Terasen Gas

Tom A. Loski
Chief Regulatory Officer

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7464
Cell: (604) 250-2722
Fax: (604) 576-7074
Email: tom.loski@terasengas.com
www.terasengas.com

Regulatory Affairs Correspondence
Email: regulatory.affairs@terasengas.com

August 14, 2009

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")
2010 and 2011 Revenue Requirements and Delivery Rates Application

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

On June 15, 2009, Terasen Gas filed the Application as referenced above. In accordance with Commission Order No. G-89-09 setting out the Regulatory Timetable for the Application, Terasen Gas respectfully submits the attached response to BCUC IR No. 1.

If there are any questions regarding the attached, please contact the undersigned.

Yours very truly,

TERASEN GAS INC.

Original signed:

Tom A. Loski

Attachment

cc (e-mail only): Registered Parties

1.0 Reference: Executive Summary

Part I, p. 1

One page 1 of the Application, it states: "The increase sought for 2010 is 5.3 per cent, with an additional effective base rate delivery increase of 4.1 per cent (cumulative increase of 9.4 per cent) in 2011. It results in relatively modest changes to the annual bill of an average Lower Mainland residential customer with an approximate net increase of 2.8 per cent or $31 in 2010 and an additional 1.7 percent or $19 in 2011."

For the following questions, please provide all requested information in the form of fully functioning electronic spreadsheets:

1.1 Please provide the calculations and assumptions for the above statement and provide references to the financial schedules.

Response:

Please refer to Attachment 1.1.

1.2 TGI bases the impact of the proposed rate increase on a typical annual consumption of a Lower Mainland residential customer (95 GJ/year). TGI weather data shown in Appendix D-1 indicate that there is significant difference in the annual Heating Degree Days in the various regions. Please provide the data and calculations of the average residential consumption of natural gas based on a weighted average of all the regions that TGI serves.

Response:

Please refer to Attachment 1.2.

1.3 For the data provided in Appendix C-26, please extend the bar graphs to include data for the forecast period 2010 and 2011. Based on this graph, please provide an analysis of the volatility of burner tip prices during the forecast period 2010 to 2011.

Response:

Please refer to Attachment 1.3 for the TGI Residential Annual Bill forecasts for 2010 and 2011. The forecasted cost of gas per GJ for 2010 and 2011 is based on AECO monthly forward prices (exclusive of hedging activities) averaged for 2010 and 2011 respectively, as at May 11, 2009. TGI has used the AECO forward monthly index as a proxy for the TGI gas costs, as about 85% of the volume purchased through the Commodity Cost Reconciliation Account ("CCRA") has a relationship to the AECO price point. The cost of gas that gets reflected in customers' rates for 2010 and 2011 will be determined at a later date and will follow the normal process for setting gas cost recovery rates for TGI customers. Factors that will impact the gas cost recovery rates in place during 2010 and 2011 will be the forecasted, and actual, gas costs, deferral account balances, and hedging gains or costs for 2010 and 2011. The AECO forecast monthly price, averaged over 12 months equals $6.28 per GJ for 2010 and $7.00 per GJ for 2011. This is a $0.72 per GJ difference, which is substantial and due to market price volatility, has the potential to change on a daily, monthly and quarterly basis. When using this forecasted cost of gas in a total overall burner tip cost as shown in Attachment 1.3, there is low volatility between the years. It is important to note that due to the volatility of the natural gas market, the forecasted burner tip prices will change along with the forecasted change in the natural gas monthly forward prices depending on the date used for the analysis. The TGI hedging program will protect customers from some of this volatility but will not eliminate the exposure customers will have to changes in natural gas prices over time.

1.4 For the typical residential customer, please provide a bar graph and tabular data for the period 2003 to 2011 that segments the average bill between delivery cost and gas cost.

Response:

Please refer to Attachment 1.4. Consistent with the forecast methodology in BCUC IR 1.1.3, the forecasted cost of gas per GJ for 2010 and 2011 is based on AECO monthly forward prices (exclusive of hedging activities) averaged for 2010 and 2011 respectively, as at May 11, 2009.

2.0 Reference: Executive Summary

Part I, p. 3

"TGI's competitive position in B.C. continues to decline with increases in natural gas prices and the gradual erosion of the cost advantage of natural gas over electricity."

For the following questions, please provide all requested information in the form of fully functioning electronic spreadsheets:

2.1 Please provide tabular and graphical data for the period 2003 to 2008 that compare the customer price differential of natural gas to electricity for residential sales.

Response:

Please refer to Attachment 2.1.

2.2 Please provide an estimate of the price elasticity of demand coefficient for natural gas in British Columbia. If the price elasticity of demand is not known for B.C., please provide published figures for North America.

Response:

TGI's analysis indicates the price elasticity of demand coefficient for TGI residential customers is approximately 0.21 and for TGI commercial customers is approximately 0.17.

2.3 Please provide an estimate of the cross elasticity of demand between natural gas and electricity in B. C. If the cross elasticity of demand is not known for B.C., please provide published figures for North America in general.

Response:

TGI does not have an estimate of the cross elasticity of demand between natural gas and electricity, but for North America in general the cross elasticity is estimated to be approximately 0.01. This value is quoted from the research report provided in Attachment 2.3, entitled *Price Responsiveness in the AEO2003 NEMS Residential and Commercial Building Sector Models*, Energy Information Administration, U.S. Department of Energy by Wade, Steven, H.

2.4 It is generally understood that Terasen uses financial risk management tools, including a portfolio of fixed price contracts from various supply sources to manage gas prices, but that the cost of gas largely flows through to consumers based on market prices. Data provided by TGI on page 62 indicate that the price of natural gas declined significantly over the past 12 months, but that prices are forecasted to increase in during the test period 2010 and 2011.

Please discuss what impact the reduction in gas prices over the past 12 months has had on TGI's customers. Please also provide a projection of what impact the forecasted increases in gas prices in 2010 and 2011 will have on TGI's various rate classes.

Response:

This response addresses impacts on core market customers choosing to remain on the TGI default commodity offering. Residential and commercial customers electing to purchase natural gas from an independent gas marketer under the Customer Choice program will sign fixed rate agreements of one to five years in length. Further, TGI cannot comment on the effects the commodity cost changes will have on transportation customers that arrange their own commodity purchases.

The reduction in gas prices over the past twelve months has had a favourable impact on TGI's customers in terms of rates. Since July 2008, the TGI commodity cost recovery rate has declined by 39%, falling from $9.780/GJ effective July 1, 2008 to $5.962/GJ effective April 1, 2009. This latter rate represents the lowest level the commodity cost recovery rate has been at since the gas cost recovery charges were disaggregated into commodity and midstream in April 2004 in support of the commodity unbundling program. By utilizing a balanced portfolio approach to price risk management, which includes a portion of hedges, storage, and floating (or unhedged) gas, and effectively utilizing option instruments within the hedging program, the TGI portfolio of costs decreases with the decline in natural gas prices. The portfolio also protects customers from significant rate increases should prices run up.

The TGI 2009 Second Quarter Gas Cost Report, filed with the Commission on June 8, 2009, provided updated gas cost forecasts that were based on the June 1, 2009 forward prices. The June 1, 2009 forward prices continued to indicate contango in the natural gas commodity market with gas prices forecast to increase during 2010 and 2011. The twelve month cost of gas outlook, in conjunction with the current Commodity Cost Reconciliation Account ("CCRA") deferral account balance, indicated that the existing commodity cost recovery rate was currently over recovering costs but that natural gas prices gas prices were forecast to increase beyond the twelve month period. On June 11, 2009 the Commission issued Letter No. L-43-09 accepting TGI's recommendation that the commodity cost recovery rate remain unchanged effective July 1, 2009.

Consistent with Commission guidelines, TGI will continue to monitor the commodity forward prices and report CCRA balances, including any recommendations for changes to the commodity cost recovery rate, on a quarterly basis. Further, TGI will continue to monitor and report Midstream Cost Reconciliation Account ("MCRA") deferral account balances consistent with TGI's position that midstream rates be reported on a quarterly basis and that, under normal circumstances, midstream rates will be adjusted on an annual basis with a January 1 effective date.

3.0 Reference: Executive Summary

Part I, pp. 5-6

Inflation Rate (CPI)

On page 5 it states: "At the same time, customers also saw delivery rates hold steady when compared to inflation."

3.1 Please provide updated 2009, 2010, and 2011 forecasts for CPI. Please use the same financial sources as in the most recent PBR. Please provide copies of all references.

Response:

Updated CPI (BC) forecasts are as follows:

Source	CPI Forecast			Forecast Publish Date
	2009	2010	2011	
Conference Board of Canada	0.65%	2.57%	2.40%	July 15, 2009
Ministry of Finance[1]	0.80%	2.00%	2.00%	February 17, 2009
RBC Financial Group[2]	n/a	1.50%	1.80%	October 2008
Toronto-Dominion Bank[3]	0.10	1.50%	2.00%	July 16, 2009

[1] The Ministry of Finance forecast dated February 17, 2009 is the most recent

[2] RBC Financial Group no longer provides BC CPI forecasts so an update was not available

[3] The July 16, 2009 forecast did not provide an update for 2011; 2011 forecast is based on March 2009 forecast

The average of the updated reported forecasts is 1.9% for 2010 and 2.0% for 2011 (the forecasts included in the RRA filing also showed 1.9% for 2010 and 2.0% for 2011).

Attachment 3.1 provides copies of the forecasts used above.

3.2 Data presented on page 160, Table B-1-11 indicate Approved and Adjusted CPI rates for the period 2003 to 2009. Please describe the method used to amend Approved CPI to Adjusted CPI.

Response:

The CPI was not amended from the approved rate for the calculation of the adjusted net inflation factor. The CPI rates and adjustment factors shown in the adjusted column represent the approved rates and were included so that the reader could see the components that derive the net inflation factor for each year. Consistent with the PBR Agreement, in determining the formula O&M for each year the previous year's net inflation rate was adjusted to account for actual customer growth.

Gross O&M Formula = (Previous Ye (Previous Year Adjusted Formula O&M[1]) X [(1+ Customer Growth) X (1+CPI-Adjustment Factor)] + Pension & Insurance Variance

($ thousands)	Approved 2003	Approved 2004	Adjusted 2004	Approved 2005	Adjusted 2005	Approved 2006	Adjusted 2006	Approved 2007	Adjusted 2007	Approved 2008	Adjusted 2008	Approved 2009
Adjusted Formula O&M		182,420	182,420	186,089	186,089	190,888	190,888	196,001	196,001	200,183	200,183	203,899
Customer Growth Factor		0.96%	1.15%	1.40%	1.56%	1.60%	1.92%	1.68%	1.44%	1.53%	1.17%	1.01%
CPI		1.70%		2.00%		2.20%		2.00%		2.00%		2.10%
Adjustment Factor		-0.85%		-1.00%		-1.45%		-1.32%		-1.32%		-1.39%
Net Inflation Factor		101.82%	102.01%	102.41%	102.58%	102.36%	102.68%	102.38%	102.13%	102.22%	101.86%	101.73%
		185,740	186,089	190,575	190,888	195,394	196,001	200,657	200,183	204,624	203,899	207,424
Pension & Insurance Variance		2,245		11		1,526		(1,194)		(4,571)		(3,430)
Total including Ft Nelson	182,420	187,985		190,586		196,920		199,463		200,053		203,994
Less Ft Nelson	(684)	(696)		(714)		(732)		(752)		(767)		(778)
Gross Formula O&M Expense	**181,736**	**187,289**		**189,872**		**196,188**		**198,711**		**199,286**		**203,217**

[1]The formula O&M expense for each year is based on the previous year's formula O&M expense adjusted for actual customer growth

4.0 Reference: Executive Summary

Part I, p. 6

Historical demand for Natural Gas

On page 6 it states: "All of this has been accomplished in a period where overall normalized demand for natural gas has declined, the rate of customer growth (which peaked in 2005) has declined in the last four years of the PBR Period, and the expectations of customers have evolved."

4.1 Please explain whether the actual demand for natural gas has also declined over the same period in which normalized demand declined.

Response:

As illustrated in the chart provided in response to BCUC IR 1.4.2, both actual and normalized annual demand for natural gas has declined over the period 1999 to 2008. This information is included in the Application in Appendix D-1.

4.2 Please provide tabular data with a graphical representation that compare actual demand to normalized demand over the period 1999 to 2008. Please provide an analysis of the graph which includes comments on the degree to which normalized data optimize forecasts of actual results. Please provide any supporting data and graphical representations in a fully functioning electronic spreadsheet.

