: CONDITIONAL DEMAND ANALYSIS."

11.1 Please compare and contrast the FEU's End-Use methodology with the CDA methodology utilized in PNG's 2014 Resource Plan. Please include a discussion of the advantages and disadvantages of the FEU's End-Use method when compared to CDA utilized by PNG.

Response:

Please refer to the response to BCUC IR 2.10.1.

11.2 Would the CDA methodology be appropriate for the FEU? Please elaborate.

Response:

Please refer to the response to BCUC IR 2.11.1.

8 http://www.bcuc.com/Documents/Proceedings/2014/DOC_41306_B-1_PNGWest-2014ResourcePlanApplication.pdf

12.0 Reference: ENERGY DEMAND FORECASTING

Puget Sound Energy (PSE) 2013 Resource Plan, p. 7-10[9]; Appendix H, p. H-2;[10]

Comparison with PSE Residential Demand Forecast Methodology

On page 7-10 of the 2013 Resource Plan, PSE states: "For longer-term forecasting, we use an econometric forecasting method that includes population growth and employment data by county." Figure H-1 on page H-2 of PSE's 2013 Resource Plan: Appendix H indicates the inputs to the in-house econometric models used to forecast the load. These include employment, income, population, housing which are input into one model and historical data, major accounts, demand-side resources, weather, retail rates and technology trends which are input into a separate model.[11]

12.1 Please compare and contrast the FEU's End-Use methodology with the methodology utilized in PSE's 2013 Resource Plan. Include a discussion of the advantages and disadvantages of the FEU's End-Use method.

Response:

Please refer to the response to BCUC IR 2.10.1.

12.2 Does the FEU's Annual Demand End-Use model include all of the inputs as listed in the preamble? If not, please identify which inputs were not included and explain why.

Response:

The FEU End Use Model does not include all the inputs listed in the preamble. The FEU understand that the PSE model is an in house developed model that is used to forecast both gas and electric demand and revenues. The FEU are not of the opinion that the PSE model is the perfect model implementing the perfect methodology and therefore uses the precise list of inputs that all other models should be judged against. Just because the FEU End Use Model does not use retail rates or employment, for example, does not mean that it is less suitable for its intended task. The PSE model answers both the same and different questions (for example peak demands and revenue) so it is not surprising that the inputs are different. From the cited

9 http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf
10 https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppH.pdf
11 Ibid.

appendix it is also not clear what inputs are used for what parts of the forecast so a comparison to the FEU End Use Forecast is irrelevant.

The FEU can state that the following inputs are not used in the FEU End Use Model.

Employment is not an input because economic growth is already an input to the model. The effects of employment levels on natural gas consumption are broadly similar to those of economic growth. Therefore, adding employment as an input would not provide additional information to the LTRP process.

Income is not an input to the model, because gas consumption within a given type of dwelling is relatively inelastic with respect to income. Sometimes consumption will drop in the short-term in response to a sudden income shock, but the effect is usually transient and consumption soon returns close to what it was before.

Retail rates: The End Use Model is a volume forecast not a revenue forecast so retail rates are not an input.

Other inputs described in the preamble appear to be similar to considerations included in the FEU's annual demand forecast using the end-use methodology.

13.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.1.2, p. 38;

Exhibit B-2, BCUC IR 1.19.7, pp. 63-64; IR 1.19.13, p. 75; IR 1.19.14.1, p. 76; Attachment 19.11, p. 1;

Costs of Annual Demand Forecasting Methodologies

The FEU discusses the calibration of the End-Use model in its response to BCUC IR 1.19.7. The FEU state: "The current budget estimate for running the full model for a different base year is in the range of $75,000 to $100,000." (Exhibit B-2, p. 63) The FEU further states: "The FEU's current plan is to continue the development of the model and renew it with new base years on a regular basis." (Exhibit B-2, p. 64)

13.1 Please indicate the frequency in years that the FEU considers to be a "regular basis" as stated in the preamble.

Response:

The long term annual demand forecast is completed primarily for the FEU's Long Term Resource Plan, which is submitted every 3 to 5 years. As such, the FEU expect to prepare a revised long term annual demand forecast, including new base year data, and publish it with the LTRP every 3 to 5 years.

13.2 Please provide a high-level estimate to complete the table below, which seeks to allocate costs to each of the demand forecasting methodologies listed, if that methodology was the sole methodology used. Please provide details where necessary.

		Demand Forecasting Methodologies		
		Traditional	End-Use	SAE
Item	Incremental Costs	$	$	$
1	Labour			
2	External Resources			
...	*List Other Relevant Costs*			
	Total			

N.B. This table should highlight the costs allocated to the End-Use methodology without a previously done CPR

Response:

SAE

The FEU have not used and are not licensees of the SAE model and thus cannot determine the costs required to develop a demand forecast using this methodology. Please refer to the response to BCUC IR 2.10.1 for additional information in this regard.

Item 1

For the reasons outlined in the response to BCUC IR 2.4.1, the FEU are unable to calculate the labour costs for internal staff involved with the operation of either the traditional or end use demand forecasts.

Item 2

The approximate cost and total person-hours for external resources to develop the end-use forecasting model for the 2014 LTRP is indicated in the table below. Since the end use model has now been developed, the future costs to update that model will be lower so an additional column has been added to the table. No external resources are required for the operation of the traditional model.

		Demand Forecasting Methodologies		
Item	**Costs ($000's) / Person-Hours**	**Traditional**	**End-Use (First Time)**	**End-Use (Subsequent Years)**
2	External Resource	0	$358 / 1,200 hours	$175 / 600 hours

Other Relevant Costs

The CPR is required to develop the end-use annual forecast; however, the study must be conducted irrespective of which forecasting methodology is used. The cost for the use of CPRs in future end-use annual demand forecasting analyses depends on the frequency and scope of those CPRs.

Additionally, the time for external resources to assist with the long term EEC analysis is embedded in the costs of the end use model in the table above since the end use model formed the basis for the long term EEC analysis. The traditional annual demand forecasting model, if used alone, would result in additional costs for long term EEC analysis that are not captured in the table above and have not been determined by the FEU.

13.3 Please provide a high-level estimate to complete the table below, which seeks to determine the effort required in person-hours to develop demand forecasts using the methodologies listed. Please provide details where necessary.

	Demand Forecasting Methodologies		
	Traditional	End-Use	SAE
Total Person-Hours for Staff			
Total Person-Hours for External Resources			

Response:

Please refer to the response to BCUC IR 2.13.2.

14.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 9, pp. 164-166;

Discontinuation of the Traditional Annual Demand Forecasting Method

14.1 Please provide the name of other gas distribution utilities that uses solely end-use forecasting. Please elaborate on the utility including mention of its size, region serviced and number of customers serviced.

Response:

As explained in the response to BCUC IR 2.9.1, the FEU have not and will not be using a "solely" end-use forecasting approach for LTRP annual demand forecasting (note: the Companies are not proposing an end use methodology for annual RRA/PBR use and rate forecasting. The existing FIS system will continue to be used for this purpose). Instead, end-use analysis is one aspect of FEUs' annual demand forecasts, which incorporate elements of bottom-up statistical and engineering methods, as well as top down econometric methods. The FEUs' review of other utilities methodologies revealed that many utilities use end-use analysis as an aspect of their forecast.

What stands out from a high-level examination of forecasting methods among other utilities is that, while there are common elements, no two utility forecasts use the same methodology. Every utility has a unique approach to forecasting. The variety of forecasting methodologies used reflects the fact that utilities' needs and capabilities vary; each utility has different resources, unique planning environments (i.e. policies and regulations, gas-electric combined utility, etc.), unique data and data sets, and/or may utilize consultants that will all offer up their own custom approach and methods. Therefore, there are many approaches that would be considered common, often with each utility customizing the approach to suit their needs, capabilities and available data.

The FEU have chosen to use the end-use methodology after proposing this methodology in the 2010 LTRP and the Commission endorsement of the proposal. The Companies believe it is the best methodology to meet the unique requirements and needs of the FEU. The FEU were able to capitalize on existing unique resources; in this case, the 2010 Conservation Potential Review which provided a source of existing end-use demand characteristics for the development of a base year data set.

In response to the question, the FEU have provided a few examples of other utilities that utilize end-use analysis.

1. PACIFIC NORTHERN GAS

Pacific Northern Gas (PNG) delivers natural gas to customers in west-central British Columbia, and the province's northeast. At year-end 2012, PNG provided gas service to approximately 39,900 residential, commercial and industrial customers. The PNG-West system served approximately 20,500 customers and the Northeast system served approximately 19,400 customers. PNG delivered approximately 9.8 PJs of gas in 2013.

Forecast Methodologies:

In their most recent LTRP, PNG's residential forecast is based on an end-use methodology that determines the average residential use per account based on a number of influencing factors including dwelling type, construction, the numbers and types of natural gas appliances in the home, and the behavior of residents. The relationship between each of the influencing factors and the residential use per account was determined through a Conditional Demand Analysis (CDA) with data acquired through a residential end use survey (REUS).

In the Fall of 2013, PNG commissioned a REUS targeting a sample of residential customers from across all PNG divisions. The survey identified demographic makeup and consumption behavior of PNG's residential customers. Such information, combined with customers' historical billed consumption data is a key input to PNG's residential end-use model that forms the basis for a refined residential annual and peak day demand forecasting model, as well as for the assessment of the impact of various demand-side measures (DSM) being contemplated.

PNG has used a CDA technique to develop end-use models for single family dwellings, multi-family dwellings such as duplexes, triplexes and townhouses, apartments and condominiums in vertical subdivisions, and mobile homes. CDA is a statistical method that is used to estimate end-use specific energy consumption, without requiring end-use metered data for the appliances. Instead, it relies on the statistical analysis of consumption data, appliance saturation data, and other data such as demographic, household, weather, economic and market data.

2. MANITOBA HYDRO

Manitoba Hydro is a Crown Corporation and the province's major energy utility. Manitoba Hydro serves 269,700 natural gas customers in various communities throughout southern Manitoba. Natural gas service is provided by Centra Gas, a wholly-owned subsidiary of Manitoba Hydro. In 2012, Manitoba Hydro's natural gas customers used 69.19 PJ.

Forecast Methodologies:

Manitoba Hydro uses an end-use forecast methodology for their residential annual energy forecast. Their 'Mass Market' (i.e. Commercial/Industrial except for the Top customers) annual energy forecast is econometric. Their 'Top Consumers' (largest customers) annual energy forecast is individually forecast for the short term using customer information, and is forecast as a group using trend analysis for the long term. Manitoba Hydro conducts a Residential Survey approximately every 5 years and uses this information for appliance saturations in their Residential End Use model, as well as for widely varying uses in their Marketing and DSM Departments. Combined with billing data for each customer, Manitoba Hydro also performs a Conditional Demand Analysis of the survey data and the appliance average uses are used in their Residential End Use model.

The Residential energy forecast is determined using a detailed end use model. The forecast of the number of Residential Customers is derived from the growth in residential customers as forecast in Manitoba Hydro's 2012 Economic Outlook. The 2009 Residential Energy Use Survey provides end use saturation rates, detailed information on newly constructed dwellings, and appliance age distributions and their expected lifetimes. The end use assumptions included current usage information and efficiency improvement information. The number of appliances and their estimated usage are multiplied together to calculate an energy forecast for each end use. All uses are then combined to calculate the total use for the SGS Residential End Use Forecast.

3. Union Gas

Union Gas is a natural gas distribution business serving about 1.4 million customers in over 400 communities across northern, southwestern and eastern Ontario.

Forecast Methodologies:

Similar to the FEU, Union Gas contracted ICF Marbek Consulting to conduct their 2011 Conservation Potential Review. This review was conducted with an end-use analysis to determine DSM/EEC savings. Whether Union Gas will use this information for the purpose of annual demand forecasting will depend on their requirements.

4. Enbridge Gas

Enbridge Gas Distribution serves over 2 million customers in central and eastern Ontario.

Forecast Methodologies:

Similar to the FEU, Enbridge Gas contracted ICF Marbek Consulting to conduct their 2011 Conservation Potential Review. This review was conducted with an end-use analysis to determine DSM/EEC savings. Whether Enbridge Gas will use this information for the purpose of annual demand forecasting will again depend on their requirements.

5. Questar Gas

Questar Gas provides retail natural gas-distribution service to almost 900,000 customers in Utah, southwestern Wyoming and a small portion of southeastern Idaho. 2012 sales volumes were 181.70 PJ

Forecast Methodologies:

According to their *2013-14 Integrated Resource Plan*, Questar Gas' primary modeling tool for long-term residential usage is an end-use model that estimates consumption for space heat, water heating, and other natural gas appliance use based on appliance efficiency and housing characteristics. The model incorporates estimates of housing characteristics, natural gas appliance saturation by efficiency rating throughout the residential customer base, customer growth projections, and projected changes in economic variables that affect use per customer such as the average residential gas bill and household income. Effects on use per customer from the company's energy efficiency programs based on past and projected participation have also been addressed in the model. Along with the end-use model, statistical time series methods using SAS Enterprise Time Series 9.3 and Forecast Pro XE are also utilized in the forecasting process.

Questar's Commercial and Industrial annual energy forecast is econometric.

6. Colorado Springs Utilities

Colorado Springs Utilities (CSU) operates a local distribution system supplying natural gas to approximately 187,500 customers in about a 500 square mile service area, delivering 23.51 PJ in 2010.

