Diane Roy
Director, Regulatory Affairs

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

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

June 19, 2014

Via Email
Original via Mail

British Columbia Public Interest Advocacy Centre
Suite 209 – 1090 West Pender Street
Vancouver, B.C. V6E 2N7

Attention: Ms. Tannis Braithwaite, Acting Executive Director

Dear Ms. Braithwaite:

Re: FortisBC Energy Utilities[1] (FEU)

2014 Long Term Resource Plan (the Application)

Response to the British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Pensioners' and Seniors' Organization *et al* (BCPSO) Information Request (IR) No. 1

On March 25, 2014, the FEU filed the Application as referenced above. In accordance with the British Columbia Utilities Commission Order G-56-14 setting out the Regulatory Timetable for review of the Application, the FEU respectfully submit the attached response to BCPSO IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

on behalf of the FORTISBC UTILITIES

Original signed:

Diane Roy

Attachments

cc: Commission Secretary
Registered Parties (e-mail only)

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

1.0 Reference: Exhibit B-1, page 12, Planning Environment

The referenced page states:

Presently, the natural gas supply outlook looks different than it did even a few years ago. Horizontal drilling and hydraulic fracturing technologies have unlocked the potential of North America's vast shale gas deposits, which has led to a significant growth in supply and lower commodity prices than in recent years.

1.1 Given that there have been some questions raised recently with respect to (i) the environmental consequences of fracking, (ii) the relatively shorter production profiles of fracked deposits versus conventional gas deposits, (iii) the large number of new wells required to maintain even the current level of supplies from fracking over a 10 or 20 year term, (iv) the regulatory/judicial suspension or cessation of fracking activities in some jurisdictions, and (v) the growing opposition of the public and environmental groups to fracking, what assumptions regarding fracked supplies are explicitly or implicitly contained in the FEU's LTRP?

Response:

Section 3.3.4 of the 2014 LTRP describes four alternative future scenarios under which the FEU have examined a range of annual demand forecasts. In these scenarios, the FEU examine alternative futures under which natural gas supplies become constrained or remain abundant. The degree to which natural gas supplies may or may not be impacted by government regulation, public perception or operational issues associated with the process of hydraulic fracturing is an example of an issue that could cause natural gas supplies to become more or less constrained. The degree to which natural gas supplies are more or less constrained is ultimately reflected in the price of natural gas. In our analysis of future annual demand, more constrained supplies are modelled using a higher gas price than more abundant supplies. In this way, supply constraints that might occur over the planning horizon related to issues or perceptions regarding hydraulic fracturing, or related to any other issue that constrains supply, are implicitly included in the annual demand forecast analysis.

There are a wide range of issues that could act to constrain or free up natural gas supplies. The FEU have not attempted to explicitly state which of these is more or less likely to happen over the planning period, but has recognized in its 2014 LTRP examination of potential future demand, that these issues can affect gas supplies and gas supply prices.

1.2 How would the FEU's proposed LTRP be impacted, if at all, by a scenario in which supplies from fracking were completely suspended and discontinued during the LTRP period, especially at or near the beginning of the period?

Response:

The FEU believe that this is an unrealistic scenario; however, if a situation occurred where the practice of hydraulic fracturing was suspended, we can assume a significant portion of unconventional reserves will decrease in the near term. However, because unconventional plays include other new technologies such as horizontal and deep water drilling, the potential amount of supply that could be lost due to a suspension of hydraulic fracturing cannot be accurately estimated at this time. According to a recent report from the National Energy Board, "The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta" an estimate of the ultimate potential for marketable natural gas in BC had conventional gas amounting to 13% of production while unconventional amounted to the remaining 87% (see figure below).[1]

Estimate of Ultimate Potential for Marketable Natural Gas in the WCSB – Year End 2012

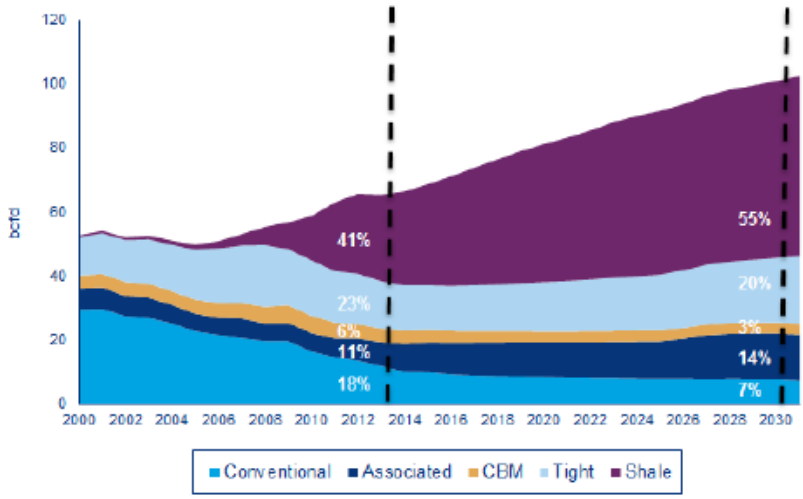
Area		Billion Cubic Metres			Trillion Cubic Feet		
		Ultimate Potential	Cumulative Production	Remaining	Ultimate Potential	Cumulative Production	Remaining
Alberta	Conventional	6,276	4,425	6,994	222	156	247
	Unconventional						
	CBM	*101*			*4*		
	Montney	*5,042*			*178*		
	Unconventional Total	5,143			182		
	Total	**11,419**			**403**		
British Columbia	Conventional	1,462	695	10,642	52	25	376
	Unconventional						
	Horn River Basin	*2,198*			*78*		
	Montney	*7,677*			*271*		
	Unconventional Total	9,875			349		
	Total	**11,337**			**400**		
Saskatchewan	Conventional	297	211	86	10	7	3
Southern Territories	Conventional	196	20	176	7	1	6
WCSB Total		**23,249**	**5,351**	**17,898**	**821**	**189**	**632**

