Terasen Gas

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September 30, 2008

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

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc. (collectively the "Companies") 2008 Resource Plan

Response to the British Columbia Utilities Commission ("BCUC" or the "Commission") Information Request ("IR") No. 1

On June 22, 2008, the Companies filed their consolidated 2008 Resource Plan. In accordance with Commission Order No. G-120-08 setting out the Regulatory Timetable, the Companies respectfully submit the attached response to BCUC 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.

Yours very truly,

TERASEN GAS INC.,
TERASEN GAS (VANCOUVER ISLAND) INC. and
TERASEN GAS (WHISTLER) INC.

Original signed:

Tom A. Loski

Attachment

cc: Registered Parties (e-mail only)

1.0 Reference: None

1.1 What date does Terasen feels would be appropriate for the filing of its next combined resource plan, and why?

<u>Response:</u>

Terasen Gas proposes the end of the second quarter (June 30) of 2010 as an appropriate date for submission of its next Resource Plan. Terasen Gas feels that a 2-year interval between Resource Plan submissions provides for a reasonable balance between allowing time for action plan implementation for the existing Resource Plan and ensuring that the latest customer and energy industry trends are considered in our next Resource Plan. Terasen Gas also feels that a second quarter submission provides the best opportunity to incorporate more recent forecasting and background data for the preceding year, and maintain consistency with other planning documents such as the annual gas contracting and price risk management plans.

2.0 Reference: Government Policy

Exhibit B-1, p. E-3

2.1 Terasen states that natural gas is an important part of reaching the goals of electricity self sufficiency and zero net GHG emissions by 2016. Is this assertion based on any provincial government policy pronouncement, and if so please provide any references?

<u>Response:</u>

This assertion is not based on any specific provincial government policy pronouncement. It is based on the fact that if the energy source for certain end uses such as space and water heating is natural gas rather than electricity, then electricity resource requirements are reduced accordingly. By reducing the overall requirement for electricity, the achievement of the policy objectives of self-sufficiency and net zero GHG emissions from electricity generation are made easier.

The direct use of natural gas in BC for space and water heating also supports reductions in greenhouse gas emissions in the region by increasing the potential for clean electricity from BC to displace higher GHG-emitting gas or coal fired generation in neighbouring jurisdictions. Further, the BC Energy Plan identifies one of the ways that natural gas will play a role in BC's energy future as follows:

> "It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas".[1]

[1] 2007 BC Enerergy Plan. p 21

3.0 Reference: Peak Day Demand

Exhibit B-1, pp. E-4, E-5, p. 40, Appendix F, p. F 1

3.1 Peak day demand is stated to be the daily demand expected on the "coldest day planned for". Please explain this term – for instance does it relate to the coldest day which has occurred in some historical period such as the last 20 years. And if so, why was the particular time period (20 years) chosen?

Response:

At Terasen Gas, the "coldest day planned for", also referred to as the design day, represents the coldest day that is expected to occur once every 20 years, determined through an extreme value analysis (explained below in Q3.2). The return period of once every twenty years is used as it is consistent with past practice at TGI and provides a reasonable timeframe compared against those used by other utilities.

The Extreme Value analysis is based on weather data from the last 60 years and the result could vary from the coldest day experienced in the last 20 years. For comparison purposes, the design day for the LML region is 30.8 HDD while the coldest day in the last 20 years was experienced on December 28, 1990 and was 29.8 HDD and the coldest in the last 60 was on December 28, 1968 and was 33.2 HDD.

3.2 Please explain Extreme Value Analysis and provide a numerical example.

Response:

Extreme Value Analysis is a statistical technique used to model observed data extremes in order to allow for generalizations about the likely recurrences of those events. This type of analysis is the accepted standard in Canada and is approved by the Atmospheric Environment Service of Environment Canada.

At Terasen Gas, the data extremes are very cold temperatures (the coldest temperature experienced in each year), and the objective is to identify the coldest temperature that would be expected to reoccur once every twenty years.

To achieve the objective, historical weather data (the coldest day in each year) is collected and modeled using a non-linear regression approach known as Dr. Gumbel's Method of Moments. The functional form of this model is:

r(t) = 1/(1-exp(-exp(Sigma X (t-Mu))))

Where:

r(t) = the predicted return period as a function of the temperature;

Sigma, Mu = constants determined from the regression analysis;

t = the temperature, in degrees Celsius; and,

exp() = the exponential function.

The regression determines values for Sigma and Mu such that the sum of squares of error is minimized, using the above formula. Once the equation has been solved, the extreme value temperature can then be determined for a given return period using the following formula:

t = Mu + ln(ln(r/(r-1)))/Sigma

Where:

t = the extreme value temperature;

ln = the natural logarithm function;

r = the return period; and,

Mu and Sigma are the coefficients solved for in the above model.

For the Lower Mainland Region, the coldest temperature in each year from 1938 to 1999 was identified and sorted from coldest to warmest. The actual return period was calculated as follows:

The coldest temperature has a return period of one in sixty years (the temperature was as cold or colder than this temperature once in the sixty year data set), the second coldest temperature has a return period of two in sixty years (the temperature was as cold or colder than this temperature twice in the sixty year period), …, and the sixtieth coldest day has a return period of one year (the temperature was as cold or colder than this temperature sixty times in the sixty year period).

Applying Dr. Gumbel's Method of Moments to the data resulted in the following values of Sigma and Mu:

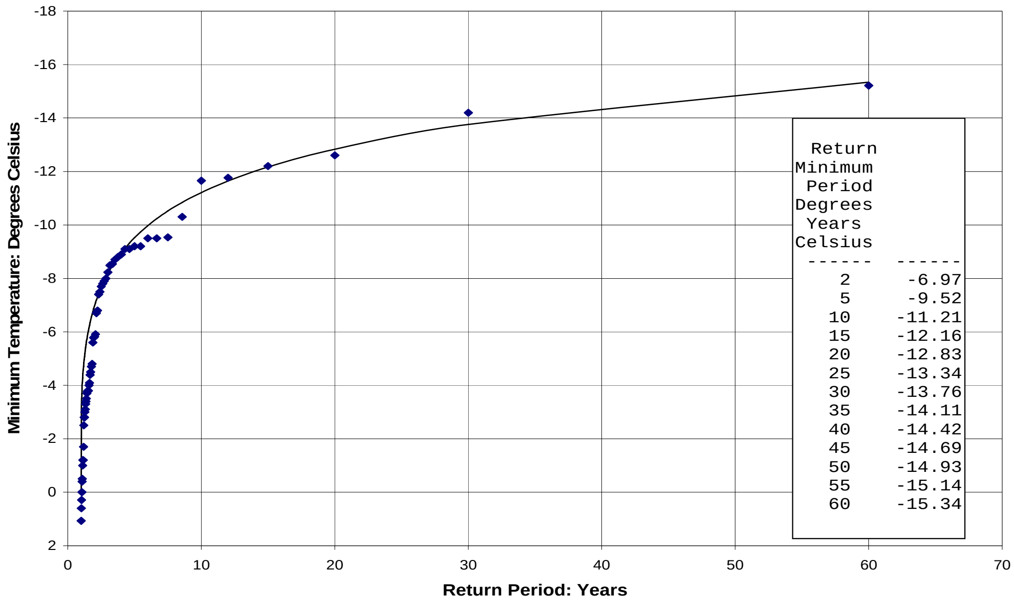
Sigma = 0.444442

Mu = -6.146717

Finally, the temperature with a one in twenty year return period is calculated as follows:

t = 0.44444 + ln(ln(20/(20-1)))/-6.146717 = -12.8 degrees Celsius.

The return periods are illustrated in the following graph:



3.3 It is stated that EEC programs such as retrofitting with more efficient furnaces will impact annual consumption but have minimal impact on peak day demand since even high-efficiency heating equipment will be working hardest during extreme cold weather. Please explain this statement in more detail and provide any available empirical support or other evidence.

If the retrofit furnace uses half as much input energy to produce the same output energy as the old furnace, and the old furnace was capable of heating the residence satisfactorily on the coldest day, wouldn't the impact be significant rather than minimal?

Response:

From the question it appears the reader has assumed Terasen Gas is of the opinion that there is no difference in peak day usage between standard and high-efficiency heating equipment. It is recognized that high-efficiency heating equipment uses less input energy to produce the same output energy as low-efficiency heating equipment, and the impact to the individuals that retrofit to high-efficiency heating equipment could be significant. However, when considering the impact of the number of households who implement this type of EEC program across all of our core customer demand during extreme weather events, EEC programs such as furnace retrofit programs are expected to have minimal impact on peak day demand.

As illustrated in Exhibit B-1, table 3-1, p. 36, the projected annual savings for TGI/TGVI's residential customers under all EEC programs is estimated to be 102,439 GJ in 2008, 220,599 GJ in 2009, and 304,008 GJ in 2010. Those amounts, when compared to the total TGI/TGVI annual demand of all core customers (which are the customers for which peak day demand is estimated), represents only 0.08%, 0.17%, and 0.23% of total annual demand for all core customers. Given that there is minimal impact to core annual demand, Terasen Gas believes there would also be minimal impact to peak day demand.

	2008	**2009**	**2010**
Total Expected Residential Savings (TJ)	102.4	220.6	304.0
Total Core Annual Demand (TJ)	128,277.6	129,349.7	130,068.6
Savings as a % of Annual Demand	0.08%	0.17%	0.23%

Another point to consider is the fact that peak day demand is not only affected by the efficiency rating of the heating equipment, but also by the ability of the home/building to retain heat. For instance, an older, poorly insulated home with a high-efficiency furnace might conceivably consume a similar amount of energy for heating as a well insulated home using a standard efficiency furnace, or alternatively the high efficiency retrofit furnace being put into that older, poorly insulated home might have a higher output rating in order to heat the home more comfortably.

4.0 Reference: Southern Crossing Pipeline

Exhibit B-1, p. E 7

4.1 What has been the load factor on the Southern Crossing Pipeline over the last five years?

Response:

The Southern Crossing Pipeline ("SCP") is used to meet core customer demand in the Okanagan region and also to deliver gas to the Westcoast system at Kingsvale for transport to Huntingdon. It is also used at times to transport gas eastbound from Kingsvale to Yahk. The physical capacity of SCP is approximately 257 TJ/d of capacity from Yahk to Oliver where it connects with the interior transmission system serving the Okanagan region and the 12"pipeline to deliver to Kingsvale. The capacity of the 12" Oliver to Kingsvale line is approximately 113 TJ/d.

The five year load factor for SCP between Yahk and Oliver and the Oliver to Kingsvale pipeline ("12"") is as follows:

	SCP Load Factor	Oliver to Kingsvale (12") Load Factor
2003/04	14%	13%
Winter	19%	2%
Summer	10%	21%
2004/05	21%	26%
Winter	27%	9%
Summer	18%	38%
2005/06	19%	4%
Winter	39%	4%
Summer	4%	3%
2006/07	27%	15%
Winter	49%	25%
Summer	11%	8%
2007/08	34%	38%
Winter	58%	64%
Summer	10%	14%

As cited in the Background section on page one, paragraph one, of the Commission's Decision regarding the SCP Project dated May 21, 1999, "The primary purpose of the SCP is to meet the peak and seasonal needs of its firm system sales customers ("core market") over the next 30 years."

The data referenced above illustrates how SCP has been used according to its primary purpose, namely as a means of meeting peak and seasonal demand.