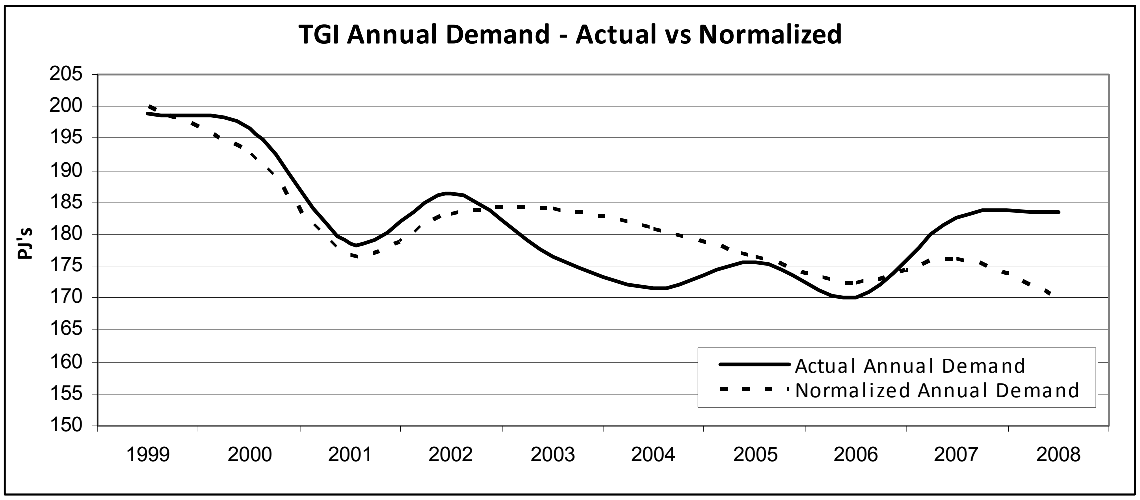
Response:

The following table illustrates the actual and normalized annual demand over the period 1999 to 2008. This information is also contained in Appendix D-1 of the Application.

	1999	2000	2001	2002	2003
Actual Annual Demand (PJ)	198.9	196.7	178.5	186.5	176.6
Normalized Annual Demand (PJ)	200.1	192.5	176.8	183.2	184.1

	2004	2005	2006	2007	2008
Actual Annual Demand (PJ)	171.6	175.7	170.1	182.6	183.4
Normalized Annual Demand (PJ)	180.8	176.4	172.4	176.2	170.0

The following chart provides a graphical representation that compares the actual annual demand to normalized annual demand over the period 1999 to 2008.



Over the period 1999 through 2008, both normalized and actual annual demand for natural gas have declined. Normalized demand has declined by approximately 15%, or 1.8% annually (compound average growth rate). Actual demand has declined by approximately 8%, or 0.9% annually (compound average growth rate). On average over this period, normalized annual demand has been 0.4% lower than actual demand, but ranging from being 5% greater than actual demand (in 2004) to being 7% lower than annual demand (in 2008). These variances are attributed to weather patterns that become warmer or colder than normal.

By normalizing demand, TGI is removing the impacts weather fluctuations have on annual demand, which when compared to other years then allows for the identification and analysis of trends resulting from other factors, such as efficiency improvement and changes in the housing mix. It is for these reasons that TGI believes normalized annual demand provides the optimal basis for forecasting the future demand for natural gas.

Attachment 4.2 provides the supporting data, in a fully functioning electronic spreadsheet.

5.0 Reference: Executive Summary

Part I, p. 6

Customer Expectations

On page 6, reference is made to increasing and changing customer expectations.

5.1 Please provide a description, and supporting data if available, of the method used by TGI to measure and assess customer expectations in 2008 and 2009. Please also explain the impact that changing customer expectations will have on the type and level of service that TGI provides in 2010 and 2011.

Response:

As noted on Page 6 and further elaborated in Part III, Section A, Tab 1 of the Application, we believe that customer expectations are changing in the following areas: Community Involvement in Energy Choices, Growing Need for Increased Customer Care Activities, Increased Public Concern about Safety, and Security, and Continuing Complexity in Aboriginal Rights.

TGI's response to BCUC IR 1.23.1.1 addresses customer's desire for alternative energy solutions provided by TGI. Increased Public Concern about Safety is addressed in responses BCUC IR 1.95.2, and Complexity in Aboriginal Rights is addressed in responses to BCUC IR 1.99 and 101. The growing need for Customer Care Activities is addressed below.

Through market research activities and customer feedback, TGI regularly monitors the Company's service performance and customer expectations related to the services they receive from TGI. In particular, for residential customers, TGI undertook qualitative research related to customer expectations in the form of focus groups conducted by Ipsos-Reid in mid 2008 and followed the focus group research with a quantitative survey of over 800 customers conducted by Angus Reid Strategies in early 2009, and another survey conducted by Ipsos Reid in summer 2009 (see BCUC IR 1.23.1.1). From these studies, TGI understands that its customers prefer to conduct business with TGI through their preferred communication channels and at their preferred time.

In addition to traditional call centre service, customers also expect Terasen Gas to offer a variety of service options through online communication channels, including self service transactional capabilities, to address account issues and information requests. For example, the 2008 Angus Reid Strategies study identified that over 85% of Terasen Gas customers expect to have the ability to start, stop or transfer their service using the Company's online channel. Currently these customer expectations are not met as Terasen Gas provides only limited online self-service transactional functionality as a result of the current CIS capabilities.

As noted in responses to the series of questions under BCUC IR 1.23, there are a large number of customers (primarily commercial, institutional and industrial) who are seeking information with regard to energy consumption, energy efficiency and alternative energy. As noted in the Application, we see an increase in:

- the need for detailed information that is not readily available today. This is driving the need for more communication with our Account Managers and Sales staff;
- the need for more detailed data from our system. At present this has resulted in manual work arounds to address these customer needs.

During 2010 and 2011, the Company is not planning to implement any broad service changes. The Company's Customer Care Enhancement Project, which is the subject of a separate proceeding, will enable Terasen Gas to respond to changing customer requirements and is planned to be implemented in January 2012.

6.0 Reference: Executive Summary

Customer Care - System IT Strategy

Part I, p. 6, par. 4

"Terasen Gas has implemented an IT strategy that focuses on adopting industry best practices. Key aspects of this strategy are scheduled refreshes of key equipment, infrastructure and application software, and standardization of processes and infrastructure where appropriate."

6.1 Please comment on the refreshes to the Customer Care system since 2006, including comment on whether TGI views the Customer Care System as "key".

Response:

Customer Care services, including the provisioning of a Customer Care system, are outsourced to a third party. The service provider implemented a technical upgrade of the system in 2008. This upgrade did not provide an increase in system functionality. Terasen Gas is not privy to, nor has any influence or control over, the refresh policies or schedules of any other hardware or software that supports the Customer Care system provided to Terasen Gas as a service.

Terasen Gas views the Customer Care system as "key". The customer care function is a vital part of providing service to our customers, and consequently represents a core element of our business. It is the main point of interaction between customers and the Company in all aspects of our business. Providing customers with sustained service excellence rests on Terasen Gas consistently being able to offer a range of communication options, billing and payment alternatives, and additional product and service options. It requires the ability to manage communications related to outages and restoration of service, provide accurate and timely monthly bills, promptly address customer concerns, and ensure the Company's representatives have appropriate product and service knowledge and regional understanding. In order for the Company to continue to serve customers well, it needs to adapt and change as customers require new and different services. Underpinning this ability to provide service excellence is a technology platform, referred to as a Customer Information System, or CIS.

We believe that, going forward, the ownership and control of the Customer Care system is critical to the ability to support customers in a cost effective manner. Terasen Gas has a CPCN Application currently before the Commission to modify our current Customer Care model (Customer Care Enhancement Project – CCEP), which includes the replacement of the current system and Terasen Gas direct ownership and control of the technologies to support Customer Care. For further details as to Terasen Gas' views on the key nature of the Customer Care system, please refer to Terasen Gas' CCEP CPCN Application.

7.0 Reference: Executive Summary

Customer Care - Transition from Outsourcing

Part I, p. 9, par. 2

"Transitioning away from a comprehensive outsourcing arrangement is a critical component of the Company's long-term strategic direction."

"In the shorter term, as reflected in this Application beginning in 2009 and through the 2010/2011 forecast period, the Company will be increasing its efforts to improve the quality of our customer care activities while bridging to an orderly transition for implementation of the new customer care delivery model effective 2012."

7.1 Please explain why this change in strategic direction is in the ratepayer's best interest.

Response:

On June 2, 2009, TGI filed an Application for the Customer Care Enhancement Project (CCEP), which involves (1) insourcing key elements of the Company's customer care services, and (2) the implementation of a new Customer Information System (CIS). TGI respectfully submits that the justification for the CCEP is best addressed in the context of the CCEP Application for the following reasons.

First, in the CCEP Application TGI has sought approval for the creation of a non-rate base deferral account attracting AFUDC and approval to record incremental operating and maintenance costs associated with the Project that are incurred prior to the Project implementation date of January 1, 2012, for the purposes of permitting cost recovery. TGI also seeks approval in the CCEP Application for the creation of a rate base deferral account into which the accumulated amount in the non-rate base deferral account will be transferred, effective January 1, 2012, for the purposes of recovering costs through customer rates. Based on these orders sought, the costs incurred with respect to the CCEP will not contribute to the 2010 or 2011 Revenue requirement for TGI.

Second, the Project justification is addressed extensively in the CCEP Application, and further information is expected to be provided in that regard at the end of August. It is most efficient to address the project justification in the context of the CCEP Application, rather than replicating the entire project justification in the current Application. This is particularly the case since TGI is not seeking recovery in 2010 or 2011 rates for any project related costs, including any costs related to the build-up of in-house Customer Care capability in preparation to in-source Customer Care operations.

Third, if the CCEP was addressed within the 2010-2011 TGI Revenue Requirement proceeding, it would introduce the risk of inconsistent decisions from two Commission panels on the same subject.

However, the executive summary from the CCEP Application is quoted below for the benefit of further context:

> *"The Company's customer care function is currently outsourced to CustomerWorks LP. This arrangement has been in place since January 1, 2002. At that time, the key drivers that favoured an outsourcing model for the customer care function were cost certainty, maintaining or enhancing customer service levels, and implementation risk transfer related to expanding and redefining operations to support the repatriation of the 535,000 Lower Mainland customers. These customers had historically been supported through an outsourcing arrangement with BC Hydro. At the time of the outsourcing decision in 2001, the Company had already committed to a packaged CIS solution founded on the then market-leading Peace CIS platform. The move to a new comprehensive outsourcing model was consistent with a broader industry trend. The arrangement with CustomerWorks LP succeeded in meeting the original outsourcing objectives by providing customers and Terasen Gas with cost certainty and risk transfer, as well as delivering generally satisfactory customer service over much of the time since 2002. When service has fallen short of contractual standards, which has happened more frequently of late, CustomerWorks LP has been required to pay contractual penalties to Terasen Gas. The payment of penalties to Terasen Gas accompanied by service shortfalls, is not a sustainable model going forward.*
>
> *Eleven years have passed since the Peace CIS system was selected by BC Gas, and eight years have passed since the decision was made to enter into a comprehensive outsourcing arrangement with CustomerWorks LP. There have been four key developments in the intervening period that affect the Company's customer care function.*
>
> *First, the evolution of the Company's business environment since 2002 has changed the customer care needs of Terasen Gas. The ability of Terasen Gas to retain and add customers is increasingly challenged by volatile commodity prices, housing trends towards smaller multi-unit dwellings, and the growing availability and customer awareness of alternative energy sources. Policy-driven factors such as the Carbon Tax, greatly expanded energy efficiency and conservation initiatives as well as a broader range of energy options available require a skilled, knowledgeable, and flexible customer care staff. The energy marketplace and the Company's business model will continue to significantly evolve over the next number of years. Terasen Gas must be able to manage that evolution in a proactive manner in order to provide the services its customers will expect.*

Research of customer perceptions, as well as anecdotal evidence, suggests that customers now expect public utilities to provide a greater range of communication channels than Terasen Gas is generally able to provide today. This includes more flexibility in moving from traditional voice response centres and hardcopy bill presentment to stronger web support including online transactional tools and enhanced electronic bill presentment and payment options. Moving forward, the Company will best meet these requirements through direct control of core customer care services and the implementation of a new CIS.

Second, the outsourcing market has matured. Additional options are available for outsourcing that were not generally available in 2002. In 2008, the Company retained UtiliPoint International Inc. to undertake a study of "Outsourced Customer Care Models in the North American Utility Industry and Beyond", a copy of which is attached as Appendix B [of the CCEP Application]. The study indicated that the original drivers for comprehensive outsourcing and resulting operational, pricing and governance models are changing. Many of the early adopters of comprehensive outsourcing arrangements are reconsidering their original decisions and adjusting their operating models to provide for a hybrid of insourced and outsourced functions. Terasen Gas is at a similar decision point due to its evolving needs, and our proposal is consistent with the industry trend.

Third, the Company has concluded that the current legacy CIS platform used by the outsourcer is not a sustainable, long-term solution for Terasen Gas. The fundamental reshaping of the Company's business environment over the past seven years has already required significant changes to the CIS. Implementing these changes was and continues to be increasingly challenging and costly given the architectural design of the current CIS platform and a diminishing pool of knowledgeable, experienced resources to support it. CIS platforms have evolved since 2002 and are now based on a significantly improved technical design that provides utilities with features that are not available in older systems. These newer systems have become true "packaged" solutions that are better equipped to evolve over time to support business changes. In particular, these newer systems inherently provide support for configurable customer choice programs, complex metering alternatives, and more advanced billing formats and delivery mechanisms.