Source: NEB Table 4 in "The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note"

[1] *The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta - Energy Briefing Note* – http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.pdf

This is consistent with production in the United States, as shown in the below graph, where unconventional production accounted for 81% of U.S. production in 2013.

United States Production by Type[2]



The above graph also shows the conventional production number continues to decrease as the unconventional plays, which include using hydraulic fracturing and horizontal drilling, are more economical.

The North American natural gas market as a whole would be significantly impacted if a suspension of hydraulic fracturing occurred given the amount of natural gas production involved. It would be difficult or impossible to replace all of the discontinued production and so there would likely be constrained supplies and the need to develop LNG import projects, as was considered in the market environment prior to the shale gas boom. Therefore, there would also be significantly higher natural gas prices.

The FEU believe that such a scenario is unrealistic and have not contemplated a full suspension of hydraulic fracturing in their 2014 LTRP. Hydraulic fracturing has been used for decades and provides gas supply that is a critical component of the energy mix in North America. Although there have been questions raised about the environmental impact of the use of hydraulic fracturing technology, the US Environmental Protection Agency has been monitoring the use of this technique for a considerable period of time. In their studies they have found no proven

[2] Wood Mackenzie, North America Natural Gas Long-Term View, June 2013. CBM, coal bed methane, is natural gas extracted from coal bed formations. Tight gas is a form of unconventional supply that is extracted from rock and sand formations. Associated gas supply is extracted during petroleum (oil) production. Shale gas is natural gas produced from the fractures, pore spaces, and physical matrix of rock shale.

cases that the hydraulic fracturing process has caused contamination of ground water, which is the chief concern raised by the use of this production process.

The constrained gas supply scenario developed in the LTRP included the possibility of some gas supplies being reduced, however not to the degree described above. If production costs face additional pressure regarding environmental requirements or alternatives to reducing water usage, then some production may be curtailed and natural gas prices may go up. This more moderate possibility is considered under the constrained scenarios included in the Long Term Resource Plan as discussed in BCPSO IR Response 1.1.1.

1.3 Please provide FEU's estimate as to the impact on North American physical gas supplies and commodity prices of a complete suspension of fracking in North America at or near the beginning of the LTRP Planning Period?

Response:

Please refer to the responses to BCPSO IRs 1.1.1 and 1.1.2.

2.0 Reference: Exhibit B-1, page ES-3, Energy Demand Forecasting

The referenced page states:

As directed by the BCUC, the FEU have developed a new approach to modelling the 20-year horizon which will provide a more insightful forecast of the long term range of potential demand.

This approach uses a number of future scenarios that allow the FEU to examine changes in natural gas demand at the end-use level. A reference case is based on the 2010 Conservation Potential Review, recent customer additions data and market research, while four additional future scenarios examine a range of alternative demand scenarios. These scenarios are based on key uncertainties—such as an abundance or limitation of natural gas supply, or centralized versus decentralized energy delivery systems—that may unfold over the planning horizon and incorporate varying assumptions for gas commodity and carbon prices, the policy environment, and the development of renewable and district energy systems.

The FEU's end-use annual demand forecast methodology captures and analyses the impact of shifting trends in customer behaviour, energy choice and energy consumption that the Utilities have begun to observe. The new, end-use annual demand forecasting approach is applied to the range of potential future demand scenarios (shown in Figure ES-1) so that the Utilities can ensure that they have the appropriate resources in place to meet customer needs across the range of future demand scenarios. It is important to note that the end-use forecasting methodology does not assign any probabilistic outcomes to the future scenarios—the scenarios are considered together to provide a reasonable range of potential future demand that the FEU will need to serve over the 20-year planning horizon. [Emphasis added]

2.1 Is it correct to interpret the "Reference" scenarios as either "most likely" or "expected" scenarios? If not, does FEI have a best estimate for any of the forecasted demands?

Response:

The FEU do not consider the reference case to be any more likely than any other annual demand scenario. As cited in the preamble, the FEU have been careful and consistent in pointing out that none of the results should be considered more or less likely than any other. The scenarios (including the reference case) are only intended to put reasonable boundaries on future annual demand.