Forecast Methodologies:

According to their *2011 Gas Integrated Resource Plan*, CSU's demand forecast is developed through a combination of statistical adjusted end-use modeling and econometric analysis. The natural gas sales and use-per-customer forecasts employed a combination of econometric and end-use modeling. New federal appliance efficiency standards were accounted for by using an end-use model to adjust the results of the econometric model of the residential sector. The commercial sector used a traditional econometric approach.

14.2 Does the FEU consider the proposal of utilizing solely the end-use demand forecasting methodology for all sectors in future long-term resource plans, to be commonly used within the natural gas distribution industry? Please elaborate.

Response:

Please refer to the response to BCUC IR 2.14.1.

15.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Application, Section 5;

Reinforcements and Expansions

15.1 Please indicate if there is any infrastructure project, or category of projects, relevant to the FEU's business which has a lead time (design, build, commission) greater than five years. If so, please describe briefly, the nature of this project(s), the lead time in years and discuss the factors which contribute to the duration of project. Please consider projects related to transmission pipelines, distribution pipelines, storage facilities, system reinforcement and any other relevant areas of the FEU's natural gas distribution business.

Response:

No, generally there are no projects or category of projects that require a lead time greater than five years to complete the design, build and commissioning. Specifically, the FEU currently have no projects approved and in design that have a projected in service date beyond 2019.

16.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.19.13, p. 75;

Alternate Use of Input Data for End-Use Methodology

In the response to BCUC IR 1.19.13, the FEU state: "The FEU conduct a range of customer and market research to meet a range of business needs, much of which helps to inform the LTRP and the long term demand forecast … these costs will be incurred irrespective of the end use annual demand methodology. … Absent the CPR [Conservation Potential Review], two key studies that are vital to the end-use methodology are the Residential End Use Study (REUS) and the Commercial End Use Study (CEUS). The most recent costs for these two studies provide insight into the costs of acquiring the background information that goes into the end use annual demand forecasting study. These costs would still be incurred if the traditional methodology continued to be used."

16.1 Please describe in detail the "range of business needs" referred to in the preamble, and discuss how the acquired data allows the FEU to meet these needs.

Response:

The FEU conduct a broad range of customer and research projects to support business needs including: customer satisfaction; energy efficiency; communications; safety; demand forecasting; regulatory submissions and marketing.

Customer satisfaction research is used to enhance the customer experience by ensuring that the services provided to the customer are appropriate, relevant, delivered in a timely manner and of high quality. The FEU conduct a suite of surveys to measure satisfaction with various customer transactions and contact channels. The information is used to coach staff, refine business processes, and tailor services to best meet the needs of our customers.

Energy efficiency research has two primary roles: identifying which areas of energy efficiency and conservation (EEC) the FEU should focus on and measuring the effectiveness of EEC programs. The CPR informs program choices by estimating the likely market for various measures and the potential Total Resource Cost (TRC). Evaluation reviews determine the validity of the assumptions used to plan programs and measures customer satisfaction with how the program was delivered. This information is used to refine programs to ensure they are relevant and delivered in an effective manner.

Communications research is used to measure the effectiveness of corporate communications messages and the channels used to deliver those messages. The research helps the FEU measure public awareness of key messaging around issues such as safety and energy efficiency and helps inform decisions around the design of creative content and selection of media channels.

Research is also used extensively to support submissions to the BCUC covering such topics as rate design, amalgamation, the Customer Choice program and the MX Test. The Marketing group also uses research to understand trends in natural gas end-uses and customer attitudes towards competing energy options.

16.2 Please provide a table showing the duration and anticipated date of completion of the next: (i) CPR, (ii) REUS, (iii) CEUS, and (iv) LTRP.

Response:

Item	Est. Start Date	Est. Completion Date	Est. Duration
Conservation Potential Review (CPR)	Q1-2015	Q3-2016*	1.5 years
Residential End-Use Study (REUS)	Q3-2015	Q3-2016	1 year
Commercial End-Use Study (CEUS)	Q3-2014	Q1-2015	6 months
Long Term Resource Plan (LTRP)	Q4-2014	*See note***	2-4 years

* As indicated in the response to CEC IR 1.59.1, the FEU have recently started discussions with BC Hydro and FortisBC Inc. on how the CPR collaboration will operate, and do not currently have an agreed upon timeframe for completion of the CPR. However, based on discussions to date, the FEU anticipate that all final CPR reports will be completed by mid-2016.

** The FEU estimate that the next iteration of the LTRP will be completed approximately two to four years following the Commission's acceptance of the 2014 LTRP.

17.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.20.1, p. 78;

Exhibit B-1, Application, Appendix A-1, pp. 26-27, Long Range Price Forecasts; Exhibit B-1, Application, Appendix B-3, Scenario Descriptions, p. 14; Gas Supply Scenarios and Gas Price Forecasts

In the response to BCUC IR 1.20.1 the FEU state: "The forecast of natural gas prices was conducted by the FEU exogenously from the model and provided to the external consultant, ICF Marbek. Future scenarios that included abundant gas supplies utilized a lower natural gas price forecast than those that included constrained natural gas supplies as explained in Appendix B-3 of Exhibit B-1."

Figure 2, at page 27 of Appendix A-1 in the Application, is a graph titled "Natural Gas Price Forecasts" that shows four long range forecasts for the period 2013 to 2031.

Appendix B-3 of the Application includes in each scenario description assumptions and interpretations of the assumptions regarding future gas prices.

17.1 Are the four long-range price forecasts shown in Figure 2 of Appendix A-1 of the Application the same price forecasts that are used to derive the regional price forecasts? If not, please provide the long-range price forecasts used in the forecast model and describe the relationship between the gas price forecasts in Appendix 2 to those used in the End-Use model.

Response:

The FEU presume that the references made in the preamble and the request above are Figure 22 rather than Figure 2 and Appendix A-1 rather than Appendix 2 (in the last line of the request).

No, the four long-range price forecasts shown in Figure 22 of Appendix A-1 of the application are the latest long-range price forecasts from different sources (EIA, WoodMac, GLJ) and the NYMEX forward price curve at the time of the 2014 LTRP submission. The long-range price forecasts used in the forecast model are based on GLJ long-range price forecasts only. Historical GLJ long-range price forecasts from different moments in the past were used in each of the model scenarios to capture and represent a broad range of pricing scenarios based on the different historical gas market price environments.

For example, the GLJ long-range price forecast from July 2008, a year where energy prices were among the highest in the past 10 years, was used for Scenario B to represent gas prices in a moderate to high price environment. The GLJ long-range price forecast from July 2011 was used for Scenario A, January 2013 for Scenario C, January 2010 for Scenario D, and October 2010 for the Reference Case.

18.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.20.1.1, pp. 78-79;

Fuel Share and Price Elasticity

In response to BCUC IR 1.20.1.1 the FEU state: "Furthermore the model makes changes to fuel shares which are linked to price elasticity."

18.1 Are electricity price forecasts used in the end-use model?

Response:

No, the electricity price in the model is static and is the same for all five scenarios.

18.2 Does the model implicitly assume the same electricity prices for all scenarios so that only the relative gas price changes between scenarios? Does such an assumption impair the results? Please explain your answer.

Response:

The model uses the same electricity price for all scenarios and only the gas price changes between scenarios.

No, this assumption does not impair the model, but rather allows the model to function as it should. The primary issue the FEU were exploring through variations in fuel pricing was the likely changes in fuel share, primarily between electricity and natural gas. Varying the electricity price would introduce an unnecessary complication to this exploration by increasing the number of different pricing combinations, without producing any useful new information. This is because the financial driver for a fuel switching action is the relative price between the fuels, not the absolute price of each. Holding electricity price constant permits a full investigation of the effects of changing relative pricing between the two fuels.

If all fuels are rising in price, there is some downward pressure on consumption of all fuels, but the elasticity is much smaller than the price elasticity that leads to switching between fuels. People still have to live and work, and there is a limit to how much they can adjust their need for the services energy provides. The FEU have therefore not made adjustments for this effect in any explicit way. To some extent, the variation in economic growth would have a similar effect on gas consumption to the effect of parallel variations in all energy pricing. Economic growth is varied between scenarios.

One tangible effect that varying electricity prices would have is to change the results of the TRC tests applied for energy efficiency measures that save both electricity and gas. However, there are relatively few measures that are so close to the margin between passing and failing that a change in electricity pricing would tip them one way or the other, so the effect would be very small. The FEU have explored the effects of varying gas prices by running EEC scenarios B and C, and we believe varying electricity prices as well would add very little new information.

19.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IRs 1.20.1.3 and 1.20.2, pp. 79-80;

Fuel Share and Price Elasticity

In response to BCUC IR 1.20.1.3 the FEU state: "There was an iterative feedback process of making adjustments to these input assumptions and examining the resulting consumption changes to assess how it compared to expected price elasticity, but this was a manual process."

In response to BCUC IR 1.20.2 the FEU state: "Scenario Explanation Documents were developed for each scenario and sector, to describe the assumptions involved in each scenario and the specific actions planned to implement these assumptions … As an example, if the client/consultant discussion concluded that the price change for Scenario X would result in a 5% decrease in commercial gas consumption to 2031, we would make manual adjustments to specific values in the feeder workbooks for space heating and DHW."

19.1 Are these Scenario Explanation Documents in a readable format and of a manageable size so they can be placed on the record in this proceeding? If so, please provide them.

Response:

The Scenario Explanation Documents are already on record in this proceeding in Appendix B-3 – End-Use Annual Demand Forecasting Scenario Descriptions, of the 2014 LTRP. These documents are in a readable format and of a manageable size.

19.2 To what extent do the iterative feedback and manual adjustment processes render the results more subjective due to the judgment involved in the manual adjustments?

Response:

There is subjectivity in the manual adjustment process: however, it is important to note there is subjectivity in all forecasting. There would also be subjectivity in the way an automatic adjustment process works in that the subjectivity occurs earlier in the process when coefficients and equations are set up. The FEU believe that this approach is more transparent and understandable, and therefore if problems do arise it is easier to correct them. The FEU have dealt with subjectivity by bracketing answers. In this way using the multiple scenario model protects against errors in judgment in setting the adjustment factors.

20.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.38.1, pp. 142-143;

Variables in the Scenario Analysis

In response to BCUC IR 1.38.1, the FEU provide a table that shows, for each variable, the value in the reference case and the value in the other scenarios.

20.1 To what extent does this table summarize the major components and variables of the end use model? If it is a limited description of the model, could it be modified to make the model and its results more transparent to observers such as the Commission and Interveners? If so, would the FEU be able to do that?

Response:

The table provided is a complete summary of the major components and variables in the end use model. It is at a very aggregated level, to make it easy to read and understand, but it does not reflect the full level of detail in the model itself.

As stated in the response to BCUC IR 2.7.1, the FEU believe one of the strengths of the end use modeling approach is that the assumptions are explicit in the model and can be reviewed. As with the original reference case, the model of each scenario is large and detailed, and a complete listing of the varying assumptions would be very bulky. As stated before, the FEU recognize the value of external review of the scenario assumptions, and is interested in finding an efficient and workable approach to facilitate that review.

The available approaches to scenario review are the same as those described in the table provided in the response to BCUC IR 2.7.1. The FEU believe the same approach should be chosen for both tasks.

While the FEU understand that it is important to provide opportunity for such review, the FEU also note that the model did undergo review with the Resource Planning Advisory Group over a two year period, which included BCUC staff, and therefore was not developed in isolation from such review.

21.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.49.2, pp. 173-174;

Peak Day Demand Forecast

The response to BCUC IR 1.49.2 describes the method for forecasting the peak day demand.

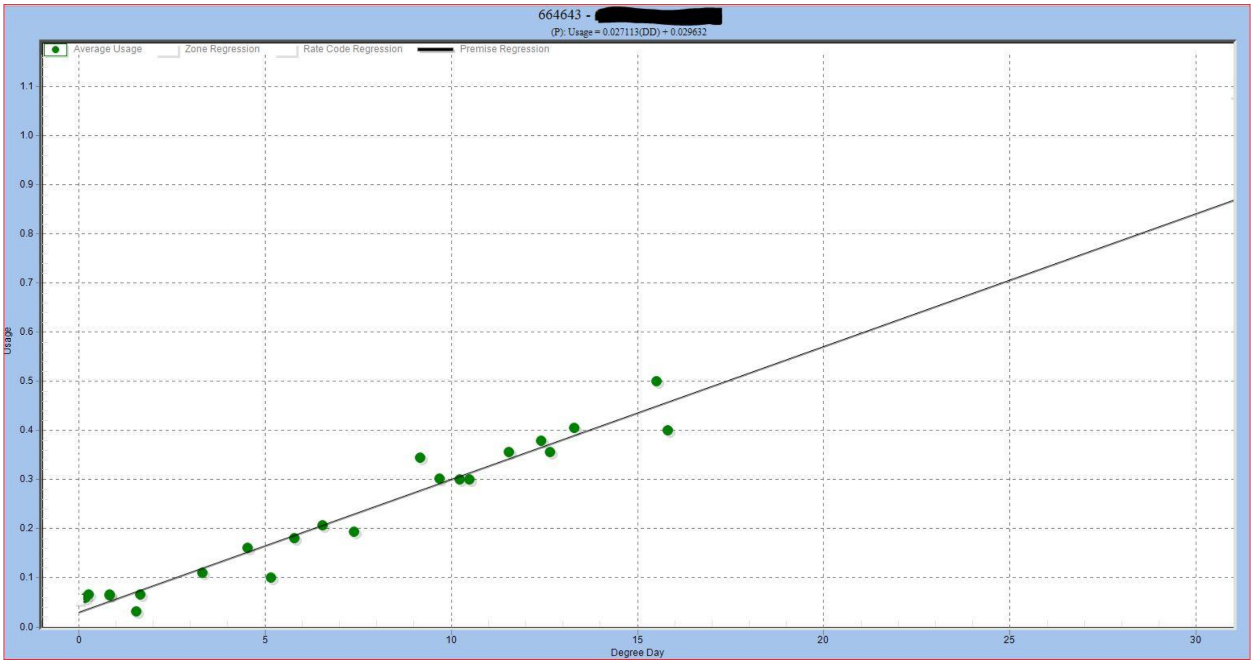
21.1 Please provide a plot of the regression analysis and the regression statistics used to develop the use per customer for each of the service areas.

