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October 18, 2010

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: Terasen Utilities (comprised of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc.) 2010 Long Term Resource Plan

Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 1

On July 15, 2010, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-146-10 setting out the Regulatory Timetable for the review of the Application, the Terasen Utilities respectfully submit the attached response to CEC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned or Ken Ross at (604) 576-7343 or ken.ross@terasengas.com for further information.

Yours very truly,

on behalf of the TERASEN UTILITIES

Original signed:

Diane Roy

Attachment

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

1. Reference: Exhibit B-1, Page E-1

Table ES-1: 2009 Service Statistics for the Terasen Utilities

	TGI Lower Mainland	TGI Interior	TGVI	TGW	Alternative Energy Services**
Number of Customers	582,199	253,480	97,705	2,580	748†
Annual Demand (TJ)	86,409	27,865	11,651	663	--
Peak Day Demand (TJ/d)	918	331	110	7	--
Length of Transmission Pipeline (km)	256	2,063	671	--	--
Length of Distribution Pipeline (km)*	11,030	8,237	3,435	95	--

1.1 Could Terasen please provide the Annual heating demand supplied or serviced by the AES. Please provide this in equivalent GJs.

Response:

Corresponding annual demand for the number of customers or 'units served' total has not been assessed since the majority of the units are served under infrastructure use agreements which may or may not meet full capacity requirements and which may or may not include both heating and cooling provisions. The Terasen Utilities expect that as this business grows, consistency will emerge and it will be able to define and apply metrics to provide annual equivalent demand information.

1.2 Please provide the length of any distribution system connected to these customers owned by Terasen.

Response:

As noted in the response to CEC IR 1.1.1, metrics have not been applied to number of customers or 'units served' and as such no data is readily available to calculate distribution system lengths. In addition, some of the customers included in the number are served by stand alone systems and hence are not connected to a distribution system.

2. Reference: Exhibit B-1, Page E-2

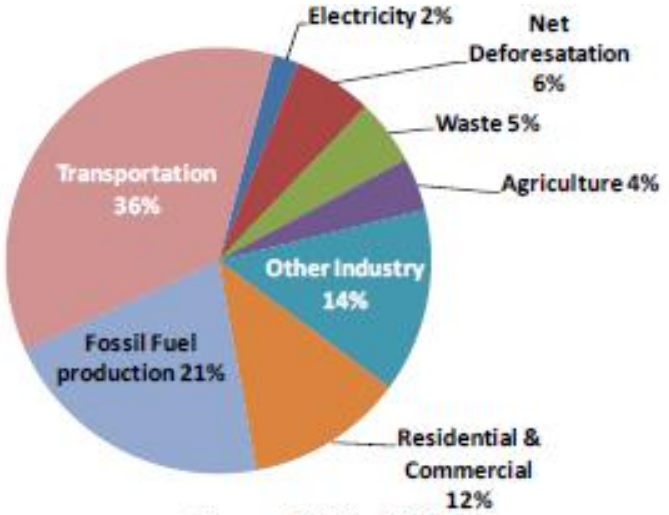
An ever-increasing factor affecting the planning environment today is the requirement to continually reduce the carbon footprint of the province's and Pacific Northwest ("PNW") region's energy systems over time, thus contributing to climate change solutions in an economically responsible way. This one factor is driving government policy, social attitudes, environmental

2.1 Given this requirement does Terasen believe it should have plans, including resource plans that match the decrease in natural gas usage that would be necessary to achieve or better the Provincial Government targets, even though those targets do not apply prescriptively to Terasen? If not why not?

Response:

The B.C. government has set GHG emissions reduction targets for total emissions in the Province, but has not prescribed how such reductions are to take place. How we comply in obtaining these goals will have an economic impact for the province and our customers.

As a starting point, how GHG emissions are generated in British Columbia is important because it gives an indication of potential areas where emissions reductions will be targeted over time. The figure below shows the sources of emissions in B.C.



Source: NRCan 2007

As the figure above shows, only 2 percent of B.C.'s GHG emissions comes from the electricity sector, which is significantly lower to other jurisdictions where higher portion of emissions are created by the electricity sector. This is due to the fact that B.C. electricity is produced from hydro sources while other jurisdictions in Canada and the U.S. produce most of their electricity from a combination of coal and natural gas fired generation.

With the oil and gas sector stimulating economic growth in the B.C., it will be a significant challenge to reduce GHG emissions from the fossil fuel production sector (21 percent) as this sectors emission is expected to grow with the recent Horn River and Montney resource plays being discovered. This leaves the transportation sector at 36 per cent, other industry at 14 percent, and the residential and commercial sector at 12 percent as the biggest areas for potential GHG reductions in the Province.

The GHG emissions reduction targets have the potential to change people's perception of natural gas over the long term, moving them away from natural gas use towards the consumption of electricity or other renewable energy alternatives. However, given that B.C. is unique in its sources of emissions, we need to take a balanced approach in striving to obtain the established targets, while maintaining economic prosperity for B.C.

The Terasen Utilities do not have any regulatory compliance obligations as of yet to reduce natural gas throughput to meet the government GHG emission reduction targets. However, we strive to reduce our own operating emissions and bring forth solutions for customers that help them support the energy and climate change goals of the province, while helping customers manage their energy costs. We continue to help our customers reduce their GHG emissions in the province through Energy Efficiency and Conservation ("EEC") programs and by offering them an integrated approach to low carbon energy consumption through programs such as biogas, geothermal, district energy systems and NGVs. These new service offerings and alternative energy solutions will help customers meet their climate change goals and may help achieve GHG reductions in a more economic way than other alternatives.

Although the Terasen Utilities are facilitating more efficient use of energy and are advancing low carbon energy solutions, with the growth of the population in British Columbia more energy is expected to be consumed and therefore natural gas usage and throughput will not necessarily decline. However, the same of amount of natural gas may be serving more customers energy demands as their intensity of natural gas usage changes overtime. Moreover, as we switch from diesel to natural gas for transportation through our NGV service offerings, we are reducing overall emissions in the province but are also displacing the emissions from one sector to another. So from the Terasen Utilities customer's standpoint, we are still creating emissions from natural gas usage in vehicles, albeit these emissions are much lower than what would be produced from the consumption of diesel, propane, or gasoline.

Consequently, the Terasen Utilities are not necessarily reducing throughput levels to meet government's GHG emissions reduction targets. Instead we are actively helping the province reduce its overall emissions, particularly in the residential, commercial, and transportation sectors.

2.2 Does Terasen believe that this resource plan will have Terasen matching the government targets for reduction of GHGs or will the plan have Terasen delivering more natural gas than would be required if it were to meet the government's GHG targets?

Response:

Please see the response to CEC IR 1.2.1.

3. Reference: Exhibit B-1, Page E-2

> The most common forms of energy used in B.C. and throughout the PNW are natural gas, electricity and petroleum based fuels. Historically, the economic alternatives to these energy types have been higher carbon and/or pollutant emitting fuels such as coal, fuel oil and wood. Today, both the demand for and costs of energy continue to rise steadily along with our population growth. Due to the large hydro generation base in B.C., there is a belief that electricity represents the best low carbon choice to meet energy needs. However, B.C.'s electricity grid cannot physically or economically meet all of these requirements. Figure ES-1

3.1 Please provide the analysis and or any report information Terasen has with respect to the assertion that the BC electricity grid cannot physically or economically meet all of these requirements?

Response:

There are a number of factors that the Terasen Utilities look to in support of the assertions that the BC electricity grid cannot physically or economically meet all the energy needs in the province.

First, as shown in Figure ES-1 electricity served only 21% of the energy demand in the province in 2006, meaning that a large majority of energy consumed is from other energy sources. Even if electricity was to displace natural gas, which at 21.8% provides a similar amount of end use energy in BC, the electricity supply in the province would more or less need to double. Demand growth from electrification in other sectors, such as if there was significant penetration of electric vehicles in the transportation sector, would give rise to further cost and infrastructure challenges for the electricity sector. It is important to note that adding new electrical load is not only a matter of acquiring new higher cost marginal electricity supplies but it also involves increasing the capability of the transmission and distribution systems to deliver the additional energy to match the profile of this energy demand.

A second factor is that adding new electricity supply is already much more costly than existing embedded supply costs. BC Hydro's Clean Power Call "Report on the RFP Process" indicates that the weighted-average levelized and adjusted Firm Energy Price of $124.3/MWh is a reasonable proxy for the costs that will be borne by BC Hydro's ratepayers for electricity being acquired to the Clean Power Call. If it was necessary to acquire much larger quantities of electricity to meet demand growth due to electrification it would be reasonable to expect that the prices would continue to rise as the supply projects with better economics and lower prices would be developed first.

A third factor in support of the assertions quoted in the question is that much of the load served by other energy sources such as natural gas is meeting thermal energy demands for space heating which occur mostly in the winter months. The electricity system in BC is winter peaking already so adding winter peak load due to displacement of thermal loads served by other

energy sources will add challenges to the system at the time of the year that supply is most costly and the infrastructure to deliver the energy is most utilized.

While it may be physically possible to expand the electricity system and acquire new electricity supply to meet a larger share of the province's energy demands, the Terasen Utilities believe that there is a large potential for inefficient electrification which in turn will lead to more costly solutions to achieving the province's energy objectives and GHG emissions reduction targets.

3.2 Does Terasen have a view as to approximately how much of the provincial energy requirements can be physically and economically met by electricity?

Response:

The Terasen Utilities do not have a specific view about how much of the provincial energy requirements can be physically and economically met by electricity. It is well known that the province has significant potential for renewable electricity. For instance the Western Renewable Energy Zones – Phase 1 Report identifies BC as having a total renewable electricity potential of 66,010 GWh/yr. This is similar in magnitude to BC's current total electricity generation. As increasing quantities of this renewable electricity potential are developed the cost of additional supply would become successively more expensive on the basis that the most attractive and economic projects would be developed first. There is also the potential to develop non-renewable electricity supply such as gas-fired generation; but, in the absence of technological breakthroughs in carbon capture and storage, doing this would likely be viewed as contrary to current government policy. A further issue with regard to renewable electricity supply is that the output is intermittent (as with wind) or the generation profile does not match the load profile (as with run-of-river) so there are significant integration costs with bringing these resources into the overall supply resource stack.

While the foregoing indicates that there is a large potential for electricity to replace other energy use in the province the Terasen Utilities believe that the costs of extensive electrification will be prohibitive. The Terasen Utilities believes that the evaluation of energy solutions aimed at achieving the province's GHG emission reduction targets and other energy objectives must be done on an integrated basis across energy forms including electricity, natural gas and alternative energy solutions such as geoexchange, solar thermal and waste heat recovery. This evaluation is better done at the local community level and by employing the energy and emissions optimization principles common in integrated community energy systems. Evaluation at the local level can better incorporate the unique circumstances and demographics as they vary from one community to the next. The Terasen Utilities believe in general that electricity is a valuable and scarce resource that should be preserved for end uses such as providing lighting and powering appliances and electronic equipment, uses that cannot be served by other energy

sources. On the other hand, end-uses such as the thermal energy needed for space and water heating should in general be served by lower value energy forms such as alternative energy and natural gas.

3.3 At what point does Terasen believe that electricity becomes a less than economical substitute for displacing other energy uses in the province?

Response:

The Terasen Utilities does not believe there is a bright line delineation that marks when electricity becomes a less than economical substitute for displacing other energy uses in the province. As discussed in the response to CEC IR 1.3.2, the Terasen Utilities believes that integrated solutions at the local level will be needed to resolve the energy issues of the future and to achieve the province's energy objectives. Electricity, alternative energy, natural gas and energy efficiency and conservation will all play roles in getting to this future.

4. Reference: Exhibit B-1, Page E-4

> the trading patterns and flow of natural gas throughout the continent. At the same time, the British Columbia Hydro and Power Authority's ("BC Hydro") most recent Service Plan expects electricity rate increases of approximately 9%, 13% and 5% in each of the next 3 years as electricity self sufficiency, renewable resource development and replacement of aging infrastructure are top agenda items. A key consideration in developing sustainable energy plans is affordability, and as electricity prices increase, customers will continue to look for energy solutions that fit their needs and budgets.

4.1 Does Terasen in its resource planning for natural gas use make 20 year forecasts or use 20 year forecasts of future electricity prices in the province?

Response:

The Terasen Utilities do not forecast energy prices. When needed, the Terasen Utilities will use independent, third party forecast sources for its analysis and planning purposes.

There are two aspects to the consideration of forecasts of electricity prices in B.C. One is the forecast of prices on the open electricity market and the other is electricity rates in B.C. While the market price of electricity does provide some context for the energy planning environment within the Pacific Northwest, its value as a planning input in B.C. is limited since electricity rates here are based on cost of both heritage and new electricity resources rather than on open market pricing. While both BC Hydro and FortisBC purchase electricity from the open market, these purchases make up a small portion of their current and planned resource portfolios.

Electricity rates in B.C. provide useful insights into the competitiveness between natural gas and electricity and assist with resource planning efforts. The availability of electricity rate forecasts in B.C., however, is limited to information on expected rate increased prepared by BC Hydro. Even with such information, rates are subject to approval by the BCUC and circumstances change between the time a long-term forecast is made and the actual rate applications are filed; thus, the final rate increases are likely to be different from expected increases published by BC Hydro. For this reason, the inclusion of future electricity prices in B.C. within the Terasen Utilities' Long Term Resource Planning is limited to that discussed in Section 2.1.1.2, pages 21 to 27 of Exhibit B-1 of the LTRP.

4.2 Does Terasen in its resource planning anticipate fuel switching behavior in the market in response to differential pricing in the future?

Response:

The Terasen Utilities does consider the potential for fuel switching behaviour based on pricing differential, but do not attempts to define the amount of fuel switching that might occur over varying levels of price differential. As discussed in Section 2.1.1.3.1 (page 26) of the LTRP, TGI's rates currently have a competitive advantage over electricity although this advantage has been eroded in recent years.

Fuel switching and fuel choice, however, are influenced by a number of factors. For one, the public's perception of price differentials between fuels can vary from the actual price differentials. For example, residential customer rates for electricity are in cents per kilowatt while natural gas rates are in dollars per GJ. The conversion factors to assess these differentials are not well understood by many customers. This difference in presentation of the rates can lead some customers to believe that heating with gas is more expensive that heating with electricity when on an annual basis this is not necessarily the case.

Public perception of preferred fuels can also be influenced by media and public policy even when price differentials would suggest otherwise. Messaging from utilities, governments, academia and others that suggests the availability of green, renewable electricity at low costs is unlimited in B.C. might result in customers choosing to use electricity for heating purposes rather than natural gas or renewable thermal energy services.

Another factor is price volatility. Because natural gas commodity prices are market based, spikes in prices can occur that drive natural gas rates up temporarily with the potential to cause fuel switching.