Fourth, our corporate capacity to build projects, manage operations, and integrate sophisticated systems has expanded significantly over the past seven years. This is evidenced by the success of our operating model and financial results delivered to the benefit of our customers and shareholder.

Thus, Terasen Gas is at a decision point similar to where we were in 2001. Change is needed if we are going to successfully meet the needs of our customers and the energy market into the future. This Project is critical to our business and to our customers. We are well positioned to deliver it."

7.2 Please provide the data presented by the Company to justify the decision to outsource Customer Care.

Response:

Please see the response to BCUC IR 1.7.1.

7.3 Please expand on the events that resulted in the change in strategic direction.

Response:

Please see the response to BCUC IR 1.7.1.

7.4 Please detail all costs included in this Application that are related to the build-up of in-house Customer Care capability in preparation for the repatriation of the outsourced activities.

Response:

Please see the response to BCUC IR 1.7.1.

8.0 Reference: Executive Summary

Customer and Stakeholder Expectations - Public Safety and Security

Part I, p. 3, par. 2

"The expectations of customers, regulators, and other stakeholders are changing with a renewed interest in public safety and security."

8.1 Please provide your external references for the renewed interest in public safety and security.

Response:

TGI believes that customers, regulators and other stakeholders have consistently been interested in safety and security. However, TGI observes a shift towards greater interest in public safety and security. It can be demonstrated in several ways in the external environment, such as the development of new standards and regulations (see p. 51 to 55 of Application), new Government policy, extensive media coverage, and even more visible security threats in the industry. These factors are addressed in further detail below.

With respect to developments in standards and regulations, the Oil & Gas Commission (OGC), for example, has adopted a comprehensive integrity standard, Annex N of CSA Z662-07, as mandatory. The OGC has also indicated, in discussions with Terasen Gas, that it plans to adopt the new CSA pipeline security standard (CSA Z246.1). In addition to the codes and standards discussed in the Application, there is also a new pipeline emergency management standard being developed by the CSA (Z246.2) that is now in the early stages of development.

Extensive media coverage related to pipeline incidents also illustrates the growing concerns regarding the reliability and safety of public infrastructure. The 2007 Kinder Morgan Canada oil pipeline rupture in Burnaby BC, and the 1999 Olympic Pipeline rupture in Bellingham, Washington are two examples described on page 52 of the Application.

Similarly, on the issue of media, a review[1] conducted by Washington Utilities and Transportation Commission on Public Safety and Awareness found that:

"A review of pipeline safety media coverage finds a great deal of feature and editorial coverage in recent years. The continuing story has several major themes, yet it boils down to how significantly hazardous liquid and natural gas pipelines are impacting people and the environment....... It is clear that the public looks to the media as the source of information and protection as a reliable watchdog against pipeline industry and regulator errors and indifference. The recent passage of the national pipeline regulatory

[1] http://www.wutc.wa.gov/webimage.nsf/9f7b2ed366e9fec588256efc00506bc0/15800e41d56c92cf88256f27007b66d9!OpenDocument

act was forced, in part, by public concern and alarm over a transportation solution that appears to be suffering due to pipeline age and concern over pipeline management."

Regulators across North America have responded by adopting new codes and standards, and enacting new regulations. The codes, standards, and regulations impacting TGI are outlined on pages 52-55 of the Application, as noted above.

Demonstrating the importance of Public Safety concerns in the U.S is Resolution 484, asking the U.S. House of Representatives to make June 10 National Pipeline Safety Day, with the recommendation that:

"That the House of Representatives—
(1) supports the designation of National Pipeline Safety Day;
(2) encourages State and local governments to observe the day with appropriate activities that promote pipeline safety;
(3) encourages all pipeline safety stakeholders to use this day to create greater public awareness of all the advancements that can lead to even greater pipeline safety; and
(4) encourages individuals across the Nation to become more aware of the pipelines that run through our communities and do what they can to encourage safe practices and damage prevention."

At the national level in Canada, the National Energy Board (NEB) issued a news release on August 11, 2009, "National Energy Board Taking Steps to Improve Worker Safety." The release related to its recent publication: Focus on Safety and Environment: A Comparative Analysis of Pipeline Performance 2000-2007. There were concerns raised relating to the number of pipeline incidents in 2007, and the report discussed the steps the NEB is taking to improve worker safety, which include increased compliance activities among other things. It was reported that nearly two out of every 100 pipeline workers suffered a serious workplace injury in 2007, almost double the seven-year average. It is the highest worker injury rate since the NEB began reporting on safety performance indicators in 2000.[2]

Internationally, the December 2004 audiotape message by Osama bin Laden in which he called on his cohorts to take their holy war to the oil industry and to disrupt supplies to the U.S from the Persian Gulf brought increased pressure for fortifying pipelines from attack.

More locally, the recent EnCana bombings in British Columbia, called an act of domestic terrorism by the RCMP, is an example where the issue of the reliability and safety of public infrastructure has once again become an issue as important as environmental, pipeline integrity and maintenance issues.

---

[2] http://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/sftyprfrmncndctr/sftyprfrmncndctr-eng.html

In summary, the growing interest in public safety and security is a reality. TGI believes it is prudent and necessary to respond to these changing expectations, ensuring that it continues to provide safe, efficient, and reliable service.

8.2 Please indicate when the customer, regulator and stakeholder interest levels dropped, and if this was reflected in lower activity and spending on the safety and security issues by TGI in specific years.

Response:

TGI believes that the public, regulators and stakeholders have consistently been interested in safety and security, and did not intend to suggest that interest levels have previously dropped. Rather, TGI believes that developments in TGI's external environment point to the prudence of increasing investment in safety and security at this time. Please see the response to BCUC IR 1.8.1.

Public safety and security programs within Terasen Gas are primarily assured by ensuring pipeline and distribution system asset integrity. Terasen Gas has an on-going commitment to maintain and enhance its integrity management practices and management systems. Prior to the development of the new standards, Terasen Gas executed many asset integrity activities.

Activity and prioritization of work is determined based on a corporate risk profile, and annual plans ensure that the highest risk items are addressed. With finite dollars available, the challenge comes when addressing medium and low risk items, which over time could become high risk items. In years where funds are available after addressing high risk items, medium risk items can also be addressed. In other years, the list of high risk items may be greater than the funding available and the overall funding must be increased. TGI has reached the point where additional funding is required to handle high risk items plus some medium risk items on an ongoing basis. On a go forward basis we continue to defer low risk items as we did under the PBR. Examples of deferred low risk work is painting of above ground plant and repairs to non-critical valves.

As related to asset risk profile, many of the new performance-based standards require more formal quality management systems, with more rigour and administrative costs needed for such areas as management of change, continuous improvement, risk management, performance metrics, competency of employees, and records management. New standards, growth and asset age are also increasing the risk profile of TGI's asset base and the incremental costs are identified in the RRA on page 352 in Tables C-6-4 and C-6-5.

TGI believes the proposed funding for public safety and security is prudent and reasonable to ensure the continuation of safe, reliable, cost-effective and environmentally responsible service to its customers.

8.3 Please provide details on the TGI funding for public safety and for security, actual cost by year from 2006 to 2008 and forecast for 2009 to 2011.

Response:

The terms "public safety" and "security" are interpreted to refer to all the activities we do to deliver safe and reliable services which is fundamental to all aspects of work plans. As there are many synergies at play in delivering upon design, construction, operations and maintenance of pipelines and facilities, including the associated code and standard requirements, it is not possible to isolate the total funding required to meet the ongoing requirements of public safety and security. For 2010 and 2011, Terasen Gas has identified Incremental funding that is attributable to maintaining compliance and managing the associated risks within Codes and Regulations (see Appendix F-8 of the Application).

9.0 Reference: Executive Summary

Terasen Utilities – Potential amalgamation

Part II, p. 17, par. 1

9.1 Please comment on the expected amalgamation date for the three Terasen Utilities, driven by the elimination of the Royalty Revenues for TGVI at the end of 2011.

Response:

Based on the timing of elimination of the Royalty Revenues and the rate impact that will occur at TGVI, the Terasen Utilities have considered January 1, 2012 as a logical date for amalgamation. However, the expected schedule and timing of amalgamation has not been developed or finalized. The proposals put forward in the respective TGI and TGVI applications are considered to be in the interest of the customers of each of the companies on a stand alone basis.

10.0 Reference: Terasen Utilities – Utilities Strategy Project

Part III, Section B, Tab 1, p. 86

"Shortly after the acquisition of TGVI and TGW in 2003, the three companies undertook a major restructuring aimed at delivering substantial operating cost savings. The USP was established to implement a single management team along with common work processes and IT platforms."

Ref: Part III, Sec B, Tab 1, p. 86, par. 4

"Today, the companies continue to operate with a common management structure with sharing of services and resources under a Shared Services agreement …" Ref: Part III, Sec B, Tab 1, p. 86, par. 5

10.1 Please comment on the difference between the current effective amalgamation of the three Terasen Utilities through common management, common processes, common systems, and common shared services and a statutory amalgamation of the three entities.

Response:

The main difference that amalgamation provides over the common management model is the ability to create common rate structures and tariffs ("postage stamp rates") to all natural gas customers across the province. Currently, this benefit to customers cannot occur under the shared services model.

The amalgamated utility would have one management structure and utilize processes, systems and services in effectively the same manner as provided under the common management model, employed by the Terasen Utilities during the PBR period. As most of the potential cost savings and efficiencies have already been achieved to the benefit of customers and the Company through the Earnings Sharing Mechanism, legal amalgamation, will provide limited opportunity to harvest additional cost savings. Rather, there will be minor administrative benefits and efficiencies as a result of an amalgamation, particularly in the areas of Regulatory, Finance and Customer Communications. Further efficiencies may also be achieved through the adoption of common rate classifications and the move to postage stamp rates, across the Province, which will help the amalgamated entity to communicate more effectively with its customers regarding more consistent rates and services. Today, as an example, customers in TGW have a different tariff and rates than do customers of TGI, this can lead to confusion for customers when reviewing their bill or receiving information on future rate changes from both TGI and TGVI.

10.2 Please comment on the potential cost reductions through the amalgamation of the three Terasen Utilities, including regulatory costs.

Response:

The Terasen Utilities foresee administration benefits and efficiencies as a result of an amalgamation, particularly in the areas of Regulatory, Finance, and Communications, which may result in modest cost reductions. Please also see TGI's response to BCUC IR 1.10.1.

11.0 Reference: External Situational Context

BC Economic Outlook

Part III, Section A, Tab 4, pp. 69-76

TGI refers in Appendix C-28: Economic Review 2003–2008 to eleven (11) economic indicators. The indicators identified include real GDP, unemployment, housing starts, and others. Several of these indicators are discussed throughout the RRA, with particular mention to them in sections devoted to forecasting Customer Additions and Energy Demand for 2010 and 2011.

TGI concludes on page 76 that "Lower economic growth, higher unemployment rates, and declining housing starts indicate that the economic turmoil will most likely impact Terasen Gas' customers. It will impact their ability to pay for energy, impair their ability to make investments in energy conservation measures, lower customer additions and reduce customer demand for energy consumption."

11.1 Please indicate the relative magnitude, impact or sensitivity that these economic indicators have had on the historical demand for natural gas in B.C.

Response:

Generally speaking, the magnitude, impact or sensitivity the economic indicators illustrated in Appendix C-28 of the Application have had on the historical demand for natural gas in B.C. is challenging to quantify. As seen in TGI's response to BCUC IR 1.45.2, regression analyses against a number of these economic indicators results in poor goodness of fit and/or insignificant variables. Therefore, the following provides a more qualitative approach in discussing the magnitude, impact or sensitivity those economic indicators have had on the historical demand for natural gas.

GDP growth has a significant impact on the industrial demand for natural gas. As discussed in TGI's response to BCUC IR 1.41.2, as industrial consumption is heavily weighted towards process-oriented end uses, it is ultimately tied to output or production levels. And given fluctuations in GDP growth rates are reflective of changes in output or production in the various industry sectors TGI's customers are in, it follows that GDP growth significantly influences industrial demand for natural gas in British Columbia.

The Cdn/US Exchange Rate has impacted the demand for natural gas, as the gradual appreciation of the Canadian dollar (relative to the US dollar) has led to a reduction in demand for B.C. exports, which in turn has led to reduced production levels and ultimately less demand for natural gas in sectors where exports are of significance. Although not as significant (in terms of order of magnitude) as GDP, the Cdn/US Exchange Rate has impacted the historical demand for natural gas.