As discussed in the opening paragraph, in addition to its primary purpose, the SCP is as also used for transmission service to third parties between the TCPL and Westcoast systems. For example, the transmission customer currently on Southern Crossing is Northwest Natural, who pays a toll for the firm service year-round. As a point of comparison, the load factor for core market in the Inland region was 33% between 2004-2006. The Inland load on the Terasen Gas system is met with deliveries from both SCP at Oliver and from the Spectra system at Savona.

The winter 2007/08 load factor (based on data up to September 4, 2008) is higher than previous years. This was caused by two factors: higher than normal Inland demand due to colder weather and increased flows on the east/west transmission in order to flow gas from AECO to Huntingdon. During the winter of 2007/08 the price differential between the two points was as high as $2 per gigajoule. Between December 16, 2007 and February 12, 2008 the 113 TJ/d of available Yahk to Kingsvale capacity operated at a 99% load factor.

5.0 Reference: Space Heating Consumption

Exhibit B-1, p. 32

5.1 Figure 3-5, which refers to space heating consumption for all energy types, seems to indicate disproportionately high use for mobile homes. Does or is Terasen proposing any EEC programs specific to mobile homes?

Response:

No, Terasen Gas is not proposing any EEC programs specific to mobile homes. Mobile homes are classified as residential, and as such, would be eligible to participate in any EEC programs available to residential customers.

6.0 Reference: Heat Pump Supplements

Exhibit B-1, p. 34

Terasen states that: "In areas of the province and in circumstances where alternative fuel systems such as air and ground source heat pumps make sense for customers, natural gas is expected to remain the preferred supplementary fuel to meet peak period demand."

6.1 Please provide empirical support for the statement that natural gas is the preferred supplementary fuel source for existing heat pump systems. Please provide the percentage of such systems using electric plenum heaters.

Response:

Terasen Gas does not have information on the frequency of gas or electricity being the supplementary energy source for heat pump systems. On review of the Resource Plan quote in the preamble of the question Terasen Gas appreciates that the wording could be taken to mean something other than what was intended. The intent of the statement is that it is expected that natural gas will be the preferred fuel source for supplementary space heating requirements with heat pump installations as it has been for primary space heating systems.

Natural gas back-up will provide relief to the electrical system in the peak conditions (i.e. cold weather) in which the back-up heating system would be expected to operate. In comparison, electrical back-up, whether by baseboard heaters or a plenum system, would exacerbate the peak requirements on the electrical system.

6.2 Please provide empirical support for the statement that natural gas is the preferred supplementary fuel source for new heat pump systems. Please provide the percentage of such systems using electric plenum heaters.

Response:

Please refer to the response to BCUC IR 1.6.1 above. As with existing heat pump systems, Terasen Gas does not have information regarding the percentage of new heat pump systems that use natural gas or electricity (either plenum or baseboard heaters) as a back-up fuel.

7.0 Reference: Commercial Use

Exhibit B-1, p. 34

7.1 Please explain the statement "In cases where a given commercial rate class has shown relative stability in its use per customers rates, the average growth rate is applied for the first five years of the planning period then held constant afterwards" and provide a numerical example.

Response:

To explain this statement, the TGI Lower Mainland Rate Schedule 2 customer class will be used as an example.

From 2002 through 2006, the average normalized use per customer has been 321 GJ/Year, ranging from a low 314 GJ/Year to a high 330 GJ/Year and showing both increases and declines over that period. Terasen Gas considers this usage pattern to be relatively stable.

Year	2002	2003	2004	2005	2006	2007
LML Rate 2 UPC (GJ/Year)	315	330	323	314	325	327

The average growth rate of use per customer for 2005, 2006, and 2007 was 0.8%. This average growth rate was applied to the 2007 projected use per customer rate of 331 GJ/Year to forecast the 2008 use per customer rate, and then applied for the next four years. After the fifth year, the use per customer rates are held constant at 344 GJ/yr. The following table illustrates these results:

	2008	2009	2010	2011	2012
LML Rate 2 UPC (GJ/Year)	333	336	339	341	344
Growth Rate		0.8%	0.8%	0.8%	0.8%

7.2 In 2005, the MEMPR set energy efficiency targets for new and existing construction in its plan: "Energy Efficient Buildings: A Plan for BC". The plan identified the six provincial objectives through which the MEMPR forecasts that the province will realize a savings of 22 million GJ per year in fossil fuels, equivalent to a reduction of 14% of residential and commercial sector demand in the year 2001. In May, 2008, the Ministry released its Energy Efficient Buildings Strategy which set targets in conservation and energy efficiency to reduce the average energy demand "at work" by nine per cent per square meter by 2020. Have the Ministry's energy efficiency targets, as stated in both plans, been reflected in the forecasts of commercial use per customer over the planning period of this resource plan?

Response:

The above targets have not explicitly been included in this resource plan, due to the difficulties in determining the portions of energy savings that can be attributed directly to the use of natural gas. However, the energy reductions that have occurred since 2001 are reflected in the consumption data analyzed when forecasting future consumption. Therefore, the activities undertaken to reach the above targets are implicit in the forecasts of commercial use per customer over the planning period of this resource plan.

8.0 Reference: Industrial Use

Exhibit B-1, p. 36

8.1 Please provide the relationship between industrial use and GDP growth and provide its derivation.

<u>Response:</u>

When developing the high growth scenario for the annual demand forecast, industrial consumption was assumed to grow at one half the rate of GDP (at the time of this forecast, GDP was estimated at 2.5%, and therefore industrial growth was assumed to be 1.25% per year over the long-term). When developing the low growth scenario, industrial consumption was assumed to decline at one-fifth the rate of GDP growth (or decline by 0.5% per year over the long-term). No formal relationship between industrial consumption and GDP growth was developed. However, it was felt that adding an adjustment to the industrial demand for the high and low growth scenarios would better represent a range of possible outcomes. Historically, industrial consumption has been held constant when developing planning scenarios for the Resource Plan.

9.0 Reference: Load Growth Scenarios

Exhibit B-1, p. 39

9.1 Please summarize the key drivers of the high and low scenarios and summarize their impacts relative to the reference case for the year 2018.

<u>Response:</u>

The high growth scenario assumes greater than anticipated economic growth for the province, stable natural gas costs while electricity rates experience higher than expected increases. This scenario also assumes that policies are developed that promote the use of natural gas for space and water heating. These assumptions, by the year 2018, are expected to result in the following customer and consumption figures:

	Base Scenario			High Scenario		
Company/Region	**Customers**	**Annual Demand**	**Design Day Demand**	**Customers**	**Annual Demand**	**Design Day Demand**
TGI Coastal	655,934	125,264	1,030.10	676,167	134,539	1,062
TGI Interior	286,608	59,815	376.2	295,815	64,289	389
TGVI	130,063	15,242	134.9	139,731	16,606	140
TGW	2,808	842	7.5	2,899	969	8.2

The low growth scenario assumes lower than anticipated economic growth for the province. Technology improvements and increasing efficiencies accelerate conservation efforts (as alternative technologies gain more acceptance into the market, and heating equipment is replaced at an accelerated rate), and perceptions regarding the solution to climate change cause a shift from natural gas to electricity as people seek to reduce end-use of fossil fuels. These assumptions, by the year 2018, are expected to result in the following customer and consumption figures:

	Base Scenario			Low Scenario		
Company/Region	**Customers**	**Annual Demand**	**Design Day Demand**	**Customers**	**Annual Demand**	**Design Day Demand**
TGI Coastal	655,934	125,264	1,030.10	635,716	117,134	1,001
TGI Interior	286,608	59,815	376.2	277,505	56,079	366
TGVI	130,063	15,242	134.9	120,415	13,901	128
TGW	2,808	842	7.5	2,720	640	6.2

10.0 Reference: Design Day Demand

Exhibit B-1, p. 40 and Appendix F, p. F 2

10.1 Please provide the referenced regression results and measures of statistical reliability and a plot of the actual and predicted values.

Response:

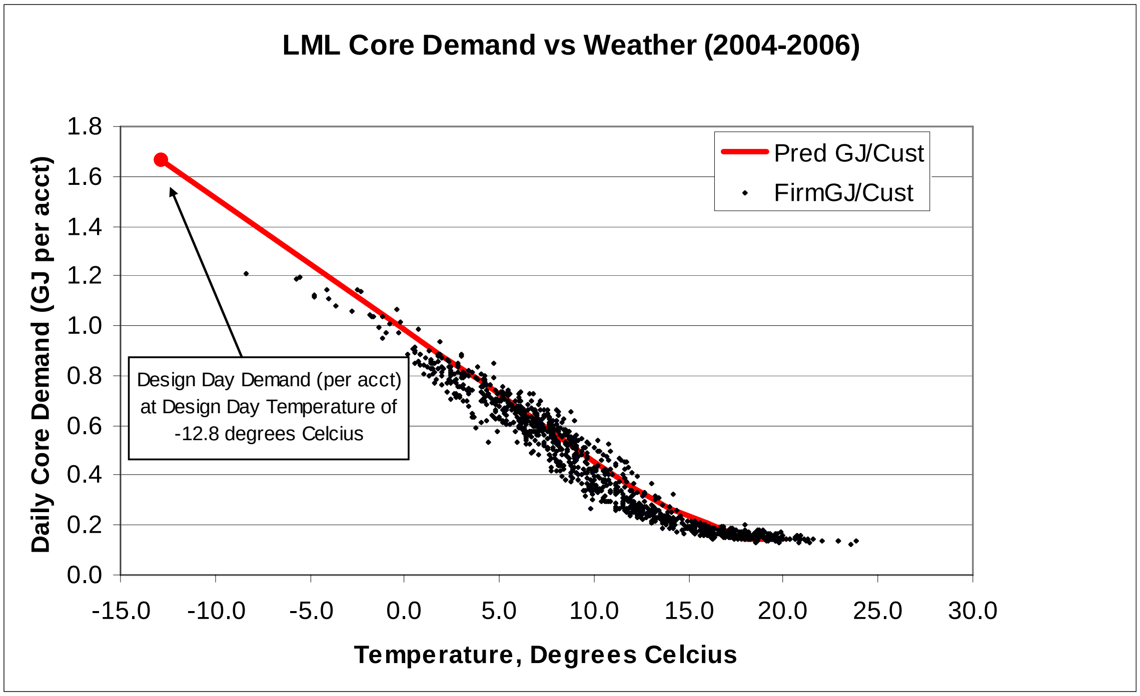
The results of the regression results for the TGI Lower Mainland region are as follows:

Regression Results - Lower Mainland Region				
Year	**Intercept**	**HDD13**	**HDD18**	**Peak UPC**
2004	0.1510	0.0283	0.0239	1.6153
2005	0.1415	0.0328	0.0207	1.6247
2006	0.1417	0.0307	0.0226	1.6296

The measures of reliability associated with the above peak day results are as follows:

Measures of Reliability - Lower Mainland Region				
Year	**R-Square**	**F-Statistic**	**HDD13**	**HDD18**
2004	97%	<.0001	<.0001	<.0001
2005	96%	<.0001	<.0001	<.0001
2006	96%	<.0001	<.0001	<.0001

Following is a plot of the actual and predicted values:



It is important to note that while peak day demand is used as an input in system capacity planning, the transient load profile (or hourly load relative to the daily load) experienced during that peak day is also an important factor in determining system requirements. The transient load profile for the Lower Mainland is high compared with that for the Interior and has remained relatively stable for several years now. However, with the relatively high growth experienced in the Okanagan region of the Interior, particularly in residential customers, the transient load profile for the Okanagan region is increasing relative to the peak day demand, and is aligning more closely to that for the Lower Mainland.