This response includes three examples of factors that can influence fuel switching and fuel choice. Quantifying these factors, however, remains a difficult challenge and the Terasen Utilities have limited their analysis of energy price differential to that contained in Section 2.1 of the LTRP.

5. Reference: Exhibit B-1, Page E-4

> **Alternative energy** systems that integrate renewable, thermal end-use energy solutions such as geo-exchange, waste heat recovery and solar-thermal technologies supplemented as required by conventional natural gas and electric services for homes, businesses and communities are a key part of the Terasen Utilities' evolving low-carbon energy strategy. These

5.1 Does Terasen maintain or have access to technology forecasts with respect to the cost-effectiveness of the different technologies and the circumstances under which they become cost-effective?

Response:

The Terasen Utilities does not have technology forecasts with respect to the cost effectiveness and circumstances, under which they become cost-effective. Instead, when the Terasen Utilities meets with a customer to discuss the customer's energy needs, we review options and provide a solution incorporating the appropriate technologies and considering cost-effectiveness. Depending on the objectives of the customer (e.g. emission reduction or building design standards), each may have a different interpretation of what is cost effective.

5.2 Do technology forecasts form a basis of the alternative energy forecasting or is Terasen still evolving its forecasting methodologies for AES?

Response:

The Terasen Utilities does not currently forecast or rely on external forecasts of the development of new technology. While the methodologies for forecasting growth in alternative energy customers and demand are still under development, the exercise is generally based on proven, commercial ready technologies. As discussed in Action Plan item 10 of the LTRP (Exhibit B-1), the Terasen Utilities will continue to monitor for new energy technologies emerging within the marketplace and assess their impact on both the growth of alternative and conventional energy and customers.

The Terasen Utilities have initiated and started working with BC Hydro and FortisBC in developing a total thermal energy demand forecast for BC. It is hoped that overtime this common energy forecast will determine the thermal energy demand in BC that can be expected into the future. Then the question becomes which energy forms and technologies are used to serve this demand.

6. Reference: Exhibit B-1, Page E-5

> With tariffs in place, we can deliver both liquefied natural gas ("LNG") and compressed natural gas ("CNG") fuel solutions to a large portion of the transportation sector. Our low carbon fuel strategy targets return-to-base fleet vehicles for CNG solutions where fueling infrastructure economics make sense and vehicle ranges can match fuel capacity. Transport industry fleets with large engines present LNG solution opportunities where larger fuel capacities are needed for heavy duty or longer haul operations. Marine and rail fleets offer future LNG fueling opportunities. The transportation markets we are targeting (light, medium and heavy duty trucks, transit, marine fleets and potentially rail) emit almost 50% of transportation related emissions in B.C. (Figure ES-2). The Utilities plan to submit an application to the Commission in the summer of 2010 to outline the business plan and provide a comprehensive solution for customers.

6.1 This opportunity would appear to have enormous strategic significance for Terasen Utilities and its customers in terms of maintaining throughput with GHG reduction uses and applications. How much conversion has Terasen incorporated in its 20 year planned forecast demand?

Response:

The traditional demand forecast described in section 4.2 of the LTRP does not incorporate the expected growth of natural gas as a transportation fuel at this point in time. As demonstration projects and first adopters in the province show success, the Terasen Utilities expect that NGV solutions will be adopted at a faster pace as businesses seek out their environmental benefits and operational cost advantages. As that occurs, the Terasen Utilities will validate and refine the underlying assumptions on fuel consumption and market uptake, and incorporate load growth expectations from this market into its traditional natural gas demand forecast. Until that time, the demand scenarios for natural gas vehicles have been described separately under section 4.3.3 of the LTRP. The underlying assumptions and target market segments are described in sections 4.3.3.1 and 4.3.3.2 of the LTRP.

The low carbon fuel strategy is an example of an initiative that the Terasen Utilities are considering to help achieve government legislative targets. The anticipated load growth from the transportation sector would be an important offset to the levelling off of demand growth from residential and commercial customer segments and would help optimize the use of the existing natural gas infrastructure to the benefit of all of the Terasen Utilities' customers, while reducing province wide GHG emissions.

6.2 How much conversion would be required to approximately parallel the provinces GHG reduction plans?

Response:

The year 2007 was established under the provincial *Greenhouse Gas Reductions Target Act* as the base year for calculation of B.C. GHG emissions targets. The Act puts into law British Columbia's target of reducing GHG emissions by at least 33% below 2007 levels by 2020 and includes the long-term target of an 80% reduction below 2007 levels by 2050.[1] This is affirmed in the *Clean Energy Act*.

In total, GHG emissions in British Columbia in 2007 were 67.3 megatonnes (Mt) of CO_2e[2], of which 36 percent came from the transportation sector. To obtain these climate change goals through fuel switching from convention diesel or gasoline to natural gas for transportation, we would have to convert all heavy fleets to natural gas and introduce lower or no carbon vehicles in the passenger vehicle market, if reductions were intended to come from the transportation sector only. Further, the development of biogas resources for use as a transportation fuel could have the potential to reduce GHG emissions even further and perhaps attain or even surpass the provincial targets. The fact that this shift in emissions from the transportation sector would involve significant change underlies the challenge of meeting such goals and the necessity of taking action on many fronts. Please see the response to CEC IR 1.2.1 for a further description of how the Terasen Utilities are bringing forward solutions for customers to support the energy and climate change goals of the province.

6.3 What are Terasen's limitations and challenges in developing and meeting this demand in terms of its system resource requirements?

Response:

In terms of system resource requirements, there are minimal limitations in developing and meeting the demand for LNG and CNG Transport solutions.

Liquefaction, storage, and transport loading facilities would be the system resources required to support LNG as a transport fuel.

In the Lower Mainland, TGI's Tilbury Island LNG Facility, in operation as a peaking supply resource for the core market customers, already has a transport loading facility and also has surplus liquefaction capacity to produce additional LNG. During the initial development of the

[1] See: www.env.gov.bc.ca/epd/codes/ggrta

[2] One megatonne (1 Mt) is one million tonnes.

market for LNG as a transport fuel, additional LNG buffer storage facility would be required as the existing storage facility is reserved to serve core market customers.

On Vancouver Island, the Mt Hayes LNG Facility is under construction with an in-service date planned for the winter of 2011. In the short term, the facility could liquefy and store LNG for transport use but a new transport loading facility would be required.

When the market of LNG as a transport fuel matures, dedicated LNG liquefaction, storage, transport loading facilities would be required.

For CNG as a transport fuel, there is no system resource requirement as natural gas is readily available from the existing gas utility infrastructure.

LNG fuelling stations and CNG compression, storage and dispensing stations, not considered as system resources, would also be required to complete the infrastructure requirements to deliver natural gas as a transport fuel.

In summary, the Terasen Utilities has few limitations with respect to system resource requirements in order meet the demands of a LNG and CNG Transport service.

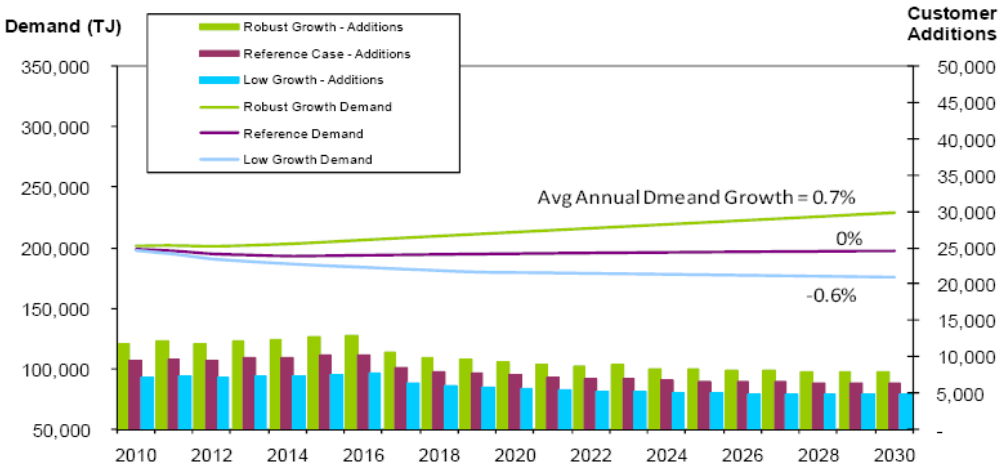
6.4 Has Terasen's scenario forecast of robust conversion of the transportation market been included in the robust growth case forecast below?

Response:

The robust growth scenario described in section 4.2.5 of the LTRP does not consider the anticipated growth from natural gas as a transportation fuel. The reference and robust growth scenarios of the traditional demand forecast are used for planning purposes and given that the Terasen Utilities are still developing a strategy for the low carbon transportation fuel, the expected demand from NGV growth was not included at this point in time. The factors affecting the outcome of the robust growth scenario are discussed under section 4.25.1 of the LTRP.

7. Reference: Exhibit B-1, Page E-6

Figure ES-3: Customer Additions and Annual Demand Forecast – All Utilities



7.1 Will the level of consumption of natural gas shown in the demand forecasts above enable Terasen to have approximately the equivalent reduction in GHG emissions as those for which the provincial targets are set?

Response:

Please see the response to CEC IR 1.2.1.

8. Reference: Exhibit B-1, Page E-7

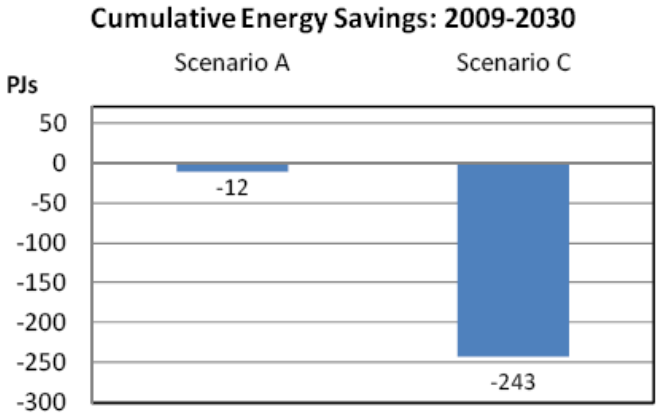
> The current methodology used to forecast annual and peak day demand does not include the impact of expected growth in adoption of integrated, alternative energy solutions by either existing or future customers; or the potential expansion of energy efficiency and conservation programs beyond 2011. The Terasen Utilities' forecasting activities are evolving to capture the changes that are underway in our customers' energy demand patterns. While these changes will not have a marked impact in the short term on natural gas demand, we need to be developing new methodologies in forecasting now to better understand the implications over the long run. Figure ES-5 shows the results of an example forecast scenario indicating how the

8.1 When does Terasen expect to have methodologies in place for forecasting the demand in response to alternative energy options being implemented in the market over the 20 year resource plan timeframe?

Response:

It is quite challenging to state when the Terasen Utilities will have the end use methodology fully developed as the Terasen Utilities will need some time to fully develop and implement it, validate the results and develop expertise and stakeholder confidence in its use.

9. Reference: Exhibit B-1, Page E-9



9.1 Is Scenario C near the extent of what Terasen could accomplish with Energy Efficiency and Conservation or was the 5% of revenues simply a convenient step jump in activity to demonstrate illustratively that more could be accomplished?

Response:

Revenues of 5% were selected by the Terasen Utilities as being one way to illustrate that should energy savings remain proportional to currently approved EEC expenditures and activity, there is the potential to accomplish fairly significant energy reductions. The Terasen Utilities are also seeking to demonstrate the benefits of having secure, long term funding approval through the different expenditure and resultant savings scenarios.

10. Reference: Exhibit B-1, Page E-10

> On the TGI Interior Transmission System, however, service through the Okanagan Valley to meet peak demand is expected to become constrained by 2017 under the reference case forecast. Alternative solutions include expanding the pipeline capacity through looping (adding a second, parallel pipeline) north of Penticton, pipeline looping east of Kamloops or adding a storage facility in the north Okanagan area. Addition of a large new industrial load could advance the need for this capacity expansion. For example, FortisBC has also identified growing electric system capacity constraints in the Okanagan. A new natural gas fired peaking generator is one of the resource options being considered to provide a firming resource for a range of potential renewable resources and to avoid extensive new transmission requirements.

10.1 What is Terasen doing with EE&C to attempt to delay the need for capacity expansion in this area and would such measures effective or expected to be too little to influence the need?

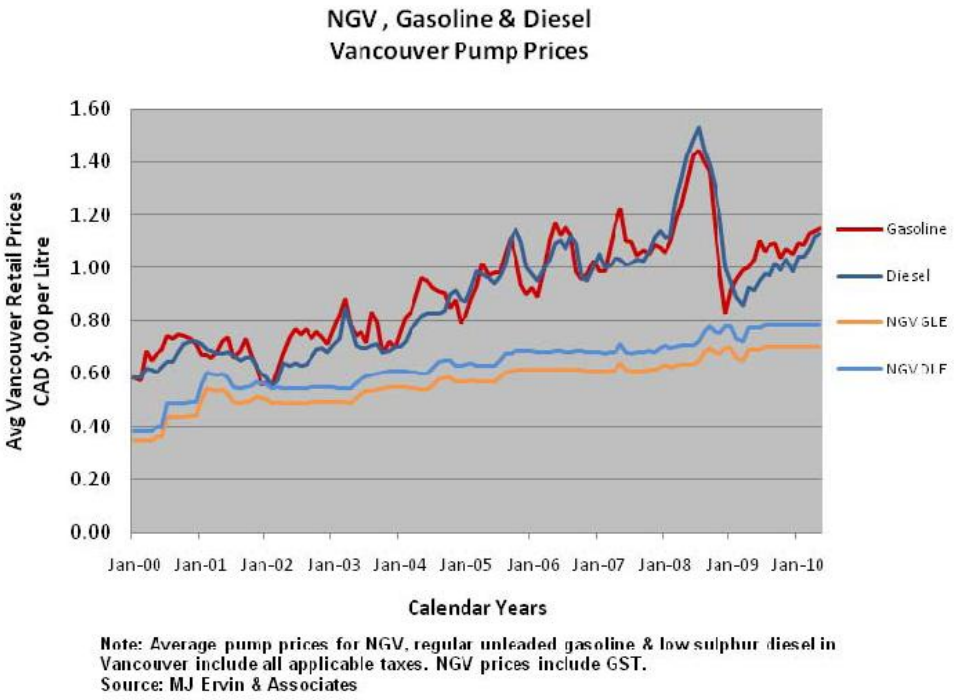
Response:

While the Terasen Utilities believes that increased and ongoing EEC activities and implementation of new building codes and standards have the potential to impact growth in design day demand, it is too early to predict these impacts. The Terasen Utilities will continue monitoring the impact from the EEC activities in the planning of the capacity expansion.