The original reference case scenario was based on the reference case used in the 2010 CPR, but updated to start with a newer base year. The CPR reference case was created based on the

best information available to the consultants about how end use energy consumption would evolve over the 20-year study period based on current trends. Energy efficiency is not assumed to remain static, but instead evolves according to best estimates of natural conservation.

2.2 Has a potential serious decline in availability of gas from fracking operations been explicitly taken into account in any of the scenarios? If so, please elaborate; if not, why not?

Response:

Please refer to the response to BCPSO IR 1.1.1 for a discussion of how hydraulic fracturing is an example of how gas supplies could become more or less constrained and how that has been modelled in annual demand forecasting.

With regard to the practice of hydraulic fracturing, the level of natural gas production in British Columbia is tracked and provided by the BC Ministry of Natural Gas Development. According to the Ministry, conventional production (which excludes the use of hydraulic fracturing) is estimated at 33% of the daily BC production. This conventional production number continues to decrease as the unconventional plays, which include using hydraulic fracturing and horizontal drilling, are more economical.

If hydraulic fracturing was suspended then we can assume a portion of the amount under the unconventional reserves will decrease in the short term. However, because unconventional plays include other new technologies such as horizontal and deep water drilling, the potential amount of supply that could be lost due to a suspension of hydraulic fracturing cannot be accurately estimated at this time. FEU and the North American natural gas market as a whole would be impacted if such a suspension occurs. One impact that the industry would face would be natural gas prices increasing to levels that make conventional, as well as other new "unconventional" drilling technologies and, production more economical again. This could in turn reduce natural gas prices again (supply and demand).

2.3 Does the FEU agree that by not assigning probabilities to any of the scenarios, it makes the estimation of confidence intervals for any and all of the forecasts?

Response:

The question appears incomplete.

However as mentioned in the preamble it was never the intention of the end use annual demand methodology nor is the capability contained in the end use methodology to assign probabilities or ranking. The FEU would have no basis for assigning such probabilities or ranking the scenarios, nor any confidence that a ranking or assignment of probabilities would be accurate, reliable, and valid. Without probabilities, confidence intervals cannot be estimated. The end use method was designed to provide a range of possible future outcomes, which the FEU believe is more useful than assigning arbitrary probabilities to any one scenario.

2.4 Is the FEU able to provide its best guess or estimate with respect to an ordinal ranking of the scenarios, i.e., from most likely to least likely, for any of the forecasted variables? If so, please provide such an ordinal ranking where the FEU is able to do so.

Response:

Please refer to the response to BCPSO IR 1.2.3.

2.5 Please confirm that the new forecasting methodology cannot be assessed by some usual metrics applied to forecasting methodology, such as accuracy, symmetry, stability, sustainability, and simplicity. If unable to so confirm, please explain.

Response:

Not confirmed. Please refer to the response to BCUC IR 1.23.1.

2.6 Does the FEU agree that where long term infrastructure needs and physical commodity procurement are considered, the utility must ensure that sufficient

capacity and commodity must be assured due to the impact of not being able to meet demands being greater than the impact of having some level of surplus capacity and commodity available?

Response:

Yes. Where long term infrastructure needs and physical commodity procurement are considered, the FEU are of the view that they must ensure that sufficient capacity and commodity is available to meet demand because customers rely on the FEU to provide safe, reliable and cost-effective natural gas services. This means that some reasonable level of excess system capacity and commodity is preferable to a situation where customer demand cannot be met.

The FEU evaluate the long term infrastructure needs and considerations for physical commodity procurement on an ongoing basis. The FEU plan to meet long term infrastructure needs through detailed analysis of FEU's natural gas infrastructure to meet current and forecast peak demand (as discussed in Section 5.1 of the LTRP) while ensuring that planned improvements optimize operation of the system as a whole (as discussed in Section 5.2 of the LTRP). In the 2014 LTRP, reinforcement options that are under consideration to meet the FEU's capacity needs have also been integrated with the system upgrade requirements identified through system sustainment planning.