<u>Response:</u>

The information request and the response to BCUC IR 1.49.2 was related to peak hour forecasting methodology, not peak day methodology. For clarity, the FEU provide the following additional detail with respect to the peak hour methodology:

The peak hour demand is used for distribution system modeling and planning as well as transmission systems such as the Coastal Transmission System (CTS) and small transmission laterals with limited available line pack. The process to determine a peak hour use per customer (UPC) does not produce a regression plot on a regional basis but performs a unique regression analysis on every heat sensitive customer in the FEU service territory. The FEU cannot therefore provide regression plots and regression statistics on a regional basis, but can provide some additional clarification on the process for determining the peak hour demand. Please note that the peak hour UPC is refreshed annually and is based on the most recent customer consumption information

The regression produced in determining peak hour UPC is based on the customers' previous two calendar years billed consumption and the prevailing regional Degree Day temperature during the individual billing periods. The figure below is an example of the regression plot of an individual Rate 1 residential customer located in North Vancouver where our local design degree day (DDD) is a 31DDD. The data points on the plot have a Y coordinate equal to the average daily consumption for a billing period and an X coordinate equal to the average degree day prevailing during the billing period. The customer's peak UPC (as a daily GJ/day value) is read from the Y axis where the line intersects with a 31DD read from the X axis.



As described in the response to BCUC IR 1.49.2 the customer UPC is converted to a peak hour value using a peak hour factor, additionally the value is converted to standard cubic meters per hour using the local average heating value. In the example plot above the converted peak UPC projected for this residential customer is 1.37 std m^3/hr. Data for all customers is summed and averaged by rate class for each local region (by municipality or group of adjacent municipalities. These municipal UPC's, refreshed on an annual basis, are averaged with the results of the previous two years results to smooth variations. Multiplication of averaged UPC for each rate class by the account forecast is used to determine the peak hour forecast for the region. The table below provides an example of the most current result of calculated UPC for Rate 1, 2 and 3 customers for the North and West Vancouver Region. Note that the customer used in the example above with a peak UPC of 1.37 std m^3/hr falls below the average UPC for residential customers in the North and West Vancouver region.

North & West Vancouver Peak Hour UPC by Rate

Rate Code	Average UPC (std m^3/hr)	Total # of Customers
1	1.82	41686
2	6.41	2952
3	42.37	276

21.2 Have any Design Degree Days occurred during the return period, and if so, how many? Are actually occurring Design Degree Days or days that are close to the Design Degree Days used to calibrate or check the accuracy of the extrapolation method?

Response:

In the last 20 years the FEU have not recorded an occurrence of a Design Degree Day condition in any of the weather zones in utility's operating areas. During the winter period the FEU do investigate the coldest occurring weather days in selected regions to confirm that the UPC's used in analysis give reasonable results. Portable pressure recorders are placed each winter at tail end locations and other points of interest within various distribution systems and compared to modeled results. Additionally, regressions are performed on select gate station flows for comparison purposes against load forecast predictions.

21.3 What checks do the FEU use to determine if the peak day and peak hour forecasts are reasonable?

Response:

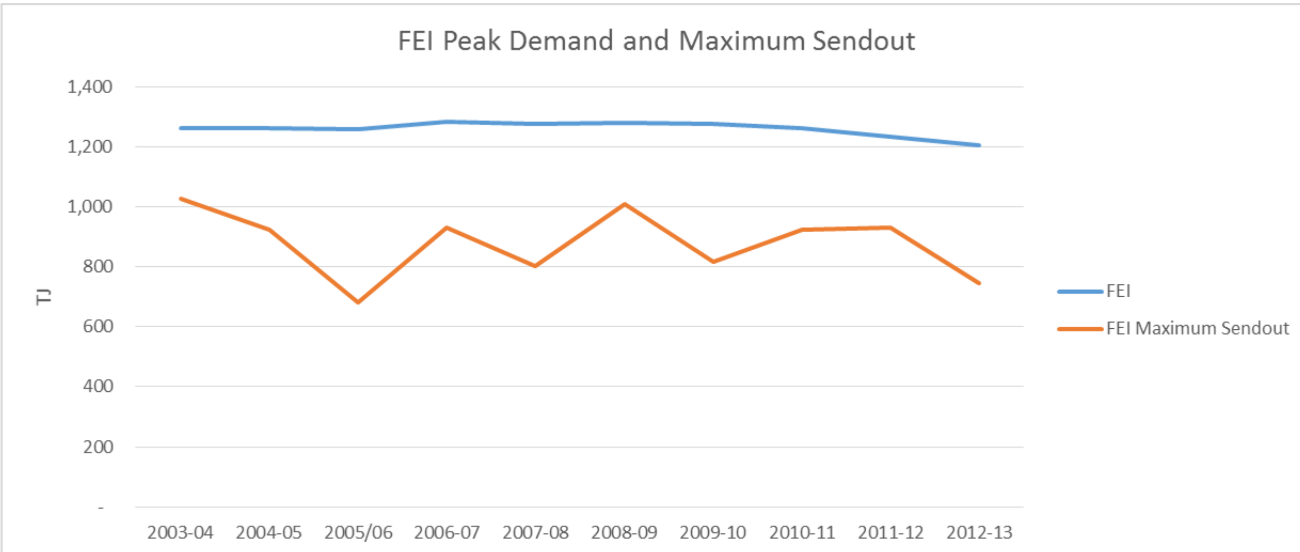
Please refer to the response to BCUC IR 2.21.2.

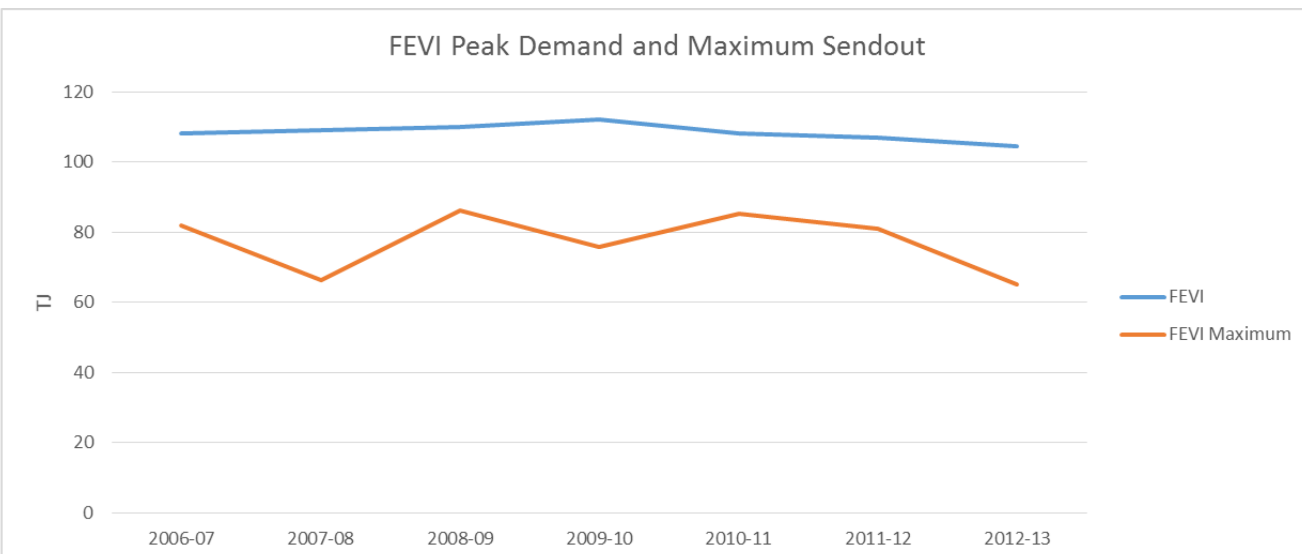
21.4 Please update Figures 3-17 through 3-20 of the Application to include at least 10 years of historic Peak Day demand (with the historic data on a consistent basis with the forecast data).

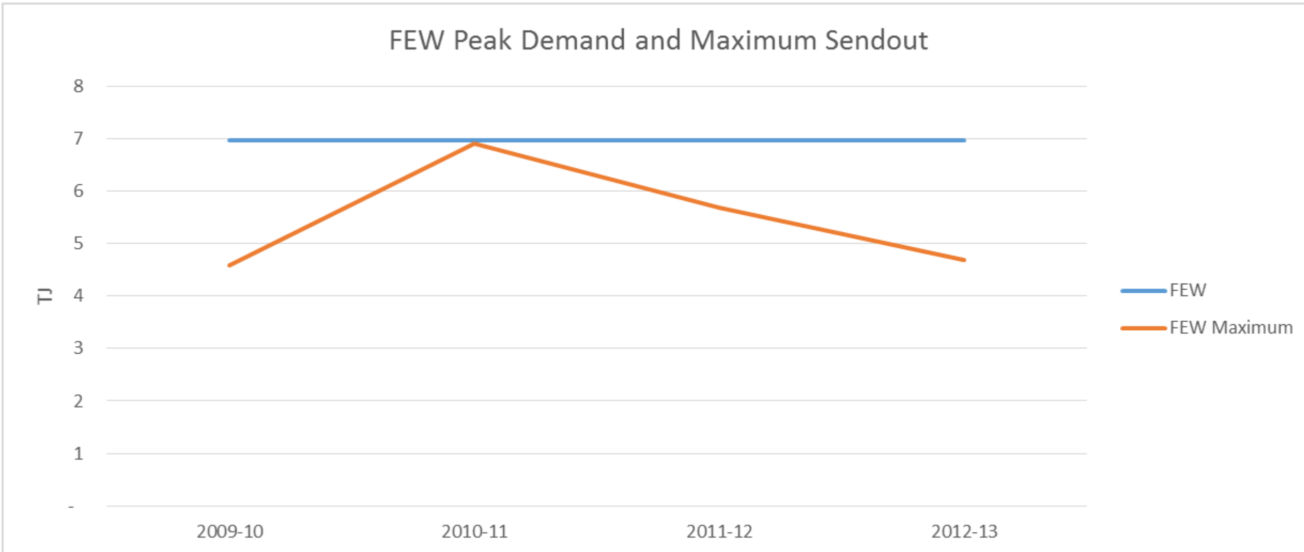
Response:

The estimated peak demand assumes an extreme weather scenario and the expected peak load corresponding to such extreme condition has a small probability of actually occurring (1 in 20). This is consistent with the Companies' planning and purchasing process where a reasonable level of contingency is needed in order to ensure adequate supply of gas even in extreme weather conditions. The peak demand forecast is reflective of this reality and the table below illustrates the difference between the actual maximum gas demand occurred and the estimate peak demand for each of the years.

Please note that the actual historical peak by region varies in terms of timing and thus, when aggregated across different regions, it does not imply the same timing.







Note FEW data prior to 2008-09 are not available due to Whistler Conversion to Natural Gas. FEVI data prior to 2006-07 are not available due to data processing change in the MICS system in Measurement.