However, the addition of a large new industrial load such as that from a new FortisBC natural gas fired peaking generator would likely offset some of the energy savings impact from the EEC activities and would advance the need for the capacity expansion.

11. Reference: Exhibit B-1, Page 21

Figure 2-7: NGV Fuel has a Price Advantage against Diesel and Gasoline



Note: Average pump prices for NGV, regular unleaded gasoline & low sulphur diesel in Vancouver include all applicable taxes. NGV prices include GST.
Source: MJ Ervin & Associates

- Pricing of NGV in B.C. has been far less volatile than both diesel and gasoline

11.1 Does Terasen have an explanation as to why the Natural Gas prices are more stable and less volatile than oil prices?

Response:

Please note that the referenced figure displays the pump prices for NGV service, gasoline and diesel and does not illustrate pure commodity prices for natural gas and oil.

In responding to this question, the Terasen Utilities has assumed it is referring to the differences between the pump prices for NGV service and gasoline and diesel prices rather than the difference between natural gas prices and crude oil prices as stated.

The pricing of NGV service is more stable and less volatile than gasoline and diesel prices for two reasons. The first reason is the proportion of market based pricing that is included in the NGV prices as compared to the gasoline and diesel prices as shown in Figure 2-7. The NGV price has three components:

1. Commodity;

2. Delivery; and
3. Compression and Dispensing.

The NGV prices contain a larger proportion of relatively stable charges which are not tied to the market price of natural gas. Of the three components, only the commodity price moves with changes in market price of natural gas. The NGV prices presented in the figure are comprised of TGI's Natural Gas Vehicle Service Rate Schedule 6 ("Rate 6") tariff rates plus an added station cost. As of July 1, 2010 the delivery component was $3.60/GJ, the commodity was $5.44/GJ and the assumed average compression and dispensing charge built into the graph is $5.00/GJ. Thus, less than 40% of the overall charge is related to the commodity price of natural gas and subject to market price volatility. The other components are not subject to price swings. By comparison the gasoline and diesel prices are more closely linked to market prices for these commodities and have a higher degree of correlation with crude oil prices.

The second reason for the difference is the natural gas commodity portion of the Rate Schedule 6 tariff rate included in the NGV prices in the figure is adjusted on a quarterly basis rather than daily or weekly adjustments for gasoline and diesel prices. While the quarterly adjustment on its own does provide a smoothing effect on rates, it does not impact the underlying cost of gas directly affected by market prices. Price risk management activities do, however, significantly lower market price volatility and the resultant cost of gas. Therefore the NGV prices are more stable and less volatile than gasoline and diesel prices or natural gas prices in the market.

11.2 Does Terasen have a view as to whether or not the stability and lower volatility would be expected to continue?

Response:

At this time the Terasen Utilities believes the relative stability and lower volatility of the NGV prices as compared to gasoline and diesel prices will continue. This assumption is based on the reasons presented in the response to CEC IR 1.11.1.

12. Reference: Exhibit B-1, Page 26

> Figure 2-10 demonstrates that while the historical natural gas cost advantage has experienced erosion, natural gas continues to have a modest operating cost advantage relative to electricity. However, the Utilities believe that other factors, such as higher upfront capital costs of a natural gas installation relative to electrical installations and greater rate volatility also figure prominently in the overall competitive position of natural gas relative to electricity. Figure 2-11 demonstrates that natural gas rates need to be lower than electricity rates by approximately $10/GJ to pay back the higher capital costs of a natural gas installation relative to electric baseboards. Also,

12.1 Do the forecast long term increased prices for electricity for the next ten years cause the difference between electricity and natural gas rates to cross over such that the capital cost hurdle is completely mitigated?

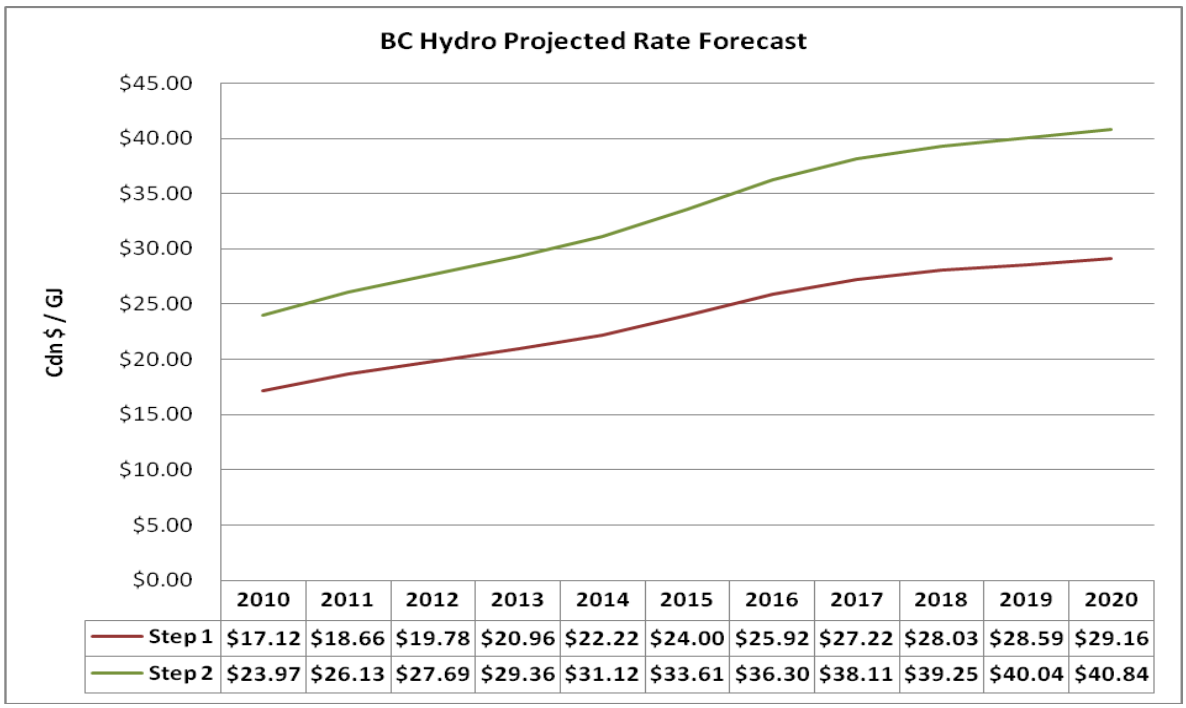
Response:

The forecast electricity[3] rate increases for the next ten years could cause the difference between BC Hydro rates and natural gas rates to exceed the $10/GJ capital cost hurdle, but only for some residential energy consumers. This could be true of larger volume residential energy consumers that have most or all of their heating load above the RIB Step 2 consumption threshold. However many residential energy consumers have much of their heating load at the RIB Step 1 rate. In any case, the $10/GJ price differential required to pay back capital cost differential between gas and electric heating systems is only one of a number of factors and is not on its own indicative of the future competitiveness of natural gas. The incremental cost analysis presented in Figure 2-11 of the LTRP does not take into consideration the changing public perceptions of natural gas as a fossil fuel-based energy source, more restrictive governmental policies targeting a low carbon future, and the possibility of substantial future increases to the BC carbon tax. These future uncertainties will ultimately shape the future competitiveness of natural gas and not the $10/GJ threshold itself.

The figure below presents BC Hydro's long term rate forecast to year 2020[4] converted to dollar per GJ.

[3] Please note that BC Hydro rates were assumed for the forecast electricity rates. Other electric utilities in the province such as FortisBC and municipal electric utilities do not have inclining block rate structures. Their flat rates fall between the BC Hydro RIB Step 1 and Step 2 rates. Other comments in the response regarding the significance of other factors in the competitiveness of natural gas versus electricity apply equally to these other BC electric utilities as to BC Hydro.

[4] Forecasted nominal rate increases based on BC Hydro 2008 LTAP IR Exhibit B-3, BCUC IR 1.7.1, Attachment 1 p. 7. Although there are more recent rate increase forecasts available for shorter time periods such as the current BC Hydro Service plan or BC Hydro's response to JIESC IR 3.40.3 in the BC Hydro F2011 Revenue Requirements Application, they do not cover the full 10 year period.



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Step 1	$17.12	$18.66	$19.78	$20.96	$22.22	$24.00	$25.92	$27.22	$28.03	$28.59	$29.16
Step 2	$23.97	$26.13	$27.69	$29.36	$31.12	$33.61	$36.30	$38.11	$39.25	$40.04	$40.84

The calculations in the above figure were based on the following assumptions:

1) Harmonized Sales Tax (HST) calculated at 5% to reflect the 7% residential energy credit.
2) The electric rates do not include the fixed monthly charges since it is assumed that a household already pays the base electric charge for non-heating use.
3) The efficiency of gas equipment is assumed to be 90%, 100% for electricity to determine the equivalent electricity.
4) The consumption of electricity for non-heating purposes will depend on various factors such as size of the residential premises and number and type of appliances using electricity.
5) Electricity Equivalence rate determined based on GJ to kWh conversion:
    - 1 GJ = 277.8 kWh
    - 50GJ= 13890 kWh

In order to assess natural gas rates against the forecasted electricity rate increases, an estimate of future rates for natural gas must be determined. It is important to note the forecast increases provided below are indicative only[5]. The table below presents a natural gas rate projection ($/GJ) to forecast year 2020 based on the most current long term natural gas AECO forecast[6] conducted by GLJ[7].

$/GJ	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Projected Rate	**14.37**	**15.40**	**16.61**	**17.30**	**17.89**	**18.94**	**19.48**	**19.48**	**19.87**	**20.26**	**20.64**
Cost of Gas	4.98	5.55	6.28	6.77	7.16	7.44	7.81	8.14	8.32	8.50	8.67
Midstream	1.73	1.76	1.80	1.84	1.87	1.91	1.95	2.00	2.04	2.08	2.12
Delivery	3.15	3.21	3.28	3.35	3.42	3.49	3.56	3.64	3.71	3.79	3.87
Carbon Tax	1.00	1.25	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
Basic	2.84	2.90	2.96	3.02	3.09	3.15	3.22	3.29	3.36	3.43	3.50
HST	0.68	0.73	0.79	0.82	0.85	0.87	0.90	0.93	0.95	0.96	0.98

The calculations in the above table were based on the following assumptions:

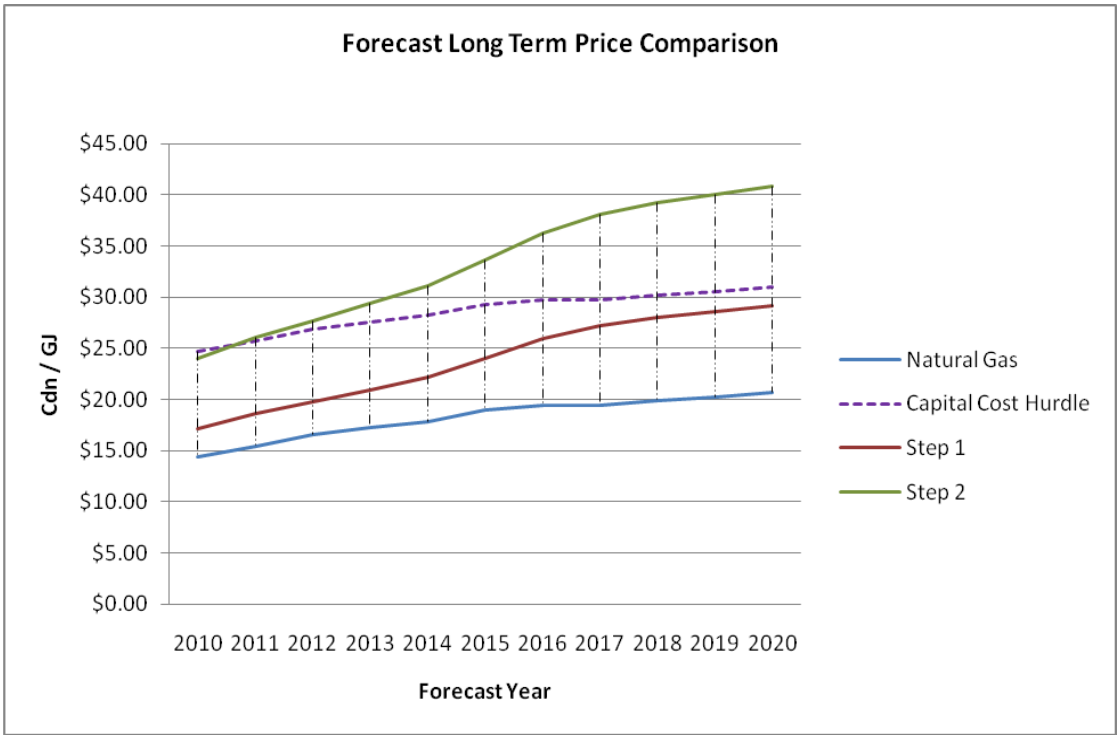
1) Projections are based on current 2010 Q4 TGI rates only and do not reflect the rates of TGVI or TGW.
2) Variable Charges (Midstream Charge, Delivery Charge) forecasts are based on 2010 rates plus an annual inflation of 2.1%.
3) Basic Charge forecast is based on 2010 plus annual inflation of 2.1%.
4) Carbon Tax is based held constant beyond July 2012 – last published rate increase.
5) All other associated costs and taxes are included, with Harmonized Sales Tax (HST) calculated at 5% to reflect the 7% residential energy credit.
6) Non-variable rates are based on annual consumption of 50 GJs per year.

The figure below compares the long term price forecasts of the Terasen Utilities natural gas rates and BC Hydro step 1 and step 2 electricity rates. For reference, this figure also includes the 'capital cost hurdle', calculated by adding $10.31 to the estimated future natural gas rates to represent the point that electricity rates must exceed in order for the incremental upfront capital costs for a natural gas heating system to be recovered over the life of the furnace.

[5] The forecast natural gas rates rely on a number of assumptions as outlined below and should be viewed as directional only for the purposes of this exercise. The forecast does not represent Terasen Utilities' views as to future revenue requirement applications beyond 2010-2011. Any rate increases requested in those applications will be based on Terasen Utilities detailed assessment of its expected revenues and costs at the time of the filing, taking into account the operating conditions and plans forecast for the relevant test period.

[6] Information modified from Terasen Utilities 2010 LTRP Section 2, Figure 2-4, P. 18

[7] GLJ Petroleum Consultants Ltd. is a private petroleum industry consultancy service that prepares quarterly commodity price and market forecasts.



As the figure above demonstrates, based on the assumptions employed the estimated electricity rates for the next ten years exceed the estimated natural gas rates by more than $10/GJ using the RIB Step 2 electricity rate staring in 2011. However, the differential is less than $10/GJ within the 10-year time frame until 2020 if the RIB Step 1 electricity rate is used as the basis of comparison.