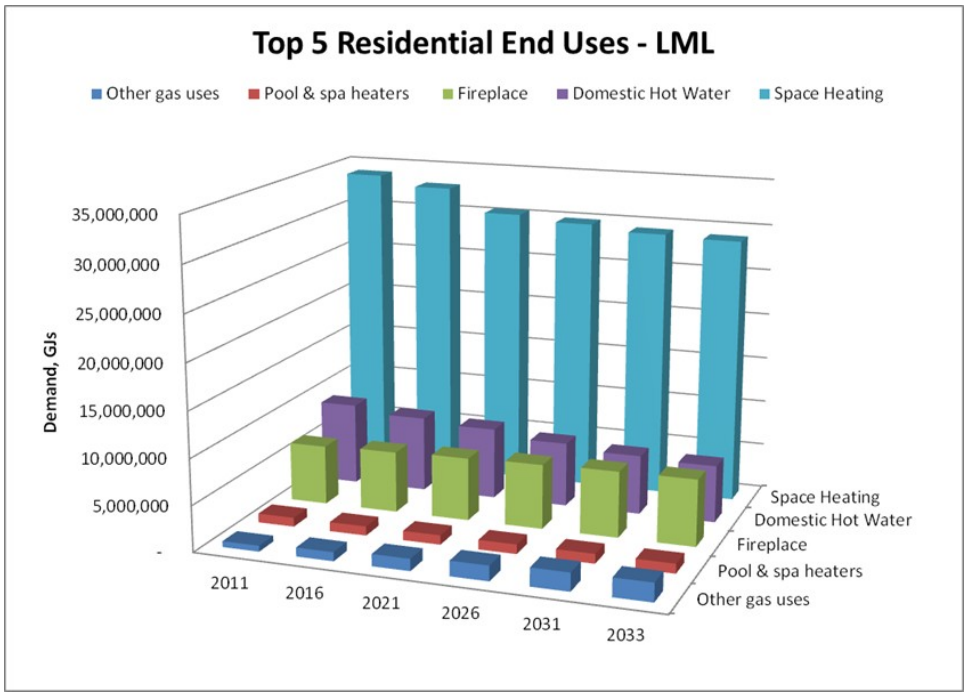
Separately, the FEU meet physical commodity procurement needs through gas supply portfolio planning and price risk management strategies that are identified in Section 6 of the LTRP. Approval for the FEU's gas supply portfolio and price risk management activities is sought through applications to the BCUC that are separate and distinct from the LTRP process. However, unlike the assurance that the FEU are able to provide that sufficient system capacity will be available over the long-term, commodity availability can only be assured through short-term procurement arrangements. Although there is a mismatch in the level of long-term commitment that supports infrastructure needs and physical commodity procurement, the risk that commodity supply will not be available in sufficient volume over the long-run is relatively low at this time.

2.7 Please elaborate as to how the new forecasting methodology provides more insightful results.

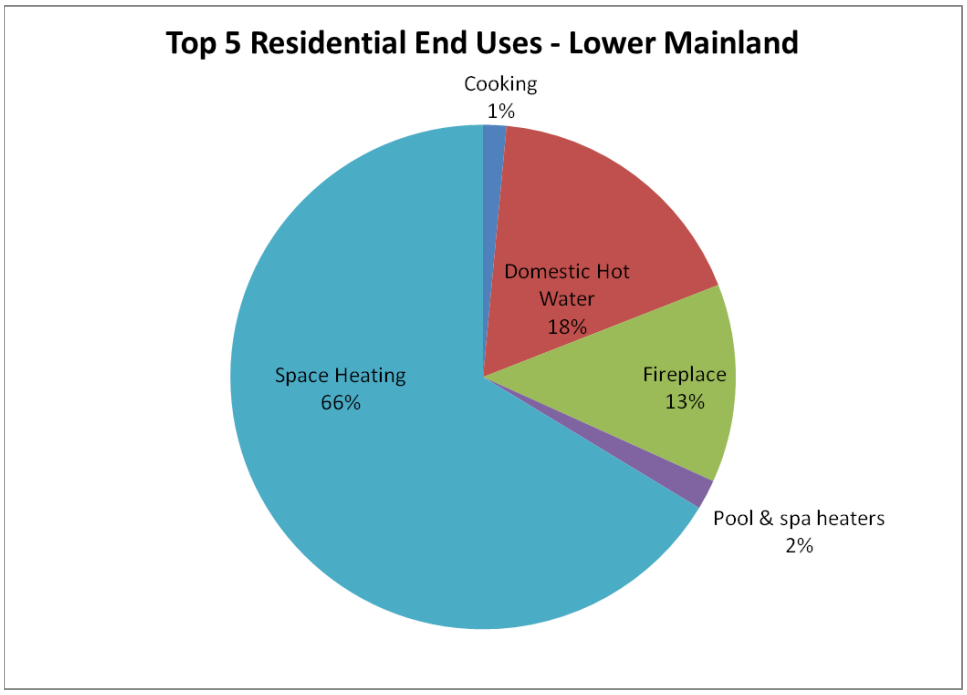
Response:

The end-use forecast methodology allows the Utilities to forecast gas usage by end-use, sector, rate class, new customers, existing customers and the vintage of housing stock. The figures below provide several examples of the insight that can be gleaned from the end use forecast. Similar insight cannot be drawn from the traditional method.

The first chart is an example using the Reference Case forecast for five residential end-uses. For residential customers, natural gas for fireplace demand is increasing while demand for space heating and domestic hot water is decreasing. In the Reference Case, natural gas for fireplace demand is set to overtake the demand from domestic hot water, which currently ranks second in residential end-uses. This trend is delayed in Scenario C, but accelerated in the other scenarios.