10.2 Please explain the calculation of the three year moving average.

Response:

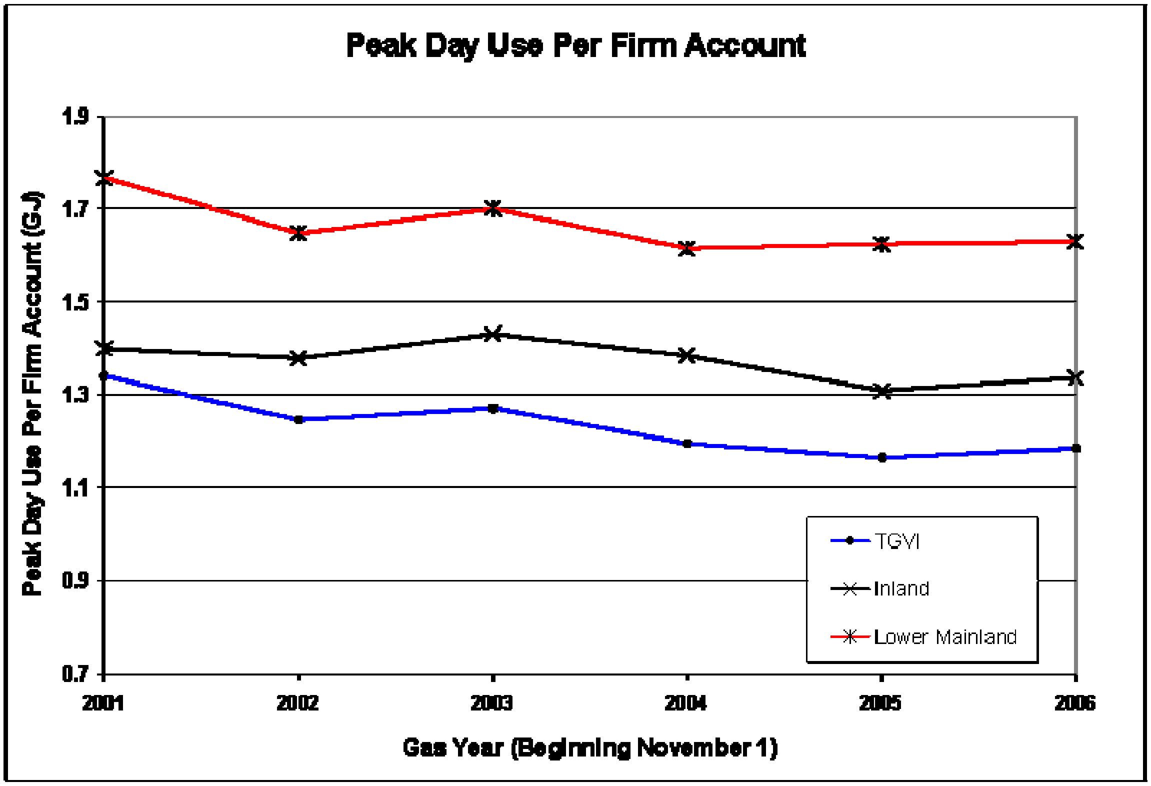
Design day demand is estimated by modeling the three most recently completed contract years separately, averaging the resulting regression parameters over the three years and then extrapolating out to the design day temperature. The three year period was chosen so as to help smooth out year over year changes, and also to incorporate recent behavior into the analysis.

10.3 Please explain the statement that no adjustment is made to design day use per customer rates to account for changing consumption patterns over time. Why is it appropriate to ignore perceived trends?

Response:

The statement that no adjustment is made to design day use per customer rates to account for changing consumption patterns over time means the design day use per customer rate is held constant throughout the planning period.

The past several years have seen residential use rates for annual demand declining, a trend that is expected to continue. Over that same period Terasen Gas has observed peak day demand per firm customer fluctuate both up and down, as illustrated in the following graph:



Given that peak day use per firm customer has increased at the same time as annual use per customer rates have been trending downward, Terasen Gas believes the current approach of holding peak day use per firm customer constant throughout the planning period is reasonable.

10.4 Please provide forecasts of design day demand for the reference, high and low scenarios that account for the forecast trends in use per customer rates that were incorporated into the projections of annual demand. Please compare the design day demand forecast in these modified scenarios to the original design day demand forecast.

Response:

The following tables and graphs illustrate the design day demand as originally estimated for the TGI Coastal (Lower Mainland) Region, and also illustrate the design day demand if it were grown as per annual demand under the reference, low growth, and high growth scenarios. Terasen believes that the methodology put forward by this request is inappropriate for the reasons stated in response to BC Hydro IR 1.3.1 and 1.3.2.

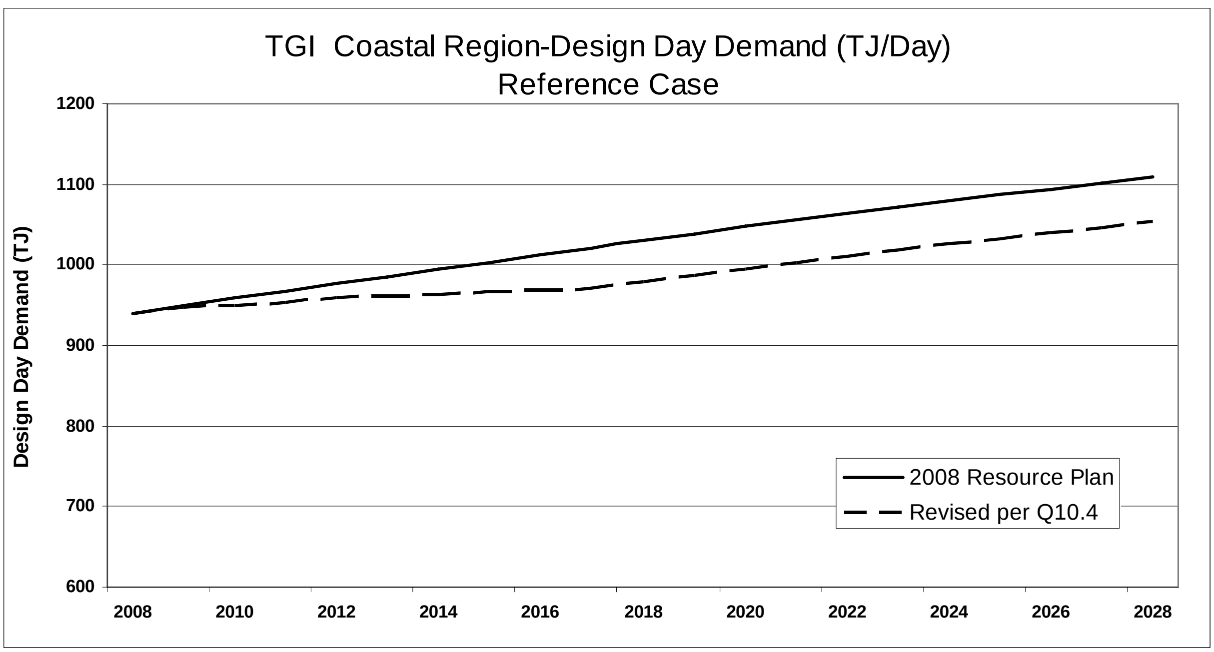
TGI Coastal Region – Reference Case:

TGI Coastal Region - Design Day Demand (TJ/Day) - Reference Case

	2008	2009	2010	2011	2012	2013	2014
2008 Resource Plan	940	950	959	968	977	986	995
Revised per Q10.4	940	947	949	954	958	961	964
Actual Change	**0**	**-3**	**-9**	**-14**	**-18**	**-24**	**-31**

	2015	2016	2017	2018	2019	2020	2021
2008 Resource Plan	1,004	1,012	1,021	1,030	1,039	1,047	1,056
Revised per Q10.4	966	969	971	980	988	996	1,004
Actual Change	**-37**	**-43**	**-50**	**-51**	**-51**	**-52**	**-52**

	2022	2023	2024	2025	2026	2027	2028
2008 Resource Plan	1,064	1,072	1,079	1,087	1,094	1,102	1,109
Revised per Q10.4	1,011	1,019	1,026	1,033	1,040	1,047	1,054
Actual Change	**-53**	**-53**	**-53**	**-54**	**-54**	**-55**	**-55**



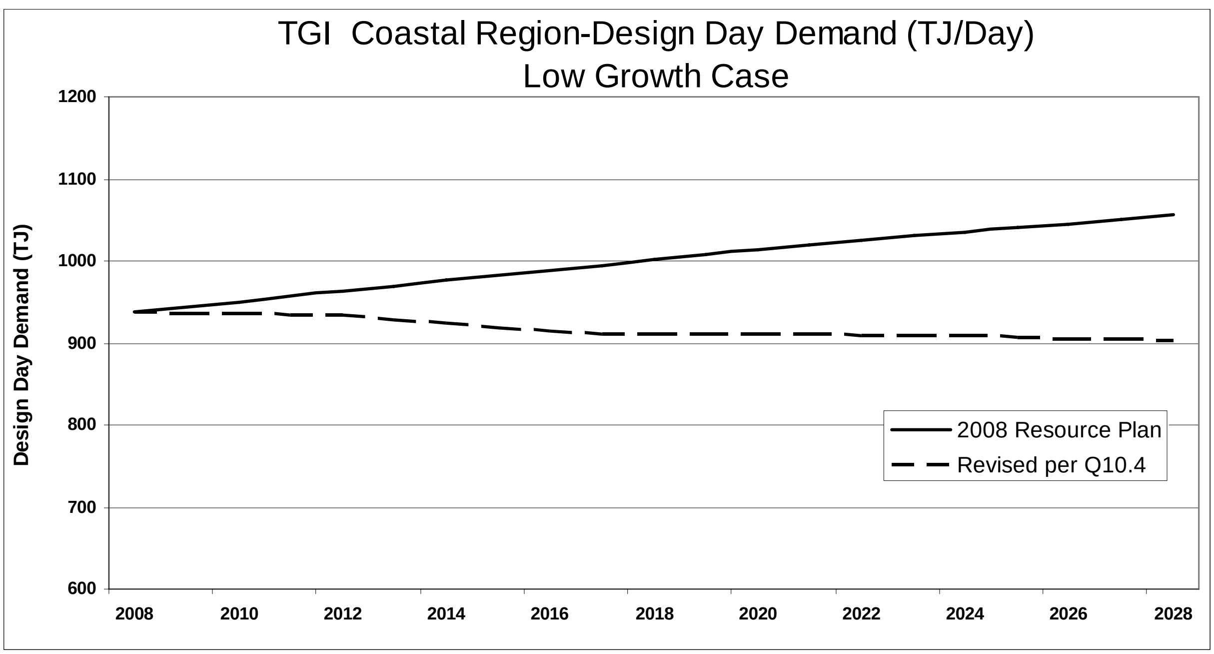
TGI Coastal Region - Low Growth Scenario:

TGI Coastal Region - Design Day Demand (TJ/Day) - Low Growth Scenario

	2008	2009	2010	2011	2012	2013	2014
2008 Resource Plan	937	944	950	957	963	970	976
Revised per Q10.4	937	937	936	935	934	927	923
Actual Change	**0**	**-7**	**-15**	**-22**	**-30**	**-42**	**-53**

	2015	2016	2017	2018	2019	2020	2021
2008 Resource Plan	982	989	995	1,001	1,007	1,013	1,019
Revised per Q10.4	919	915	911	911	911	911	910
Actual Change	**-63**	**-73**	**-84**	**-90**	**-96**	**-103**	**-109**