While the above analysis projects a reasonably favourable competitive position for natural gas over electricity today based on the current GLJ natural gas price forecast, it does not factor in larger societal forces in terms of public policy changes, potential increases in the carbon tax and changing public perceptions of burning fossil fuels. It also does not factor in the potential for future natural gas commodity prices to be significantly different from current forecasts as the full cost of developing the shale gas potential and associated infrastructure becomes better understood. These future uncertainties will ultimately influence the future competitiveness of natural gas as much or more than a basic cost-benefit analysis.

12.2 At what point of increase in electricity prices would natural gas reach the point of having a $10/GJ advantage?

Response:

Please refer to Figure 3 in the response to CEC IR 12.1. If the RIB Step 2 rate is taken as the reference point for comparison, the $10/GJ differential may occur as early as 2011 based on the assumptions employed in the analysis. However, the RIB Step 1 rate is not likely to exceed the natural gas rate by the $10/GJ amount in the ten-year period. The relative exposure to the Step 1 and Step 2 rates will vary from customer to customer. The Step 1 rate will be the relevant reference point for many smaller volume residential energy consumers. As stated in the response to CEC IR 12.1 the $10/GJ differential is only one factor among many that will affect the competitive position of natural gas going forward. Such issues as the changing public perceptions of natural gas as a fossil fuel-based energy source, more restrictive governmental policies targeting a low carbon future, and the possibility of future increases to the BC carbon tax will also influence the competitive position of natural gas going forward.

13. Reference: Exhibit B-1, Page 33

> The Figure 2-13 above illustrates that the trucking (light trucks, medium truck and heavy trucks) segment makes up approximately 44% (or 11.4 Mt) of the total emissions profile. Passenger cars (small and large) represent approximately 17% (4.4 Mt), and marine consists of 16% (4.1 Mt). Data from NRCan indicates heavy-duty NGVs emit 15%-30% less GHG emissions than their diesel counterparts[29]. These sectors represent an important opportunity for the Utilities to use natural gas as a transportation fuel in these high emission sectors to help meet B.C.'s legislated GHG reduction targets.

13.1 Has Terasen been able to identify the trucks and marine markets down to the level of potential customers?

Response:

TGI's NGV sales efforts have identified a variety of customers and specific projects for NGV development. One such example is Waste Management Canada ("WM"), which operates a fleet of 100 commercial garbage trucks from a location in Coquitlam. This company has recently signed an agreement with TGI (subject to BCUC approval) that involves the purchase and fuelling infrastructure for 20 natural gas garbage trucks. WM plans to convert all 100 trucks at this site to natural gas as their fleet replacement schedule allows. For LNG markets, TGI is progressing contracts with the City of Vancouver and with Wastech Services Ltd. for garbage transfer operations. These customers would use LNG powered tractor trailer units. On the marine side discussions have been held with two major ferry operators on the BC coast. One is conducting a detailed feasibility evaluation regarding the conversion of a ferry to natural gas engines. TGI supports this project.

13.2 If not when does Terasen expect to have itself in the position to understand the market at that level?

Response:

Please refer to the response to CEC IR 1.13.1.

13.3 Has Terasen identified the key criteria for getting companies to switch to NGV and has Terasen identified the size of target markets which may be ready to address the conversion decisions?

Response:

TGI has identified the key criteria for getting companies to switch to NGV. The key criteria are:

- Availability of proven vehicles[8] for the intended type of service.- This is through a variety of OEM such as Mack, Crane Carrier, Autocar, Freightliner, New Flyer, Kenworth and Perterbilt.
- Economics - Customers are attracted to the potential to reduce their fuelling costs. For example, a recent evaluation conducted for Waste Management indicated savings in excess of 40% versus diesel.
- GHG emission reductions - Customers are attracted to the potential to achieve 20 -30% reductions in GHG emissions. GHG savings can help customers meet legislative and self-imposed reduction targets, and may provide an advantage over competitors.
- Fuelling infrastructure - Customers are interested in having complete fuelling service solutions made available to them from a trusted supplier. TGI's proposal to supply fuelling solutions that deliver the gas in a form that the vehicle needs is being well received.

The size of the target market has been identified and is provided as part of the LTRP (See Appendix B-8). A detailed breakdown of the market penetration estimates is being developed and will be filed within the Transportation Application by the end of 2010.

[8] "Proven Vehicles "refer to NGV engine technology which has been manufactured and installed in Original Equipment Manufacturers (OEM) vehicles. NGV engine technology designed by Cummins-Westport has proven performance with over 25,000 engine deliveries worldwide. For more details, please see: http://www.westport.com/products/md.php.

14. Reference: Exhibit B-1, Page 44

> As part of the B.C. Throne Speech delivered on February 13, 2007, the government first announced targets for provincial GHG reductions. Effective January 1, 2008, the *Greenhouse Gas Reductions Targets Act* enshrines in law the provincial government's commitment to becoming carbon neutral, and sets province wide targets for GHG emissions reductions of:
>
> - 33% from the 2007 level by 2020, and
> - 80% from the 2007 level by 2050

14.1 At this point the Terasen LTRP appears to have higher levels of natural gas use than would be required to assist in meeting a 33% reduction from 2007 levels by 2020. Does Terasen at the time of this LTRP have any perspective on the risks associated with plans which to not incorporate some scenario as to how the companies would accommodate future policy that may lead the Province to meet these targets?

Response:

Please see the response to CEC IR 1.2.1.

15. Reference: Exhibit B-1, Page 55

15.1 Has Terasen identified waste heat opportunities in its markets and matched them to the market opportunities to displace existing heating?

15.1 Has Terasen identified waste heat opportunities in its markets and matched them to the market opportunities to displace existing heating?

Response:

The Terasen Utilities have identified a number of cases where there is waste heat from a manufacturing or commercial process through conversations with large industrial customers and market scanning across industry sectors. Once a waste heat opportunity is identified, there are a variety of different approaches that may be considered by the business operator and TGI:

- Do nothing – the customer may choose to do nothing as there is not the incentive, financial or otherwise, to either reduce energy or use the waste heat.
- Undertake EEC – the customer may choose to undertake energy efficiency initiatives to reduce energy via the capture of waste heat to use for their own needs. Through the EEC program, the Terasen Utilities may be able to provide financial incentives to assist the implementation of the required measures.
- Utilization of waste heat by others – depending upon the location of the customer, it may be possible to capture the waste heat and transport it for use by other users. In this case there is an opportunity to develop the infrastructure to capture, transport and deliver the waste heat in the form of hot or ambient water for heating and/or cooling requirements at other locations.

Each opportunity is unique and the customer solution is therefore unique. As such there has not been a formal matching of waste heat to market opportunity.

15.2 Does the development of the AES market depend more on the new development market as opposed to the existing communities market?

Response:

The development of the AES market, or integrated energy market, depends upon both new development and converting or retrofitting existing building stock.

Examples of new developments include the development of a district energy system for the Fraser Mills project in Coquitlam that will ultimately house 3700 residents and geoexchange systems for a new townhouse project in Delta. Examples of retrofit projects include the district energy systems being developed for two areas in Kelowna that will connect several existing buildings and the geoexchange system for the Helen Gorman School in Kelowna.

16. Reference: Exhibit B-1, Page 65

> TGI intends to bring forward an application to the Commission in the summer of 2010 for approval of more complete transportation fuel service offerings. That application will include the requirement for and appropriate treatment of CNG and LNG fueling infrastructure being sought from the Utilities by existing and potential future customers. Extension of a more complete NGV service to the TGVI and TGW service territories is contemplated at a later date pending future unbundling of gas delivery rates for these utilities.

16.1 Has Terasen yet identified where in the Province appropriate CNG and LNG fuelling infrastructure may be likely required?

Response:

Under the strategy being developed, the Terasen Utilities will primarily target heavy duty truck and bus[9] operations. These would naturally be based in the major population centres and the major transport corridors.

CNG stations would be established at customers' sites which would include:

- Transit operations bases (e.g. Abbotsford, Nanaimo, Kelowna)
- Refuse vehicles operations servicing municipalities
- Local distribution companies (e.g. beverage distributors, local haulers)

LNG stations would be established to service specific point-to-point hauling operations such as:

- Garbage transfer from Vancouver to Cache Creek

General trucking corridors such as from Vancouver to Calgary CNG and LNG stations will be established in response to customer demand as exemplified by the willingness to sign fuelling purchase commitments.

[9] Primarily transit and urban buses

16.2 Given that the summer of 2010 appears to be behind us, is Terasen on track to further its natural gas fuelling offerings and when will this likely reach the Commission?

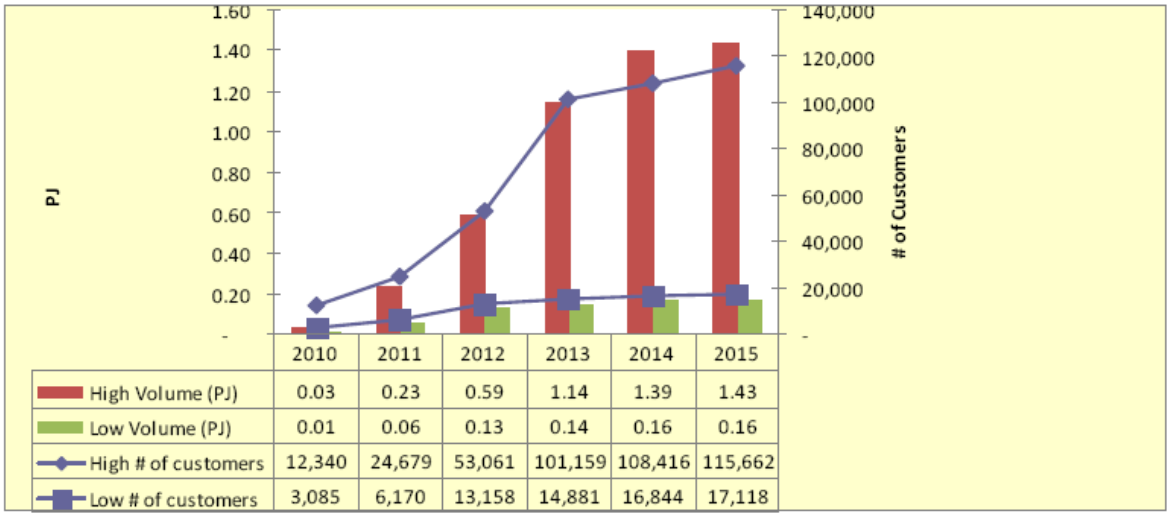
Response:

The Terasen Utilities is now planning to submit the application by the end of 2010.

17. Reference: Exhibit B-1, Page 71

- Ramping up to the industry average participation rate of 2.2%[84]; and
- Ramping up to the potential market share identified in the primary research Study of 16% for residential customers and 10% for commercial customers.

Figure 3-6: Low and High Demand Scenario



	2010	2011	2012	2013	2014	2015
High Volume (PJ)	0.03	0.23	0.59	1.14	1.39	1.43
Low Volume (PJ)	0.01	0.06	0.13	0.14	0.16	0.16
High # of customers	12,340	24,679	53,061	101,159	108,416	115,662
Low # of customers	3,085	6,170	13,158	14,881	16,844	17,118

17.1 What sort of resources does Terasen require to have in place to develop and respond to the potential demand of 2.2% or 16% residential and 10% commercial?

Response:

The Terasen Utilities currently have the resources in place to respond to the potential demand of 2.2% residential in terms of billing, gas supply and management and proposed customer education. Additional supply will need to be developed in order to serve the high demand scenarios as discussed in the Terasen Utilities' response to CEC IR 1.17.2. For multiple offerings, the Tersen Utilities will be waiting until the new billing system is in place in 2012 in order to avoid additional administrative cost of multiple tariff offerings.

TGI is actively seeking additional Biomethane projects to meet the expected demand from residential and commercial customers, as well as potential transportation and industrial customers. In addition to working with several potential private companies, TGI has had preliminary discussions with six (6) regional districts and six (6) municipalities. As detailed in the response to BCUC IR 1.3.1 in TGI's Biomethane Application filed to the Commission on June 8, 2010, these entities are listed below.

Regional Districts:

- Regional District Nanaimo
- Columbia Shuswap Regional District
- Regional District of North Okanagan
- Metro-Van (previously GVRD)
- Capital Regional District
- Regional District of Fraser-Fort George

Municipalities:

- City of Chilliwack
- City of Kelowna
- City of Surrey
- City of Abbotsford
- City of Vancouver
- District of Mission

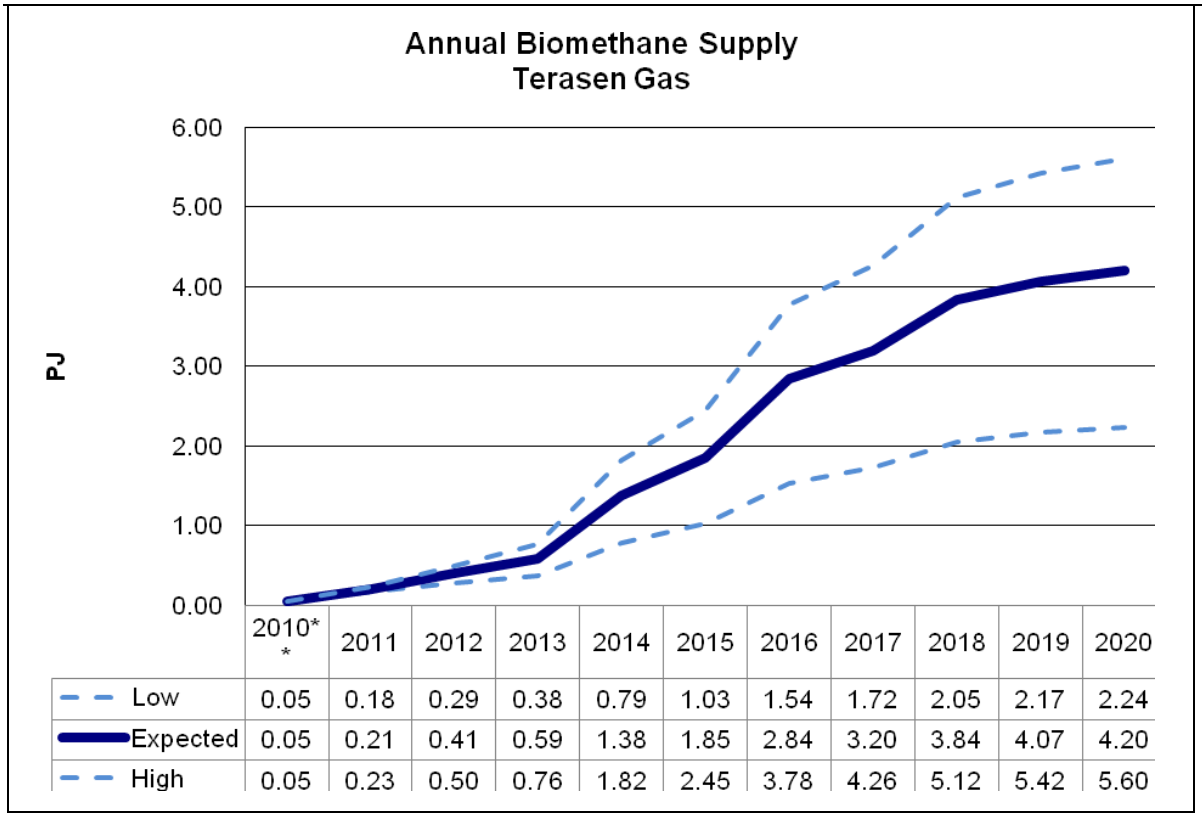
17.2 What is Terasen's response time to be able to ramp up its resource requirements between the scenarios shown in Figure 3-6?