22.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Section 3.3.5, p. 58; Section 5, pp. 108, 113, 114;

Exhibit B-2, BCUC IRs 1.25.5 and 1.25.5.1, p. 115;

Exhibit A2-4, WesPac Midstream LNG Export Application to the NEB, p. 3;

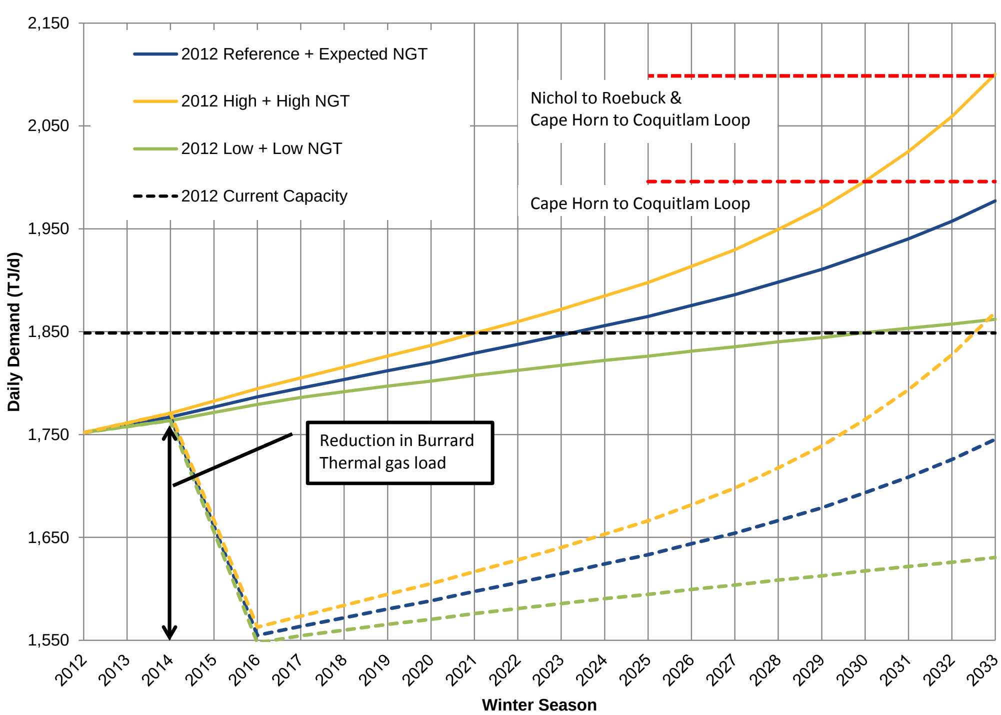
BC Hydro 2013 Integrated Resource Plan (2013 IRP), p. 2-2, p. 6-1;

End-Use Demand Forecast Results by Scenarios

22.1 In the FEU's response to BCUC IR 1.25.5.1 the graphs indicate that the proposed Tilbury LNG expansion project has enough capacity to meet Natural Gas for Transportation (NGT) forecasted demand in the short and long term future. How does this directly influence other system reinforcement/system capacity/system sustainment projects?

Response:

Figure 5-8 of the Application reproduced below illustrates the possible range of influence of the NGT forecast loads on system reinforcement projects by comparing the range of potential future peak demand to the capacity provided by the current system and to respective system reinforcement projects.



22.1.1 In particular, considering the reference and low demand scenarios for transportation LNG, showing excess capacity of LNG from the Tilbury facility what system reinforcement/system capacity/system sustainment projects in the Fortis system could be delayed or reduced?

Response:

There is currently no planned increase in send out capacity (e.g. vaporization) and hence no opportunity to reduce or delay system improvement reinforcement projects.

In response to BCUC IR 1.25.5.1 the FEU state: "If further LNG plant or infrastructure expansions are required to serve higher LNG demand and if additional industrial load locates in the Lower Mainland, there would be a need to upgrade existing pipeline and compression systems in order to accommodate these development activities."

22.2 On what basis would the FEU determine the best (optimal) use for any excess LNG capacity considering the interests of new markets and existing customers?

Response:

The best use, or optimal use, will depend upon the requirements of all customers, including new LNG customers, at that time. It should be noted that the principal purpose of the Tilbury expansion is to serve customers who require LNG and therefore only new liquefaction and storage facilities are being built. If excess liquefaction or storage capacity existed, the FEU could assess the value of using that capacity as additional on-system peaking storage. However the storage value to the gas supply portfolio would depend on the ability to add additional vapourisation or 're-gasification' capacity. The FEU will continue to monitor and assess this potential as part of its gas portfolio planning.

22.2.1 Is the LNG expansion project intended for any other use?

Response:

The FEU are unsure what is being requested in the question. The LNG expansion project is to expand the production and storage of LNG for customers seeking LNG liquefaction and storage.

In the WESPAC Midstream LNG Export Application to the NEB it states: "Pursuant to the requested licence, the Applicant itself, and as agent on behalf of affiliates and third parties, will export the LNG from Canada … WPMV [WesPac Midstream – Vancouver LLC] will export LNG produced at the Tilbury LNG Plant located in Delta, British Columbia. The Tilbury LNG Plant is currently owned and operated by FortisBC Energy Inc. ("FEI") … The Tilbury LNG Plant is currently being expanded to increase the LNG production capacity at the site by approximately 33 million cubic feet per day … Pursuant to a development agreement with affiliates of FEI, WPMV is currently developing a marine terminal facility in the Fraser River adjacent to the Tilbury LNG Plant … Engineering and site analyses have confirmed that the Tilbury site is capable of accommodating further LNG export production expansion of approximately 462 million cubic feet per day of natural gas equivalent LNG production … The applied-for export licence volume corresponds to 400 million cubic feet per day of natural gas equivalent LNG production." (Exhibit A2-4, pp. 3-4)

22.3 Did FEI have input to this NEB application and does it agree with the statements and values above?

Response:

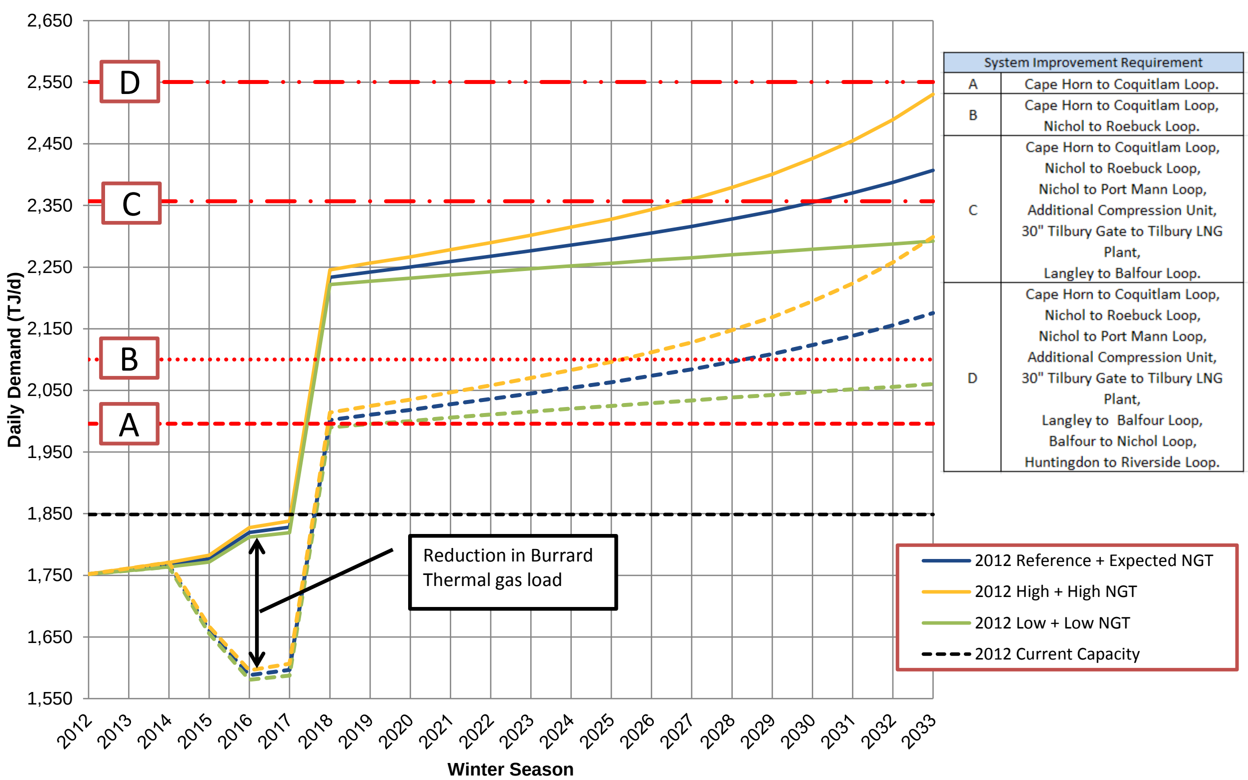
FEI did have the opportunity to review the NEB application but did not have input. FEI agrees that the site may have the potential to have the level of production capability noted but to determine the actual feasibility of this potential would require significant front end engineering design work that has not been performed at this time.

22.4 Please update (i) Figure 5-5 on page 108 and (ii) Figure 5-8 on page 113 of the Application to include this single LNG export application volumes.

Response:

i) Figure 5-5 has not been updated since this specific plot was used to provide an isolated view of the capacity constraints on the Nichol to Coquitlam pipeline within the Coastal Transmission System. The relationship between the capacity of the Nichol to Coquitlam pipeline relative to the capacity of the entire CTS is complex and the FEU feel that an update of this plot would not provide useful information. Figure 5-8 provides a more functional indication of capacity requirements on the CTS.

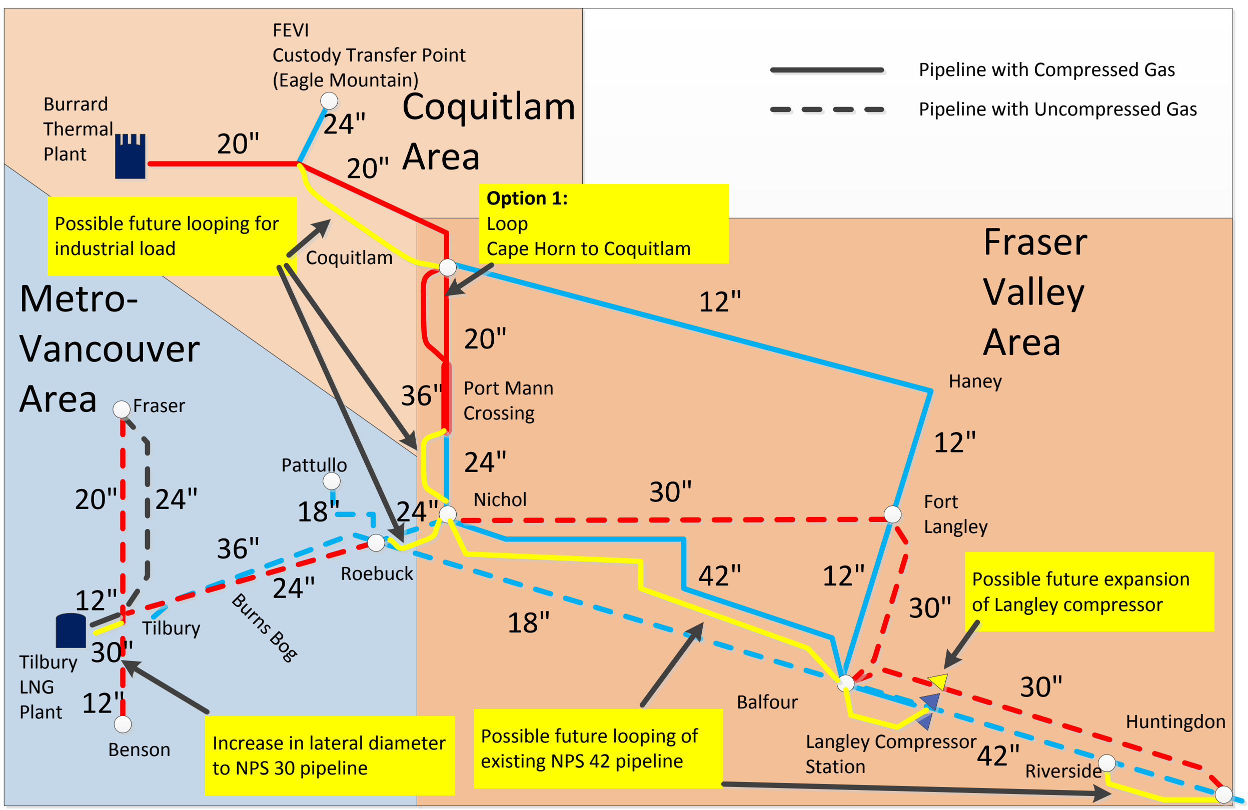
ii) Below is an updated version of Figure 5-8 with the addition of 400 mmscfd load as contemplated by the LNG export application. Since the potential timing and phasing of the proposed export volumes is not known, for the purposes of this response it is assumed that the 400 mmscfd [mmscfd = million standard cubic feet per day] load is added in 2018 resulting in a marked increase in daily demand. Dashed red lines indicate the Coastal Transmission System capacity for different combinations of reinforcements. The different reinforcements are described in the legend to the right of the figure. No conclusions regarding the timing and phasing of the proposed export volume or the timing of reinforcements should be drawn from this figure.



22.5 Does Figure 5-9 on page 114 of the Application show the possible future expansions necessary to serve this single LNG export volumes? If not, please update.

Response:

Additional expansions that may be required to accommodate this single LNG load are shown on the updated Figure 5-9. The extent of some of the looping downstream of the Langley compressor are dependent upon the presence / absence of the Burrard Thermal load.



22.6 Please further update the figure provided in the FEU's response to BCUC IR 1.25.5 to include the volumes in the LNG export application.

Response:

At present, FEI and Wespac have not entered into an agreement whereby FEI would provide LNG supply to Wespac.

The figure provided in the response to BCUC IR 1.25.5 was limited to FEI's expansion of the Tilbury LNG plant as allowed under Special Direction No. 5 for a total capital expenditure of up to $400 million. The volumes quoted in Wespac's applied-for-export license (up to 0.4 billion cubic feet per day) are well above the capability of this expansion. For these reasons, providing a graph including Wespac's *stated* demand would not provide any more useful information and would dramatically skew the NGT demand forecasts as provided in the response to BCUC IR 1.25.5.