	2022	2023	2024	2025	2026	2027	2028
2008 Resource Plan	1,025	1,030	1,035	1,041	1,046	1,051	1,056
Revised per Q10.4	909	909	908	907	905	904	903
Actual Change	**-115**	**-121**	**-128**	**-134**	**-140**	**-147**	**-153**



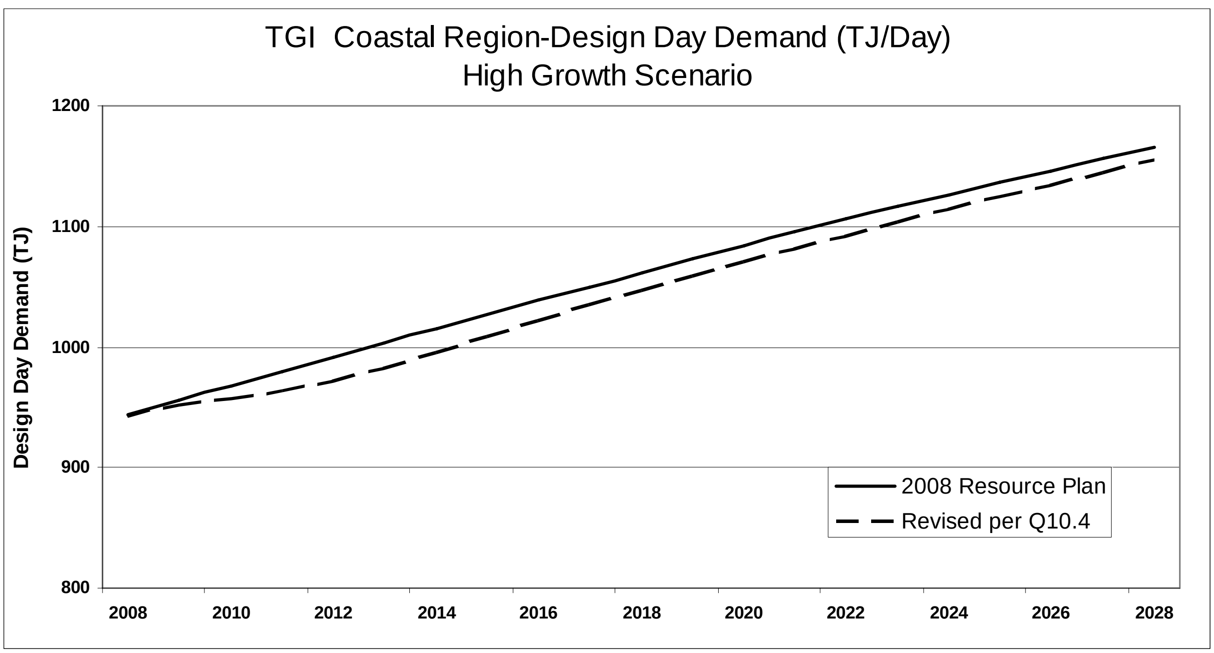
TGI Coastal Region – High Growth Scenario:

TGI Coastal Region - Design Day Demand (TJ/Day) - High Growth Scenario

	2008	2009	2010	2011	2012	2013	2014
2008 Resource Plan	943	956	968	980	991	1,003	1,015
Revised per Q10.4	943	952	957	964	971	982	995
Actual Change	**0**	**-4**	**-11**	**-15**	**-20**	**-21**	**-20**

	2015	2016	2017	2018	2019	2020	2021
2008 Resource Plan	1,027	1,038	1,050	1,062	1,073	1,084	1,095
Revised per Q10.4	1,009	1,022	1,036	1,047	1,059	1,070	1,081
Actual Change	**-18**	**-16**	**-15**	**-15**	**-15**	**-14**	**-14**

	2022	2023	2024	2025	2026	2027	2028
2008 Resource Plan	1,106	1,117	1,127	1,137	1,146	1,156	1,166
Revised per Q10.4	1,092	1,103	1,114	1,124	1,135	1,145	1,155
Actual Change	**-14**	**-14**	**-13**	**-12**	**-12**	**-11**	**-10**



10.5 Rather the choosing to ignore consumption patterns would it be more appropriate to use the coldest temperature experienced over a more extended period such as 30 or 40 years? Please discuss.

Response:

Terasen Gas does not believe consumption trends are being ignored. As illustrated above in BCUC IR 1.10.3, there is no clear trend for design day use per customer. The decision of whether or not to extend the period from which the design day temperature is derived has been considered, but as stated in BCUC IR 1.3.1, a design day temperature with an expected return period of once in twenty years is a reasonable approach.

10.6 Please explain why the regression equation described which employs both base 13 and base 18 degree days will not suffer from collinearity and thus impact the statistical usefulness of the results.

Response:

It is recognized that collinearity is present in the modeling of design day demand. However, the measures of reliability (as illustrated in BCUC IR 1.10.1) imply the model is a good fit. Also, a comparison of actuals to predicted values, as seen in Exhibit B-1, Appendix F, Tables 1 and 2 p.F4, indicate the model provides a reasonable estimate of design day demand. More importantly, the comparison shows the model does not tend to underestimate peak day demand. Terasen Gas does recognize there are other ways of modeling peak day demand, but believes the current model selected is reasonable given the above, and most importantly the fact that it does not underestimate peak day demand.

11.0 Reference: Lower Mainland Regional Storage Facility

Exhibit B-1, p. 87

11.1 An expansion of the Tilbury LNG plant in Delta with its proximity to a high population area would present unique issues for public acceptance. In fact, the public reaction to such a plan may put the location of the present facility at risk of relocation. Is this a realistic option for expansion and how would Terasen present a convincing argument to the public that such an expansion does not present an increased public danger (i.e., no increase in the actual plant foot print, increased safety of the plant with improved equipment, history of safety at the plant, etc.)

Response:

When evaluating options for additional Lower Mainland regional storage such as an LNG peak-shaving facility, Terasen Gas would consider the Tilbury LNG plant location as one of many potential site options for a new storage facility.

The Tilbury LNG facility is located in an industrial development remote from high density residential and commercial areas and has space available for an expansion. The facility operations maintain excellent coordination with local fire, security and safety authorities in emergency preparedness and response. The facility has been in continuous operations since 1971 to provide safe, reliable and efficient service to gas customers. The facility met all of the code requirements and industry practices at the time of design and construction. It has since undergone a number of safety upgrades and additions throughout its operating life, with major works in 1986 and in 2002, to ensure that Terasen Gas continues to operate the facility with a high level of due diligence, to achieve a prudent level of care, and to have no significant risk to local public or property. In fact, Tilbury is a positive demonstration of the safe, reliable and efficient operation of an LNG facility.

For any specific site selected for a new Lower Mainland regional storage facility, with the Tilbury location as one of many potential options, specific design features and construction techniques would need to be adopted to be meet all code, regulatory, and safety requirements, as well as to meet public acceptance. Terasen Gas will follow regulatory processes and consider all feedback from stakeholders to ensure appropriate inputs into the development, design, construction and operation of any such new Lower Mainland regional storage facility, whether at Tilbury Island or elsewhere.

12.0 Reference: Transit Buses

Exhibit B-1, pp. 94-95

12.1 Since hydrogen buses with fuel cell technology are now contemplated for Whistler service, does Terasen still anticipate that there will be 150 additional CNG buses in the transit fleet? Has hydrogen replaced CNG as the alternative fuel of choice in the transit system?

Response:

The Province has allocated approximately $90 million to be used for the hydrogen fuel cell buses for BC Transit's ("BCT") Whistler fleet. TGW understands that this will provide for twenty (20) hydrogen fuel cell buses, the fuelling infrastructure (hydrogen fuelling station) and the hydrogen to operate the vehicles. TGW understands that the fuel cell buses will be in operation in Whistler from 2009-2014 at which time the funds supporting the project will have been depleted and the hydrogen buses will be retired, sold or converted to an alternative fuel system. BCT's Whistler bus fleet will require additional buses above and beyond the hydrogen buses for the 2009-2014 time period; these buses could be either diesel or CNG. In the RFP from BCT, it is disclosed that BCT anticipates Whistler will require approximately 27 buses in 2010. Additionally, upon retirement of the hydrogen bus fleet, BC Transit will require additional buses to replace the hydrogen buses in Whistler.

In comparison the same funding ($90 million) would provide for approximately 119 CNG buses (including natural gas commodity and delivery in Whistler at current TGW prices for five years), and five (5) refuelling stations in the TGW service area. If the funding was available for lower mainland service area the same funding would purchase approximately 142 CNG buses including TGI delivery and commodity and five (5) refuelling stations.

Given the above, the Terasen Gas does not believe that it is economically feasible for BCT and Translink to use hydrogen as the fuel choice for the transit system in BC within the next 20 years without significant additional funding or subsidy. Terasen Gas believes it is commercially reasonable to assume that there will be a minimum of 150 additional CNG buses in the BC Transit and Translink fleets combined in British Columbia.

13.0 Reference: New Metering Technologies

Exhibit B-1, p. 103

13.1 It states on page 103 that: “Terasen Gas recently received approval to develop and implement a thermal metering pilot project to assess the distribution of energy use in multi unit developments that use hydronic heating.” Please explain what Terasen expects to learn through this pilot project and the next steps in the evaluation process.

Response:

In TGI's Application to the Commission for "tariff changes to allow for thermal metering" on May 8, 2007, TGI stated that Terasen Gas believes that the thermal metering option should be available on a pilot project basis with the project being reviewed after five years. At the end of five years Terasen Gas proposes to review the thermal metering option to better determine average consumption, cost of service impacts, if it is cost effective and if the option is desired by the marketplace. Terasen Gas would at that time make a submission to the Commission regarding the future of the program. These remain TGI’s expectations for the initiative.

14.0 Reference: Total Customers and Customer Additions

Exhibit B-1, Appendix E, Figure 1-1, p. E-1 and Figure 2-1, p. E 8

14.1 Please compare the forecast of year-end customers of TGI over the planning period with the forecast presented in the 2006 TGI Resource Plan.

Response:

Generally, the difference in forecast customer additions between the 2006 and 2008 Resource Plans is a result of incorporating both recent trends in household formations observed and actual customer additions recorded into the 2008 forecast.