Response:

As illustrated in the following table, in addition to the two supply agreements included in the Biomethane Application that total between 0.10 PJ - 0.22 PJ, TGI would need up to an additional 0 PJ - 1.33 PJ / yr in order to serve the demand scenarios in Figure 3-6. As discussed in the response to CEC IR 1.17.1, the Terasen Utilities currently have the resources in place to respond to the potential demand of 2.2% residential in terms of billing, gas supply and management and proposed customer education. TGI's current supply contracts at their maximum volume already provide for the low demand scenario out to 2015. Therefore, no additional resource requirements are required for the low demand scenario.

		Additional Supply Needed (GJ) (Min Contracted Volume 104,000 GJ)	**Additional Supply Needed (GJ) (Max Contracted Volume 222,500 GJ)**
High Demand Scenario / GJ	1,430,000	1,326,000	1,207,500
Low Demand Scenario / GJ	160,000	56,000	(62,500)

For the high demand scenario, TGI's expected supply ramp up is described in the figure below which shows expected supply of 1.38 PJ's by 2014. Therefore, it is expected the Tersen Utilities could ramp up to the high demand scenario of 16% residential and 10% commercial customers by 2014.



	2010**	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Low	0.05	0.18	0.29	0.38	0.79	1.03	1.54	1.72	2.05	2.17	2.24
Expected	0.05	0.21	0.41	0.59	1.38	1.85	2.84	3.20	3.84	4.07	4.20
High	0.05	0.23	0.50	0.76	1.82	2.45	3.78	4.26	5.12	5.42	5.60

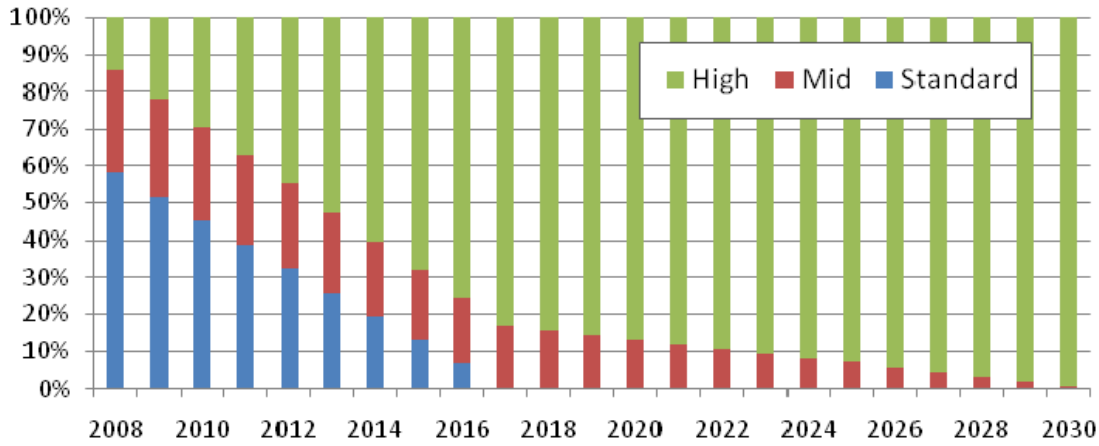
17.3 What is Terasen's response time to ramp up to 2.2% or 16% residential and 10% commercial?

Response:

Please see the Terasen Utilities' response to CEC IR 1.17.2.

18. Reference: Exhibit B-1, Page 79

Figure 4-2: Furnace Efficiency Share in Single Family Dwelling-LML



18.1 Given that declining average use per customer is certainly in part tied up with the furnace efficiency conversion taking place, does Terasen have any data or perspective on whether or not the efficient use of the thermal heat in these homes is changing or likely to change and further affect the declining use pattern?

Response:

The factors related to declining residential use rates are discussed in Section 3 of the Terasen Utilities' Residential End Use Study, included as Appendix B-1 in the 2010 LTRP. Changes to building codes, which certainly affect the efficiency of thermal energy, only impact new construction. At this time, there is no regulation other than that requiring any new furnace being installed to be minimum 90% efficiency that governs the efficiency of the existing housing stock. It is the Terasen Utilities' perspective that the existing housing stock offers significant opportunity to upgrade furnaces from standard to high efficiency. When considered across the entire existing housing stock in British Columbia, declining residential use per customer should not preclude the Terasen Utilities from engaging in a furnace early retirement program.

19. Reference: Exhibit B-1, Page 88

> For industrial customers the robust growth scenario is based upon a quicker than anticipated economic recovery in the sectors for the first two years followed by a period of stability. For example should the U.S. and world economies come out of recession sooner than expected, exports dependent sector such as the wood products, mining, chemical manufacturing and pulp and paper sectors could see higher demand than currently anticipated. At the same time, strong growth in provincial economy translates into higher demand for sectors such as apartments / condominiums and food and beverage manufacturing. The above factors have been taken into consideration while preparing the robust growth industrial demand scenario.

19.1 What is Terasen's view of the probability that the US and world economies, particularly the US economy, will come out of recession sooner than expected in a way that would have robust growth effects on the BC economy?

Response:

Through reviewing recent available economic information[10], the Terasen Utilities has considered the probability that the US and world economies will come out of recession sooner than expected in a way that would have robust growth effects on the BC economy. Although there are differing views on the future of the US and global economies, TD Economics, BMO Economic Research, and the Conference Board of Canada all indicate that a slow recovery from this recession is to be expected, and that there are more downside risks than upside ones. As such, the Terasen Utilities is of the view that it is unlikely that the US and other world economies will come out of recession sooner than expected.

[10] The economic information considered in developing this response includes the following publications:

- TD Economics: Quarterly Economic Forecast, September 16, 2010
- BMO: The Bottom Line, September 17, 2010
- The Conference Board of Canada: Would You Like To Make That A Double Dip?, September 27, 2010
- The Conference Board of Canada: No Light Yet In America's Dark Fiscal Tunnel, October 7, 2010
- The Conference Board of Canada: The U.S. Month at a Glance, October 8, 2010

20. Reference: Exhibit B-1, Page 89

> The customer additions forecast is derived from long-term provincial forecasts of household formations at the community level and validated against CMHC's nearer term forecasts in order to reflect the most current market situation. The forecast of customer additions is applied to both residential and commercial rate classes while no growth is assumed for industrial customers. The latest available economic analyses from the B.C. Government, major banks and other organizations are reviewed for consistency with the overall trend in household formations. For the forecast produced in support of the 2010 LTRP, the B.C. Statistics 2009 Household Formation Forecast (based on P.E.O.P.L.E. 34) was used to determine customer additions by area over the forecast period.
>
> Commercial customer additions tend to reflect the same long-term growth patterns as those for residential customers, since growth in the business sector generally stems from growth in the population. This trend is captured in our forecast of commercial customer additions.

20.1 Is it possible that there may be opportunities for customer additions and growth in the industrial sector in more remote BC locations where diesel applications have been the more traditional forms of energy such as mines and remote communities?

Response:

There may be opportunities for customer additions in the industrial sector in remote BC locations. These would typically be to serve the energy requirements of mining operations. From the Terasen Utilities' perspective, these customers could be served with LNG or integrated energy solutions such as biomass or geothermal based district energy systems. As opportunities arise, the Terasen Utilities investigates and analyses the opportunity; but to date, we have not proceeded further than a cursory review of potential projects in northern remote industrial opportunities.

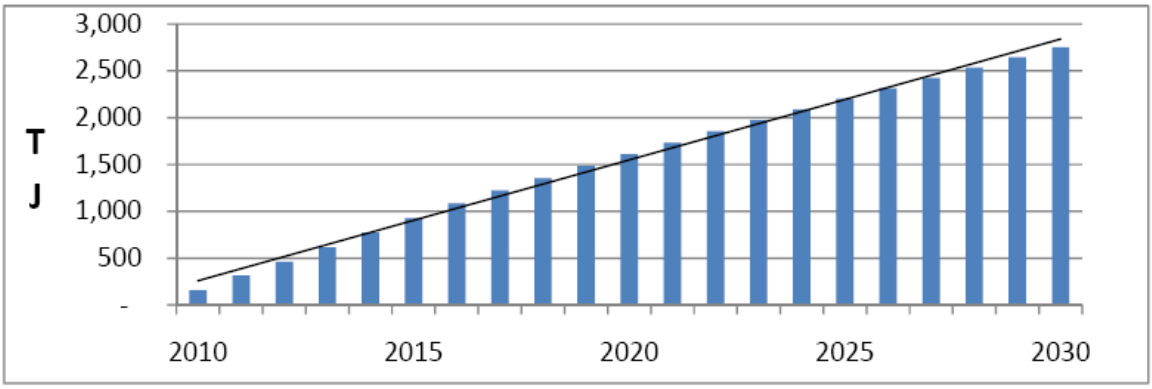
20.2 Has Terasen examined this possibility and determined whether or not this may represent a market, which Terasen has not previously looked to service?

Response:

Please see the response to CEC IR 1.20.1.

21. Reference: Exhibit B-1, Page 97

Figure 4-15: Natural Gas Demand Forecast for New Residential Customer Space Heating



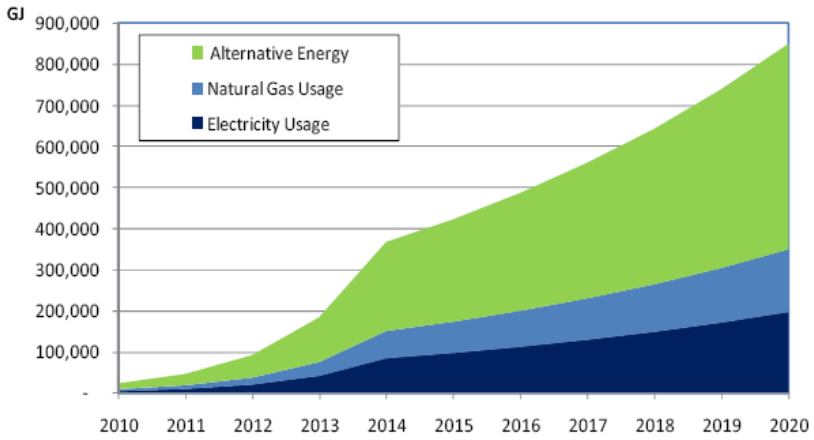
21.1 At what rate of use per residential customer are new customers being added to the system assumed to be?

Response:

Exhibit B-1 illustrates space heating demand for new customers in the LML region and assumes an annual use rate of 51.3 GJ/year for single-family dwellings, 23.6 GJ/year for Townhouses, and 4.8 GJ/year for Apartments/Condominiums. These figures were developed through incorporating results from the 2008 REUS, and also assume that new residential customer additions are in compliance with building codes and standards that now mandate high efficiency furnaces as well as higher levels of insulation throughout the dwelling.

22. Reference: Exhibit B-1, Page 101

Figure 4-19: Total Annual Thermal Energy Consumption for 185 Buildings - Alternative Systems



22.1 What is the anticipated investment in alternative systems to achieve the thermal energy fuel source displacement shown?

Response:

The amount of investment in an alternative energy system is dependent on type of energy system selected and the region in which it is being installed. The choices can range from a standalone solution for a single building (based on technologies such as geoexchange or solar) to a district energy system that distributes steam, hot water, ambient water or chilled water at central or distributed plants and then pipes the energy to multiple buildings (based on technologies such as waste heat recovery, geoexchange or biomass). Investment estimates are dependent on both type and amount of equipment installed. Systems may range from $3000 to $8000 per 1,000 sq. ft unit, but costs could vary from these estimates for the reasons identified above.

It should be noted that the economic proposition for alternative energy systems is based on the composite blend of capital costs and ongoing operating and maintenance (O&M) costs compared with the costs in these same categories for a conventional energy system. Alternative energy systems are typically characterized by higher upfront capital costs but lower ongoing O&M costs relative to conventional energy systems. Different types of alternative energy systems will have different blends of capital costs and ongoing O&M expenses relative to other alternative energy systems.

To develop Figure 4-19, a specific alternative energy system was assumed to be a reasonable proxy system for a 100-unit condominium. The chart is based on 185 buildings adopting this type of system by 2020. The assumed alternative energy system for the 100-unit condominium was a geoexchange system with a ground loop field and mechanical equipment estimated to

cost $525,000 in current dollars. This would translate into an average cost of $5,250 per suite. The total capital investment for 185 buildings with energy systems of this type would be $97.1 million (current dollars). There are also costs within the building for piping to the suites and radiant heating equipment within the suites but these costs are borne by the developer.

22.2 How would that investment compare to traditional energy systems investment?

Response:

A conventional energy system for the same generic 100-unit condominium used to develop Figure 4-19 would typically consist of natural gas boilers for domestic hot water and heating the common areas in the building and electric baseboard space heating within the suites. The costs for the internal piping, ducting, wiring and baseboard heaters in the suites would be borne by the developer. In some areas it may be more common to have conventional energy system that is a hydronic gas system employing gas boilers for space and water heating in both the common areas and within the suites. The developer would typically look after the costs of in-house piping and radiant heating equipment throughout the building in this case.

The centralized components in a conventional energy system for this 100-unit condominium that would compare with the loop field and mechanical equipment in the alternative energy configuration would consist of the natural gas boilers and related equipment. These are estimated to cost approximately $45,000. For 185 buildings the overall investment would be $8.3 million (or less than 10% of the $97.1 million for the corresponding alternative energy investment). For the hydronic gas option, the estimated capital cost of centralized equipment is approximately $85,000. For 185 buildings the overall investment would be $15.7 million (or about 16% of the $97.1 million for the corresponding alternative energy investment).

As discussed in the response to CEC IR 1.22.1 the ongoing O&M costs for conventional energy systems are higher than for an alternative energy system since conventional systems use more energy and are therefore more exposed to gas and electricity rates. For the end user, when comparing on a lifecycle basis, the lower ongoing O&M for an alternative energy system will compensate for much or all of the lower upfront capital costs of a conventional system.