Some additional insights follow:



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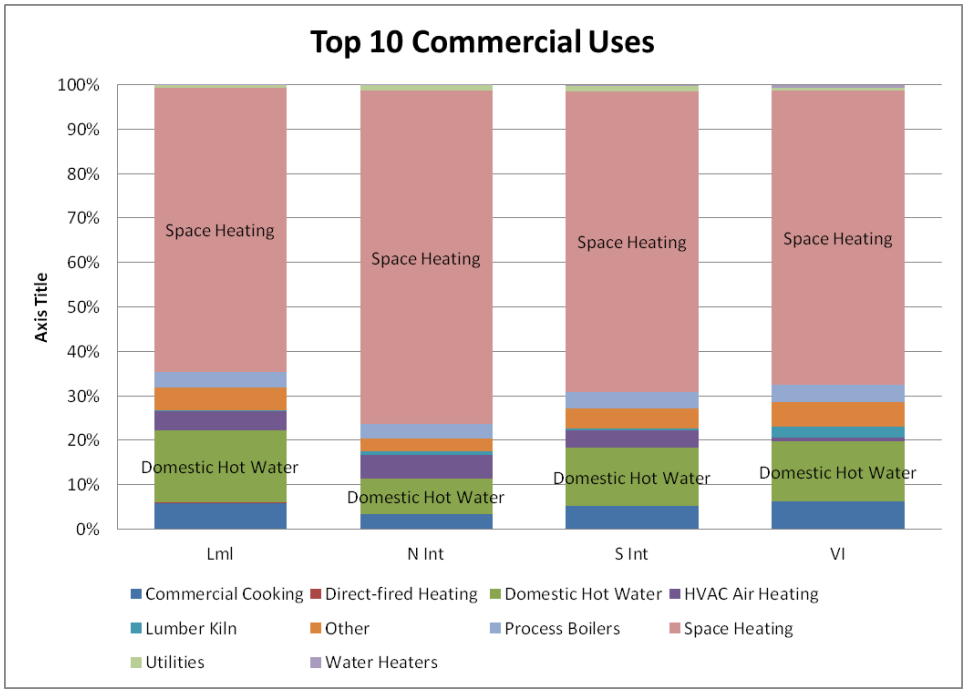
2 • Space heating represents 2/3 of the LML residential load



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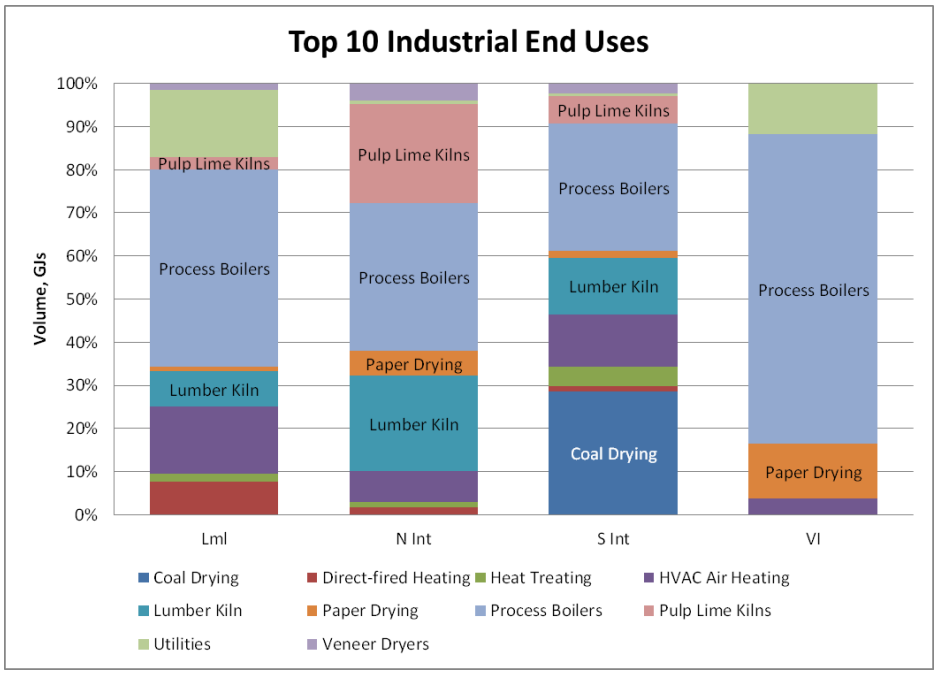
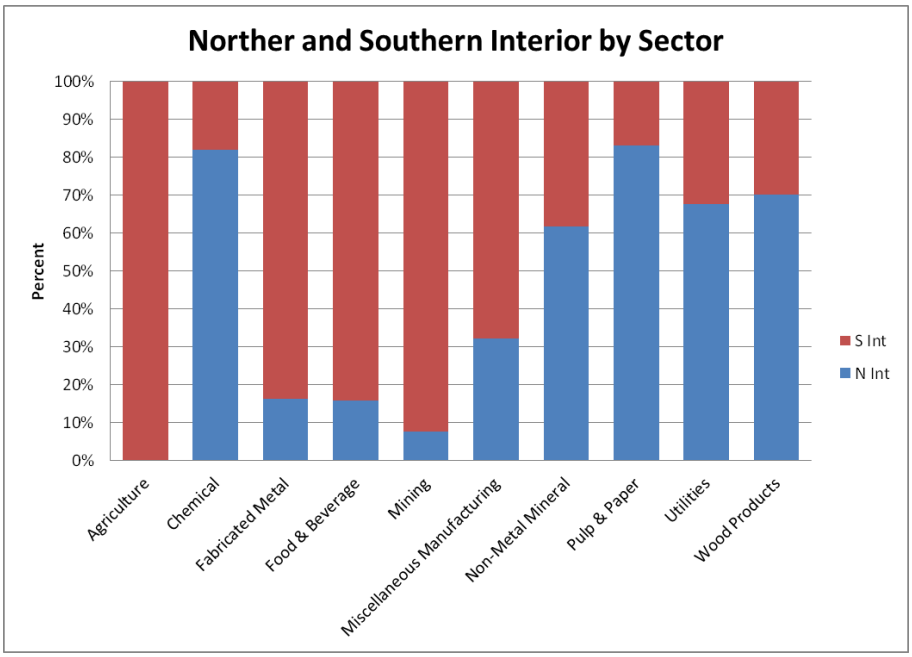
4 • Space heating dominates commercial load.