The housing market, also discussed in TGI's response to BCUC IR 1.41.2, is another economic indicator that is considered to be a highly significant variable in the forecast of demand for natural gas. The rate of growth in TGI's customer base is strongly correlated to the rate of growth in the housing market, and therefore TGI considers the rate of growth in the housing market (typically measured by housing starts) to be a good proxy for future growth in its customer base. At the same time, the shift towards more multi-family dwellings in the housing mix has contributed to the declines experienced in average use per customer rates. Given the housing market impacts both customer additions and average use per customer, it follows that the housing market has significantly influenced the historical demand for natural gas in British Columbia.

The CPI, Prime Rate, and Conventional Mortgage Rate have also impacted the historical demand for natural gas, but in a more indirect fashion. These factors indicate levels of affordability and also the cost of financing, and therefore have impacted the purchase and consumption of goods which would include new homes and natural gas appliances. Additionally, mortgage rates (and also housing prices) have played a significant role in the shift towards more multi-family dwellings in the housing mix. And although these economic indicators have impacted the historical demand for natural gas, their impact is considered to be less significant than that for either GDP or the housing market.

Natural gas prices are regional in nature (North American), and therefore react to specific events occurring in that region. Significant price spikes in the price of natural gas, such as those occurring in 2001 as a result of the California energy crisis or in 2005 as a result of Hurricane Katrina, are considered to be the primary drivers of the significant declines experienced in average use per customer in those years. Although price spikes have a significant impact on the demand for natural gas, more typical volatility has a lesser impact, evidenced by the relatively inelastic price elasticity with respect to demand for natural gas, which is approximately 17% for TGI's residential customers.

The price of oil is determined on a global scale, influenced by world events and in that sense can be thought of as an economic indicator. The price of oil has played a less significant role in the historical demand for natural gas than the other economic indicators mentioned. However, as some industrial customers have fuel switching capabilities and are therefore able to take advantage of the spot markets, the demand for natural gas is impacted by changes in the price of oil.

Electricity prices, when compared to the price of natural gas, provide an indication of the competitive environment in which TGI operates. The competitiveness of natural gas with respect to electricity, as discussed in the Application (pages 56-67), has eroded over the period 1998 to 2008 and this decline, together with the lower capital and installation costs for electric baseboard heaters has led to a more challenging competitive market environment, ultimately placing downward pressure on throughput levels and therefore upward pressure on delivery rates (all else being equal).

11.2 Please identify which of the Economic Indicators listed in Table 1 of Appendix C-28 have been used by TGI to forecast energy demand in 2010 and 2011. In addition, please describe the methodology and assumptions used in connection with Economic Indicators to forecast energy demand in 2010 and 2011.

Response:

Each of the Economic Indicators listed in Table 1 of Appendix C-28 were considered when developing the demand forecast for 2010 and 2011. However, Real GDP and housing starts (with the expected Can/US Exchange Rate, CPI, Prime Rate, and Conventional 5-yr Mortgage Rate considered as supporting variables) were the primary economic indicators used by TGI to forecast energy demand in 2010 and 2011, and the methodology used is described in TGI's response to BCUC IR1.41.1.

12.0 Reference: External Situational Context

Growth - Costs to service growing customer base

Part III, Section B, Tab 2, p. 213, par. 5

12.1 Please confirm if the revenues per customer addition exceed the costs to service those customers. In short, do all new customers provide incremental positive contribution?

Response:

TGI confirms, based on the findings of the 2008 Main Extension Report (included in Appendix E-2), that the revenues exceed the cost to service new customers on a portfolio basis.

In the Company's Main Extension Report for 2008 filed on April 3, 2009 with the Commission, TGI and TGVI reported that the Profitability Index (PI) for 2008 was 1.2 for TGI and for the combined utilities as well (Pages 1 and 4, Appendix E-2). The Profitability Index value is the present value of revenues divided by the present value of costs over a 20 year period. The conclusion of the report is: "The report demonstrates that on a portfolio basis, the main extensions installed in 2008 are economical and do not harm existing customers because the average actual PI is 1.2, higher than the threshold of 1.1" (Page 11, Appendix E-2).

The basis of determining if new customers provide sufficient margin is covered under the Company's Main Extensions as presented in Section 12 of the General Terms and Conditions of the TGI Tariff. The economic test which is used to assess main extensions is described in Section 12.3 with changes approved effective January 1, 2008 by Commission Order No. G-152-07. The Order also required TGI and TGVI to file a Main Extension Report each year.

While some customers' incremental revenues might be deficient in covering all of the incremental costs, other customer additions revenues will exceed the incremental costs. For each main extension an economic test is calculated based on a 20 year discounted cash flow model of forecasted revenues and costs for all new customers on the main extension. (The discounted cash flow model methodology has been approved by the Commission.) For any individual main extension in which the PI is less than 0.8, a Contribution in Aid of Construction is required sufficient to increase the PI to 0.8. As approved by Commission Order No. G-152-07, while any one individual main extension may be less than a PI of 1.1 to a minimum of 0.8, collectively all main extensions in the year must not be less than 1.1. As stated in the April 3, 2009 report, the average PI for the main extensions installed in 2008, is 1.2, which is in excess of the threshold.

13.0 Reference: External Situational Context

Tariff Changes – Energy Plan Innovative Rate Design

Part III, Section A, p. 30, par. 4

13.1 Please comment on any plans to introduce stepped rates for energy conservation, life-line, or any other reason.

Response:

TGI has no plans to introduce stepped rates at this time. Terasen Gas's current rate structures and the proposed rates impacts included in this Application will continue to send price signals that will help to encourage the principle of energy efficiency and conservation to natural gas consumers in BC.

The rates customers pay for natural gas service is largely composed of the gas costs or commodity cost of natural gas, which is subject to market-based prices. These market costs serve as a proxy for the marginal cost of supply and send efficient price signals to customers that support energy efficiency and conservation.

The delivery costs of natural gas service include the basic charge (a fixed flat monthly fee) and the delivery charge (calculated on a per gigajoule basis). With this Application, TGI has sought the recovery of the proposed 5.3% and 4.1% increases in revenue requirement for 2010 and 2011 through volumetric and demand based delivery rates rather than an increase in the basic charge. In so doing a large proportion of rates will be volumetric-based, which should help to encourage conservation.

Finally, rather than offering life-line or subsidized rates to certain customer groups, TGI offers energy efficiency funding for low-income customers through its EEC activities.

14.0 Reference: External Situational Context - Business Risk

Part III, Section A, p. 24, par. 1

"Over the next 20 years the province of B.C.'s population is expected to grow by more than 25 per cent or over 1 million people. Demand for all types of energy is expected to increase – even as the pressure to improve energy conservation and efficiency measures intensifies."

14.1 Please comment on the percentage of growth in B.C.'s population that would likely be within the Terasen Utilities' service areas.

Response:

TGI estimates that the population within the Terasen Utilities' service areas will grow by approximately 30% over the period 2008 through 2028. TGI also estimates that approximately 96% of British Columbia's population lives within the Terasen Utilities' service areas. These estimates were derived from population forecasts published by BC Stats, available on their website. It is important to note that although population is expected to continue to grow, as indicated in TGI's response to BCUC IR1.42.3 and BCUC IR1.46.1, capture rates by the Terasen Utilities' will vary due to a variety of factors including housing type, competitive position and customer perception towards natural gas given the provincial GHG reduction targets.

15.0 Reference: Business Risk – Cost Advantage of Natural Gas

Part III, Section A, p. 62, par. 1

"TGI has a competitive advantage against electricity on an operating cost basis over the next five years."

15.1 Please comment on the economic outlook over the next five years for the Terasen Utilities compared to other natural gas utilities in British Columbia, in Canada, and in the United States.

Response:

British Columbia faces economic challenges as a result of the current economic downturn, as does the rest of Canada and the United States. This downturn in the economy impacts demand for natural gas by reducing housing starts and reducing consumption of natural gas in the industrial sector. The current economic downturn has impacted Terasen Utilities and other natural gas utilities across Canada and the United States, but the severity of the impact will be determined by specific factors that are unfolding in each utility's service territory.

16.0 Reference: Business Risk – Balanced Scorecard

Part III, Section B, Tab 1, pp. 99-102

16.1 Please provide copies of the TGI Balanced Scorecard targets and results for 2007 and 2008.

Response:

Following are copies of the 2007 and 2008 Scorecards for the Terasen Gas Group of companies, including TGI, TGVI and TGW. As the Companies operate under a common management team and approach, there is no scorecard for TGI on a stand alone basis.

Terasen Gas Group 2007 Scorecard

December 2007 Results

		Results to Date	Target
FINANCIAL	1. Terasen Gas Group Net Earnings	$108.2m	$103.3m
CUSTOMER	2. O&M per Customer	$224.27	$231.00
	3. Base Capital	$103.9	$102.4m
	4. Customer Satisfaction	79.3%	*78.0%*
KEY PROCESSES	5. Credit & Collections	0.27%	0.35%
	6. Customer Additions	13,861	17,000
			Challenge
EMPLOYEE	7. Recordable Veh. Accid.	10	11
	8. Recordable Injuries	31	29
	9. Wellness	5.7	5.3
	10. Public Safety	*Service Quality Indicator*	

Terasen Gas Group 2008 Scorecard

December 2008 Results

		Results to Date	Target
FINANCIAL	1. Terasen Gas Group Net Earnings	$111.7m	$105.2m
CUSTOMER	2. O&M per Customer	$229.15	$231.31
	3. Base Capital	$115.4m	$124.8m
	4. Customer Satisfaction	79.7%	*79.0%*
KEY PROCESSES	5. Credit & Collections	0.24%	0.35%
	6. Customer Additions	12,830	15,500
			Challenge
EMPLOYEE	7. Recordable Veh. Accid.	13	10
	8. Recordable Injuries	20	28
	9. Wellness	5.1	5.6
	10. Public Safety	*Service Quality Indicator*	

17.0 Reference: Business Risk – Disaster Recovery

Part III, Section B, Tab 2, p. 205, pars. 3-4

17.1 Please expand on the level of disaster recovery planning and capability in place at Terasen Gas prior to the sale to Kinder Morgan.

Response:

Prior to sale of Kinder Morgan, Terasen Gas followed a "high-availability" strategy for "mission critical" systems as opposed to a full Disaster Recovery Strategy. "High Availability" is defined as having an alternative server that can be brought on line quickly in the event that the production server is rendered inoperable or is anticipated to be inoperable for an extended period of time. This differs from a true Disaster Recovery capability as it only addresses a point solution for a single application and does not support the ability to continue business in the event that all servers are rendered inoperable in the case where the data centre or physical building is compromised or the nature of the disaster is such that the vast majority of employees cannot get to the building in the event that transportation routes are compromised. For the "mission critical" systems, the "high-availability" servers were located in different geographical locations to address these concerns.

The systems that were deemed "mission critical" by the operating business units at the time prior to the sale of Terasen Gas to Kinder Morgan were the:

- Nucleus system – for managing energy procurement, contracts and invoicing; and
- AM/FM (automated mapping / facilities management) system - the repository for the Outside Plant Facilities information, both graphical and digital of the Terasen Gas Utility gas distribution and transmission systems
- SCADA (Supervisory Control And Data Acquisition) - a real-time system used by the Gas Controllers to monitor the flow of gas and control the pipelines

17.2 Please expand on the inability to utilize Fortis capability in a similar manner to Kinder Morgan.

Response:

At the time Terasen Inc. was owned by Kinder Morgan, Kinder Morgan had two major data centres located in Texas and Colorado and an IT staff in excess of 280 employees. It was Kinder Morgan's IT strategy to centralize as much infrastructure services as it could so it was well positioned to provide these services. No IT department within the Fortis group of companies has the same staffing levels or mandate to replicate Kinder Morgan's business model or execution capabilities in the area of DRP. Having said that, Terasen Gas is working with Fortis Alberta to explore areas where there still may be opportunities to share, such as physical locations.

17.3 Please provide the date of the purchase of Terasen Gas Inc. by Fortis Inc. and comment on the DRP activity between the purchase date and the date of this Application.

Response:

The purchase of Terasen Inc. by Fortis Inc. was completed May 17th, 2007. The DRP activities that have been conducted from that date to the date of the filing of this Application are:

- Implemented a High-availability server in Kelowna for the Gas Nomination / Authorization System (WINS).
- Initiated a Business Continuity and Disaster Recovery Initiative consisting of:
  - A Criticality Analysis;
  - A Recoverability Assessment;
  - A Disaster Recovery Strategy;
  - A detailed design and planning phase for DRP (ongoing).

- Continued with annual maintenance and licensing renewals for the SCADA system.
- Currently upgrading the SCADA system including the two DRP sites in Kelowna and Burnaby (to be completed by year end, 2009).

"$375 thousand is for Disaster Recovery Planning ("DRP") with an additional $375 thousand anticipated in 2011". Ref: Part III, Sec C, Tab 6, p.389, par. 4

17.4 Please confirm if the $375 thousand O&M anticipated in 2011 is included in this Application.

Response:

Confirmed

17.5 Please provide a table of total spending on Disaster Recovery Planning, by year from 2006 through 2011, separating O&M and capital.