22.3 Would there be any efficiencies achieved?

Response:

Alternative energy can achieve higher levels of efficiency compared with conventional energy technologies. For example, for a geoexchange system the Coefficient of Performance of 3 to 4 produces 3 to 4 kWh of heat for every kWh of electrical energy employed to run the heat pumps. This translates to a reduction in energy usage of up to 75 per cent.

The representative 100-unit condominium employed to develop Figure 4-19 would use 4,594 GJ/year of input energy (natural gas and electricity) if the building was configured with a conventional energy system. On the other hand the alternative energy system selected would only consume 1,891 GJ/year of input energy (mainly electricity to run the heat pumps with some natural gas use as backup in the colder winter conditions) to yield the same output. The particular AES example used in Figure 4-19 therefore results in a 58.8% efficiency improvement relative to a conventional system. The input assumptions for the representative 100 unit condominium example are described in detail in Appendix B-6 of the LTRP.

22.4 What would the effective cost of the GHG reductions achieved be?

Response:

It is estimated that the generic 100-unit condominium using a geoexchange system as the alternative energy system would reduce GHG emissions by 105 tonnes annually relative to a conventional system using in-suite electric baseboards and natural gas heating for water and common areas[11]. For 185 buildings with geoexchange systems, the total GHG emission reduction would be up to 19,425 tonnes annually. If the conventional system for 100-unit building is assumed to be a hydronic gas system, the GHG emissions reductions for the building with a geoexchange system would be about 210 tonnes annually (38,850 tonnes annually for 185 buildings).

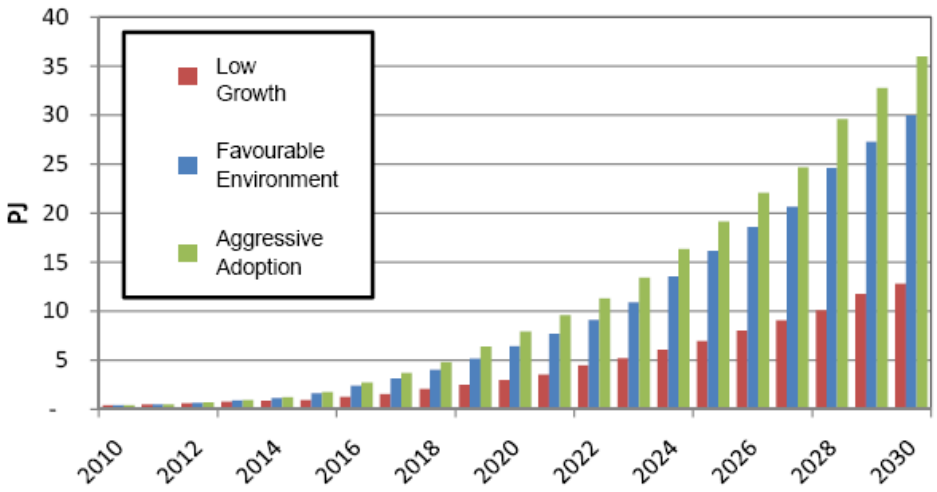
The Terasen Utilities has calculated an effective cost for GHG emission reductions using a present value of the cost differential between the conventional and alternative systems divided by the present value of the GHG emission reductions. The effective cost for GHG emission reductions varies considerably based on the evaluation period employed. Using the electric baseboard system as the basis for comparison, the effective cost of the GHG reductions for the geoexchange system is \$176/tCO_2 over a 20-yr evaluation period or \$42/tCO_2 based on a 35-year evaluation period. With the hydronic gas system as the basis for comparison, the effective cost of the GHG reductions is \$131/tCO_2 over a 20-yr evaluation period or \$71/tCO_2 based on a

[11] See Terasen Utilities 2010 LTRP Appendix B-6, Tables 1 and 2.

35-year evaluation period. The effective cost per tonne of GHG emission reductions is lower over a longer evaluation period because the geoexchange system is initially more costly than the conventional system but crosses over and becomes less costly. The savings for the geoexchange system, which uses less energy than the conventional system, continue to increase in the later years as the input energy costs for electricity and natural gas escalate over time.

23. Reference: Exhibit B-1, Page 112

Figure 4-22: Comparative NGV Demand Scenarios



23.1 Would it be fair to say that the potential for NGV demand at this 6% to7% market share level would have as much effect on the demand requirements and throughput as all of the additions of new customers for traditional residential, commercial and industrial growth over the same time period?

Response:

The estimated 30 PJ of NGV demand growth or 34,540 new vehicle additions under the favourable environment scenario, will have significantly higher impact on demand than the addition of 150,000 new residential and commercial customers over the planning period. The impact of ongoing conservation efforts, stricter building codes and standards and integrated energy solutions is expected to further reduce the use per account impacting the overall throughput of the traditional residential and commercial customer additions. The addition of load growth in the system from the NGV initiatives will be an important offset to the levelling off of demand growth from residential and commercial customer segments. It will also utilize the existing natural gas infrastructure to the benefit of all of the Terasen Utilities' customers while reducing province wide GHG emissions.

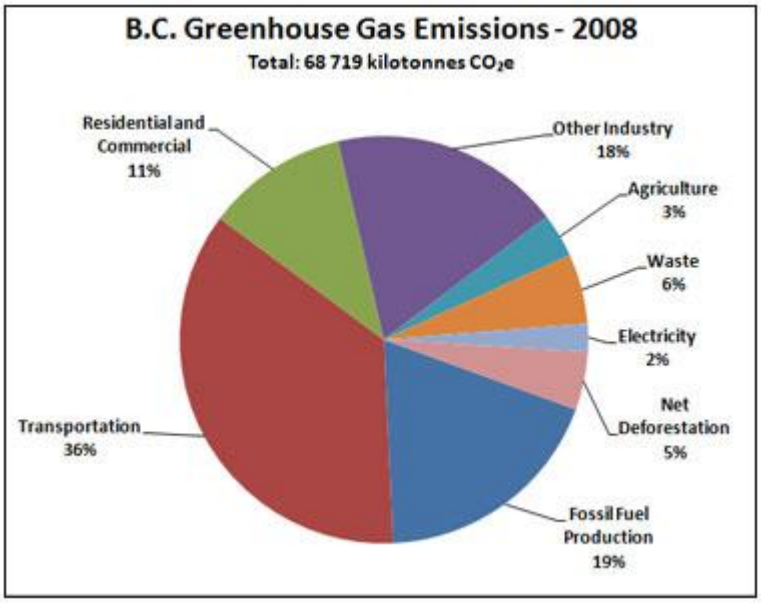
24. Reference: Exhibit B-1, Page 118

> TGI believes that there is significant potential for a reduction in Interruptible Industrial[113] consumption. Initiatives are currently being developed for this segment, but it is not yet clear how future load will be affected by conservation efforts. To assist TGI in determining the size

24.1 Why does Terasen believe that there is significant potential for reduction in interruptible industrial customer consumption?

Response:

In B.C., the industrial sector represents one third of the Province's total energy consumption, and is a significant contributor to the regional GHG inventory. The figure below depicts the contributions by sector to B.C.'s GHG emissions. Transportation accounts for the largest share of provincial GHG emissions; the oil and gas sector is the second largest share of B.C.'s emissions followed by "Other Industry" such as the chemical manufacturing and pulp and paper industries. The residential and commercial sector account for only 11 per cent.



Source: http://www.livesmartbc.ca/learn/emissions.html

Of the Terasen Utilities rate classes that are considered industrial, the interruptible industrial consumption is forecasted to be greater than the firm consumption, as can be seen in Table "Forecast 2010 Consumption" below.

Firm(TJ)	
Rate5	2,770
Rate 23	6,722
Rate 25	12,111
Total	**21,603**
INTERRUPTIBLE(TJ)	
RATE7	7
RATE 22	28,090
RATE 27	5,484
Total	**33,581**

The Terasen Utilities believe those industrial customers, both firm and interruptible, offer opportunities for energy efficiency and conservation. For example, in the 2006 Conservation Potential Review, filed as Appendix 1 of the TGI and TGVI's 2008 EEC Application, it was stated that the majority of lumber dry kilns in B.C. use natural gas and there are a number of upgrades possible to convert an average kiln into an energy efficient kiln. These upgrades include automatic venting, improved insulation and heat recovery. Opportunities for improvement also exist in the chemicals, non-metallic minerals, paper and other manufacturing sectors where boilers are used. Energy efficiency opportunities for boilers include near condensing and condensing boilers, boiler economizers, boiler combustion air-preheating, boiler condensation heat recovery and advance boiler controls such as boiler reset controls. The following cross-industry technology matrix is summary of savings opportunities vs. for each different industry.

	Waste heat recovery/ gases and liquids/ chemicals, petroleum, forest products	Combined heat and power	Advanced industrial boilers	Heat recovery from drying	Steam best practices	Pumped system optimization	Energy system integration	Improved process heating/ heat transfer/ chemicals, petroleum	Efficient motors/ rewind practices	Waste heat recovery/ gases/ metals and minerals.	Energy source flexibility	Improved sensors, controls	Improved process heating/ heat transfer/ metals melting, heating	Compressed air optimization	Optimized materials processing	Energy recovery/ by product gas	Energyexport and co-location	Waste heat recovery/ calcining	Heat recovery/ metal quenching/ cooling	Advanced process cooling/ refrideration
Petroleum Refining	■	■	■		■	■	■	■	■		■	■		■	■	■	■			■
Chemicals	■	■	■	■	■	■	■	■	■		■	■		■	■	■	■			■
Forest Products	■	■	■	■	■	■	■	■	■		■	■		■	■	■	■	■		
Iron and Steel		■	■		■	■	■		■	■	■	■	■		■	■	■		■	
Food and Beverage	■	■	■	■	■	■	■	■	■		■	■		■	■		■			■
Cement				■		■	■		■		■	■			■			■		
Heavy machinery		■	■		■	■	■		■		■	■	■				■		■	
Mining						■	■		■		■	■			■				■	
Textiles	■	■	■		■	■	■	■	■		■	■		■			■			
Transportation Equipment		■	■		■	■	■		■		■	■	■				■		■	
Aluminum & Alumina						■	■		■	■	■	■	■		■				■	
Foundries						■	■		■	■	■	■	■		■				■	
Plastic and rubbers	■	■	■		■	■	■	■	■		■	■		■			■			
Glass and Glass products						■	■		■	■	■	■	■		■					
Fabricated Materials						■	■		■	■	■	■	■						■	
Computers, electronics, appliances						■	■		■		■	■								

Source: http://www1.eere.energy.gov/industry/intensiveprocesses/pdfs/energy_use_loss_opportunities_analysis.pdf

Given the volume of natural gas consumed by interruptible customers, the Terasen Utilities is of the view that it should have an energy efficiency and conservation stream for our industrial customers as well as for our residential and commercial customers

25. Reference: Exhibit B-1, Page 119

> The NGV market shows particular promise for this portfolio. As a result of potential EEC incentives, the City of Vancouver, City of Surrey, City of Port Coquitlam and other third party partner have all expressed interest in converting some of their current high carbon diesel fleet into NGVs, and purchasing new NG trucks for garbage disposal. Switching to natural gas as a transportation fuel reduces GHG emissions by displacing higher carbon fuels like diesel and gasoline, and by adding load, optimizes use of the gas distribution system.

25.1 Please describe and quantify the incentive being provided for NGV conversions?

Response:

The new support program being developed for NGVs is for new vehicle purchases rather than conversions. This is to ensure that the vehicles purchased are commercially proven reliable offerings.

This initiative is part of the overall EEC program. Under the program TGI will offset up to 100% of the incremental cost of purchasing NGV's versus conventionally fuelled vehicles. The amount approved is subject to a business case assessment which includes a Total Resource Cost test.

The amount of the support incentive will vary by the type of vehicle being proposed and the amount of diesel fuel displaced. A garbage truck for example may receive an incentive of $26 - $55,000. A heavy duty long haul LNG tractor may receive an incentive of up to $80,000.

Funds available under this program are limited and it is TGI's intention to utilize the incentives on key customers that have an ability to influence market adoption. TGI is also seeking to leverage this incentive program with similar programs expected to be launched by federal and provincial governments in 2011. That may lead to lowering TGI's contribution from 100%.

26. Reference: Exhibit B-1, Page 128

> A challenge in developing EEC programs is estimating program uptake rates and energy savings. There are a number of factors that affect participation rates including emergence of new technologies, economic conditions, the political climate, changes in adoption rates for current technologies, energy price fluctuations, changes in consumer behaviour and consumption patterns, and initiatives by other utilities or government. Inconsistent incentive funding hinders program development, as staff cannot develop programs with long term goals in mind, and communications with participants and market factors such as equipment installers about program lifetimes are erratic.

26.1 What period of advance funding commitment and approval would be required to enable stable and consistent development of the EEC efforts and undertakings?

Response:

The Terasen Utilities believe that approval of a five-year funding envelope would be appropriate. This would provide many of the benefits that come along with long-term funding. The primary benefit would be the certainty for the various actors in the marketplace that "efficiency is here to stay" and that investments made in advanced equipment and building development, training and the establishment of installation protocols and market transformation work in advance of regulations are worthwhile and will have lasting payoffs. A five-year funding envelope would also free up the EEC staff from the work associated with more frequent EEC funding applications. Oversight of the Terasen Utilities' EEC activity would be provided formally by the EEC Stakeholder group, which includes representation from the Commission and currently meets semi-annually, and through the EEC Annual Report to the Commission and stakeholders, as well as on an informal basis.

27. Reference: Exhibit B-1, Page 143

> The Cache Creek/Ashcroft Lateral is served from the Westcoast Pipeline in the Thompson region. The lateral delivers gas to Cache Creek and Ashcroft which are located approximately 70 km west of Kamloops. The lateral consists of a combination of two pipelines and is at its capacity to meet peak demand. Reductions in available supply pressure from Westcoast are increasing the frequency of curtailment to an industrial customer on the lateral. The addition of a 17 km pipeline loop is required to meet current firm transportation service by the industrial customer, but TGI is currently exploring the option of further reducing this contractual demand, and alternately the possibility of developing a Cache Creek landfill gas project to avoid the need for a pipeline addition.

27.1 Would the Kamloops loop require more capacity on the T-south mainline to service the demand and would that reduce the capacity available to the Lower Mainland on the Spectra system?

Response:

With the addition of a 17 km pipeline loop on the Cache Creek/Ashcroft Lateral, the increased flow to the industrial customer in Ashcroft represents 0.07% of the T-south flow to the Lower Mainland on a design peak day. Therefore, there would be negligible impact on the capacity available on Spectra's T-south to the Lower Mainland.

27.2 If Terasen were to develop a Cache Creek landfill operation would it increase capability on the T-south mainline and or would there be any system wide impacts beyond providing the Kamloops/Cache Creek/Ashcroft loads?