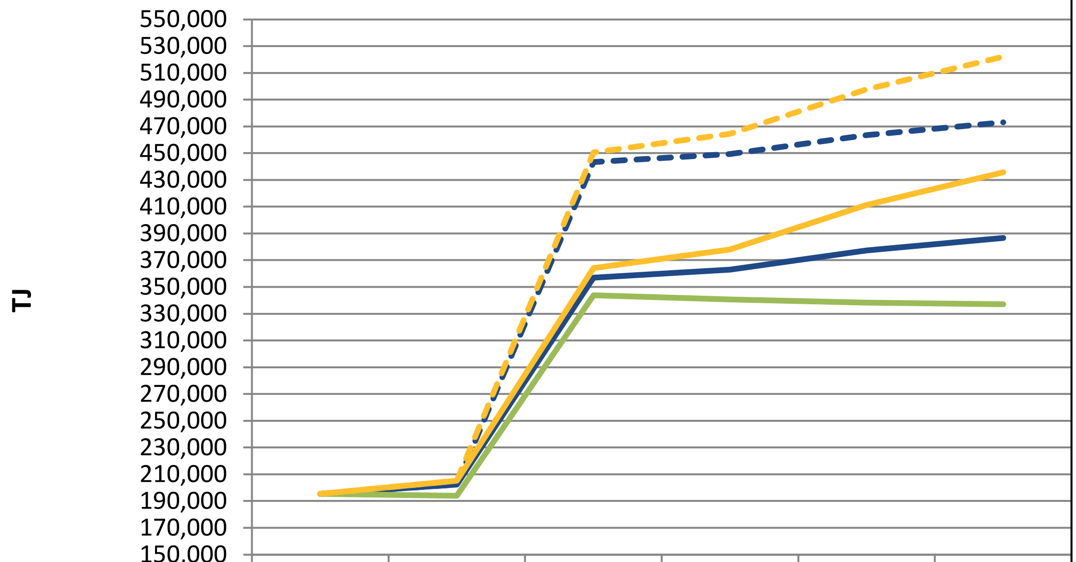
22.7 Please update Figure 3-16 in the Application to include the LNG export volumes presented in the WPMV LNG export application to the NEB.

Response:

Figure 1 below provides Figure 3-16 from the LTRP with the inclusion of the LNG export volumes presented in the WPMV LNG export application to the NEB. Since the timing and phasing of the proposed export volumes is not known, it is assumed that Wespac's load is added in 2018, but due to the fact that the scenarios were presented by milestone years the change is only reflected as of the 2021 milestone year. Figure 1 is for illustrative purposes only.

It is important to note that as stated in the response to BCUC IR 2.22.6, the FEU and Wespac do not currently have an agreement in place in which the FEU would provide LNG to Wespac.

Figure 1: Total Annual Demand Including NGT, Woodfibre, and WPMV LNG



	2011	2016	2021	2026	2031	2033
Ref + NGT + WPMV LNG	195,317	202,426	356,886	363,038	377,177	386,653
Ref + NGT + Woodfibre + WPMV LNG	195,317	202,426	443,286	449,438	463,577	473,053
Scen B + NGT + WPMV LNG	195,317	194,010	343,867	340,616	338,242	337,077
Scen C + NGT + WPMV LNG	195,317	205,099	364,034	378,041	411,235	435,804
Scen C + NGT + Woodfibre + WPMV LNG	195,317	205,099	450,434	464,441	497,635	522,204

In its 2013 IRP, BC Hydro states: “Regarding future demand from the LNG industry, BC Hydro considered a range of potential LNG loads as scenarios in the 2012 Load Forecast. Future demand from the LNG industry warrants specific analysis given the scope of its potential impact on resource plans. … BC Hydro’s current estimate suggests the LNG industry could need in the range of 800 to 6,600 GWh/year (100 to 800 MW), with an expected LNG load of approximately 3,000 GWh/year and 360 MW by F2022.” (BC Hydro 2013 IRP, p. 2-2)

BC Hydro further states: “Future demand from the LNG industry warrants specific analysis given that the size of these loads … can have a significant impact on resource plans.” (BC Hydro 2013 IRP, p. 6-1)

22.8 Please discuss the robustness of the FEU 2014 LTRP in considering a range of potential future scenarios that could be expected to unfold with regards to the future NGT demand in addition to the LNG export industry and the impact on system capacity and infrastructure during the planning period.

Response:

The 2014 LTRP provides a robust outlook on future NGT and potential LNG export demand and the impact on the FEU's system capacity and infrastructure.

Detailed analysis and discussion around potential future NGT demand is provided in Section 3.3.7 as well as in Appendix A-8 – FEU's Natural Gas for Transportation Initiatives. The FEU have focused on three NGT scenarios covering a broad range of potential market uptake that were developed based on FEI's experienced learned from the 2012 and 2013 Greenhouse Gas Reduction (Clean Energy) Regulation vehicle incentive calls, the allocated funding period from the GGRR, discussions with the Resource Planning Advisory Group and actual NGT customer additions to date. These scenarios, depicted in Figure 3-13, see NGT market penetration rates increasing by a range of 1 percent to 30 percent by the end of the forecast in 2033. The impact of additional NGT load on peak day demand is examined in Section 3.4.2 of the LTRP.

While Section 5.1.2.2 examines the impact of potential future demand for LNG and CNG as transportation fuels on the Coastal Transmission System (where NGT demand growth is expected to be the largest),Figure 5-8 illustrates the effect of the various NGT scenarios on system capacity. Figure 5-8 also identifies system constraints related to NGT demand at various points during the planning horizon. In addition, Section 5.1.2.3 examines the potential for new LNG demand for transportation on the Interior Transmission System.

Section 3.3.9 of the LTRP discusses the effect of new industrial load and demonstrates the impact that the addition of a potential LNG export customer may have on annual demand in Figure 3-16. The impact of adding LNG export customers on peak day demand is further analyzed in Section 3.4.3. The impact of adding potential large new industrial load from a LNG customer on the FEVI and FEI Coastal Transmission Systems are discussed in Sections 5.1.2.1 and 5.1.2.2 respectively, as well as the system impacts including expansion, reinforcements, and looping alternatives.

Sustaining the FEU's existing natural gas system infrastructure and planning to meet future demand growth across a range of potential future scenarios is of critical importance to the FEU. The FEU are confident that the 2014 LTRP thoroughly considers a range of potential future scenarios and system impacts that could be expected with regard to future NGT demand and potential demand from the LNG export industry.

23.0 Reference: ENERGY DEMAND FORECASTING

Steelhead LNG (A) Inc. LNG Export Application to National Energy Board;

The Globe and Mail article dated July 8, 2014, "Aboriginal group on Vancouver Island signs deal for LNG project";[12] Quicksilver Resources Inc. Discovery LNG website;[13]

End Use Demand Forecast Results by Scenarios

Steelhead LNG (A) Inc. together with Steelhead LNG (B) Inc., Steelhead LNG (C) Inc., Steelhead LNG (D) Inc. and Steelhead LNG (E) Inc. (collectively the Steelhead Group), filed an application for LNG Export Licenses with the National Energy Board on July 7, 2014, for the export of a total of 4.25 Bcfd anticipated to commence in 2019. According to the above referenced July 8, 2014 Globe and Mail news, this LNG export facility will be located on the west coast of Vancouver Island at a site near Bamfield and would require a new pipeline across Georgia Strait.

A second LNG Export project has been proposed by Quicksilver Resources Inc. at the Elk Falls mill site near Campbell River, referred to as the Discovery LNG project. The FAQ section of the project website describes how gas will arrive at the Discovery LNG site as follows:

> "Natural gas would be transported to the Project from northeast British Columbia via existing pipeline right-of-ways and/or physical pipeline networks connecting northeastern British Columbia to the lower mainland. A new pipeline would be required to transport the gas from the lower mainland to Campbell River. Any new pipelines associated with the Project would be separate Projects that would be constructed, owned and operated by a third party and assessed independently under the applicable regulatory regime."

23.1 Please describe and discuss the potential impact the Quicksilver Resources Inc. and Steelhead Group LNG Export projects might have with regard to the need for future expansion of the FEU systems and/or future demand for transportation capacity on the FEU system on the FEVI system, FEI coastal transmission system and FEI interior transmission systems, respectively.

<u>Response:</u>

The FEU have very little information beyond what is publically available regarding Quicksilver and Steelhead's plans or expectations on how or where gas pipeline infrastructure will be built

[12] http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/aboriginal-group-on-vancouver-island-signs-deal-for-lng-project/article19507257/

[13] http://www.discoverylng.com/project-details/faq/

to serve their proposed facilities and therefore it is difficult to speculate on what it may mean for future expansions of the FEU system. It should be noted however, that Steelhead's export licence application suggests an LNG export facility of up to 4.5 BCF/d and Discovery LNG recently filed an Export License application[14] for up to 20 million tonnes per annum (approximately 2.6 BCF/d)[15]. In comparison, the maximum capacity of Spectra's T-South system to transport WSCB production to the Huntingdon/Sumas is currently 1.7 Bcf/d, FEI's Coastal Transportation System currently delivers approximately 1.1 BCF/d on a peak day, and the FEVI system max capacity is approximately150 mmcfd. The size of these projects suggests that any pipeline solutions will be stand-alone, as is the approach for the northern LNG projects. However if these projects do go ahead, there may be a opportunity for the FEU to meet part of its future incremental requirements by contracting for any available expansion capacity on Spectra's T-South or on the project specific facilities.

23.1.1 Please discuss the potential for other LNG export projects of this nature to impact the FEU infrastructure and throughput over the LTRP forecast period.

Response:

Please refer to the response to BCUC IR 2.23.1.

[14] http://www.discoverylng.com/export-application-filed/
[15] http://www.discoverylng.com/export-application-filed/

24.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-2, BCUC IR 1.37.2, p. 141;

LNG Component of Demand Forecast

In response to BCUC IR 1.37.2, the FEU state: "There is no discrimination or preference given to a customer based on the customer's end use requirement, nor are parties who receive vehicle incentives given higher priority than any other segment of customers. If there are competing requests for service, the provision of service is decided solely on the terms of the contract; specifically the length and demand volume as approved under Rate Schedule 46."

24.1 Is the FEU able to change the terms of Rate Schedule 46 to give priority access to NGT customers and other domestic LNG customers over LNG customers who intend to export the LNG from British Columbia? Please elaborate.

Response:

Rate Schedule 46 gives priority to customers seeking longer term service over shorter term service. It is not the intent of the FEU to distinguish between domestic and export customers and it is not the intent of the FEU to change Rate Schedule 46 to give effect to these requirements. Further, under NAFTA, the FEU could not give priority to domestic customers over US customers.

24.1.1 Please discuss the advantages and disadvantages of amending Rate Schedule 46 to provide domestic LNG customers priority access over export LNG customers.

Response:

Please refer to the response to BCUC IR 2.24.1.

25.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-2, BCUC IR 1.47.1, p. 169;

System Resource Needs and Alternatives

In the response to BCUC IR 1.47.1, the FEU state: "Pipeline projects discussed in the 2014 LTRP on pages 95 to 131 are listed in the following table showing which ones are driven by reliability and/or increasing demand."

25.1 Please indicate whether the specified table was submitted. If the table was submitted, please highlight where it is located and if it was not submitted, please provide the table.

Response:

The specified table is on the proceeding record under Exhibit B-2-1, filed as an Erratum to the response to BCUC IR 1.47.1, filed by the FEU on June 26, 2014.

26.0 Reference: ENERGY DEMAND FORECASTING

Exhibit B-1, Application, Appendix E, Tables 2 and 4, pp. E-9 and E-11;

Exhibit B-2, BCUC IR 1.25.3, p. 113; Attachment 25.3; BCUC IR 1.58.1, p. 194;

LNG Demand for Winter Peaking for Core Customers

In Appendix E of the Application, Tables 2 and 4 set out the components of the FEI and FEVI gas supply portfolios for the 2013/14 peak day portfolio.

26.1 Please confirm that the Tilbury and Mt. Hayes LNG resources represent a total of 161 TJ/d and 166 TJ/d respectively, for a total of 327 TJ/d or 25 percent of the combined FEI and FEVI total 2013/14 peak day demand of 1,324 TJ/d. If not confirmed, please explain.

Response:

Confirmed.

26.2 Please confirm that the Market Area Storage component represents 213 TJ/d or 16 percent of the resources to supply the combined FEI and FEVI total 2013/14 peak day demand. If not confirmed, please explain.

Response:

Confirmed.

In response to BCUC IR 1.25.3, the FEU provided Attachment 25.3 with the low, reference and high case forecasts broken down by the categories requested. In each of the three scenarios, the LNG demand for the category "Winter Peaking for core natural gas" shows 1518.0 TJ per year for each year from 2014 through 2033.

In response to BCUC IR 1.58.1 the FEU state that the existing Tilbury and Mt. Hayes facilities "are already fully utilized within the existing Annual Contracting Plans."

26.3 Please confirm that 1,518.0 TJ per year of LNG demand for the core natural gas customers represents approximately 4.6 days of peak day demand for the combined FEI/FEVI gas resource portfolio. If not confirmed, please explain.

Response:

Confirmed.

26.4 Please describe how the FEU arrived at 1518.0 TJ per year as the maximum amount of demand allocated to the "Winter Peaking for core natural gas" category of LNG demand.

Response:

The 1518.0 TJ per year in maximum LNG demand for winter peaking for core natural gas is based on an assumption of two send-out events at Mt. Hayes of 623 TJ and 645 TJ and one send-out event at Tilbury of 250 TJ.

The development of this amount is described in detail in the *Application for Amendment to Rate Schedule 16 Liquefied Natural Gas Sales and Dispensing Service* that was filed with the Commission on September 24, 2012, on pages 35-37.