Response:

Capital	2006	2007	2008	2009	2010	2011
WINS		$103,594				
AM/FM	$10,500	$11,500	$16,500	$16,500	$16,500	$16,500
Corp IT DR			$98,142	$255,000	$2,700,000	
SAP DRP *	$57,920					
SCADA	$25,000	$25,000	$25,000	$650,000	$25,000	$25,000
NUCLEUS						
Total	**$93,420**	**$140,094**	**$139,642**	**$921,500**	**$2,741,500**	**$41,500**

O&M	2006	2007	2008	2009	2010	2011
WINS		$1,463	$5,536	$5,055	$5,055	$5,055
Corp IT DR					$375,000	$750,000
AM/FM	$31,844	$48,760	$40,684	$40,656	$40,700	$40,700
SAP DRP [3]	$4,300	$12,900	$12,900	$12,300	$ 0	$ 0
SCADA	$ 26,000	$ 26,000	$ 26,000	$ 32,000	$34,000	$ 34,000
NUCLEUS	$16,400	$16,400	$16,400	$16,400	$16,400	$14,450
Total	**$78,544**	**$105,523**	**$101,520**	**$106,411**	**$481,585**	**$856,659**

It is expected that the requirements for "high-availability" of the key applications identified above (WINS, Nucleus and AM/FM) will be continue to be required after the corporate DRP plan is in place and therefore the O&M costs associated those applications as per the table above are anticipated to continue after the corporate plan is in place.

---

[3] The ability to produce financial statements in the event that the SAP system was unavailable was a SOX compliancy requirement met in 2006.This is very limited functionality and does not support any kind of DRP activity for the SAP system. In 2010, this capability will be incorporated into the corporate DRP requirements.

18.0 Reference: The Future

Part III, Section B, Tab 2, page 200

Terasen Gas Must Enhance its Customer Care Service Quality, section 2.1.1, page 201

18.1 If the SQI have been met and TGI finds there is a need to improve Customer Care Services, does this indicate the SQI's have not been stringent enough to identify deficiencies in customer care?

Response:

No, TGI does not believe that is the case. The current SQI's were developed as part of the Negotiated Settlement of the TGI PBR and were meant to address both stakeholder and Company desires and as such were balanced against other factors and mechanisms of the Negotiated Settlement. The SQIs related to customer care performance have identified deficiencies where they have occurred throughout the duration of the Client Services Agreement for the provision of customer care services. Where applicable, penalties have been assessed against CustomerWorks LP, the services provider, due to deficient performance as defined under the contract (See BCUC IR 1.93.0).

For example, in 2008, TGI did not meet SQI targets for SQI 3 - non-emergency call answer speeds, 5 a) - the mass market billing index and 5 b) - industrial customer billing accuracy. Up to the end of April 2009, SQIs 5 a) and 5 b) were not meeting performance targets as noted on page 115 of the TGI 2010-2011 Revenue Requirements Application.

TGI believes the SQIs have provided a thorough view of the Company's performance through the duration of the PBR Settlement and have been stringent enough to identify deficiencies in customer care. We believe that they worked as intended pointing to areas of weakness in some areas, while in others pointing to areas of success.

18.2 Can the existing Customer Care Service contract with Accenture be modified in such a way as to duplicate the effect of the proposed enhanced Customer Care Service?

Response:

TGI intends to implement its new Customer Care model through changes to the current contractual arrangement. An important element of the model TGI is moving towards is strategic shift to Company ownership and management of critical customer-facing functions and processes. TGI does not believe that continuing to outsource these functions with different contract terms would achieve its objectives.

When the existing agreement was developed in 2001, we did not anticipate the degree of organizational change and the resulting staff turnover the contractor has initiated and experienced over the years, nor the significant degradation in gas industry and end to end business process knowledge as a consequence of these changes.

There are several reasons why moving to company ownership and management of critical customer-facing functions is the best model for Terasen Gas and Terasen Gas customers:

- Direct management and ownership of the customer experience will provide Terasen Gas with the ability to ensure service quality for customers.
- In-house management of call centre and billing staff will ensure representatives have appropriate product and service knowledge combined with regional understanding. Representatives will also be able to relate to customer needs and experiences specific to Terasen Gas' service territory and apply that understanding when working with customers. With direct ownership and control over staff training and ongoing performance management, we will have the ability to build key knowledge and understanding within our billing and call center agents that will give them the tools to apply appropriate judgment when working to address a customer inquiry or concern.
- Direct management of call centre and billing operations will also allow for greater flexibility in developing and implementing future service changes and ensuring issues and opportunities are addressed in the most timely manner possible. The Company will also be able to identify opportunities more proactively and implement these opportunities to benefit the Company and our customers.
- The Terasen Gas owned and operated integrated CIS solution will result in greater control over end-to-end business processes that will be managed internally using the Company's own resources. This will enable better understanding across functional areas to support process changes more proactively with a more complete understanding of the downstream impacts of these changes on other operating areas. It will also ensure that Terasen Gas can better respond to the needs of various customer groups. The Company will have control over how the system is maintained, what support processes are in place and ensuring implementation and configuration decisions are made to support the greatest flexibility in the future. By understanding the nature of each change from an application perspective the Company can ensure that changes are addressed in the most cost effective manner.

18.3 What events have occurred that justifies a new customer care delivery model at this time?

Response:

Please see the response to BCUC IR 1.7.1.

19.0 Reference: External Situational Context

Growth - Opportunities beyond Natural Gas

Part III, Section A, p. 27, par. 2

"There are opportunities for TGI to be a provider of energy solutions beyond just gas."

19.1 Please explain the logic for the natural gas rate payers to fund TGI's learning curve to provide other energy solutions.

<u>Response:</u>

TGI does not agree with the description of the funding it is seeking in the Application for development of alternative energies as learning curve costs. Rather, these costs are marketing and sales costs related to providing customers with the service they request (which include both gas and alternative energy) and in addition, providing energy efficiency education and information. As such, these costs are no different than any other sales, marketing, and development costs that are spread across all customers and as such these costs should not be segregated. Alternative energy service (AES) customers, who for the most part may already be existing gas customers or who may be potential gas customers, will be allocated a fair portion of these costs and as the alternative energy business grows and more customers are added, the overall share of these costs allocated to AES customers will grow accordingly. As discussed in BCUC IR 1.20.1 the costs included in the economic tests for AES customer will include an overhead allowance (see page 267 of the Application), similar to the overhead allowance included in TGI's main extension test, so that AES rates will recover more than the direct costs of the particular project only.

TGI believes that the long term interests of rate payers are better served by supporting the development of alternative energy solutions, in combination with gas delivery solutions, within the utility now rather than adopting a wait-and-see approach that may result in long term harm to the utility and ratepayers. There are several aspects of the underlying logic for all rate payers to fund the early stages of marketing, sales and development costs (both gas and alternative energy):

- The provision of Alternative Energy Solutions and gas delivery are consistent with the definition of a public utility in the *Utilities Commission Act* (see also response to BCUC IR 1.24). Incorporating alternative energy solutions within the natural gas utility will support the objective of regulatory efficiency by avoiding a patchwork of small alternative energy utilities that will be difficult to regulate effectively.
- The BC government's recent policy imperatives and recent legislation enactments strongly support the development of energy efficiency initiatives and alternative energy solutions in support of the Government's Energy Objectives and climate change mitigation initiatives, among other things. The role of public utilities in the delivery of

alternative energy solutions is recognized in the Energy Plan and the recent amendments to the *Utilities Commission Act*.

- Utilities by nature are long lived infrastructure systems that are established to serve the public good over the long term. In this context it is recognized that utilities must do what they can to anticipate the future to be prepared to serve the future needs of customers as they arise (be that in a utility's traditional business such as gas or in another business area such as delivery of heat). Using utility capital investments as an example, it is frequently said that utility investment in infrastructure is lumpy and that large system expansion-related investments are frequently made before the system growth occurs so that adequate system capability is there when the growth actually does occur. The utility typically commits time and resources to assess the nature and timing of demand growth and assessing alternative solutions to meeting that demand growth before selecting the best option from among the alternatives.
- TGI believes it is appropriate for a utility to spend time and resources on learning-related activities and emerging developments in the utility's field of business. In TGI's opinion, it is incumbent upon utilities to constantly learn, refine, adapt and change to meet the growing needs of customers, but to also ensure that the utility is providing the most efficient and effective service to customers. If utilities did not adapt and learn, we may still see widespread use of gas lighting, the use of inferior pipe materials, and inefficient furnaces. Learning and adapting has helped customers through reductions in energy usage and more efficient use of infrastructure.

  In the case where the costs are not simply part of sales, marketing and development and are unique to the investigation of or analysis of a new opportunity, utility revenue requirements generally include allowances for spending on items that are in the nature of research and development or preliminary investigations. For instance, in BC Hydro's case work of this nature is occurring with respect to the potential for electricity demand from electric plug-in vehicles and in studying new sources of generation that are not commercially viable as yet (i.e. power from wave or tidal energy). Research and development activities are seen as useful in preparing the utility for the future.
- Alternative energy solutions display similar qualities to those described in the preceding paragraphs. Alternative energy development promises to occupy a larger portion of the energy landscape in the future so utility planning and preparing for such an eventuality is prudent.
- Another objective of planning and preparing for future energy needs is so that development can occur in an orderly and efficient manner, and in a way that seeks to minimize the impacts of energy and infrastructure on the environment and human quality of life. Integration of alternative energy solutions with the existing utility infrastructure offers the promise of achieving these objectives.
- As discussed in the Application the future integration of alternative energy solutions with natural gas service will offer TGI the opportunity to mitigate the impacts of declining

throughput on natural gas delivery rates, and in doing so will provide benefits to natural gas rate payers.

For all of the foregoing reasons TGI believes that it is appropriate that all rate payers fund the marketing, sales and development activities of both gas and Alternative Energy Solutions as set out in the Application, based on an appropriate allocation of costs as proposed.

19.2 If, at a future time, one of the non-regulated Terasen entities became involved in an energy solution investigated or developed by Terasen Gas, would the investigation and/or development cost be recovered as a credit to the natural gas ratepayers?

Response:

As a preliminary comment, TGI's strategic direction with its alternative energy strategy is to offer these energy solutions within the regulated utility and not as non-regulated offerings. That being said, there is more than one possibility as to how a situation such as that described in the question might come about. If TGI was selling an existing alternative energy development to a non-regulated affiliate the normal practices prescribed by the BCUC for such a sale would apply. Such an asset sale would normally take account of the market value of the assets. Development or investigation costs would not be explicitly included in a transaction that was based on market value, although arguably they are implicitly included. If a non-regulated affiliate was involved in an alternative energy project from the outset or after commencement but before completion of the project, TGI would expect the prevailing NRB code of conduct and transfer pricing policy to determine the amount the NRB affiliate would have to pay, which would include any development and overhead costs implicit in those policies.

20.0 Reference: External Situational Context

Growth - New Alternative Energy Offerings

Part III, Section B, Tab 2, p. 204, pars. 1-2

20.1 Please explain how the learning curve costs will be factored into the economic tests and thereby recovered from the clients of these new energy offerings, even though the actual costs for programs, development and sales are proposed to be recovered as part of this RRA.

Response:

As discussed in BCUC IR 1.19.1 , with the exception of biogas (which costs are limited in scope and are necessary in the pilot period for reasons described elsewhere) , TGI does not agree with the characterization of the funding it is seeking in the Application for Alternative Energy developments as learning curve costs . The types of costs such as for sales efforts, account management and market development costs will be sunk costs as far as the economic tests are concerned. As long as the rates for the alternative energy projects are recovering more than the direct incremental annual cost of service, there will be some contribution towards the common costs for sales, account management and market development. This is consistent with existing gas development for projects such as main extensions where sales staff costs are recovered through existing rates and, should a main extension be required, a MX test is conducted using future capital and O&M costs, but not the general marketing costs for customer support and promoting the use of natural gas.

TGI intends to include an appropriate overhead allowance in the alternative energy rate setting process, similar to the overhead allowance included in the TGI and TGVI Main Extension Tests, which will ensure that rates recover more than the direct incremental cost of service of the alternative energy offerings.

21.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section C, Tab 3, p. 227

"Recovery in a deferral account of the revenues and ongoing O&M and the related expenditure of capital related to investment in energy solutions in NGV and alternative energy." Page 227, par. 1

21.1 Given the above statement, please confirm that the costs incurred to date in the areas of EEC and Alternative Energy Solutions have been previously expensed and charged to rates? If yes, please provide a breakdown of capital and O&M costs **already** spent in EEC and also in Alternative Energy Solutions. Please identify the nature of these costs (i.e. developmental, research, capital investment). If no, please explain the treatment of these costs to date.