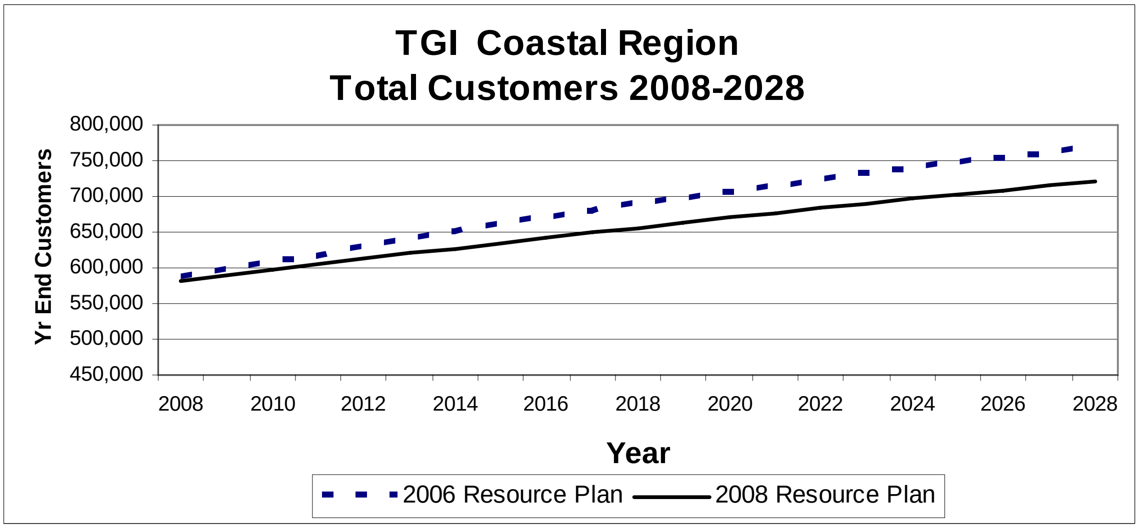
The following table illustrates the year-ending accounts from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Coastal Region, both in tabular and graphical form:

TGI - Coastal Region - Year-Ending Accounts

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	586,212	596,200	606,615	617,094	627,682	638,464	649,002
2008 Resource Plan	582,847	590,382	597,785	605,121	612,457	619,757	627,000
Actual Change	**-3,365**	**-5,818**	**-8,830**	**-11,973**	**-15,225**	**-18,707**	**-22,002**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	659,654	669,912	679,546	688,618	697,466	705,989	714,355
2008 Resource Plan	634,284	641,514	648,738	655,934	663,091	669,970	676,829
Actual Change	**-25,370**	**-28,398**	**-30,808**	**-32,684**	**-34,375**	**-36,019**	**-37,526**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	722,499	730,690	738,635	746,151	753,546	760,821	768,113
2008 Resource Plan	683,437	690,063	696,305	702,523	708,481	714,562	720,579
Actual Change	**-39,062**	**-40,627**	**-42,330**	**-43,628**	**-45,065**	**-46,259**	**-47,534**



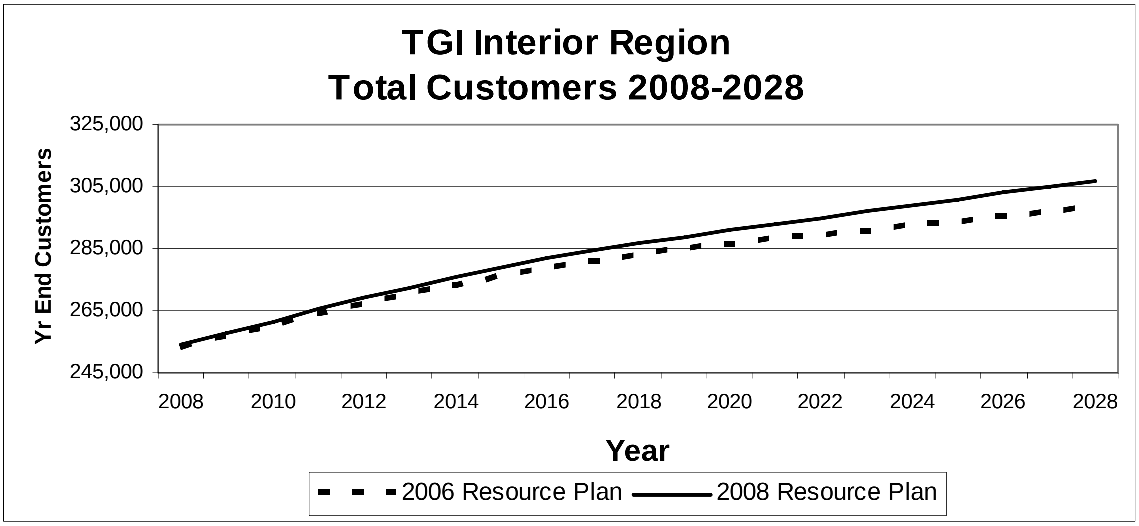
The following table illustrates the year-ending accounts from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Interior Region, both in tabular and graphical form:

TGI - Interior Region - Year-Ending Accounts

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	253,120	256,691	260,302	263,802	267,101	270,193	273,110
2008 Resource Plan	253,986	257,813	261,575	265,304	269,033	272,532	275,804
Actual Change	**866**	**1,122**	**1,273**	**1,502**	**1,932**	**2,339**	**2,694**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	275,903	278,470	280,825	282,826	284,727	286,389	287,850
2008 Resource Plan	279,242	282,119	284,498	286,608	288,694	290,763	292,836
Actual Change	**3,339**	**3,649**	**3,673**	**3,782**	**3,967**	**4,374**	**4,986**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	289,233	290,630	291,993	293,611	295,142	296,816	298,567
2008 Resource Plan	294,865	296,920	298,989	301,022	303,088	305,043	306,985
Actual Change	**5,632**	**6,290**	**6,996**	**7,411**	**7,946**	**8,227**	**8,418**



14.2 Please compare the forecast of year-end customers of TGVI over the planning period with the forecast presented in the previous TGVI Resource Plan.

Response:

The number of customers as forecast in the 2008 Resource Plan is similar to that forecast in the 2006 Resource Plan.

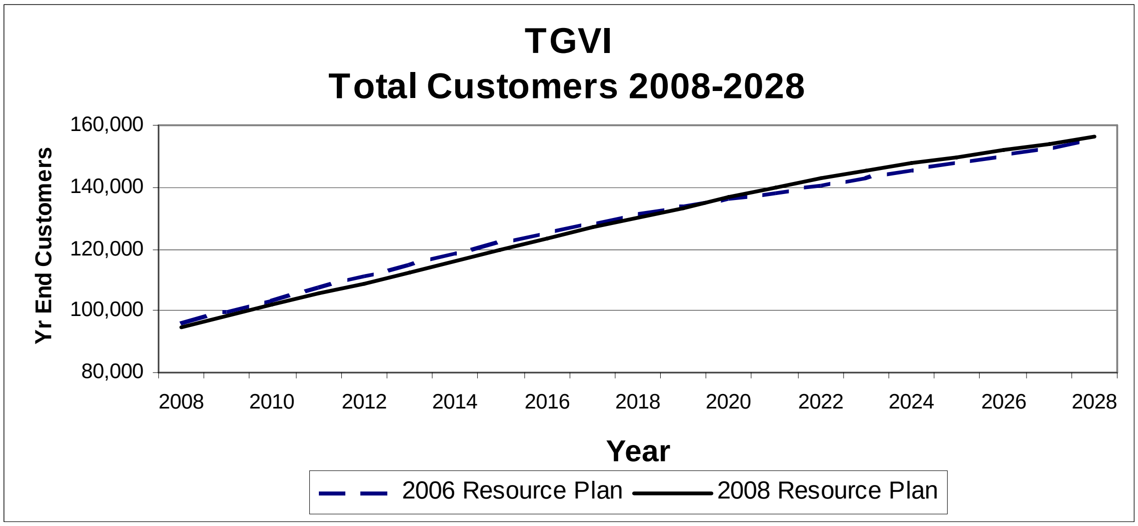
The following table illustrates the year-ending accounts from both the 2006 and 2008 TGVI Resource Plans (base forecast and reference forecast, respectively), both in tabular and graphical form:

TGVI Year-Ending Accounts

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
2006 Resource Plan	95,994	99,554	103,493	107,340	111,286	115,074	118,543
2008 Resource Plan	94,894	98,494	102,094	105,594	108,994	112,651	116,253
Actual Change	**-1,100**	**-1,060**	**-1,399**	**-1,746**	**-2,292**	**-2,423**	**-2,290**

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2006 Resource Plan	122,013	125,348	128,351	131,066	133,647	135,976	138,302
2008 Resource Plan	119,855	123,358	126,760	130,063	133,324	136,546	139,638
Actual Change	**-2,158**	**-1,990**	**-1,591**	**-1,003**	**-323**	**570**	**1,336**

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2006 Resource Plan	140,586	142,963	145,096	147,543	150,063	152,693	155,504
2008 Resource Plan	142,608	145,383	147,742	149,896	151,861	153,945	156,282
Actual Change	**2,022**	**2,420**	**2,646**	**2,353**	**1,798**	**1,252**	**778**



TGVI
Total Customers 2008-2028
Yr End Customers
160,000
140,000
120,000
100,000
80,000
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Year
2006 Resource Plan
2008 Resource Plan

15.0 Reference: Annual Demand Forecasts

Exhibit B-1, Appendix E, Figure 1-2, p. E 4 and Figure 2-2, p. E 10

15.1 Please compare the forecast of total annual demand on TGI over the planning period with the forecast presented in the 2006 TGI Resource Plan.

Response:

Generally, annual demand in the 2008 Resource Plan is lower than what was forecast in the 2006 Resource Plan. This can be attributed to the 2008 industrial survey results being lower than those seen in 2006, the assumption of declining residential use rates throughout the planning period in the 2008 Resource Plan (they were held constant after year 5 in the 2006 Resource Plan), and to lower than expected actual normalized use rates than forecast in 2006.

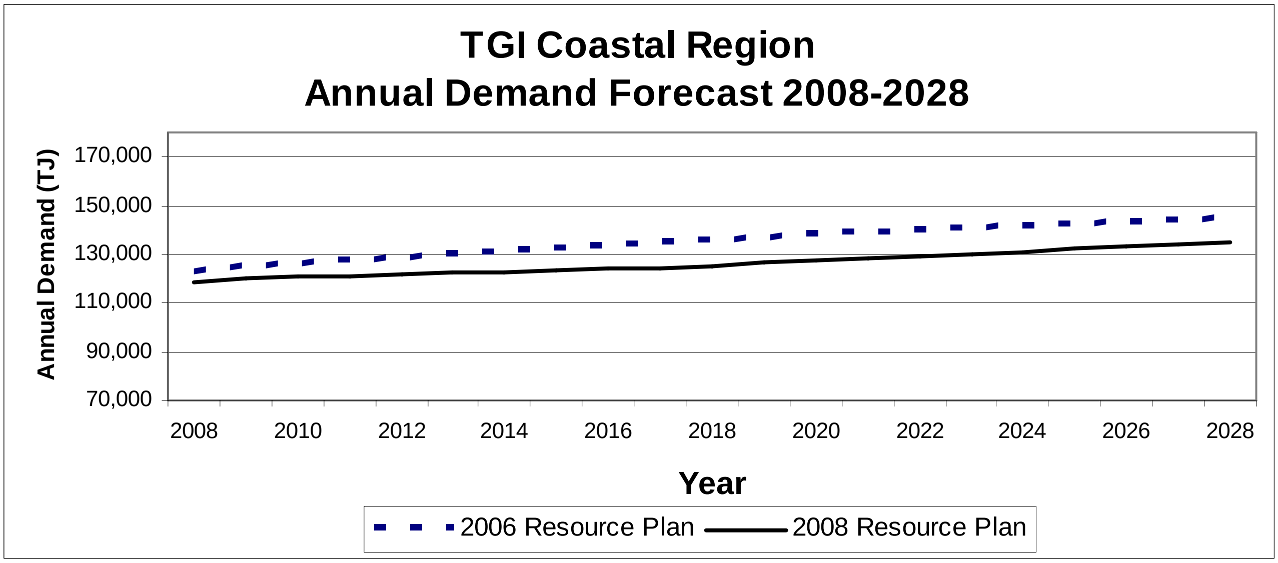
The following table illustrates the total annual demand from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Coastal Region, both in tabular and graphical form:

TGI Coastal Region - Annual Demand (TJ)