The FEU state in response to BCUC 1.58.1 that "FEU is currently planning to expand the liquefaction and storage capacity at the Tilbury site", and further that:

> "This may provide an opportunity for the FEU to source additional on-system storage resources, in particular if additional vaporization facilities can be incorporated into the expanded facility. The addition of vaporization to the facility and ability to liquefy at a greater rate than the original peak shaving Tilbury facility could allow FEI to utilize this resource as a market area storage resource during cold weather events. FEI could potentially replace expiring Mist and NWP (Northwest Pipeline) transportation contracts in the future or replace incremental resources that may be required to meet growing load requirements." (Exhibit B-2, BCUC 1.58.1)

26.5 Please provide the incremental annual LNG load requirement for the "Winter Peaking for core natural gas" LNG demand category that would be required to fully replace the expiring Mist and NWP transportation contracts.

Response:

The analysis required to respond to this question is not straightforward because the characteristics of the Mist storage and LNG Peaking resources are different. FEI (on behalf of the FEU) currently contracts for 3,017 TJs of Mist capacity at the maximum injection and withdrawal capacity of 115 TJ per day. The allowable daily withdrawal rate declines as the storage inventory is drawn down, however the high injection rate allows FEI to refill the storage capacity during warmer periods in the winter months if inventory is being used (particularly if it is being drawn down in early winter). In the case of an on-system LNG storage facility, additional vapourisation facilities providing a maximum sendout rate of 115 TJ/d would be required to fully replace the maximum withdrawal capacity from Mist available to meet peak day.

The amount of LNG storage capacity required would depend on how much liquefaction capacity was available. For example, if it is assumed FEI does not require the ability to cycle the storage inventory and only liquefies in the summer months, then FEI would need to hold 3,017 TJ of LNG storage capacity and a minimum of 14 TJ/d (i.e. 3,017 TJs divided by 214 days) of liquefaction capacity to fully replace the Mist resource. However, at this level there may be other resources (such as additional Aitken Creek storage and firm T-South capacity) that can be more cost effective to replace at least part of this requirement. In addition, because the sendout rate would not decline as inventory is drawn down, less storage capacity may be required in combination with other resources. A full portfolio analysis would need to be performed to determine the optimal balance of different resources to meet the requirements of the Annual Contracting Plan if the Mist storage resource was no longer available.

26.5.1 Please provide an updated version of the tables in the live Excel spreadsheet that is Attachment 25.3, including this incremental amount of "Winter Peaking for core natural gas" LNG demand in the "High Case" scenario.

Response:

Further to the response set out in BCUC IR 2.26.5 that explains the challenge in determining the incremental annual LNG load requirement for the "Winter Peaking for core natural gas" given the different characteristics of Mist storage compared with LNG peaking resources, it is not possible to update the tables provided as part of the response to BCUC IR 1.25.3, Attachment 25.3, at this time.

27.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-1, Application, Section 6.3.3, p. 142;

Exhibit B-2, BCUC IR 1.59.1 and 1.59.2, pp. 196-197;

Price Risk Management - Reserves Acquisition

In response to BCUC IR 1.59.1 regarding the strategy of investing in natural gas reserves, the FEU state that: "depending on how future infrastructure is developed, the FEU may not be able to access the supply, or may have reduced access to supply, at fair market prices and/or face price disconnects during periods of high demand."

In response to BCUC IR 1.59.2 the FEU state:

> "By 'acquisition of reserves' the FEU are referring to the potential to acquire part ownership of a specific gas production play which would give it control on how production from that play would be connected to market. Obviously, if the FEU were to consider acquiring reserves in Northeast BC, it would ensure it would contract for either existing or expansion capacity to move the production to Station 2 or some other point where the FEU can move the gas into its service areas."

On page 142 of the Application, the FEU state that: "Hedging strategies are another way of managing regional basis risk and price volatility."

27.1 Alternatively, is it possible to address the risks of potential price disconnects at Station 2 during periods of high demand through the use of financial tools, such as the Sumas-AECO basis swaps that the FEU recently used to address potential price disconnects at the Sumas trading hub? Please discuss.

<u>Response:</u>

Generally the FEU agree that use of financial instruments are a useful tool to mitigate the risk of potential price disconnects and volatility. However, the financial market at Station 2 is not very mature or active and therefore it is not an appropriate tool for that market as price discovery is difficult. The FEU do note that the majority of their physical supply sourced at Station 2 is priced based on the monthly AECO price +/- a negotiated market factor. This market factor will change from period to period based on the market view of changing supply and demand factors, in particular the ability of gas to flow between the BC and Alberta markets. This is in turn impacted by the way infrastructure is developed to connect new production to either Station 2 or the Alberta market.

In the referenced response to BCUC IR 1.59.2, the FEU discuss the option of holding producing reserves and contracting for pipeline capacity (e.g. on Spectra's T-North and T-South systems) to deliver the production to its service territory. This would provide two benefits toward managing price disconnects and volatility. The cost of the gas would be based on production costs rather than market prices and the gas would be physically connected to Station 2. The FEU are considering this as one option to use along with other tools to manage the risk of price disconnects and volatility.

27.2 In order to ensure the strategy of controlling how gas reserves are connected by acquiring the reserves is effective, in addition to acquiring the natural gas reserves, the FEU would also need to make long term commitments to third party transportation capacity to ensure the required expansion capacity is constructed. Please discuss.

Response:

As discussed in the referenced example, if the FEU held production in NE BC, it would also contract for Spectra T-North capacity to move the production to Station 2. It would then move the gas to its service territory using its existing capacity contracted on T-South. If T-North capacity from the location of the production is fully contracted, an expansion of the T-North capacity would be required. Under Spectra's current practices, in order to obtain renewal rights on any existing uncontracted capacity, the FEU would need to contract for a minimum of two years. If expansion capacity is required, a contractual commitment of 10 to 15 years is generally required. This would also be the case if the FEU required incremental T-South capacity to transport the gas to its service territory.

27.3 Is it possible to also accomplish the same objective of controlling how reserves are connected in order to ensure liquidity at trading hubs such at Station 2 by entering into long term firm supply contracts with producers? Please discuss.

Response:

Entering into long term firm supply contracts with producers is another way of helping promote liquidity at Station 2. However, the difference between long term supply contracts and investing in reserves is twofold. Firstly, long term supply contracts are expected to be for a shorter term of up to ten years compared to a reserves arrangement that could be up to thirty years. Secondly, in terms of managing price risk, long term supply contracts would be based on market prices while a reserves investment would be based on production and operating costs. The FEU have considered these longer term tools, as well as shorter term instruments such as hedging, as part of a portfolio approach to managing price risk for customers.

27.4 What percentage of the FEU's overall gas supply portfolio does the FEU believe would need to be supplied by FEU-owned reserves for this strategy to be effective? Please discuss.

Response:

If the FEU were to invest in reserves, it would be considered one component in a portfolio of instruments to manage price risk and ensure supply security for customers. As the FEU are still in the early stages of considering such longer term price risk management tools, it is too early to say what proportion would be effective. The percentage would depend upon the other components in the portfolio, the structure of the long term supply arrangement, as well as gas market conditions.

28.0 Reference: GAS SUPPLY PORTFOLIO PLANNING AND PRICE RISK MANAGEMENT

Exhibit B-2, BCUC IRs 1.60.1 through 1.61.4, pp. 198-202;

Exhibit B-3, BCPSO IR 1.6.4, pp. 18-19;

Price Risk Management - Reserves Acquisition

In response to BCUC IRs 1.60.1.1 through 1.61.4, the FEU refers the reader to the FEU response to BCUC IR 1.60.1. The FEU response to BCUC IR 1.60.1 does not answer the subject IRs. In response to BCUC IR 1.60.1 the FEU state that the FEU plans to file a Price Risk Management Review Report in mid 2014 that will form the basis for a stakeholder consultation process in advance of filing an application for specific action. The FEU state that the FEU believe, if it is necessary to explore the questions related to price risk management activities raised by the BCUC in IRs 1.60.1.1 through 1.61.4, that the Price Risk Management Review Report and the associated stakeholder consultation process would be the proper forum to address these questions.

28.1 Is the long term resource plan the appropriate forum to discuss broad issues regarding price risk management principles and objectives so to inform the planned Price Risk Management Review Report?

Response:

The FEU believe that the review of the Price Risk Management Review Report, rather than the Long Term Resource Plan, is the appropriate forum to discuss price risk management principles and objectives. This is consistent with past practice wherein previous Price Risk Management Plans have been the appropriate place to discuss, and have the Commission review, the price risk management objectives and strategies. The forthcoming Price Risk Management Review Report is an extension of that process.

The next Long Term Resource Plan may be an appropriate forum to discuss, at a high level, price risk management strategies or outcomes resulting from the Price Risk Management Review, which are long term in nature and which impact long term resource planning decisions, such as long term supply contracting or investing in reserves.

28.1.1 If not, please explain why not.

Response:

Please refer to the response to BCUC IR 2.28.1.

In BCUC IR 1.61.1 the FEU was asked to discuss whether investing in gas reserves was an activity that gas distribution utilities typically engage in. In BCUC IR 1.61.1.1 the FEU was asked to provide examples of natural gas distribution utilities that have invested in natural gas reserves and describe the circumstances that lead to such utilities investing in gas reserves. As noted the FEU did not provide answers to these IRs.

28.2 Does the FEU consider that investing in natural gas reserves to be common practice for North American gas distribution utilities? Please discuss.

Response:

While the FEU do not believe that investing in natural gas reserves is currently a common practice for most North American gas distribution utilities, there are a few utilities that the FEU are aware of that have invested in reserves in recent years. Further discussion of this, and the FEU's consideration of investing in reserves in the context of their price risk management objectives and market environment, will be discussed within the Price Risk Management Review Report as discussed in the response to BCUC IR 1.60.1.

28.3 Is FEU aware of any instances in North America of a gas distribution utility obtaining regulatory approval to invest in natural gas reserves?

Response:

The FEU are aware of instances in North America of utilities obtaining regulatory approval to invest in natural gas reserves. These include Northwest Natural Gas Company (NWN), a natural gas distribution utility, and Northwestern Energy (Northwestern), a gas and electric distribution utility. NWN received regulatory approval to invest in reserves from the Oregon Public Utilities Commission under Order No. 11-140 while Northwestern received approval from the Montana Public Service Commission to purchase Devon Energy Production Company and its natural gas production interests in Montana under Order No.7307b.

The FEU are also aware of other utilities that are investigating investing in reserves but have not yet completed any deals or received regulatory approval. These include Florida Power and Light Company[16] and Portland General Electric[17].

More details will be provided in the FEU's Price Risk Management Review Report. Please also refer to the responses to BCUC IRs 2.28.2 and 1.60.1.

28.3.1 If so, for each of these instances please provide the name of the utility and the regulatory order approving the investment.

Response:

Please refer to the response to BCUC IR 2.28.3.

In response to BCPSO IR 1.6.4, the FEU confirms that if it were to invest in natural gas reserves, the FEU would expect to earn a return on that investment and that return would be recovered through customer rates.

28.4 Please discuss whether the FEU would recover the investment from customers by adding the reserve expenditures to rate base.

Response:

If the FEU were to invest in natural gas reserves, the FEU would expect to recover the investment from customers by adding the expenditures to its rate base.

[16] http://www.naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal

[17] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf, page 98.

29.0 Reference: ENERGY EFFICIENCY AND CONSERVATION

Exhibit B-1, Application, Appendix C-2, pp. 11-36;

FEU PBR Application, Exhibit B-11, BCPSO IRs 1.221.1.3, 1.222.1;

Exhibit B-9, BCMEU IR 1.8.1; Final Submission, p. 127;

Exhibit B-24, BCUC IR 2.369.2, p. 480

The FEU average customer incentives are 58 percent of program costs, compared to 76 percent industry average found in a 2009 ACEEE benchmarking study. (PBR Application, Exhibit B-24, BCUC 2.369.2)

FEI state in the PBR Application (Exhibit B-11, BCUC 1.221.1.3, 1.222.1): "Since the 2010 CPR did not include non-energy benefits and the value of emission reductions, it likely does understate the amount of EEC which provides a societal benefit to BC" and "The FEU cannot determine a way to provide a meaningful potential energy saving comparison between forecasted natural gas savings in the 2010 CPR and the forecasted achievable potential savings from the EEC Plan 2014-2018."

FEI state in the PBR Application that it incorrectly included a statement that Energy Efficiency and Conservation (EEC) plans are designed to implement all cost effective EEC (Exhibit B-9, COPE 1.8.1), and in the Final Submission (p. 137) "The currently approved [EEC] amortization period of 10 years results in an equity return of $37.1 million."

29.1 Please confirm that the FEU adopts all EEC evidence submitted in the PBR Application (in particular benchmarking data) as evidence in this proceeding.

<u>Response:</u>

The FEU adopt the "EEC Evidence" from the PBR proceeding as defined below.

The FEU take this opportunity to comment on some of the legal and practical issues that this type of information request raises.

First, the record of a tribunal proceeding needs to be kept clear. The concept of "all EEC evidence submitted in the PBR Application" is open to interpretation and adopting it without specificity would introduce ambiguity as to what is on the record. For this reason, as set out below, the FEU first define the "EEC evidence", and then confirm the adoption of this evidence as "evidence in this proceeding".