Response:

Prior to responding to the above question, it is important to distinguish between the requests in this Application regarding EEC and those pertaining to Alternative Energy Solutions. The requests with respect to EEC are consistent with the approvals granted in the TGI-TGVI Energy Efficiency and Conservation Decision (BCUC Order No. G-36-09). Prior to this approval, DSM-related activities and costs were treated partially as O&M and partially as capital. This is shown in Table C-3-1 of the Application for 2008 and 2009. Once TGI and TGVI received approval for their EEC Application, all future expenditures were to be capitalized and amortized over a ten year period. Table C-3-1 shows this break down for years 2009 and 2010 (this is further elaborated in response to BCUC IR 1.28.0). EEC programs and expenditures primarily related to activities to reduce energy usage via incentives, education, and audits etc. They do not include the ownership of alternative energy equipment.

With respect to Alternative Energy Solutions, TGI intends to offer energy and heat delivery services to customers where that energy delivery is via a district energy system (DES), solar, geothermal or other energy source, where TGI would own and operate the heat delivery systems and where TGI would charge the end use customer for the delivery of heat. Primarily, this service would be to commercial and industrial customers and those who could tie into a district energy system. We do not contemplate building stand alone geothermal or solar heat delivery systems for single detached homes. These alternative energy customers may also be eligible for EEC funding, however that funding is separate from the provision of heat from alternative energy.

For alternative energy, the statement quoted in the question above regarding deferral account treatment refers to costs and revenues that will be incurred once a specific project begins engineering and construction activities, within the 2010/2011 Forecast Period. Once a potential alternative energy customer has signed a contract for the provision of alternative energy delivery, costs incurred from that point forward that can be capitalized as per IFRS would be put in a non-rate base deferral account (attracting AFUDC) or comparable mechanism such as work-in-process attracting AFUDC (also non-rate base), as described on page 270 of the Application. Once the project is complete and revenues are being collected, these would also be put into the deferral account. And lastly, once the project is delivering energy, any ongoing O&M or feedstock fuel costs related to the actual delivery of energy would also be put in the deferral account. There have been no costs incurred by TGI to build an alternative energy heat delivery system as yet since TGI has not constructed such as system to date or received approval from the Commission to do so.

The only costs expensed and charged to rates for alternative energy services to date relate to high level strategy and business planning by senior TGI employees and the costs associated with this Application.

For NGV, Terasen Gas currently has one staff member devoted to this initiative in addition to support from other regional sales staff that to date have been selling Rate Schedule 6 Natural Gas Vehicle Service. This is not a new service as TGI has been in this marketplace for over a decade (please see response to BCUC IR 1.34). These costs are treated as O&M. If TGI receives approval for the Compression Service tariff, once a potential NGV customer has signed a contract for the provision of Compression Service, costs incurred from that point forward that can be capitalized as per IFRS would receive similar deferral account treatment as described above for alternative energy, as described on page 249 of the Application. Once the project is complete and revenues are being collected, these would also be put into the deferral account. And lastly, once the project is delivering compressed natural gas, any on going O&M costs related to the actual delivery of energy would also be put in the deferral account.

21.2 Has Terasen Gas given any consideration to tracking these development costs in account 172: Preliminary Survey and Investigation Charges according to the Uniform System of Accounts? If not, please explain.

Response:

TGI does not consider Account 172: Preliminary Survey and Investigation Charges to be an appropriate account to use in place of the deferral account approach requested in the Application for alternative energy projects. As discussed below, the deferral accounts for the alternative energy projects are more general in nature than the types of expenditures contemplated for Account 172. TGI believes that specific subaccounts (established for each alternative energy project) within Account 179 - Other Deferred Charges are the appropriate place to track the alternative energy projects.

Account 172 is ill-suited for the proposed purposes. The following is the description of Account 172 extracted from the BCUC Uniform System of Accounts Prescribed for Gas Utilities:

> 172. PRELIMINARY SURVEY AND INVESTIGATION CHARGES
>
> This account shall include all expenditures for preliminary surveys, plans, investigations, etc., made for the purpose of determining the feasibility of projects for gas services. If, as a result of the surveys, plant for gas services is acquired or constructed this account shall be credited and the appropriate gas plant account charged. If the work is abandoned, the charge shall be to account No. 329, "Other Income Deductions", or if the amount is material, to account No. 332, "Extraordinary Deductions".

Account 172 is to be used for preliminary investigations for determining the feasibility of projects for gas services. If a project goes ahead the preliminary investigation charges are capitalized with the other capital costs of the project and if it does not go ahead the preliminary investigation charges are expensed. Account 172 does not encompass the scope of what is anticipated for the deferral accounts for alternative energy projects. The alternative energy deferral accounts are intended to capture the cost of service elements of alternative energy projects that are operational and have come into service. The deferral account for a particular alternative energy project will capture revenues, ongoing O&M and capital-related cost of service elements for that project. It should also be noted that TGI will have contracts with the alternative energy project customers that will be filed with the Commission so capital and O&M expenditures will not be incurred without offsetting revenues. The cost and revenue items that will be captured in alternative energy project deferral accounts are conceptually different than preliminary investigation charges. Also, TGI believes that the sales and marketing expenditures included in the Application related to developing the alternative energy business are more general in nature than the preliminary investigation costs contemplated for Account 172. TGI has proposed the deferral account approach for alternative energy projects for several reasons. Projects of this nature have a high degree of uniqueness and often take time to develop so it is difficult to forecast how many alternative energy projects will go forward in a given period or how much capital will be spent on them. A further purpose of the deferral account approach is to isolate the cost of service of each alternative energy project in order to charge the customers of that project according to its specific costs.

21.3 Please confirm that TGI is proposing to accumulate these costs in a non-rate base deferral account (which may or may not attract AFUDC). What is the proposed time period for when this deferral account is to be collected in rates?

Response:

TGI confirms that both the costs and the revenues would be accumulated in non-rate base deferral accounts during the two-year RRA period. TGI is requesting that the net balances in the deferral accounts attract AFUDC and believes that is the appropriate mechanism to reflect the fact that TGI has invested capital in these initiatives and accordingly is entitled to an opportunity to receive a fair return. Regarding the collection of these costs in rates, the proposed economic test will ensure that rates charged to and paid by customers will equal costs over time on a levelized basis; therefore the amount in the deferral account would only be as a result of timing differences between the cost incurred and the collection of revenue. . The specific recovery period for the net deferral account balance will vary from project to project based on the circumstances of each project. A development project involving alternative energy may, for example, have a longer build out period and so it may be necessary to recover the deferral account over a longer period to accommodate this.

22.0 Reference: Revenue Requirements and Rate Proposals

Part III, Section B, Tab 1, p. 133, Table B-1-6

Operational Performance over the PBR Period

"Table B-1-6 outlines the energy savings and GHG reduction as a result of number of different energy efficiency programs implemented since 2005."

22.1 With reference to the data presented in Table B-1-6, please describe the method and identify any assumptions used to determine the Annual Savings (GJs) in energy.

Response:

The methodology that Terasen Gas uses to determine Annual Savings is to first apply the results of formalized studies and analysis in order to ascertain what the gross savings are per unit. The gross savings amount per unit is then multiplied by the number of gross participants to obtain the gross savings. Net savings are then calculated by multiplying gross savings by the net to gross ratio to provide the amount of net savings. TGI then converts the resulting net savings values to net present value.

Net to gross ratios are calculated by reducing the amount of gross savings by the percentage of free riders (free riders are program participants that would have undertaken an efficiency activity regardless of a program, but who participated in the program anyway). The Terasen Utilities proposed in our May 28, 2008 EEC Application to exclude the free rider impact from cost-benefit analysis for EEC programs in British Columbia. This proposal was rejected in the April 16, 2009 decision to our EEC Application and therefore the Terasen Utilities include the impact of free riders in its energy savings calculations.

Free rider rates are challenging to determine with any accuracy and the Terasen Utilities use several different approaches to ensure that the rates used reflect as closely as possible the actual ratio of participants who are free riders. In cases where Terasen Gas has operated a program which has been evaluated (such as our Energy Star Heating Upgrade Program which was evaluated for the program years 2005–2007 by Sampson Research in the 2008) the free ridership rate from the Sampson evaluation has been used. In the evaluations, the free riders rate has typically been determined by a combination of information from: a customer survey; a trade ally survey; and in some cases by discrete choice analysis modeling using participant and non-participant data.

As an example to illustrate how savings have been calculated in our reports, the steps taken to determine the savings for the 2008 Energy Star Heating Upgrade Program (retrofit) are based on the free ridership rates identified in the 2008 Sampson evaluation and are presented in the table below and are described as follows:

TGI reported 2,110 participants and gross savings of 29,118 GJs (2,110 x 13.8 GJ saving per unit). Net savings was then calculated by applying the applicable net to gross ratio (a net to gross ratio of 57% as calculated in the Sampson evaluation was used for this program), resulting in net savings of 16,597 GJs. The net present value (NPV) of 16,597 GJs was then calculated, resulting in energy savings of 179,709 GJs.

In order to calculate GHG savings, energy savings are multiplied by a GHG gas factor of .05069 which is number of tonnes of GHGs emitted by a GJ of natural gas. This factor has been derived from industry accepted studies and is in line with the factor of .05045 used by Natural Resources Canada. The variance between the factor use by NRC and the Terasen Utilities is due to the calorific value of the gas used.

We were then able to determine GHG savings by multiplying energy savings of 179,709 by a factor of .05069, resulting in GHG savings of 9,109 GJs.

Program Name	Number of Participants Per Year	Savings Per Participant Per Year (GJ)	Gross Annual Savings For Program (GJ) (*participant X savings)*	Net to Gross Ratio	Net Annual Savings For Program (GJ) *(gross X ratio)*	NPV Annual Savings For Program (GJ)	Annual GHG Savings I *(savings X .05069)* (NPV)
2008							
Energy Star Heating Upgrade (Retrofit)	2,110	13.8	29,118	57%	16,597	179,709	9,109

22.2 To what extent could macro economic circumstances in BC and Canada account for the realized annual savings in natural gas for 2005 to 2008?

Response:

The annual savings in natural gas presented in Table B-1-6, are directly tied to the specific measure being installed by the customers and are a result of the delivery of energy efficiency programs to customers by TGI. In other words, the energy savings presented in this table are tied to EEC activities for which an incentive was provided by TGI, according to the methodologies described in BCUC IR 1.22.1.

As indicated in the Application, total energy savings that are derived from EEC programs depend on a number of factors such as available funding, number of programs, and number of participants in those programs. Macro economic circumstances can influence annual savings in natural gas associated with EEC activities due to the fact the economic factors may influence participation by customers in EEC programs or measures.

22.3 Please compare the energy savings that would be realized with and without funding of the EEC initiatives as detailed in Part III, Section C, pages 227 to 270. Please provide these data in the following format:

TGI - DSM Program Energy Savings

		2005	2006	2007	2008	2009P	2010F	2011F
[1]	Annual Savings (PJs)	1.35	0.74	1.20	0.61			
[2]	Actual Demand of Natural Gas (PJs)	175.7	170.1	182.7	183.4			
[3]	Energy Savings (%)	0.8%	0.4%	0.7%	0.3%			
[2]	Energy Volumes (PJs)	212.0	208.9	221.5	221.9			

Notes:
[1] data from Table B-1-6
[2] data from Appendix D-1
[3] Annual Savings / Total Demand for Natural Gas

Response:

The table below provides the present value of energy savings from the EEC activity proposed in this Application. The savings are calculated based upon customer participation in the EEC activity proposed.

	2005	2006	2007	2008	2009P	2010F	2011F
Annual Savings (PJs)	1.35	0.74	1.2	0.61	3.66	5.60	5.60
Actual Demand of Natural gas (PJs)	175.7	170.7	182.7	183.4	167.3	162.0	161.8
Energy Savings (%)	0.8%	0.4%	0.7%	0.3%	2.2%	3.5%	3.5%
Energy Volumes (PJs)	212	208.9	221.5	221.9	205.2	200.9	201.0

23.0 Reference: EEC and Alternative Energy

Part III, Section C, Tab 3, p. 227

23.1 On page 234 of the Application, Terasen Gas states that: "TGI has…evaluated the market and need for innovative technologies."

23.1.1 Please provide all supporting evidence to suggest that TGI's customers have not only an interest but a demand for alternative energy sources. Please quantify where possible.

Response:

The statement referenced speaks to the "market and need for innovative technologies", an EEC program, however the question following speaks to a demand for alternative energy sources. As noted in response to BCUC IR 1.21.1, Innovative Technology requests are for EEC funding in this case to provide incentives for reducing energy usage. In contrast, we have proposed to enter into the Alternative Energy Solution market whereby TGI will own and operate components of NGV compression, biogas facilities, alternative energy delivery systems (geo-exchange, solar thermal and DES) and in turn sell customers heat or compression and purchase biogas. This response will cover both those customers who may be interested in EEC activities such as the Innovative Technology requests (incentives for hydronic systems, integrated systems, solar thermal systems, geothermal systems) as well as customers who are interested in and have a demand for Alternative Energy Solutions provided by, owned and operated by TGI.