Response:

Dependent upon the output capability, the development of a Cache Creek landfill operation as an alternative gas supply could possibly provide the following two benefits:

1. Defer or avoid the need to loop the Cache Creek/Ashcroft lateral.
2. Slightly reduce gas delivery from the Spectra T-south Mainline to Cache Creek/Ashcroft which could be diverted to the Lower Mainland.

However, the Terasen Utilities have not conducted analyses to determine whether the project is cost effective.

27.3. What value is the interruptible customer losing because of curtailment of loads?

Response:

In the event of curtailment, the customer would have to curtail production as they do not have an alternative or backup fuel source. The customer is therefore losing the value of its production capacity during curtailment of loads. The industrial customer has a firm contract that is partially interruptible if TGI's system capacity is not able to meet the customer's full requirements due to the fact that TGI is receiving below normal pressures from Westcoast and weather is approaching design day conditions. The Terasen Utilities has a curtailment plan in place that determines the available capacity for the industrial customers under certain conditions. To date the Terasen Utilities has not had to curtail the customer; however, this could change with future growth in the region. This risk of partial curtailment needs to be weighed against the benefit to the customer of having a lower transportation rate for that portion of service that is interruptible.

28. Reference: Exhibit B-1, Page 156

> Within the Terasen Utilities, asset management practices have also evolved over time. Examples of existing practices include:
>
> - meter inspection and replacement programs based on a statistical sampling,
> - seismic vulnerability assessments for pipeline river crossings,
> - assessment of safety risk to justify the cast iron main replacement, and
> - an in-line inspection program to assess pipeline conditions identify repair and re-inspection frequencies.

28.1 How many kilometers of cast iron main replacement does Terasen have left to complete?

Response:

Approved in June 2006 through a Certificate of Public Convenience and Necessity ("CPCN") by BCUC Order No. C-2-06, Terasen Gas completed the replacement of 93 km of low pressure ("LP") cast iron mains by 2008. They were replaced with high density polyethylene ("HDPE") pipe, along with the upgrade of 6981 LP services and the removal of 24 LP regulating stations. There is no cast iron main left in the Terasen Utilities` distribution systems.

28.2 What is the age profile of the inventory of iron main kilometers?

Response:

The low pressure (LP) cast iron mains were installed from the initial distribution of manufactured coal gas in Vancouver in 1886 to well into the 1950s. Available records indicated that well over 800 km of LP mains were installed by 1932. Significant replacement took place in 1970s and 1980s based on the criteria of leak history and the time required for emergency response. The last remaining 93 km that were removed from 2006 to 2008 were likely the latest lengths installed in the 1950s.

28.3 What is the schedule for replacement and when will it be complete?

Response:

Please see the response to CEC IR 1.28.1.

28.4 What are the safety risk issues and tradeoffs being managed by Terasen in regard to this issue?

Response:

The Terasen Utilities understand this question to be referring to the replacement of cast iron mains as cited in CEC IR 1.28.1. The aging Low Pressure ("LP") cast iron mains experienced a rate of increased leakage and water ingress problems over 19 times more than that of steel and PE mains. The risk to the integrity of the LP mains from ground disturbance, nearby excavation, and minor or significant seismic events exceeded acceptable levels.

The tradeoffs were a significant investment of 18.3 million 2008$CDN to upgrade the distribution system, and associated effects on the public during the construction phase. In particular, during the construction phase, there was a potentially significant effect on the public through increased traffic and noise, gas service interruption and potential safety hazard to the public and worker. The impact to the public was minimized through an effective communication plan, strict observance of job site safety and adherence to environmental protection, external coordination with the city, other utilities, and building contractors, and the use of PE main insertion method through existing cast iron mains to minimize interruption to existing surface landscape and sub-surface infrastructures.

28.5 Has Terasen's perspective changed since the events in the US caused regulators to look at re-evaluating the asset management practices for this category?

Response:

The events in the U.S. such as pipeline ruptures causing harm to the public and environment confirm that the Terasen Utilities have the correct perspective in asset management practices. That is, the Terasen Utilities should, and will, continue to apply a strategic management system to optimally manage assets over the life cycle by balancing asset performance, risks and

expenditures to provide a safe, reliable, environmentally responsible, and economical gas delivery services to its customers now and into the future. This means that the Terasen Utilities should and will continue the monitoring and assessment of its asset conditions and performances, and where appropriate developing capital investment and maintenance strategic actions to mitigate risk to safety and gas delivery services. In addition, asset management practices are subject to continuous assessment and improvement.

29. Reference: Exhibit B-1, Page 172

> In comparison to this incremental take-away capacity, B.C. production is forecast to increase by only 1.9 Bcf/d from 2009 to 2014. The increased competition for B.C. supply could ultimately lead to higher prices and increased volatility at Station 2 and Sumas, the Utilities' main sources of supply to meet customer demand.

29.1 In Terasen's estimate what is the range of likely price increases and volatility increases which might affect Terasen's BC customers due to this increased take-away capacity?

Response:

Price and volatility changes vary largely due to the market conditions based on supply, demand and available infrastructure utilized to facilitate movements of supply from the production region to the marketplace. At this point in time it is difficult to determine the degree of price and volatility and impact the increased take-away capacity will have on the BC marketplace given the number of pipeline activities happening simultaneously.

There are several variables that will impact price volatility in the new gas supply from north eastern BC. The development and level of long term commitments by producers on new expansions combined with modifications in pipeline tolling methodology are some of the key factors that could likely increase the price for gas in the BC marketplace. Many of these complex issues are currently being discussed among a wide range of stakeholders such as the pipeline companies, producers, shippers, customer groups and regulators. As a result, any estimates to pricing and volatility are greatly unknown and cannot be derived with any level of certainty at this point.

However, the pricing and volatility can be expected to increase at the Station 2 marketplace should the major pipeline expansions bypass Station 2 and/or if the pipeline tolling methodologies stemming from the major pipeline expansions increase the cost to deliver to Station 2. Should the Station 2 market be bypassed as a delivery point, increases in pricing and volatility can be expected since the Station 2 market will be forced to bid for gas at higher prices particularly during the winter months. Furthermore, this pricing and volatility has the potential to increase significantly relative to other regional markets should the BC and PNW markets undergo a cold snap which has been the case during prior winter weather related events.

29.2 If the risks are significant for long-term price impacts, should Terasen be examining the potential for ownership of some of the supply capability?

Response:

The Terasen Utilities are continually exploring options of ownership of supply capability designed to meet customers load requirements in a cost effective manner. Ownership of supply capability could include the ownership of wells that produce natural gas, the ownership of transmission or distribution pipeline assets that are used to transport the natural gas to markets, and ownership of storage or LNG assets.

The Terasen Utilities' business model as a public utility with rates set by the BCUC is based on earning a fair and reasonable return on its regulated assets, which currently include pipeline assets like SCP and LNG assets like Tilbury and Mt. Hayes. The Terasen Utilities will continue to explore opportunities in developing assets or infrastructure projects like SCP or Mt Hayes if they are in customer's best interests.

The business of commodity production and sales is conducted at market prices based on the dynamics of supply and demand unlike the regulated business model of the Terasen Utilities. As a result, the business of commodity production would likely need to be segregated from and conducted outside of the Terasen Utilities publicly regulated business entities. It is unlikely that the Terasen Utilities would explore opportunities within this area, as there are many market participates focused on developing supply in BC.

The Terasen Utilities attempt to mitigate and manage situations that can negatively affect the long term pricing of commodity via a variety of methods which include:

1. Contracting for gas supply at different market hubs such as Sumas, AECO, Station 2 and upstream of Station 2 at a plant's outlet.

2. Withdrawing gas from storage (that was injected at lower summer prices) during winter months and periods of cooler weather in order to reduce its exposure to expensive winter priced commodity.

3. Up until 2010, the Terasen Utilities utilized market price hedging as a tool to manage higher prices and increased volatility at market hubs. Terasen's Price Risk Management Plan ("PRMP") had helped it achieve competitive rates (relative to other sources of energy) and reduced market price volatility on behalf of customers.[12]

4. Optimizing its gas cost portfolio by conducting cost mitigation activities around its gas supply contracting, storage and transportation assets.

[12] Pursuant to Commission Orders No. E-23-10, E-24-10, and No. E-27-10, the Terasen Utilities has suspended hedging activity pending a review of the primary objectives of the PRMP.

5. Implementing the T-South Enhanced Service pilot with Westcoast in order to promote southbound gas supply in and through the province. Facilitating the increase of gas flow to Station 2 and on Westcoast's T-South system in order to increase market liquidity within BC at the Station 2 and Huntingdon hubs while potentially reducing the toll on that pipeline system.

6. Representing customers' interests in NGTL and other regulatory proceedings due to their direct affect on the tolling and pricing of gas in the BC market.

30. Reference: Exhibit B-1, Page 185

> The Action Plan describes the activities that Terasen Utilities intends to pursue over the next four years based on the information and recommendations provided in this Resource Plan.

30.1 In conducting its resource planning how does Terasen evaluate its proposed action plans, such that it has demonstrated to itself that the plans represent optimal choices of direction?

Response:

The development of an Action Plan within a Long Term Resource Plan can be both iterative and based on a business case evaluation of alternative solutions or portfolios. In the iterative process, the Terasen Utilities examine the planning environment in which they operate and identify to the extent possible the significant opportunities and risks. Strategic responses to these opportunities and risks are developed, refined and prioritized through ongoing business planning activities that can adapt as new information is acquired.

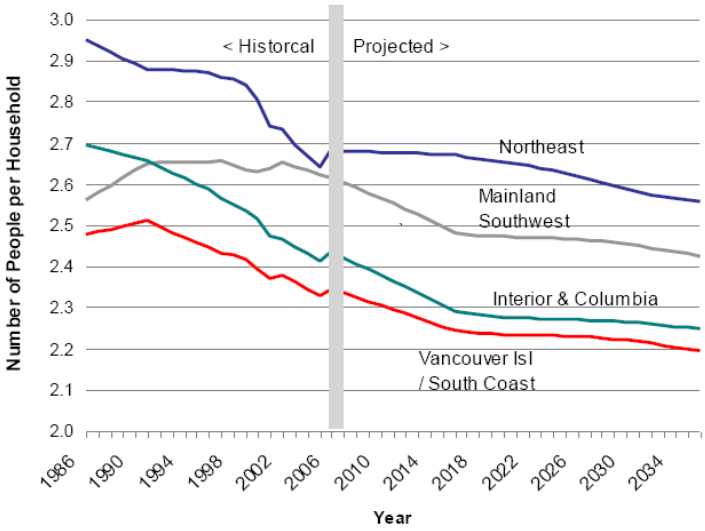
The business case analysis approach is employed in response to the identification of a specific, technical problem or problems such as approaching system capacity constraints. A process of identifying and evaluating alternative solutions is undertaken to identify and justify a preferred solution. Where a number of different but related problems and/or solutions may exist, they may be combined into portfolios which can be examined across a range of potential future scenarios to identify a preferred portfolio approach. In both the iterative and business case approaches, the Terasen Utilities engage stakeholders throughout the planning process to review and provide input into the strategies and solutions being developed.

It is important to note, however, that the resource planning process is an ongoing process and the Long Term Resource Plan offers only a snap-shot in time of the outcome of that process. Therefore, in cases where additional information is needed in order to select or finalize a preferred approach or properly assess alternative solutions, the LTRP will not include the full analysis, but rather conclude that the full analysis needs to be completed and reviewed through a separate submission to the Commission.

Further, because of the ongoing nature of the resource planning process and the introduction of new information, the LTRP should not be taken as a definitive plan from which the Terasen Utilities cannot deviate. The resource planning process uses both of these approaches to identify optimal strategies for meeting the challenges the Terasen Utilities foresee, and the LTRP presents those strategies at a given point in time. While major deviations from the Action Plan outlined in the LTRP are not anticipated, the changing nature of the planning and policy environment for the energy industry in B.C. require that the Terasen Utilities be able to adapt in order to provide customers with safe, reliable and cost effective energy services now and in the future.

31. Reference: Exhibit B-1, Appendix B-1, Page 3-4

Figure 3.4: Average Number of People per Household – History and Projection



31.1 To what extent is a reduction in the number of people per household responsible for declines in average use per customer?

Response:

The Terasen Utilities recognize that the decreasing trend in number of people per household contributes to declining average use per customer. According to a 2005 EIA report that examined the relationship between household size and gas consumption, a one person household was estimated to consume 6% less natural gas for space heating compared to a two person household. The relationship between space heating and household size is not strictly linear. As such, the amount of energy to keep a two person household warm did not vary much between a two person household and a four person household. Natural gas consumption for water heating shows a much stronger relationship between household size and consumption, rising from 16 GJ for a one person household to 39 GJ for households with six or more people. The following table illustrates natural gas consumption by the number of people living in the home for space heating and water heating purposes (source data is included in Attachment 31.1).

As there are many other factors that contribute to declining average use per customer and the fact that the relationship between expected load and number of people per household is not linear, the Terasen Utilities are unable at this time to isolate the effects due to the number of people per household only.

32. Reference: Exhibit B-1, Appendix B-5, Page 1

> solutions. The development of renewable thermal energy solutions, increased energy efficiency programs and low carbon transportation fuel alternatives is not expected to have a material impact on demand over the next few years. However, as demand for

32.1 Is it Terasen's view that these alternative energy solutions will not have a material impact over the 20 year planning period or is this view confined to the near term "few years"?

Response:

The Terasen Utilities believe that the development of renewable thermal energy solutions, increased energy efficiency programs and low carbon transportation fuel alternatives will not have a material impact for the near term based on information available at this point in time. The development and consideration of renewable thermal solutions became prominent only after the introduction of the 2007 BC Energy Plan. There is little historical data available to estimate trends. However, given British Columbia's energy objectives of reducing GHG emissions, the Terasen Utilities believe there will be impacts to our natural gas demand over the planning period of twenty years. The Terasen Utilities expect that in the 2012 LTRP, we will be able to provide more details on the nature, growth and impact that integrated energy solutions and our conservation efforts may have on demand in the near term as additional data becomes available.