Second, by adopting the EEC evidence (as defined below), the FEU:

(a) do not agree that all of the evidence adopted from the PBR proceeding is relevant to (or within the scope of) this proceeding; and

(b) do not agree that all of the issues raised in the PBR proceeding relating to EEC are within the scope of this proceeding.

Third, the Commission Panel in this proceeding should be mindful of the issues and determinations that are to be made regarding EEC issues in the PBR proceeding. The LTRP is not the place to re-try issues raised in the PBR. The issues relating to these two proceedings should be kept distinct, and the fact that the FEU are adopting the EEC evidence from the PBR proceeding in this proceeding is not agreement on the part of the FEU that the issues from the two proceedings overlap.

The fourth point is that the FEU suggest that the preferred approach to the adoption of evidence from other proceedings is for the Commission to file the specific exhibits that it is interested in, and to then ask the FEU whether they adopt those exhibits for the purposes of the current proceeding. The FEU suggest that this is a much more practical and efficient way to have evidence from other proceeding adopted because:

(a) it avoids burdening the record with an unnecessary dump of information that no one may ever look at;

(b) it ensures that the record is clearly identified; and

(c) it ensures procedural fairness by putting the public utility on notice as to the specific items of evidence from the other proceeding that the Commission is interested in for the current proceeding.

The FEU are concerned about having a significant body of additional evidence adopted in the proceeding, in the second round of IRs, without having any indication from the Commission about what specific items of evidence the Commission is interested in for the purposes of this proceeding. The FEU submit that this concern is significantly mitigated by the Commission adopting the preferred approach to the adoption of evidence described above.

The FEU have identified the following as the “EEC Evidence” from the PBR proceeding:

(a) Exhibit B-1-1 Appendix I, EEC_DSM, with the addition of Exhibit B-15, Evidentiary Update, pgs. 184-5, and Exhibit B-43, Amendment to EEC Programs

(b) Exhibit B-7, BCSEA Round 1 IRs: 1-16

(c) Exhibit B-8, CEC Round 1 IRs: 79-80

(d) Exhibit B-9, COPE Round 1 IRs: 8 series

(e) Exhibit B-11, BCUC Round 1 IRs: 178, 207-241

(f) Exhibit B-13, COC Round 1 IRs: 2 series

(g) Exhibit B-19, COC Round 2 IRs, 9 series

(h) Exhibit B-20, BCSEA Round 2 IRs: 1-6

(i) Exhibit B-23, CEC Round 2 IRs: 89-94

(j) Exhibit B-24, BCUC Round 2 IRs: 313, 363-385

(collectively, the "EEC Evidence")

Subject to the caveats set out above regarding the scope of the LTRP and the relevance of this evidence, the FEU adopt the EEC Evidence as evidence in this proceeding.

If there are specific items of evidence the Commission is interested in for the purposes of this proceeding, then the FEU ask that the Commission provide notice of these items and the related issues in advance of final submissions.

Finally, the FEU have not taken the step of actually filing all of the EEC Evidence (and was not asked to do so in any event). The FEU trust that since these exhibits are available on the Commission's website for the PBR proceeding, and since the EEC Evidence adopted herein has been specifically defined, there is no need to take the additional step of actually filing the adopted evidence.

29.2 Please provide updated graphs on pages 11, 20, 28 and 36 of the CPR to include the FEU LTRP actual/forecast EEC results. Please also provide the underlying data.

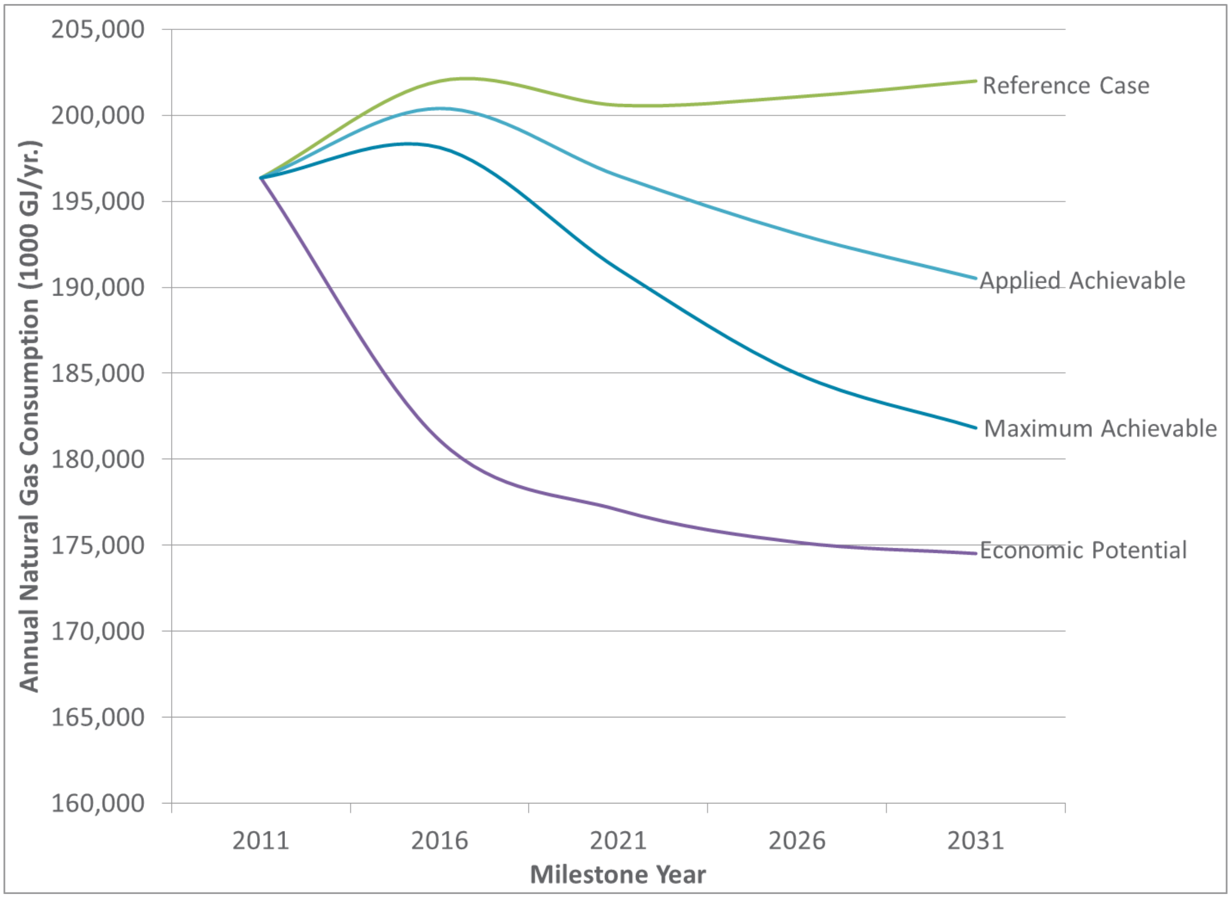
Response:

Please find updated graphs corresponding to those found on pages 11, 20, 28 and 36 of the CPR to include the FEU LTRP forecast EEC results. The underlying data for these graphs is provided in a table preceding each graph.

Please note that for the purposes of the LTRP forecast, 2011 is the base year built on actual demand data. All other data in the following figures is based on forecast demand and forecast energy savings. Please also note that as described in Section 4.2.2.1 of the 2014 LTRP (Exhibit B-1), the "Most-likely" and "Aggressive" scenarios from the 2010 CPR were not re-created. Rather, for the purposes of the 2014 LTRP, EEC savings over the 20-year planning horizon were estimated to develop an overall energy savings estimate. This estimation acknowledges that energy savings are likely less than the economic potential. Estimated savings were adjusted by an analysis that determined a range that bounds the estimated achievable measure savings over the long term. Both the planned and achieved savings over the history of EEC programs were examined on a program by program basis to understand and apply this range of savings to the cost effective measures used to estimate long term savings in the LTRP. For the purposes of the LTRP, these range limits were labeled “maximum” and “applied”, which are portrayed in the following graphs.

Summary of Forecast Results for the Total FortisBC Service Area, Annual Natural Gas Consumption and Savings, by Milestone Year and Forecast Scenario, 3 Sectors

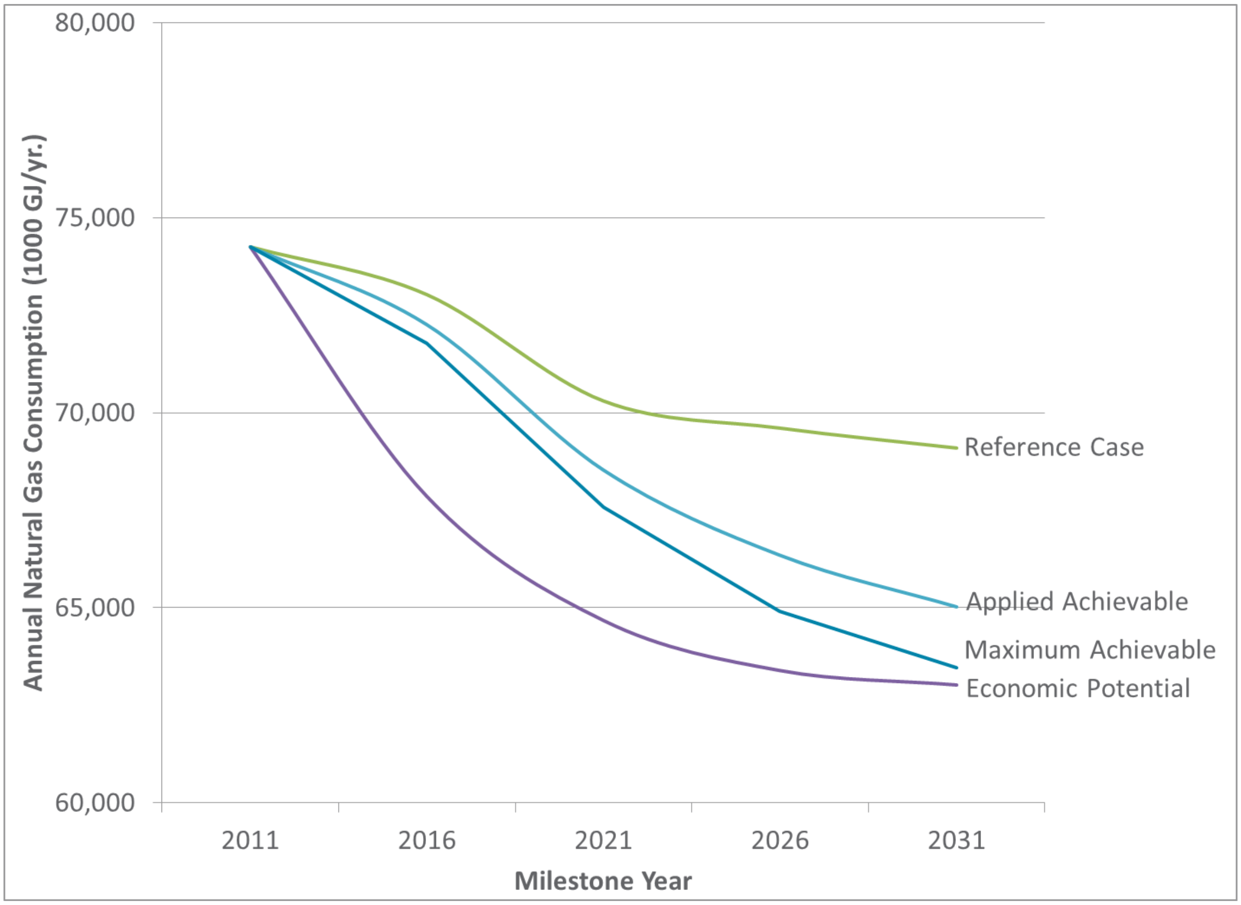
Milestone Year	Annual Consumption, All 3 Sectors (1000 GJ/yr.)				Potential Annual Savings (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Applied	Maximum		Applied	Maximum
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2011	196,361						
2016	201,993	181,108	200,404	198,128	20,884	1,588	3,865
2021	200,583	177,058	196,485	191,057	23,525	4,098	9,526
2026	201,072	175,175	193,113	184,984	25,897	7,959	16,088
2031	201,993	174,527	190,522	181,825	27,466	11,471	20,168



Summary of Forecast Results – Annual Natural Gas Consumption, Residential Sector (GJ/yr)

Milestone Year	Annual Consumption (1000 GJ/yr.)				Potential Annual Savings (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Applied	Maximum		Applied	Maximum
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2011	74,252						
2016	73,027	67,854	72,256	71,785	5,174	771	1,242
2021	70,301	64,674	68,529	67,576	5,627	1,772	2,725
2026	69,605	63,391	66,344	64,902	6,214	3,261	4,703
2031	69,095	63,022	65,023	63,460	6,073	4,072	5,635