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	122,754	124,621	126,032	127,297	128,553	129,830	131,079
2008 Resource Plan	118,725	119,870	120,627	121,183	121,933	122,410	122,886
Actual Change	**-4,029**	**-4,751**	**-5,405**	**-6,114**	**-6,620**	**-7,420**	**-8,193**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	132,340	133,552	134,692	135,766	136,807	137,810	138,793
2008 Resource Plan	123,346	123,806	124,256	125,264	126,271	127,276	128,253
Actual Change	**-8,994**	**-9,746**	**-10,436**	**-10,502**	**-10,536**	**-10,534**	**-10,540**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	139,748	140,707	141,639	142,519	143,385	144,235	145,086
2008 Resource Plan	129,231	130,188	131,145	132,054	132,964	133,858	134,762
Actual Change	**-10,517**	**-10,519**	**-10,494**	**-10,465**	**-10,421**	**-10,377**	**-10,324**



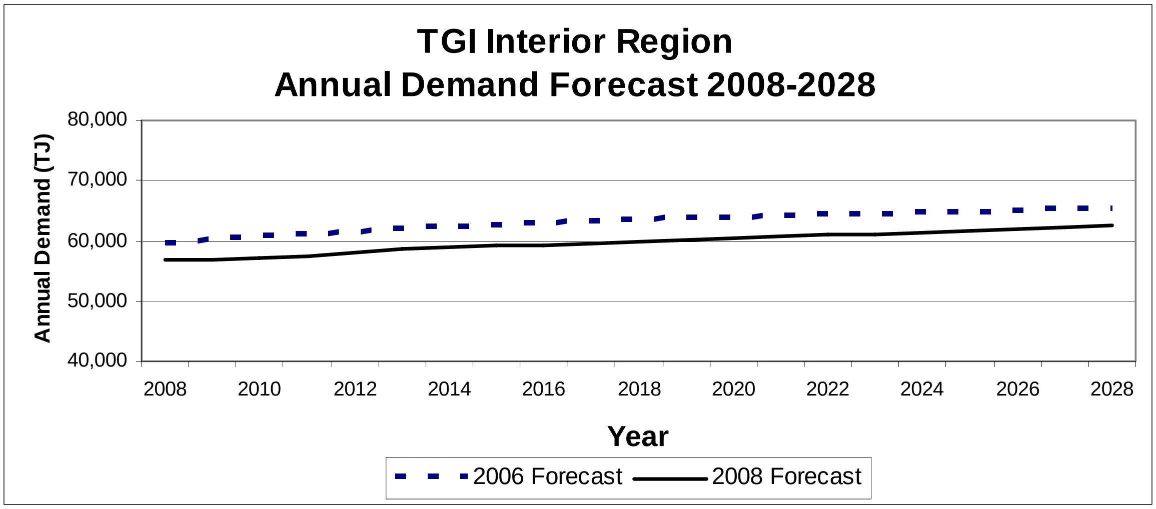
The following table illustrates the total annual demand from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Interior Region, both in tabular and graphical form:

TGI - Interior Region Annual Demand (TJ)

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	59,572	60,193	60,656	61,084	61,477	61,854	62,214
2008 Resource Plan	56,693	56,971	57,216	57,483	57,939	58,687	58,943
Actual Change	**-2,879**	**-3,222**	**-3,440**	**-3,601**	**-3,538**	**-3,167**	**-3,271**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	62,559	62,882	63,177	63,426	63,665	63,874	64,060
2008 Resource Plan	59,171	59,386	59,531	59,815	60,083	60,358	60,634
Actual Change	**-3,388**	**-3,496**	**-3,646**	**-3,611**	**-3,582**	**-3,516**	**-3,426**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	64,238	64,417	64,585	64,771	64,977	65,190	65,408
2008 Resource Plan	60,911	61,196	61,480	61,761	62,035	62,314	62,573
Actual Change	**-3,327**	**-3,221**	**-3,105**	**-3,010**	**-2,942**	**-2,876**	**-2,835**



15.2 Please compare the forecast of total annual demand on TGVI over the planning period with the forecast presented in the previous TGVI Resource Plan.

Response:

Annual demand as forecast in the 2008 Resource Plan is similar to that forecast in the 2006 Resource Plan (less than a 2% difference in 2008, and less than 7% in 2028).

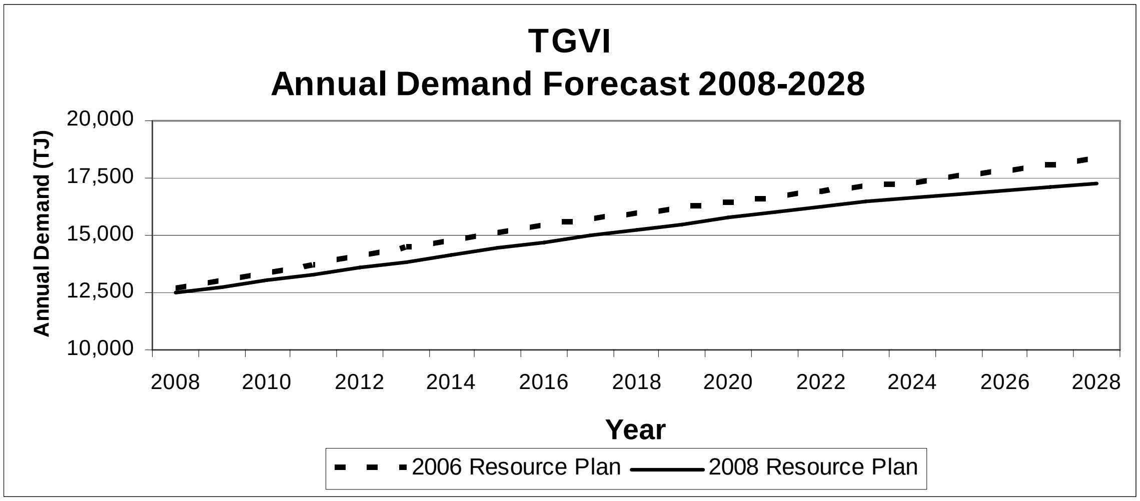
The following table illustrates the total annual demand from both the 2006 and 2008 TGVI Resource Plans (base forecast and reference forecast, respectively), both in tabular and graphical form:

TGVI - Annual Demand (TJ)

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	12,675	12,981	13,315	13,678	14,050	14,429	14,753
2008 Resource Plan	12,467	12,746	13,027	13,306	13,579	13,855	14,138
Actual Change	**-208**	**-235**	**-288**	**-372**	**-471**	**-574**	**-615**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	15,096	15,414	15,709	15,971	16,210	16,430	16,667
2008 Resource Plan	14,419	14,700	14,976	15,242	15,499	15,754	16,004
Actual Change	**-677**	**-714**	**-733**	**-729**	**-711**	**-676**	**-663**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	16,882	17,119	17,238	17,566	17,818	18,075	18,345
2008 Resource Plan	16,238	16,446	16,629	16,790	16,937	17,081	17,235
Actual Change	**-644**	**-673**	**-609**	**-776**	**-881**	**-994**	**-1,110**


TGVI
Annual Demand Forecast 2008-2028
Annual Demand (TJ)
20,000
17,500
15,000
12,500
10,000
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Year
2006 Resource Plan
2008 Resource Plan

16.0 Reference: Design Day Demand Forecasts

Exhibit B-1, pp. 41-42

16.1 Please compare the forecast of design day demand on TGI over the planning period with the forecast presented in the 2006 TGI Resource Plan.

Response:

Generally, peak day demand is lower in the 2008 Resource Plan than what was forecast in the 2006 Resource Plan. TGI has observed a slight decline in the three-year average peak use per customer since the 2006 Resource Plan was prepared, which has been incorporated into the 2008 forecast. The changes seen above in the customer account forecast are also reflected in the peak day demand forecast.

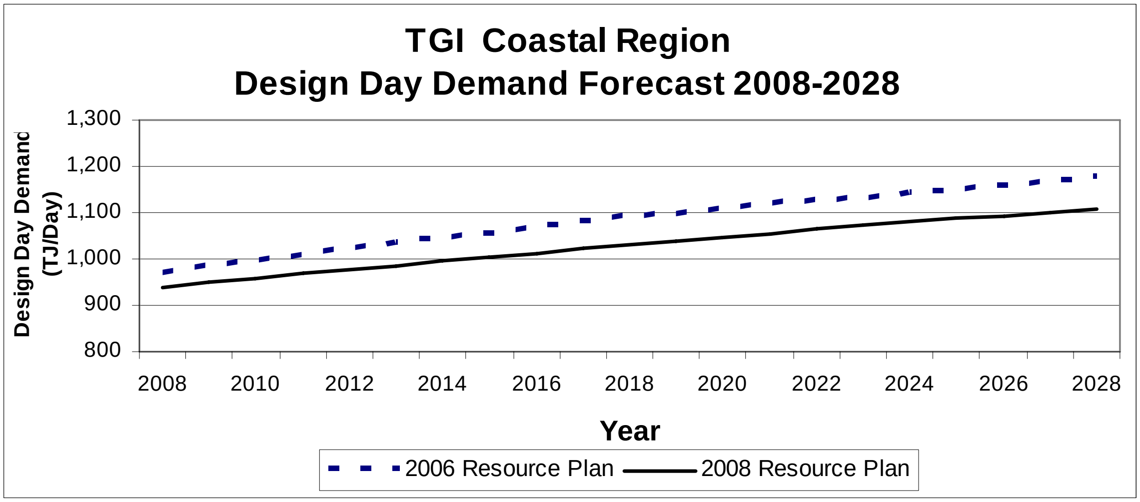
The following table illustrates the design day demand from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Coastal Region, both in tabular and graphical form:

TGI Coastal Region - Design Day Demand (TJ/Day)

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	968	985	997	1,007	1,023	1,034	1,045
2008 Resource Plan	940	950	959	968	977	986	995
Actual Change	**-28**	**-35**	**-38**	**-39**	**-46**	**-49**	**-51**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	1,054	1,070	1,081	1,091	1,096	1,108	1,117
2008 Resource Plan	1,004	1,012	1,021	1,030	1,039	1,047	1,056
Actual Change	**-50**	**-57**	**-60**	**-61**	**-57**	**-61**	**-62**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	1,127	1,133	1,144	1,151	1,159	1,164	1,176
2008 Resource Plan	1,064	1,072	1,079	1,087	1,094	1,102	1,109
Actual Change	**-63**	**-61**	**-65**	**-64**	**-65**	**-62**	**-68**



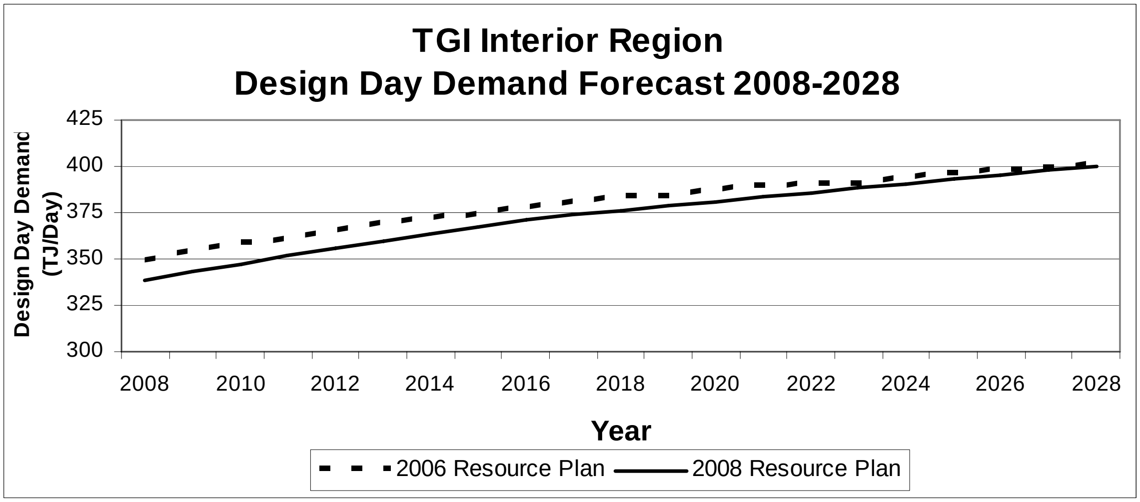
The following table illustrates the design day demand from both the 2006 and 2008 TGI Resource Plans (base forecast and reference forecast, respectively) for the Interior Region, both in tabular and graphical form:

TGI - Interior Region - Design Day Demand (TJ/Day)

	2008	2009	2010	2011	2012	2013	2014
2006 Resource Plan	350	355	358	360	366	369	372
2008 Resource Plan	338	343	347	351	356	360	364
Actual Change	**-11**	**-12**	**-11**	**-9**	**-10**	**-9**	**-9**

	2015	2016	2017	2018	2019	2020	2021
2006 Resource Plan	374	378	380	383	384	388	389
2008 Resource Plan	368	371	374	376	379	381	383
Actual Change	**-6**	**-7**	**-7**	**-7**	**-5**	**-7**	**-6**

	2022	2023	2024	2025	2026	2027	2028
2006 Resource Plan	390	390	394	396	398	399	401
2008 Resource Plan	386	388	391	393	396	398	400
Actual Change	**-4**	**-2**	**-4**	**-3**	**-3**	**-1**	**-1**



16.2 Please compare the forecast of design day demand on TGVI over the planning period with the forecast presented in the previous TGVI Resource Plan.