5 • Domestic hot water is significant in all regions



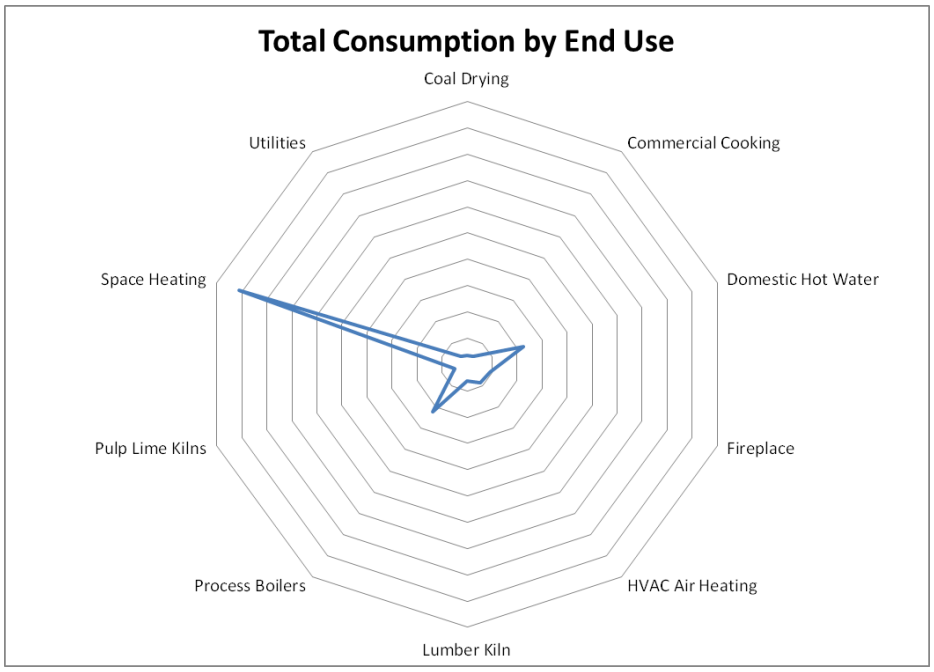
1

2 • Process boilers are significant in all regions
3 • Coal drying is significant only in the southern interior

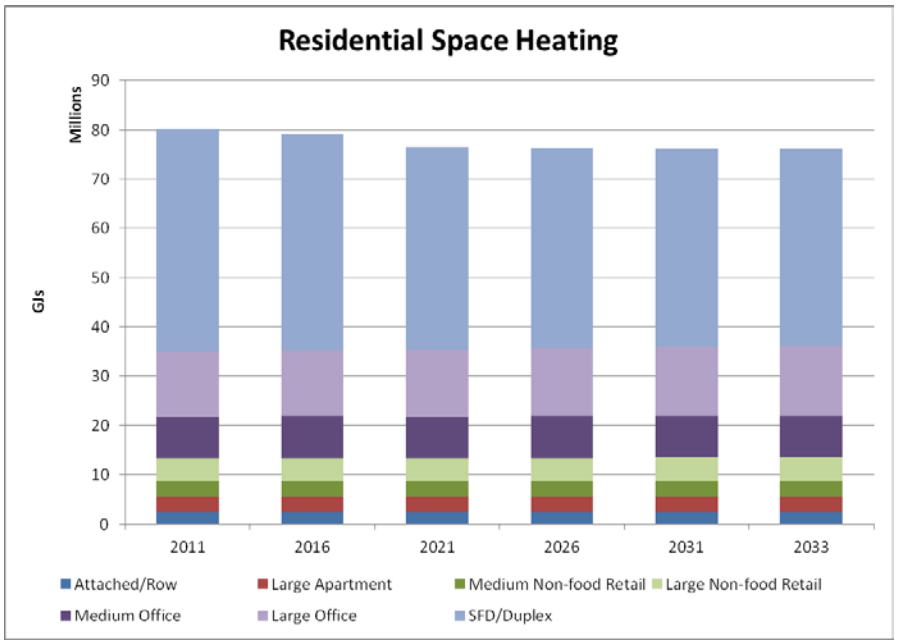


4

5 • Southern interior is driven predominantly by mining end uses
6 • Northern interior is predominantly forestry based