1



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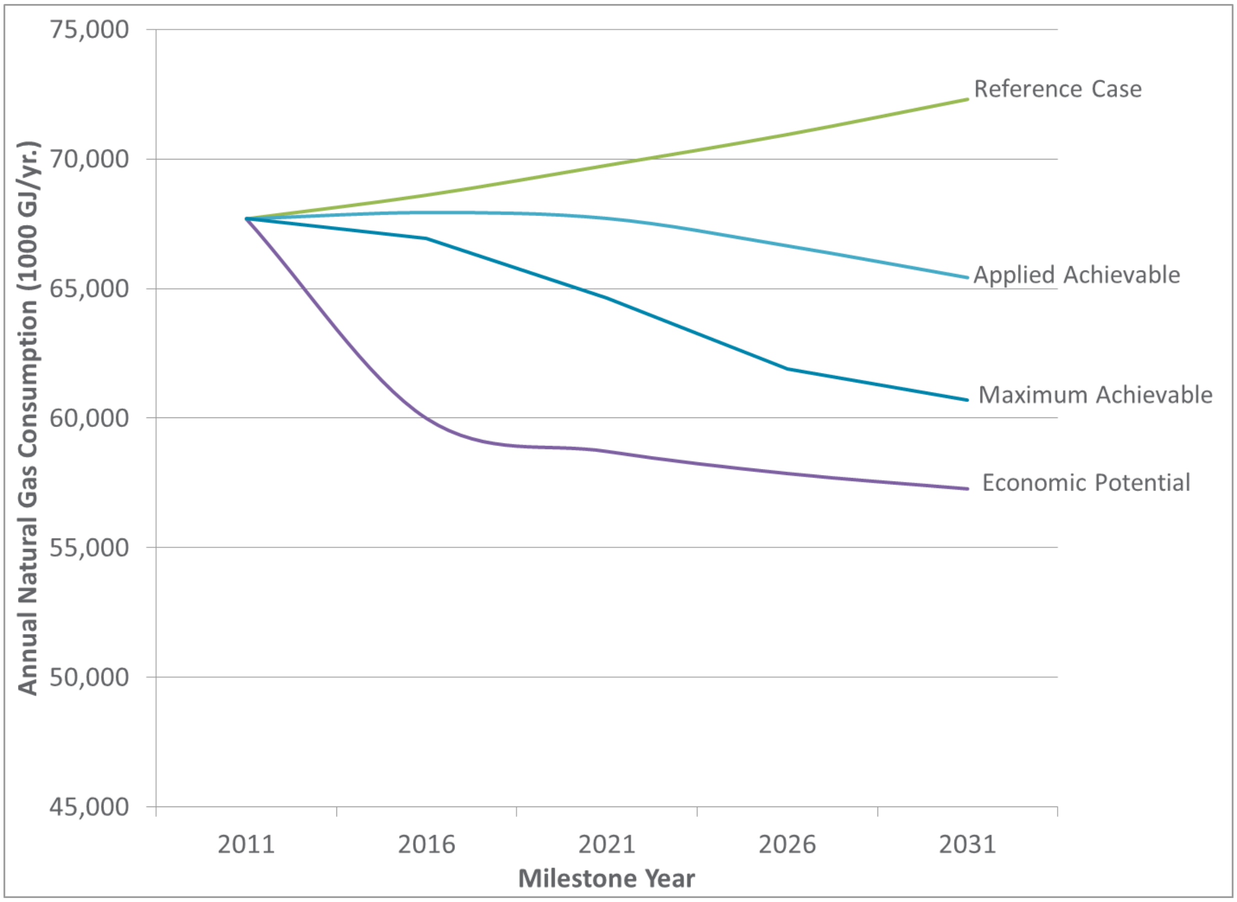
Summary of Forecast Results – Annual Natural Gas Consumption, Commercial Sector (GJ/yr)

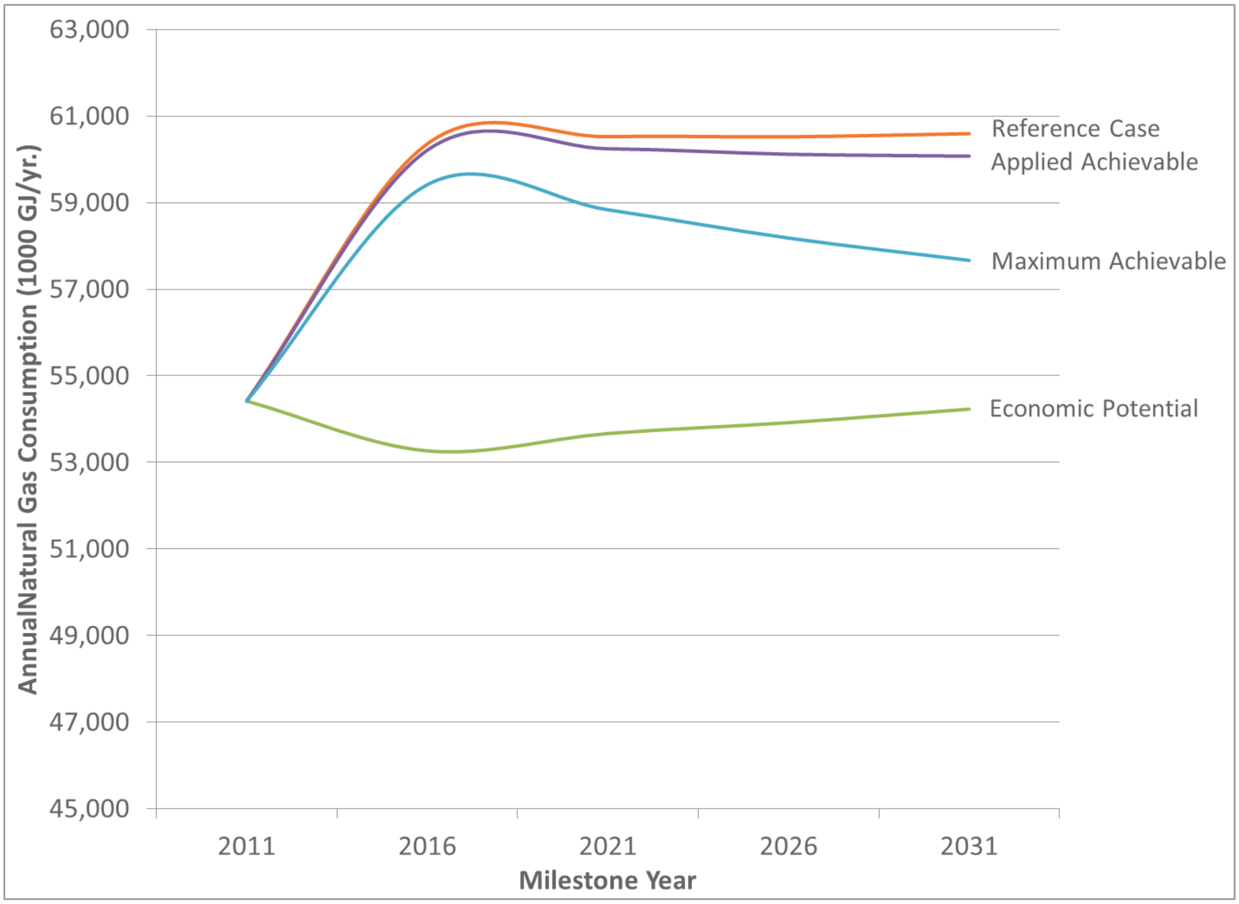
Milestone Year	Annual Consumption (1000 GJ/yr.)				Potential Annual Savings (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Applied	Maximum		Applied	Maximum
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2011	67,691						
2016	68,608	59,988	67,935	66,928	8,620	673	1,680
2021	69,757	58,716	67,710	64,645	11,041	2,047	5,111
2026	70,946	57,865	66,650	61,899	13,080	4,295	9,046
2031	72,304	57,273	65,425	60,698	15,031	6,879	11,606

1 

Summary of Forecast Results – Annual Natural Gas Purchases, Industrial Sector (GJ/yr)

Milestone Year	Annual Consumption (1000 GJ/yr.)				Potential Annual Savings (1000 GJ/yr.)		
	Reference Case	Economic Potential	Achievable Potential		Economic Potential	Achievable Potential	
			Applied	Maximum		Applied	Maximum
	(A)	(B)	(C)	(D)	(A-B)	(A-C)	(A-D)
2011	54,419						
2016	60,358	53,267	60,213	59,414	7,091	144	943
2021	60,525	53,668	60,246	58,835	6,857	279	1,690
2026	60,521	53,919	60,118	58,183	6,602	403	2,338
2031	60,594	54,232	60,074	57,667	6,362	520	2,927

2



29.2.1 Please comment on any significant differences between actual/forecast EEC results and EEC identified as cost effective in the 2010 CPR.

Response:

The FEU would first like to point out that the 2010 CPR and the 2014 LTRP are very different sets of analyses and submit that such a comparison is of limited use for the following reasons:

- The CPR was developed as a planning document for the purposes of developing actual DSM activity, while the LTRP, in this context, is a planning document for the purpose of estimating long range energy savings from demand-side measures. Although the base data is the same, their purposes and objectives are quite different;
- The CPR was re-purposed for use in the End-Use Annual Demand Forecast, which was then used as a basis for estimating long term energy savings from demand-side

activities. This included updating the base data with new information including updated actual year-end consumption, refining the segmentation of some commercial and industrial customers and utilizing improved knowledge from the actual implementation of EEC activity since the completion of the CPR.

With this in mind, there are noticeable differences between the original 2010 exhibits and the current versions. The following observations are presented for the individual sectors and then for the summary exhibit.

Residential:

- The decline in the reference case is larger than in the original 2010 table. The observed decline in the current table is consistent with a decline of approximately 1 percent per year in UPC;
- Economic potential is similar to the former result – as a percentage of reference case it is almost identical; and
- Achievable potential is also in a similar range to the former result. As a percentage of reference case, “Maximum” is nearly identical to the former “Aggressive” scenario. As a percentage of reference case, “Applied” is somewhat larger than the former “Most Likely” scenario.

Commercial:

- The commercial sector has larger overall consumption in the current model, because of the time and effort FEU devoted to preparing customer data for the model. The reference case numbers are therefore larger than in the old exhibits;
- Economic potential is larger than in the former model, but as a percentage of reference case it is about the same;
- “Maximum” is a larger percentage of reference case than the old “Aggressive” scenario;
- “Applied” is a larger percentage of reference case than “Most Likely” was; and
- Maximum and Applied are based on the FEUs’ real-world program results and plans. It appears that the 2010 estimates of what was cost-effective in the commercial sector somewhat underestimated what the utilities’ EEC staff could achieve.

Industrial:

- The industrial sector has much larger overall consumption in the current model, again because of the time and effort the FEU devoted to preparing customer data for the model. The reference case numbers are therefore much larger than in the old exhibits;

- Economic potential is also much larger, though it is slightly smaller as a percentage of the reference case;
- “Maximum” is somewhat larger in absolute numbers than the old “Aggressive” scenario, but is a much smaller percentage of the reference case;
- “Applied” is smaller in both absolute terms and as a percentage of reference case than the old “Most Likely” scenario; and
- Maximum and Applied are based on the FEUs’ real-world program results and plans. It appears that the 2010 estimates of what was cost-effective in the industrial sector somewhat overestimated what could realistically be achieved in working with actual industrial customers.

Overall:

- The reference case numbers in the overall exhibit are larger, with the biggest difference coming from the industrial sector;
- Economic, applied, and maximum are all larger by the end of the period than they were in the old exhibit; and
- Applied is somewhat smaller at the beginning of the forecast period than the old “Most Likely” scenario was, but is larger by the end of the forecast period. Most of the initial decrease comes from the difference in the industrial sector.

29.3 Does the FEU consider that EEC Evaluation Measurement and Variance results should be subject to regulatory review? If not, please explain why not. If yes, please explain if regulatory efficiency would be enhanced if Evaluation Measurement and Variance results were subject to separate review on a periodic basis rather than being reviewed at the same time as EEC funding applications.

Response:

It should be noted that the correct term to describe the Companies’ evaluation activity is “Evaluation, Measurement and *Verification”* as is common industry practice (also known as “EM&V”), not “Evaluation Measurement and *Variance*.”

It is the Companies’ view that this question is not relevant to the Long Term Resource Plan proceeding, which deals with how the FEU will cost effectively meet future demand and reliability requirements for customers over the next 20 years. While the LTRP considers the potential impact of EEC on future demand, the fine details of EEC programs and the associated EM&V activity are not a matter for consideration in the LTRP. Rather, these activities are reviewed in Revenue Requirements proceedings.

That said, the FEU point out the Companies' EM&V activity is already subject to Regulatory review and do not need to be subject to additional regulatory review. The FEU's EM&V activity is reported on in the Companies' EEC Annual Reports, which is an annual regulatory compliance filing. Evaluation report summaries are provided, details of evaluation activity are available for more detailed review upon request, and the FEU is available and open to such review. Further, staff responsible for EM&V activities have separate lines of reporting from those of staff responsible for program development and implementation. The FEU follow International Performance Measurement and Verification Protocol as described in Section 3.5 of the FEUs' EM&V Framework. Third-party consultants conduct FEUs' EM&V impact evaluations and typically provide technical assumptions for energy savings estimates. Please refer to the responses to FEI 2014-2018 PBR BCUC IRs 1.214.1, 1.214.2, 1.214.2.1 and 1.214.3, 2.371.1, 2.371.1.1, 2.371.1.2 and 2.371.1.3 (adopted in this proceeding in the response to BCUC IR 2.29.1. As noted in the response to BCUC IR 2.29.1, these IRs have not been attached). Any additional formal regulatory process contemplated by the Commission will simply increase costs to the EEC portfolio and decrease the portfolio cost effectiveness without adding value.

Attachment 8.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 8.2.2

REFER TO LIVE SPREADSHEET MODEL

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