We believe that there is substantial demand from customers[4] for alternative energy solutions provided by the Terasen Gas Inc. regulated utility. This is demonstrated by contact with customers through sales and account management activities and through three separate studies. A further discussion is provided below.

During the normal course of sales, account management activities, and community and government relations activities, our staff are speaking with existing and potential customers regarding their or their constituents use of natural gas and the role of TGI in providing energy for the province. During these discussions, more and more, customers and stakeholders would initiate conversations regarding "alternate energy sources". Customers and stakeholders have shared with the TGI staff that they were considering such technology as Geo-thermal exchange,

[4] In this response the term "Customer" means developers, engineers, architects, commercial and industrial customers, institutional customers and municipal and government stakeholders, and to a limited extent end use residential customers. This "Customer" group represents those in the marketplace who are the key decision makers determining the type of energy a building will use. In the case of developers, engineers and architects, this group represents thousands of end use customers who purchase a home with the energy choice selected by the developer.

bio gas, bio mass, waste heat recovery, district energy systems, solar and combined heat and energy systems and in addition are looking for ways to not only reduce energy consumption but reduce GHG emissions. Our staff were often challenged to compete with this technology, and to convince stakeholders how natural gas could help reduce emissions. From a sales standpoint many times this would lead to loosing the opportunity to service the customer with Natural Gas as their final decision would often be to go with an alternative energy source supplemented with electricity.

However, since 2008, TGI has begun to change its corporate focus into becoming a provider of energy rather than simply a natural gas delivery company. Stakeholders and customers have been very supportive of this change in direction for the company. In fact, there are very few customers and stakeholders with whom we have spoken that react negatively to TGI providing alternative energy solutions. Customers and stakeholders have not indicated any confusion or concern as to why a gas utility is proposing to offer alternative energy solutions. To the contrary, on average, customers and stakeholders see this corporate change as a logical move given the changing energy environment and applaud TGI for its forward looking approach. Business customers and stakeholders further understand that in today's carbon constrained world, if TGI does not adapt to the new market realities they will become akin to GM or Chrysler, formerly large companies who failed to adapt to a changing market. The effect of failing to adapt is lower gas delivery volumes and fewer customers that must pay for existing assets resulting in higher rates for all remaining customers.

Attachment 23.1.1 includes three documents, which demonstrate that customers are interested in and believe that TGI should not only move into alternative energy solutions but should be the provider of these services in a regulated environment.

The first document in Attachment 23.1.1 is a list of customers that have interacted with TGI sales, account management, market development and community/government relations staff over the past six months. This list demonstrates that 211 customers believe that TGI should provide alternative energy solutions.

The second part of Attachment 23.1.1 includes a report of a third party survey performed by TNS Canadian Facts on behalf of TGI. For the report 14 customer interviews were conducted and interviews performed. The result of these interviews is that customers expect TGI to enter into the Alternative Energy Solutions market and welcome the opportunity to work with TGI to increase energy efficiency and reduce energy usage, via these new solutions.

The third report is part of an omnibus survey undertaken by Ipsos Reid, on behalf of TGI, that surveyed 800 residential customers to determine their understanding of alternative energy and whether or not TGI should provide alternative energy solutions for customers. The results of the survey show that only 19% of customers did not feel that TGI should provide Alternative Energy Solutions. Of the remaining 81%, 33% felt that TGI should provide the solutions, 33% believed that TGI should "maybe" provide the solutions, and 12% did not know. Drilling down further in the data, it shows that the younger the responder, the more supportive they are of TGI providing these solutions. In the 18-34 age group 46% believe TGI should provide Alternative Energy Solutions, whereas in the 55+ demographic, only 24% of respondents believe that TGI should provide Alternative Energy Solutions. Overall, only 13% of those in the 18-34 demographic believe that TGI should not provide Alternative Energy Solutions. TGI believes this is a very strong endorsement of its desire to provide Alternative Energy Solutions. Further, those in the younger demographics are those individuals that are more apt to enter the housing market and therefore require energy delivery service. TGI believes that this survey shows that the individuals surveyed, which would be those who would today receive service under Rate Schedule 1, believe TGI should provide Alternative Energy Service.

23.1.2 What is the estimate number of customer additions for each test year relating to this innovative technology as described in the above statement.

Response:

As noted in response to BCUC IR 1.23.1.1, Innovative Technologies are an EEC program (i.e. not one of the Alternative Energy Solutions) whereby customers will receive incentives for Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal and Ground Source Heat Pumps. These programs do not necessarily have a direct relation to the addition of customers on the Gas system. In some cases customers may be added, in others customer may already be on the system and simply be supplementing or changing their heating appliances in their home.

23.2 Please present the information provided on pages 234-237 of the Application pertaining to Residential and Small Commercial alternative energy sources, by using the following table:

	Expected # of Customer Additions					
	2010	2011	Initial Capital Cost to Customer	TGI investment / Incentive	Annual O&M cost	Payback (years) *
Hydronic Based Heating Systems						
Integrated Energy Systems (or Combination Systems)						
Solar thermal						
Ground Source Heat Pumps ("GSHP")						
* Assume normal and expected consumption levels						

Response:

The requested table is provided below with modifications for the reasons described in this response.

The information provided on pages 234-237 of the Application pertains to Residential and Small Commercial Innovative Technologies. The information provided details regarding incentives TGI would provide to participants in the EEC Innovative Technologies program area, similar to incentives for the Residential and Commercial Energy Efficiency Program Areas which were approved by the Commission in Decision G-36-09 on the Terasen Utilities' EEC Application. The Innovative Technologies EEC Program Area is not intended to result in customer additions. The Innovative Technologies EEC programs referenced in the Information Request above are different than TGI's proposal for Alternative Energy Solutions in which TGI will own and operate heat delivery systems where that heat is delivery by Solar, DES, Geo-exchange or other energy source and where TGI would charge customers for the provision of that service, and as a result, add customers.

The table below includes the number of projected Innovative Technologies program participants instead of customer additions. In addition, a column for "annual savings" has been added to represent the capital and operating cost of a storage type gas water heater in order to provide a comparison for the solar thermal DHW system. The payback for the hydronic baseboard system, hydronic under floor system, integrated energy system and ground source heat pump are based on the incremental cost compared to a 80% AFUE** Hydronic baseboard system (in order to perform a simple payback comparison a cost of $10,000 is assumed for a base line).

In reference to GSHP's, a $1,000 incentive is provided towards the installation of pre-piping and provisions for the future installation of the heat exchanger. TGI believes GSHP are installed regardless of the payback and this incentive will enable the adaptability to other energy sources in the future.

TGI recognizes the payback for these systems are relatively lengthy; however, without incentives, these energy efficient technologies will not gain market acceptance. By promoting these technologies, over time market share will increase and capital cost of the equipment will decrease to a level where incentives are no longer required.

As the Commission's Decision dated April 16, 2009 regarding TGI and TGVI's Energy Efficiency and Conservation Programs Application states (at page 26), "Innovative Technologies, NGV and Measurement programs can be appropriate vehicles for encouraging commercial development of technologies to reduce or replace natural gas consumption and related GHG emissions." TGI believes these pilot programs will determine whether an effective program can be developed.

	Expected # of Participants*					
	2010	2011	Incremental capital cost to Customer	TGI Incentive	Annual[1] Energy Savings	Payback (Years)
Hydronic Baseboard System	400	800	$2,000	$500	$60	25
Hydronic Under floor System	400	800	$4,000	$1000	$60	50
Integrated Energy System (or Combination System	400	800	$2,500	$1000	$87	17
Ground Source Heat Pumps	400	800	$20,000	$1000	$139[2]	137
Solar Thermal	400	800	$8,000	$1000	$122	29[3]

1 These numbers are from the Excel spreadsheet originally prepared by Jack Habart. Gj's saved x $9.772

2 Gas saved minus extra electricity used at first tier rate – (36.2 GJ's x $9.772) – (3598 kwh x $0.597)

3 Based on cost of $3525 which is $8000 minus all rebates (; $1000 Solar BC discount, Livesmart Rebate $125, EcoEnergy Rebate $1250, Power Sense Rebate $300 and Home Reno Tax Credit (approx) $800)and including proposed Terasen rebate of $1000

23.2.1 Please provide supporting evidence to verify TGI's target customer additions from the above table.

Response:

As also referenced in response to BCUC IR 1.23.2, there are no "target customer additions" related to Innovative Technology EEC programs. Rather, there are participants in Innovative Technology EEC programs, similar to many other EEC programs. The participants listed in the table are estimates based upon discussions with customers, key stakeholders and innovative technology suppliers, and TGI believes the estimates to be reasonable.

23.2.2 What is the expected cost recovery plan for these alternative energy solutions should the contracted customer exit the system before expiry of the contract? Will utility rate payers ultimately be responsible for the sunk costs?

Response:

It should be noted that the expenditures proposed for alternative energy solutions in the section referenced in this question are Innovative Technologies EEC programs, not a solution whereby TGI is proposing to own and operate the heat delivery system and contract with the customer for delivery of heat to that end use customer (see BCUC IR 1.23.2.1).

The incentives proposed are for small scale residential and commercial alternative energies. The alternative energy technologies TGI is proposing (hydronic systems, combination systems, solar thermal systems and ground source heat pumps) would be installed in residential and small commercial buildings, and would be very difficult to remove without demolishing the building. Therefore, the savings resulting from the installation of the technologies proposed should continue to be realized over the life of the building.

24.0 Reference: EEC and Alternative Energy

Part III, Section C, Tab 3, p. 227-270

24.1 Does Terasen Gas agree that there is a difference between complimentary and substitution of natural gas service?

Response:

Yes, in the generic academic sense. Please see the response to BCUC IR 1.24.2 for an explanation of how alternative energy solutions can potentially be complementary to or a substitution of natural gas service depending on the circumstances.

24.2 Does TGI recognize that the alternative energy solutions of Hydronic, Solar Thermal, GSHP, and District Energy Systems will displace conventional natural gas consumption and hence are recognized as a substitution of natural gas usage?

Response:

The question references both the alternative energy solutions outlined by TGI in the Application (Solar Thermal, GSHP and District Energy Systems) where TGI proposes to own and operate the alternative energy system and EEC incentive programs (including Innovative Technology Programs such as: Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal Energy Systems, and Ground Source Heat Pumps). This response addresses both.

Depending upon the situation, alternative energy solutions such as Solar Thermal, GSHP and District Energy Systems can either be a *complementary* service to natural gas, electricity, wood, oil or other energy source, or customers may seek an alternative energy source for heating *in place of*, or *complementary to* gas, electricity, wood, oil or other energy source. Put another way, electricity, gas, oil, wood, alternative energy sources are all commodities which provide end use heat for a customer. Often these commodities can all be used in *substitution* with one another. From a customer's standpoint, in today's energy environment there is no longer a black and white choice between one commodity and another commodity. These commodities are now often integrated together in an energy system and then purchased by a consumer as a *complementary* product offering, which from an academic economic theory standpoint is a higher value offering for a customer. It is this solution that TGI is proposing in this Application.

As noted above, the reference to Innovative Technologies (including: Hydronic Heating Systems, Integrated Energy Systems, Solar Thermal Energy Systems, and Ground Source Heat Pumps) on pages 234-237 of the Application is in the context of EEC incentive funding. TGI recognizes that customer adoption of these energy systems (for which EEC funding is provided) will, all else equal, reduce gas consumption and thus would represent a "substitution" in that context. The same is true for all of the EEC programs for which the Commission approved incentive funding in the recent EEC Decision.

However, EEC programs, like the provision of alternative energy solutions, support government energy and GHG policy objectives, while meeting the needs of customers. Those policy objectives have been specifically delineated, for instance, in "government's energy objectives", which the Commission must consider in the context of resource plans, expenditure schedules and CPCN applications. The Energy Policy speaks to both substitution and complementary use of energy with as referenced on Page 21 of the Energy Plan which states: "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… *Combinations* of alternative energy sources with natural gas….will promote energy efficiency". Further information regarding how these alternative energy solutions support government policy is outlined, for example, at Part II Tab B of the Application.

24.3 Please explain how these types of natural gas substitutions use considered an essential service and hence should fall under the jurisdictions of a regulated utility.

Response:

The Act contemplates that an entity providing services in the nature of the alternative energy solutions (i.e. solar thermal, GSHP and District Energy Systems) is subject to regulation as a "public utility". The assumption implicit in the question that the Commission only regulates "essential services" is incorrect; TGI is not aware of any provision in the Act that would confer jurisdiction on the Commission to regulate only "essential services".

Under the Act, the Commission's jurisdiction extends to a "public utility". The definition of "public utility" in the Act is, in part:

> **""public utility"** means a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for (a) the **production**, generation, storage, **transmission, sale, delivery** or provision of electricity, natural gas, steam or **any other agent for the production of** light, **heat**, cold or power **to or for the public or a corporation for compensation**…" [Emphasis added.]