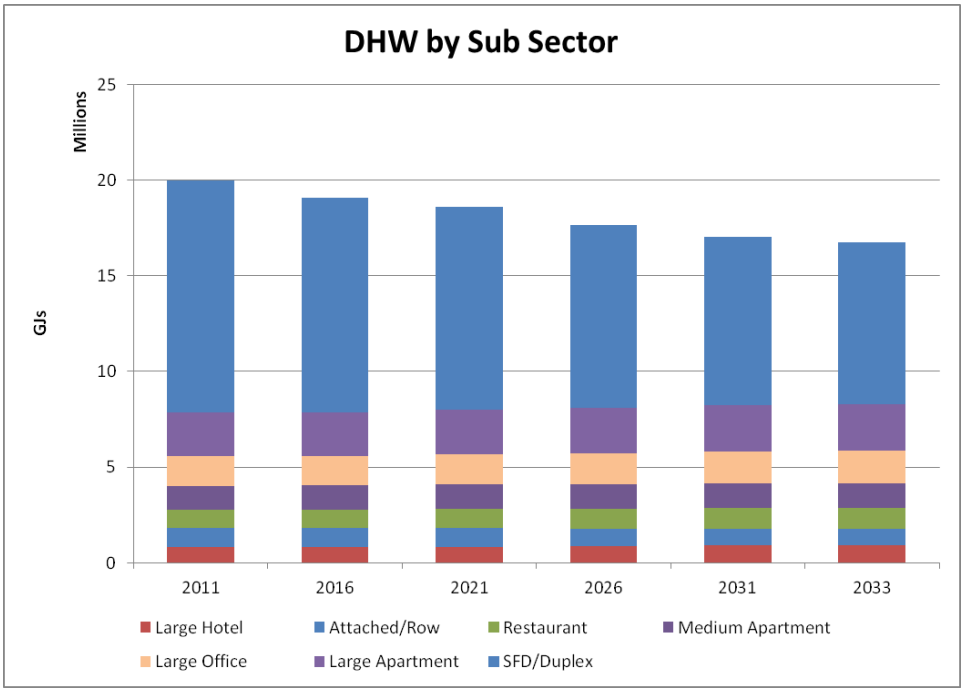


- Considers all end uses across all rate classes
- Space heating is by far the most significant end use



- SFD accounts for over 52% of the total
- Offices combine for 26%
- Retail accounts for 10%

- Large Apartments use 4%
- MFD accounts for 3%



- Gas used for DHW in the SFD market is expected to decline while other sectors remain constant.
- MFDs use much less gas for DHW than do SFDs

3.0 Reference: Exhibit B-1, pages ES-4 and ES-5 and Figure ES-3, NGT Demand

The referenced page ES-4 states:

NGT loads are expected to contribute to base load growth on the FEU's systems thereby mitigating variability of the load demand profile. The NGT forecasts presented in Figure ES-3 are based on FEI's experience from the NGT Incentive Program, allocated government funding until 2017, and actual NGT customer additions to date. In the Low case, the NGT market share of all eligible conversion vehicles is a 1% market share in 2033, the Reference Case reflects a 15% market share, and the High case reflects a hypothetical 30% market share in 2033.

3.1 Please explain the basis for the 1%, 15%, and 30% market share figures used for the Low, Reference, and High scenarios for NGT demand. Is this the same basis as used in scenarios for other forecasted variables?

Response:

The basis 1%, 15%, and 30% market share figures were provided as a basis to frame the range of forecasts that the FEU expect to materialize over the forecast period. Due to the inherent uncertainty involved in long-term forecasts, the FEU wanted to provide a forecast that was representative of the range of outcomes it could expect over the next 20 years.

The basis for the market size data was Natural Resources Canada's (NRCan) 2010 database for size of transport markets for different provinces in Canada sorted by end-use applications. The NRCan database was best suited to forecast market growth out to 2033 as this was the only source of objective forecast data that the FEU could obtain to conduct the analysis.

Please refer to the response to BCUC IR 1.24.5 for a discussion of the rationale for using the 1%, 15% and 30% market share figures in each of the respective scenarios. The NGT annual demand forecast was developed separately from the demand forecasts for the FEU's residential, commercial and industrial customer groups. The market share growth for NGT within the vehicle market is still too new to be able to examine past, current and potential future trends in the same way as was done for the residential, commercial and industrial sectors. The methodology, rationale and details of the annual forecast for these customer groups is explained in Sections 3.3.2 to 3.3.4 of Exhibit B-1 and in response to BCUC IRs 1.19.3 through 1.19.8. After the two forecast ranges (that for NGT and that for residential, commercial and industrial demand) were completed, the FEU examined the effect of combining the respective high, reference and low demand scenarios to determine the total range of potential future demand for natural gas (see Figure 3-14, page 60 of Exhibit B-1).