Response:

Generally, peak day demand is a little lower in the 2008 Resource Plan than what was forecast in the 2006 Resource Plan. TGVI has observed a slight decline in the three-year average peak use per customer since the 2006 Resource Plan was prepared, which has been incorporated into the 2008 forecast. Changes seen above in the customer account forecast are also reflected in the peak day demand forecast.

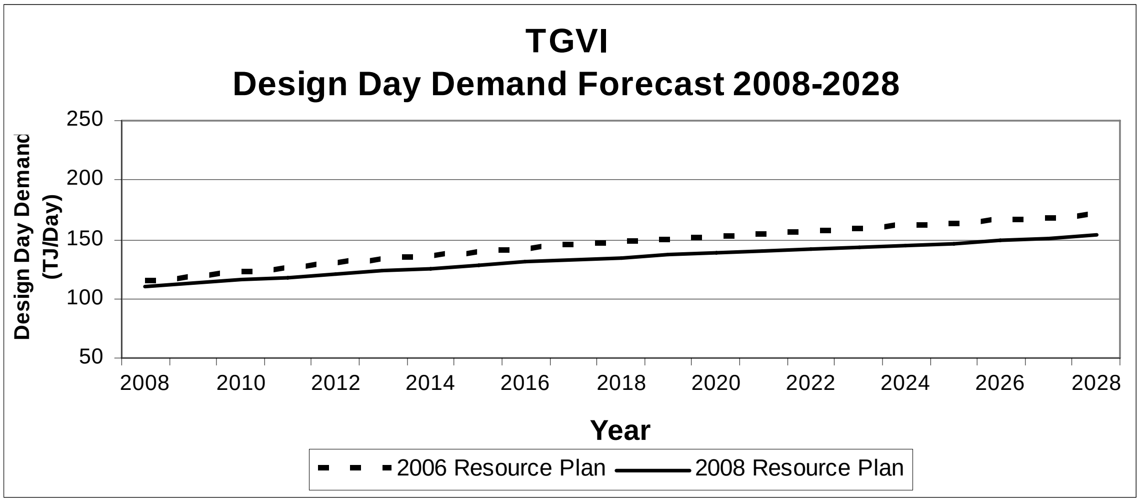
The following table illustrates the total annual demand from both the 2006 and 2008 TGVI Resource Plans (base forecast and reference forecast, respectively), both in tabular and graphical form:

TGVI - Design Day Demand (TJ/Day)

	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
2006 Resource Plan	114	118	122	125	129	133	136
2008 Resource Plan	110	113	116	118	121	123	126
Actual Change	**-4**	**-5**	**-6**	**-7**	**-8**	**-10**	**-10**

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
2006 Resource Plan	139	142	145	148	150	152	154
2008 Resource Plan	128	131	133	135	137	138	140
Actual Change	**-11**	**-12**	**-12**	**-13**	**-13**	**-14**	**-14**

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
2006 Resource Plan	156	159	161	163	165	168	170
2008 Resource Plan	141	143	145	147	149	151	153
Actual Change	**-15**	**-15**	**-15**	**-16**	**-16**	**-17**	**-17**


TGVI
Design Day Demand Forecast 2008-2028
Design Day Demand (TJ/Day)
250
200
150
100
50
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Year
2006 Resource Plan
2008 Resource Plan

17.0 Reference: Residential Use Trends

Exhibit B-1, p. 29

17.1 In 2005, the MEMPR set energy efficiency targets for new and existing construction in its plan: "Energy Efficient Buildings: A Plan for BC". The plan identified the six provincial objectives through which the MEMPR forecasts that the province will realize a savings of 22 million GJ per year in fossil fuels, equivalent to a reduction of 14% of residential and commercial sector demand in the year 2001. In May, 2008, the Ministry released its Energy Efficient Buildings Strategy which set targets in conservation and energy efficiency to reduce the average energy demand per home by 20 per cent by 2020. Have the Ministry's energy efficiency targets, as stated in both plans, been reflected in the forecasts of residential use per customer over the planning period of this resource plan?

Response:

The above targets have not explicitly been included in this resource plan, due to the difficulties in determining the portions of energy savings that can be attributed directly to the use of natural gas. However, the energy reductions that have occurred since 2001 are reflected in the consumption data analyzed when forecasting future consumption. Therefore, the activities undertaken to reach the above targets are implicit in the forecasts of residential use per customer over the planning period of this resource plan.

18.0 Reference: Robust Growth

Exhibit B-1, p. 36

18.1 It states on page 36 that: "Stronger use per customer rates in all service areas in this scenario would be supported by a higher penetration of natural gas heating appliances in new homes and the conversion to natural gas for space and water heating in existing homes where heating oil or electricity are currently used for that purpose." Please confirm whether this statement assumes that owners of existing homes that are converted to natural gas for space and water heating are existing customers of TGI/TGVI. If the premise underlying this statement is that the owners of existing homes converted to natural gas for their space and water heating requirements become new customers of TGI/TGVI, then please explain how the addition of these customers is expected to increase use per customer rates.

<u>Response:</u>

Terasen Gas confirms this statement does assume that owners of existing homes that are converted to natural gas for space and water heating are existing customers of TGI/TGVI.

19.0 Reference: Past and Current EEC Programs

Exhibit B-1, Appendix H, p. E-2

19.1 It states on page E-2 that: "TGI's EEC activity in 2007 produced a yield of $2.58 spent/GJ conserved, well below customer gas cost rates including midstream cost that averaged $8.33 Cdn/GJ for residential lower mainland customer in 2007." Please compare the yield of Terasen's EEC activities in 2007 to those of PG&E, Puget Sound Energy, Union Gas and Enbridge Gas Distribution.

Response:

PG&E reports electric and gas DSM budgets on a combined basis and therefore Terasen has not been able to determine what amount was spent exclusively on gas DSM activity for 2007. PG&E does report gas energy savings separately on an annual basis. The most current DSM report was filed by PG&E on November 7, 2007 and is a cumulative report of their EEC programs since the inception of PG&E's 2006-2008 EEC program cycle and does not include results for 2007, therefore it is not possible to isolate results for 2007.[2]

Both Union Gas and Enbridge Gas report energy savings on an NPV basis. The yield for Union Gas for 2007 was $4.82/ GJ saved.[3] The yield for Enbridge Gas for 2007 was $6.24/GJ saved.[4]

Puget Sound Energy also reports on a NPV basis. PSE spent $3.11(USD)/therm saved. Using a conversion factor of 1GJ = 9.47816 therms, this equates to $29.48/GJ saved.[5]

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[2] From California Public Utilities Commission web site http://eega2006.cpuc.ca.gov/DisplayMonthlyReport.aspx?ID=6
[3] Fiona Oliver Glasford, Manager, DSM Policy and Evaluation, Union Gas
[4] Suzette Mills, DSM Portfolio Analyst, Enbridge Gas
[5] According to Eric Engllert, Manager, Regulatory Initiatives and Tariffs, PSE spent $8,303,096 and saved 2, 664,548 therms. Calculations of conversion of therms to GJs confirmed with ESource. Results obtained form PSE Energy Efficiency Services 2007 Program Results Annual Report.

20.0 Reference: Implications of Potential New Industrial Load on the ITS

Exhibit B-1, p. 65

20.1 What is the expected load due to the new natural gas fired peaking facility currently contemplated by FortisBC in the course of their development of their resource plan?

Response:

FortisBC had not yet completed its integrated resource planning process in which a preferred resource portfolio will be selected and timing of specific resource additions will be identified. TGI understands that FortisBC will be filing its Resource Plan in late 2008 so it is premature to speculate if indeed new natural gas fired peaking facility would be selected as a preferred resource at this time. However, based on information provided by Fortis BC at its stakeholder consultation sessions, TGI understands that the following range of natural gas fired generation facilities with the corresponding gas loads are being considered, in no particular order of preference.

FortisBC gas-fired generation facility Options	Assumed Average Heat Rate [kJ/kWh][6]	Expected natural gas load
combined cycle gas turbine (CCGT) 250 MW	7,240	43.4 TJ/d
simple cycle gas turbine (SCGT) one 42 MW unit	9,950	10.0 TJ/d
simple cycle gas turbine (SCGT) three 42 MW units	9,950	30.0 TJ/d

20.2 By how many years could the peaking facility accelerate the need for an expansion of the ITS system?

Response:

Based on more detailed hydraulic analysis that has been completed since the 2008 Resource Plan was submitted, TGI now expects that an expansion of the ITS system could be required as early as the winter of 2013 to meet core customer demand only. As discussed in the Resource Plan (Exhibit B-1, p. 61-64), prior to the updated analysis, it was expected that a facility addition would not be required until winter of 2016.

[6] Heat rates for SCGT and CCGT are based on data published on BC Hydro 2006 Integrated Electricity Plan, Appendix F 2005 Resource Option Report, Page 41 of 147 and 43 of 147

However, as noted in the response to BCUC IR 1 Q10.1, since the submission of the 2008 Resource Plan (Exhibit B-1), Terasen has confirmed a trend that the transient load profile (or hourly load relative to the daily load) for the Okanagan region of the interior has increased, relative to that for the Thompson and Kootenay regions. The higher transient load profile, coupled with the concentrated growth in the Okanagan region, increases the effective demand on the transmission system. As a result, facility addition for the ITS would likely be required 2 to 3 years in advance of 2016 in order to meet the current demand forecast of core market growth in the Okanagan region.

If a peaking facility was put in service in the interior prior to 2013, it would require further advancement of the ITS expansion. Peak day demand growth on the ITS is approximately 3.5 TJ/d each year, therefore if the firm gas transportation requirement for a peaking facility is 10 TJ/d (the gas demand from a potential FortisBC gas fired generation addition with the lowest load among alternatives being considered), the expansion requirement could be advanced 2 to 3 years, However, Terasen understands that the earliest FortisBC could practically put in place a gas fired generation facility is the winter of 2012, accounting for the time required to complete its integrated resource planning process and for the project approval, design, and construction schedule.