33. Reference : Exhibit B-1, Appendix D-1, Page 3

Table 1: Forecast of Regular Capital Expenditures ('000's)

	2010 Projection	2011 Forecast	2012 Forecast	2013 Forecast	2014 Forecast
Category A					
Mains	8,807	9,306	9,227	9,696	9,889
Services	14,722	15,940	16,025	17,018	17,531
Meters (Customer Additions)	1,588	1,728	1,727	1,830	1,888
Replacement Customer Meters (Allocation)	18,178	19,055	19,814	15,772	21,061
	43,295	**46,029**	**46,793**	**44,316**	**50,369**
Category B					
Transmission Plant	9,546	8,663	9,922	9,703	8,725
Distribution Plant	7,900	6,250	8,370	6,250	6,250
	17,446	**14,913**	**18,292**	**15,953**	**14,975**
Category C					
IT	16,000	16,000	18,000	18,000	18,000
Non-IT	16,770	16,655	14,026	15,380	15,444
	32,770	**32,655**	**32,026**	**33,380**	**33,444**
Contributions in Aid of Construction	**(4,024)**	**(3,929)**	**(3,800)**	**(3,869)**	**(3,916)**
Total Regular Capital	**89,487**	**89,669**	**93,311**	**89,781**	**94,872**

Figures exclude AFUDC and Capitalized Overheads

33.1 Given the text of the resource plan referring to a variety of what seemed like incremental requirements for investment, the forecast capital expenditures appear to represent a fairly regular level of activity. Do these levels of expenditures represent significant increases from prior years?

Response:

Table 1 above, which shows Regular Capital Expenditures for TGI, does not demonstrate significant increases in the level of regular capital spending over the five year period. However, Appendix D-1 also includes Table 2, which shows the Forecast of Major Capital Projects not requiring a CPCN and Table 3, which shows the Forecast of Major Capital Projects subject to CPCN Applications. These two tables do represent some significant variations over the five year forecast period, and are indicative of some of the incremental requirements referred to in the Resource Plan.

However, expenditures for the development of natural gas as a transport fuel in the forms of CNG and LNG (as discussed in Exhibit B-1, Section 6.1.4, Page 150-153) and a portfolio of capital investments in a long term sustainment plan (as discussed in Exhibit E-1, Section 6.1.5, Page 153-159) have not been fully developed and therefore have not been included in the LTRP.

When a decision is made to proceed with any of the projects, the incremental requirements are expected to be presented for approval in future revenue requirement applications or future CPCN applications, depending on their estimated capital costs.

33.2 Does this represent the base traditional business for Terasen and many of the items referred to in the LTRP are not represented?

Response:

Please see response to CEC IR 1.33.1.

33.3 How does Terasen internally get an overall comprehensive picture of its long term resource plans without including all of the investments planned or being pursued, are there internal documents that close the gap relative to this public document?

Response:

There are three different types of capital resource planning at Terasen, each undertaken with a different purpose.

First, the LTRP includes a review of on-system natural gas infrastructure planning over a 20 year planning horizon, with a focus on areas of development during that time frame.

Second, the five year capital plan, which was included as Appendix D, provides a five year numerical overview of the anticipated capital spending. It does not include capital spending that is part of a larger initiative or program that has yet to be approved by the Commission.

Finally, the capital forecasts that are prepared annually and included in any Revenue Requirement Applications include both a numerical and descriptive overview of all planned regular capital expenditures, and only approved CPCN projects.

It is the combination of these three types of capital resource planning that provides the Terasen Utilities with an overall comprehensive picture of their capital plans. As such, no other comprehensive internal capital plans exist.

Many of the new initiatives or programs identified in the LTRP are still in development. The costs for these items are therefore also still being developed and will be subject to future review by the Commission, stakeholders and interveners.

Please also see response to CEC IR 1.33.1.

Attachment 31.1

Table US14. Average Consumption by Energy End Uses, 2005
Million British Thermal Units (Btu) per Household

	U.S. Households (millions)	Energy End Uses (million Btu of consumption per household)					
		All End Uses	Space Heating (Major Fuels)[4]	Air-Conditioning[5]	Water Heating[6]	Refrigerators	Other Appliances and Lighting
Total	111.1	94.9	40.5	9.6	19.2	4.6	24.7
Census Region and Division							
Northeast	20.6	122.2	71.8	4.5	21.9	4.3	23.0
New England	5.5	129.3	85.6	2.5	21.5	4.1	20.1
Middle Atlantic	15.1	119.7	66.9	5.1	22.0	4.4	24.0
Midwest	25.6	113.5	58.4	6.2	20.6	4.9	25.9
East North Central	17.7	117.7	63.3	5.7	20.9	4.9	26.2
West North Central	7.9	104.1	47.8	7.3	19.7	5.0	25.4
South	40.7	79.8	21.0	14.5	15.8	4.8	25.0
South Atlantic	21.7	76.1	21.3	13.3	13.9	4.8	24.2
East South Central	6.9	87.3	27.6	12.7	16.2	5.3	26.8
West South Central	12.1	82.4	16.7	17.7	19.1	4.6	25.5
West	24.2	77.4	26.3	7.6	21.3	4.3	24.1
Mountain	7.6	89.8	34.3	14.1	20.5	4.5	24.0
Pacific	16.6	71.8	22.4	4.2	21.7	4.2	24.2
Four Most Populated States							
New York	7.1	118.2	71.5	4.1	22.4	4.0	21.1
Florida	7.0	60.0	3.4	20.3	10.4	4.4	22.2
Texas	8.0	81.5	13.2	19.4	19.8	4.7	25.7
California	12.1	67.1	15.7	4.7	23.3	3.7	23.8
All Other States	76.9	101.8	47.1	8.3	19.0	4.9	25.2
Urban/Rural Location (as Self-Reported)							
City	47.1	85.3	36.7	9.5	18.3	4.0	21.2
Town	19.0	102.3	48.1	8.5	19.4	4.7	24.3
Suburbs	22.7	108.6	42.6	11.0	23.4	5.1	28.9
Rural	22.3	95.1	39.5	9.5	16.8	5.4	28.0
Climate Zone[1]							
Less than 2,000 CDD and--							
Greater than 7,000 HDD	10.9	117.9	68.1	3.1	20.6	4.9	24.9
5,500 to 7,000 HDD	26.1	115.0	63.8	4.8	20.3	4.6	24.4
4,000 to 5,499 HDD	27.3	101.7	47.6	7.4	19.6	4.8	24.6
Fewer than 4,000 HDD	24.0	76.4	21.4	9.1	20.3	4.4	25.1
2000 CDD or More and--							
Less than 4,000 HDD	22.8	72.4	10.0	19.4	15.7	4.6	24.5

Table US14. Average Consumption by Energy End Uses, 2005
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	U.S. Households (millions)	Energy End Uses (million Btu of consumption per household)					
		All End Uses	Space Heating (Major Fuels)[4]	Air-Conditioning[5]	Water Heating[6]	Refrigerators	Other Appliances and Lighting
Type of Housing Unit							
Single-Family Detached	72.1	108.4	44.2	11.0	21.7	5.2	29.3
Single-Family Attached	7.6	89.3	41.7	6.7	19.0	4.0	20.9
Apartments in 2-4 Unit Buildings	7.8	85.0	48.5	6.3	15.6	3.5	16.3
Apartments in 5 or More Unit Buildings	16.7	54.4	25.0	6.6	12.2	3.0	11.8
Mobile Homes	6.9	70.4	26.1	9.2	13.3	4.2	21.4
Ownership of Housing Unit							
Owned	78.1	104.4	43.1	10.4	20.8	5.1	28.0
Single-Family Detached	64.1	109.8	44.7	11.0	21.9	5.4	29.8
Single-Family Attached	4.2	94.9	44.0	6.3	20.2	4.1	21.9
Apartments in 2-4 Unit Buildings	1.8	110.5	65.8	4.8	18.4	4.1	19.5
Apartments in 5 or More Unit Buildings	2.3	50.9	20.4	7.3	10.8	2.9	13.1
Mobile Homes	5.7	70.5	25.5	9.4	12.8	4.2	21.8
Rented	33.0	72.4	33.8	7.7	15.4	3.5	16.7
Single-Family Detached	8.0	96.5	39.8	10.8	20.1	4.2	25.3
Single-Family Attached	3.4	82.6	38.8	7.2	17.6	3.9	19.7
Apartments in 2-4 Unit Buildings	5.9	77.1	42.8	6.8	14.8	3.3	15.3
Apartments in 5 or More Unit Buildings	14.4	55.0	25.7	6.5	12.5	3.1	11.6
Mobile Homes	1.2	70.0	29.2	8.4	15.9	4.0	19.6
Year of Construction							
Before 1940	14.7	120.4	71.6	5.7	20.2	4.5	23.1
1940 to 1949	7.4	104.0	51.6	7.9	21.8	4.2	23.8
1950 to 1959	12.5	98.3	47.3	7.9	19.1	4.3	22.5
1960 to 1969	12.5	94.9	42.9	8.6	19.2	4.7	24.3
1970 to 1979	18.9	83.4	33.8	9.5	16.8	4.6	22.9
1980 to 1989	18.6	81.4	26.7	10.7	18.0	4.6	24.2
1990 to 1999	17.3	94.4	31.0	11.8	20.1	5.4	28.6
2000 to 2005	9.2	94.4	28.7	13.4	21.3	4.5	28.5
Total Floorspace (Square Feet)							
Fewer than 500	3.2	56.5	30.3	4.9	12.2	3.2	11.2
500 to 999	23.8	62.0	28.4	6.8	13.3	3.3	14.5
1,000 to 1,499	20.8	82.0	33.5	9.2	17.2	4.0	21.4
1,500 to 1,999	15.4	93.8	36.5	10.9	19.2	4.9	26.0
2,000 to 2,499	12.2	102.3	41.2	10.2	21.0	4.8	27.6
2,500 to 2,999	10.3	112.2	48.2	9.8	22.4	5.2	29.6
3,000 to 3,499	6.7	115.6	53.2	9.8	21.1	5.4	28.9
3,500 to 3,999	5.2	129.2	60.9	10.7	23.2	5.8	31.6
4,000 or More	13.3	140.4	56.8	13.1	27.7	6.5	38.2

Table US14. Average Consumption by Energy End Uses, 2005
Million British Thermal Units (Btu) per Household

	U.S. Households (millions)	Energy End Uses (million Btu of consumption per household)					
		All End Uses	Space Heating (Major Fuels)[4]	Air-Conditioning[5]	Water Heating[6]	Refrigerators	Other Appliances and Lighting
Household Size							
1 Person	30.0	70.7	37.4	6.1	11.7	3.9	14.4
2 Persons	34.8	96.4	41.9	10.1	18.5	4.9	24.4
3 Persons	18.4	104.1	41.4	10.7	21.7	5.0	28.8
4 Persons	15.9	108.4	41.0	11.4	24.2	4.8	31.4
5 Persons	7.9	117.1	41.9	13.1	27.2	4.9	34.5
6 or More Persons	4.1	123.8	41.7	12.8	33.3	4.9	38.4
2005 Household Income Category							
Less than $10,000	9.9	73.7	38.6	7.0	14.1	3.7	15.2
$10,000 to $14,999	8.5	76.2	37.9	6.7	14.1	4.0	17.0
$15,000 to $19,999	8.4	78.8	37.5	7.6	15.3	4.0	18.2
$20,000 to $29,999	15.1	84.9	39.5	8.2	16.2	4.1	20.6
$30,000 to $39,999	13.6	86.2	36.4	10.0	17.3	4.5	22.3
$40,000 to $49,999	11.0	95.0	39.9	9.9	18.5	4.6	25.0
$50,000 to $74,999	19.8	99.2	38.7	10.5	20.8	4.9	27.2
$75,000 to $99,999	10.6	112.4	47.5	10.6	22.1	5.1	30.3
$100,000 or More	14.2	130.5	47.3	12.9	29.2	6.1	38.2
Income Relative to Poverty Line							
Below 100 Percent	16.6	79.8	39.0	7.7	16.3	3.8	18.4
100 to 150 Percent	12.9	80.7	35.3	8.6	16.0	4.1	20.6
Above 150 Percent	81.5	100.3	41.5	10.2	20.3	4.9	26.6
Eligible for Federal Assistance[2]							
Yes	38.6	83.1	39.5	7.9	16.6	4.0	19.7
No	72.5	101.2	41.0	10.5	20.6	5.0	27.3
Payment Method for Utilities							
All Paid by Household	97.5	97.3	40.2	10.1	19.7	4.8	25.9
Some Paid, Some in Rent	7.6	77.2	44.4	5.0	15.2	3.5	15.1
All Included in Rent	4.7	74.9	40.3	7.4	15.1	3.6	14.1
Other Method	1.3	95.0	42.1	9.6	18.0	5.3	26.0

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	U.S. Households (millions)	Energy End Uses (million Btu of consumption per household)					
		All End Uses	Space Heating (Major Fuels)[4]	Air-Conditioning[5]	Water Heating[6]	Refrigerators	Other Appliances and Lighting
Ethnic Origin of Householder							
Hispanic Descent	14.8	80.3	32.6	10.3	19.6	3.8	21.2
Non-Hispanic Descent	96.3	97.2	41.6	9.6	19.2	4.8	25.2
Race of Householder[3]							
White	79.1	98.2	42.2	9.6	19.2	4.9	25.6
Hispanic	5.0	73.5	26.4	10.9	18.8	3.9	20.6
Non-Hispanic	74.1	99.9	43.1	9.5	19.3	4.9	25.9
Black	13.4	92.5	39.5	9.9	18.7	4.1	22.5
Hispanic	0.3	99.6	53.0	7.1	18.0	4.2	19.3
Non-Hispanic	13.1	92.3	39.1	9.9	18.7	4.0	22.6
Asian	3.3	75.2	28.4	9.1	20.0	3.9	21.2
Multi-Racial	1.3	87.0	31.7	10.5	18.5	4.6	26.5
Other	7.1	85.9	33.8	9.8	19.7	4.4	23.2
Undetermined (Race Reported as Hispanic)	6.9	82.4	36.2	9.6	19.1	3.8	21.1

1 One of five climatically distinct areas, determined according to the 30-year average (1971-2000) of the annual heating and cooling degree-days. A household is assigned to a climate zone according to the 30-year average annual degree-days for an appropriate nearby weather station.

2 Below 150 percent of poverty line or 60 percent of median state income.

3 Respondents were permitted to select more than one racial category to describe themselves. The "Other" category includes Native Americans, Native Alaskans, and Pacific Islanders.

4 Housing units where the main or secondary space-heating fuel is electricity, natural gas, fuel oil, kerosene, or LPG.

5 The number of housing units where the end use is electric air-conditioning, does not include households that did not use their equipment (1.9 million). It does include the small number of housing units where the fuel for central air-conditioning equipment was something other than electricity; those households were treated as if the fuel was electricity.

6 Housing Units where the main or secondary water-heating fuel is electricity, natural gas, fuel oil, kerosene, or LPG.

Q = Data withheld either because the Relative Standard Error (RSE) was greater than 50 percent or fewer than 10 households were sampled.

N = No cases in the reporting sample.

(*) Number less than 0.5, 0.05, or 0.005 depending on the number of significant digits in the column, rounded to zero.

Notes: ● Because of rounding, data may not sum to totals. ● See "Glossary" for definition of terms used in this report.

Source: Energy Information Administration, Office of Energy Markets and End Use, Forms EIA-457 A-G of the 2005 Residential Energy Consumption Survey.