4.0 Reference: Exhibit B-1, page ES-13, Figure ES-6, Delivery Rate Direction

4.1 Are the cumulative delivery rate impacts expressed in 2011 dollars, excluding inflation?

Response:

No, the cumulative delivery rate impacts in Figure ES-6 include inflation.

5.0 Reference: Exhibit B-1, page ES-14 and page 164 Application, Action Plan, Updating the End-Use Forecasting Model

5.1 The cited references indicate that the Companies will update the model to a 2012 base year. When does the FEU expect to have this update available?

Response:

The 2012 base year update project is still in development and is expected to be available later in 2014. The inputs did not change appreciably so FEU does not expect a substantial difference in the results.

6.0 Reference: Exhibit B-1, page 166, and Exhibit A-3, BCUC IR 1.61.3

Action Plan, Protect and promote the interests of the Utilities' customers by securing a reliable, cost-effective long term gas supply

The first referenced page states:

Fundamental objectives for the FEU are to procure a stable, secure gas supply over the long term while minimizing the cost of the annual portfolio. In order to meet these objectives, the

FEU will use the following broad strategies to secure future resources:

- *Manage volatility in natural gas prices by maintaining access to liquid trading hubs, utilizing a variety of storage and transportation resources, and using different pricing structures and contract terms. …*

Also, to protect customers from market price volatility and help ensure the competitiveness of natural gas rates, the FEU will explore opportunities for longer term price risk management strategies that may include using fixed price purchases, investing in natural gas reserves and financial hedging.

6.1 Please explain how access to liquid trading hubs helps to manage price volatility.

Response:

Liquid trading hubs are typically characterized by a large number of buyers and sellers and often connect to multiple pipelines and storage facilities. Because of this, supply and demand have a higher probability of being in balance, as supply is able to meet demand even during peak demand periods. Therefore, market price volatility is generally lower at these liquid hubs. Examples would be the AECO/NIT trading hub in Alberta and the Station 2 hub in B.C.

Illiquid trading hubs usually do not include as many buyers and sellers or connect to multiple pipelines and storage facilities. At these hubs, supply and demand have a greater chance of being out of balance, particularly during peak demand periods when supply cannot match or reach demand. Therefore, market price volatility is greater at these hubs. An example would be the Sumas trading hub on the B.C./Washington border where pipeline constraints south to the Sumas hub limit the ability of supply to meet demand during cold spells in the winter and Sumas prices spike.

Because of this, the FEU contract for supply from more liquid trading hubs like Station 2 and AECO/NIT rather than at Sumas.

6.2 With respect to access to liquid trading hubs and spot markets, do the FEU have any concerns that prices may reflect speculative trading for "paper" rather than actual physical demands and supplies?

Response:

The FEU understand that market gas prices reflect speculative trading as well as actual physical demands and supplies and do not have any concerns with this. The natural gas marketplace includes numerous participants such as producers, marketers, utilities, industrial consumers, power generators and financial parties like banks and hedge funds. This multitude of market participants provides liquidity and transparency to market prices and enables the marketplace to operate efficiently in responding to changes in supply and demand.

6.3 Do the fixed price purchases reflect long-term agreements? If so, are the FEU aware of a competitive market in such long-term fixed price purchases?

Response:

Yes, in the context of longer term price risk management, the fixed price purchases reflect long-term agreements, potentially up to ten years in length. The FEU are not aware of a competitive market in which long-term fixed price physical purchases are actively traded. The FEU have had some initial discussions with some gas producers and suppliers regarding these types of arrangements but have not executed any long term fixed price physical deals to date. Please also refer to the response to BCUC IR 1.60.1.

6.4 If the FEU were to invest in natural gas reserves, would not the return on that investment result in the FEU earning a return on gas commodity?

Response:

If the FEU were to invest in natural gas reserves, it would expect to earn a return on that investment that would be recovered through customer rates. However the FEU would only propose to invest in reserves as part of its overall gas supply portfolio if it was able to demonstrate that it was expected to provide net benefits to customers. Please also refer to the responses to BCUC IR 1.60.1 and BCPSO IR 1.6.6. .

6.5 Please provide in detail the FEU's views on the differences between financial hedging and speculation, if any.

Response:

The FEU's view is that while financial hedging is intended to reduce risk related to market price volatility for customers, speculation is related to making a profit from price movements or "beating the market". The focus of the FEU's price risk management activities is related to reducing market price risk for customers rather than speculation.

6.6 Please provide details with respect to the types of financial instruments that the FEU would consider making use of and provide details of practices that the FEU would consider to ensure that the hedging undertaken would be of the "insurance" variety as opposed to the "gambling" variety.

Response:

As discussed in the response to BCUC IR 1.60.1, the FEU are planning to submit a Price Risk Management Review Report to the Commission in mid-2014. The FEU believe that review of that report is the correct forum to explore questions related to price risk management instruments and strategies.

6.7 With respect to attributing volatility decreases to FEU's proposed risk management practices, please provide details as to how, ex post, the decrease

in volatility would be measured, i.e., what would be the benchmark and how would the comparison be made?

Response:

Please refer to the response to BCSPO IR 1.6.6.