21.0 Reference: Natural Gas Vehicle Grants

Exhibit B-1, p. 97

21.1 What have been the actual expenditures on natural gas vehicle grants during each of the past three years?

Response:

As reported in TGI's Natural Gas Vehicle ("NGV") Annual Reports from 2005 to 2007, below is a summary of the grants. As noted in the 2007 NGV Annual Report submitted May 22, 2008, TGI expects the number of conversion grants for 2008 to be for 80 vehicles.

	Amount	Number of Vehicles	Estimated Annual Gas Volumes (GJ)
2005	$ 47,500	31	28,055
2006	$ 74,500	34	30,770
2007	$15,000	6	5,430

22.0 Reference: Waste Heat Recovery Electricity Generation

Exhibit B-1, p. 98

22.1 Please provide an update on any new developments in the project proposed by TGVI to generate electricity from waste energy from its compressor units at the Coquitlam Compressor Station.

Response:

In order for TGVI to proceed with the waste heat recovery electricity generation project at the Coquitlam Compressor Station, the project must provide an overall balance of energy efficiency, environmental and economic benefits. While the benefits in energy efficiency and for the environment are present, TGVI would require that the income from electricity sales would offset the project costs in order to maintain a net zero impact to TGVI ratepayers.

TGVI completed a project assessment for this initiative and established budgetary level capital and O&M cost estimates, a project schedule, an estimate of annual power generation potential, and a revenue projection from the potential sales of electricity to BC Hydro under the Standing Offer Program. The project assessment determined that on a 20 year present value basis the project costs would exceed the electricity sales revenue, resulting in an incremental cost of service to TGVI ratepayers of approximately $5 million. TGVI determined that, absent any other funding, the project would require that Terasen receive $110 per MWh, versus the average $87 per MWh TGVI would expect to receive under BC Hydro`s Standing Offer Program for projects under 10 MW in size. TGVI submitted a funding application to the Innovative Clean Energy Fund from the MEMPR that would be used to offset the incremental cost of service for the project and balance the economics. However, TGVI was not awarded the requested funding.

At this time, the project remains on hold until additional funding can be secured or the electricity price is raised to bring sufficient revenue to offset the project costs. TGVI will continue to explore opportunities for funding and monitor the BC Hydro Standing Offer Program, as well as search for other potential business partners for the project.

23.0 Reference: Installation and Operating Costs of Air and Ground Sourced Heat Pumps

Exhibit B-1, Appendix D, Table 1, p. D 13

23.1 Please provide an estimate of the greenhouse gas emissions associated with each of the three heating system configurations presented in Table 1. For the purpose of this analysis, assume that 15 percent of the electricity consumed by all three heating systems is imported from outside the province and generated by natural gas fired facilities.

<u>Response:</u>

The estimated GHG emissions at the end use for the three heating systems using the assumptions indicated in the question are as follows:

- High Efficiency Gas Furnace - 2,671 kg
- Air-Source Heat Pump – 388 kg
- Ground Source Heat Pump – 355 kg

Assumptions used in the foregoing estimates

- 50 kg CO2 per GJ of natural gas combusted
- Gas-fired generation @ 50% thermal efficiency
- Upstream losses and fuel not considered for either gas or electricity
- Space cooling load ignored in heat pump cases

The results presented above are based on the assumption in the question that 15% of the electricity is imported and comes from gas-fired generation. This assumption appears to be based on assigning a system-average supply mix to space heating load. It is the view of Terasen Gas that an analysis from a marginal and regional perspective (see also, TGI-TGVI Energy Efficiency and Conservation Programs Application, Exhibit B-7, response to BCSEA IR 1.17.1, included as Attachment 23.1) is a more appropriate approach to examining the GHG effects of these energy systems. Since natural gas fired generation is the marginal resource in the Western Interconnection a very high percentage of the time, it is Terasen Gas view that marginal electric space heating load will cause a corresponding increase in the amount of gas-fired generation. Under this assumption a high efficiency furnace is among the lower emitters of C02 as shown below.

- High Efficiency Gas Furnace - 2,763 kg
- Air-Source Heat Pump – 2,587 kg
- Ground Source Heat Pump – 2,367 kg

The case is even stronger if the marginal source of electricity is coal or lower efficiency gas-fired generation.

Attachment 23.1

17.0 Reference: Exhibit B-1, Application, 6.4. Residential Fuel-Switching Program Area ($3.7 million), pp. 63-65; 7.2 Greenhouse Gas Emission Reductions, pp. 98-100

The Application asserts that displacing electricity with efficiently used natural gas will reduce greenhouse gas (GHG) emissions. Footnote 29 on page 63 appears to offer the only justification for this claim.

17.1 Please provide a detailed analysis of the basis for claiming that “the use of natural gas ... in place of electricity results in lower GHG emissions overall in the region” (Application, p. 63). Please address in this analysis the basis for assigning a GHG factor to electricity that would be displaced; and please address current government policy affecting GHGs in B.C.’s electricity sector, particularly Policy Actions 10, 18, 19 and 20 of the 2007 Energy Plan.

Response:

As stated in BCUC IR 1.62.1 and supported by the Northwest Power and Conservation Council[1], the marginal source of electricity generation for the Pacific Northwest is made up of primarily natural gas and coal fired generation. Appendix H of BC Hydro’s 2008 LTAP provides additional evidence of the marginal source of electricity generation in the region being thermal-based and its implications for GHG reductions as follows:

> “…the WCI is reviewing studies done by the California Energy Commission (CEC) that show amounts of GHG reductions in each Western state under different penetrations of energy efficiency and renewables.
>
> The CEC studies discussed in the above paragraph were performed by running hourly simulations of the WECC power grid with hourly loads across WECC being served by economic dispatch of generation available in the region. …the CEC studies demonstrate the reality that much load in WECC is served by natural gas fired generation. As the CEC increased penetration of renewables in the future in its alternative views of the future, the renewables will run to meet the load, thereby displacing natural gas fired generation that would otherwise be needed to meet loads. The CEC ran a few sensitivities with high GHG taxes in place. In the cases with high penetrations of renewables, economic dispatch would sometimes displace coal fired generation… …because coal generation emits about twice the amount of GHG/kWh than does natural gas fired generation. The CEC concludes that a good way to reduce GHG is to

[1] Northwest Power and Conservation Council, June 2008. Marginal Carbon Dioxide Production Rates of the Northwest Power System. 23p.

> reduce thermal generation levels by causing higher penetration of energy efficiency and renewable power supplies."[2]

Once BC Hydro reaches a position of self-sufficiency, they will be in a position to be a net exporter of electricity in all but a critical water year, since that criteria is used by the Province to define the self-sufficiency limit. Since BC Hydro trades electricity within the WECC, and will continue trading in accordance with the 2007 BC Energy Plan, replacing the use of electricity where practical with fuel switching energy efficiency programs will displace natural gas and coal fired generation as described in the quote above, both before and beyond 2016. The assigning of a GHG factor for the electricity that would be displaced and further supporting analysis is discussed below.

According to BC Hydro's 2005 Resource Options report the Greenhouse Gas Emission Factor (Tonnes CO2 equivalent/GWh) for a 560 MW Super Pulverized Coal Combustion Plant and 250 MW Combined Cycle Gas Turbine Plant are 855 and 350 tonnes per GWh respectively. In BC Hydro's 2007 Conservation Potential Review Summary Report a GHG factor of 550 tonnes per GWh was assigned for BC Hydro's electricity imports in F2006[3]. A modern combined cycle gas fired generator operates at 50 to 55% efficiency; whereas modern direct gas fired appliances operate at much higher efficiencies. For example, new high efficiency natural gas fired furnaces operate at 95% efficiency or higher. The Greenhouse Gas Emission Factor for a high efficiency furnace is 180 tonnes CO2 equivalent/GWh[4]. Therefore, there is a clear GHG reduction advantage to using natural gas in direct use applications to reduce the quantity of electricity produced by gas or coal fired generation and therefore reduces GHG emissions in the region.

Terasen Gas provided a detailed analysis on this issue in the 2007 BC Hydro Rate Design proceeding. We have included an excerpt of this evidence as Attachment 17.1. A discussion of the regional GHG impact analysis can be found in Section 5.1, pages 5 to 7 of this attachment. In the Commission's October 26, 2007 Decisions in the Matter of BC Hydro's 2007 Rate Design – Phase 1, the Commission agreed with Terasen's assertion that the direct use of natural gas for space and water heating in BC will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest.

> "Commission Panel commends Terasen for its initiative in leading evidence both concerning the use of electricity for space and water heating in BC Hydro's service area, and concerning the potential growth in demand for electric space and water heat that BC Hydro is forecasting. The implications of the growth in demand were among the reasons that led the Commission Panel to encourage and guide BC Hydro to

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[2] Global Energy, 2008. Renewable Energy Credit – Market Analysis of Potential Renewable Energy Sale in WECC. Prepared for BC Hydro and Appearing as Appendix H to BC Hydro's 2008 LTAP. P 10-11 of 47.

[3] BC Hydro, 2007 Conservation Potential Review, Summary Report, Date Nov. 20 2007. p. 12.

[4] 3600 (GJ per GWh) x 48.5 (kg CO2e per GJ) / 97% (assumed furnace efficiency)

implement an inclining block residential rate, so that customers receive the correct pricing signal in this regard. **The Commission Panel agrees with Terasen that the use of natural gas (as opposed to electricity) for space and water heating in B.C. will make additional energy available to displace coal or gas-fired generation at the margin in the Pacific Northwest**[5]" (emphasis added).

A recent American Gas Foundation, *Direct Use of Natural Gas: Implications for Power Generation, Energy Efficiency and Carbon Emissions* supports the argument that the direct use of natural gas lowers total energy consumption and carbon emissions[6]. The study found that:

- The direct natural gas in residential and commercial applications can increase the productivity of available energy supplies, reduce the cost of energy and reduce CO2 emissions.
- In all direct use scenarios considered by the study CO2 emissions are reduced.
- The direct use of natural gas would result in significant avoidance of electricity generation capacity.

Utilities in other jurisdictions have also identified British Columbia's resources as an opportunity to help them meet renewable requirements and greenhouse gas emission targets. For example, in June 2008, Pacific Gas and Electric Company ("PG&E") in California completed Phase 1 of a BC Renewable Study which identified a "…vast amount of renewable resources in BC, …strong feasibility of building a transmission line and good indicators of commercial viability…" for acquiring renewable resources from BC[7]. PG&E is proceeding with Phase 2 of the study. This study provides an example of a possible solution cross political boundaries to find the optimal solution in reducing GHG emission for the PNW region.

It is The Companies' view the achievement of energy self sufficiency and net zero emissions from thermal generation in BC does not alter the regional GHG benefits of the direct use of natural gas for space and water heating in BC. When BC achieves energy self sufficiency the region would benefit from British Columbia exporting its clean power and displacing the use of coal and natural gas fired generation. The direct use of natural gas in British Columbia for space and water heating will reduce the amount of new generation required in BC to make self sufficiency possible and/or make available larger quantities of clean electricity for export and help reduce overall GHG emissions.

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[5] BCUC Decision in the Matter of British Columbia Hydro and Power Authority 2007 Rate Design Application – Phase 1, October 26, 2007, p. 191.
[6] American Gas Foundation, "Direct Use of Natural Gas: Implications for Power Generation, Energy Efficiency and Carbon Emissions, April 2008.
[7] Pacific Gas and Electric Company – BC Renewable Study Phase 1 report. June 2008.