The alternative energy solutions such as solar thermal, GSHP, and DES produce heat that is to be provided "to or for the public or a corporation for compensation". The provision of these alternative energy solutions to customers in the manner contemplated in this Application will be subject to Commission regulation regardless of the legal entity that provides these alternative energy solutions. Dockside Green is an example of a small regulated utility that employs a single District Energy System for the provision of heat energy, and is a good example of the type of project that TGI has in mind in pursuing these alternative energy solutions.

The *Utilities Commission Act* does not prohibit TGI from providing alternative energy solutions, or any other regulated service for that matter. Similarly, TGI is unaware of any provision in the Act that would confer jurisdiction on the Commission to prohibit TGI from pursuing particular alternative energy solutions. The Commission's core jurisdiction is with respect to rates charged by public utilities in respect of regulated services, and the management of the utility remains the responsibility of the utility management. The BC Court of Appeal has stated for instance (*British Columbia Hydro and Power Authority v. BC Utilities Commission* (1996), 20 BCLR (3d) 106 at 119):

> It is only under s.112 of the *Utilities Act* [the former entry, seizure and management provision] that the Commission is authorized to assume the management of a public utility. Otherwise the management of a public utility remains the responsibility of those who by statute or the incorporating instruments are charged with that responsibility.

Rates – in this case, the gas rates and the rates payable by alternative energy customers - must be just and reasonable and not unduly discriminatory. The Commission, in determining just and reasonable rates, must determine the appropriate allocation of costs as between gas customers and customers of the alternative energy solutions. The proposed economic tests are an efficient means of addressing cost allocation issues, modeled on the existing Main Extension (MX) test and previously accepted cost of service tests. The approval of economic tests will facilitate TGI negotiating just and reasonable alternative energy rates in the form of individual contracts entered into with individual customers and filed with the Commission. It is important to note, however, that with or without the economic tests for which approval is being sought, TGI believes that it would be possible for TGI to file individual contracts with customers for the provision of alternative energy solutions for approval as a rate. While this approach is equally valid and permissible under the Act, it is a less efficient approach because it would be necessary for the Commission, intervenors and TGI to address cost allocation issues as between the new customer and other (gas) customer's classes each time a contract is filed.

24.4 Has TGI considered offering these types of alternative energy solutions through a non-regulated business segment?

Response:

TGI has considered offering these services through other corporate entities within the Terasen group of companies. TES has provided alternative energy solutions for a number of years that due to their unique nature are not actively regulated, although a number of its projects are individually regulated by the Commission. Please see TGI's response to BCUC IR 1.24.3 for a discussion of the Commission's jurisdiction over alternative energy solutions.

There are benefits associated with TGI providing these services in the future, rather than the services being provided through other Terasen companies including TES or a proliferation of other regulated companies.

First, as part of the Company's proposed economic tests for each alternative service, overhead costs are included in the calculations and allocated to the alternative energy customers. The overhead costs for natural gas customers are reduced correspondingly, providing a benefit not seen if a separate company provided this service In the passage quoted below from Commission Order No. C-22-06 the Commission expressed a preference for the inclusion of diverse customer groups within TGI, citing cost allocation issues as a basis for the decision.

Second, it enhances regulatory efficiency for TGI to provide alternative energy solutions under the proposed economic tests, rather than providing them through a proliferation of other related entities. In Commission Order No. C-22-06 regarding an application by TES for Approval of a CPCN for a Propane Gas Distribution System for Gateway Lakeview Estates, the Commission emphasized the importance of administrative efficiency associated with having diverse customers served by TGI rather than a proliferation of smaller regulated utilities under the Terasen parent:

> *"Nevertheless, TGI has propane customers in Revelstoke, and it is not evident how TES Gateway Lakeview Estates, as a separate small utility, adds value, from the perspective of customers in the resort community, as compared to having these customers served directly by TGI, a separate but larger and related utility. As well, TES has stated, but has provided no support other than reference to the Transfer Pricing Policy and the Shared Service Agreement, that this arrangement ensures that TGI customers do not subsidize the resort community customers. Certainly, it is likely to be less efficient and more costly from the Commission´s perspective to regulate a number of small utilities, rather than one larger utility serving the same customers. Going forward, the Commission expects TES and TGI to consider and address this concern when they are developing plans to serve new developments and groups of customers that are in or near TGI´s service area. The Commission is not certain that a proliferation of*

small, but related utilities, all under the same parent, TI or KMI, is necessarily in the public interest."

The economic tests proposed by TGI in this Application further enhance administrative efficiency. So long as the customer's contract passes the approved economic test, the resultant regulatory process would be streamlined to balance the appropriate BCUC oversight with the need to expedite the process to meet customer needs. It therefore makes most sense to structure these offerings within the TGI regulated utility as opposed to another regulated option.

25.0 Reference: EEC and Alternative Energy - Biogas

Part III, Section C, Tab 3 (p. 249)

"Over the two-year RRA period, we propose to expand the development of biogas capture and upgrading in BC in a Pilot Phase of limited scope."

25.1 What is the estimated capital required for the Biogas pilot phase as discussed on pages 249-259 of the Application?

Response:

Reaching the 0.5 PJ per volume limit proposed for the biogas pilot phase is likely to involve somewhere between 5 and 10separate projects. As stated on page 257 of the Application, TGI has received nine submissions from a variety of raw biogas producers as part of the Biogas Request for Expressions of Interest ("RFEOI") and has been interacting with a number of other parties as well. It is important to note that the $15 per GJ cap on the pricing of upgraded biomethane in the pilot phase includes the costs of biogas upgrading, including the carrying costs of any capital invested.

There is a wide range of possible outcomes on how much capital will be spent to implement these projects. TGI anticipates it will own the biogas upgrading facilities at many of these projects but not all. Further there are many factors contributing to the possible capital costs at any particular project, including the proximity to TGI's system and local system capabilities, the expected throughput from the biogas project, the biogas upgrading technology adopted and various others. With the foregoing commentary as background, TGI believes a reasonable estimate of the range of capital investment over the course of this RRA is between $10 million and $20 million.

25.2 Why does TGI believe that the utility customers should fund the learning curve of the TGI employees?

Response:

Please see the response to BCUC IR 1.19.1.

25.3 Please advise whether this technology already present in the competitive market? Please provide all the reasons why TGI believe that Biogas should be considered under a regulated monopoly. Has TGI considered offering these Alternative Energy Extensions under an NRB i.e. TES? Please explain why TGI is in any better position to provide leadership and funding to Alternative Energy Extensions than Terasen Inc and TES?

Response:

This technology is already present in the U.S. market, but has not been implemented in the Canadian or B.C. market.

There are two main reasons why TGI believes that it is appropriate for TGI to pursue biogas upgrading opportunities, rather than deferring those opportunities to third parties.

First, TGI believes that there are some components of the capital investment required to connect biogas upgrading project to TGI's system that must be owned and operated by the regulated utility. These include the critical equipment and assets required to accurately test for gas quality and measure biogas gas volume as well as the connecting pipelines. TGI presently owns and operates these types of equipment to maintain safe and reliable service on its natural gas distribution system. The regulated utility possesses the skills and knowledge to operate such equipment.

Second, the pursuit of biogas opportunities by public utilities like TGI is consistent with provincial policy as expressed in the Energy Plan and legislated "government's energy objectives". For instance, the Energy Plan expressly contemplates public utilities taking a role in advancing alternative energy solutions:

> *"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. Combinations of alternative energy sources with natural gas include solar thermal and geothermal.* ***Working with*** *municipalities,* ***utilities*** *and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province."* [Emphasis added.]

This focus on utilities playing an integral role in the delivery of alternative energy solutions is reemphasized in the inclusion of "government's energy objectives" in the *Utilities Commission Act*. Biogas upgrading projects advanced by TGI would normally be subject to obtaining a CPCN (although the capital cost of individual biogas projects is expected to be below the proposed CPCN threshold and TGI is proposing an economic test to encourage administrative and regulatory efficiency), and "government's energy objectives" must be considered by the Commission with such projects. The "government's energy objectives" include two objectives that directly support a public utility like TGI advancing biogas upgrading: (i) "to encourage public utilities to use innovative energy technologies…that support energy conservation or efficiency or the use of clean or renewable sources of energy", and (ii) "to encourage public utilities to reduce greenhouse gas emissions". Biomethane is a clean and renewable source of energy provided through the development of innovative technology, and its use will encourage public utilities to reduce greenhouse gas emissions. TGI therefore believes that the Commission, through its regulation of TGI in the manner proposed in this Application, should be encouraging TGI to pursue it.

While "government's energy objectives" must be considered in conjunction with other factors, such as the impact on customer rates, TGI believes that it has appropriately addressed rate impact in its proposal. Some investment is required at the pilot phase, but the limited scope of the pilot means that the rate impact is negligible. At the same time, existing and future gas customers stand to benefit from a successful pilot. TGI has stated in the Application that its intention is to develop a "green" rate that recovers the incremental cost from customers with a desire to purchase biomethane. The availability of this "green" service has the potential to retain and attract customers that will contribute to the overall system costs for the benefit of all customers.

Thus, TGI believes in the circumstances that it has an important role in advancing the development of biogas and biogas upgrading as a resource in BC, and the proposal in the Application will help to advance that government-sanctioned objective.

26.0 Reference: Energy Efficiency and Conservation

Appendix G1 p. E4

26.1 What is the value (increase revenues / costs savings) that TGI is attempting to obtain through the $40.7m increase in funding in EEC expenditures?

Response:

There are two premises in the question which are incorrect. First, TGI is not attempting to increase revenues or seeking cost savings as a result of EEC funding. EEC funding is designed to help customers use energy more efficiently (as further outlined below). Second, TGI is not seeking an increase of $40.7 million as this amount referenced in the question is comprised of a number of Program Areas, expenditures for *most* of which were already approved in the EEC Decision and Order No. G-36-09. Please see the response to BCUC IR 1.27.1, which details funding already approved in Order No. G-36-09.

In the EEC Decision, the Commission made the following determinations with respect to the funding sought in that Application:

"The Commission Panel finds the design of Terasen's Residential and Commercial EE programs to be reasonable, flexible and in the public interest, and accepts the expenditure proposals for these program areas."[5]

"…the Commission Panel notes the comments of Terasen regarding potential GHG benefits of fuel switching, particularly away from fossil fuels with a higher carbon content than natural gas…The Commission Panel accepts EEC expenditures directed at fuel switching from fossil fuels with a higher carbon content than natural gas."[6]

"The Commission Panel finds the evidence sufficient to establish that there is a benefit to some CEO [Conservation Education and Outreach] expenditures and accepts $6.918 million as reasonable."[7]

"The Commission Panel accepts the expenditures requested for the Joint Initiatives Program area."[8]

"The Commission Panel accepts the Application's CPR update expenditure proposal."[9]

[5] BCUC EEC Decision, April 16, 2009, p. 13
[6] BCUC EEC Decision, April 16, 2009, pp. 17 - 18
[7] BCUC EEC Decision, April 16, 2009, p. 21
[8] BCUC EEC Decision, April 16, 2009, p. 23
[9] BCUC EEC Decision, April 16, 2009, p. 28

The EEC Application laid out a number of benefits arising from the expenditures proposed therein. These can be found in Section 7 of the Application. They include:

- Providing access to a wider variety of energy efficiency and conservation programs
- Expanding the range of customers for whom energy efficiency and conservation programs are available
- Providing education for customers and the public at large about energy and conservation issues
- Continuing to add efficient cost-effective customers to TGI's distribution system, keeping the use of natural gas and other energy forms competitive for all customers
- Supporting the development and training of skilled tradespeople that are fluent in the merits of conservation and in efficient technology
- The $40.7 million for TGI referenced in the question had a reduction in natural gas consumption of 8,114,000 GJ associated with it, which results in significant bill reductions for TGI's residential and commercial customers
- A reduction in natural gas consumption has a corresponding reduction in GHG emissions of 411,297 tonnes

The Commission Panel has already approved a large part of Terasen Gas' EEC Application under Decision and Order No. G-36-09. TGI is seeking approval in this Application *" for funding in 2011 for program areas outlined in the EEC Application and already approved by the Commission for 2010…".* The same benefits for EEC expenditures already approved by the Commission will be derived from the EEC expenditure being requested in this Application for 2011.

26.2 How does this benefit existing / potential residential customers aside from aligning with the government's energy objectives?

Response:

Please see the response to BCUC IR 1.26.1 above.

27.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Part III, Section C, Tab 3, pp. 227-229

Energy Efficiency and Conservation Programs

27.1 Table C-3-2 on page 229 shows the EEC Funding sought in 2010 and 2011. Please provide an amended table for 2010 and 2011 that segments the costs between incentives and non incentives.

Response:

The table below segments the EEC funding sought for Interruptible Industrial EEC activity and for Innovative Technologies for 2010 and for Residential and Commercial EEC activity, Interruptible Industrial EEC activity and Innovative Technologies EEC activity for 2011. As noted on page 229 of Exhibit B-1, the EEC Expenditures for the Residential and Commercial Programs, and for Joint Initiatives and Conservation and Outreach for 2010 (highlighted in yellow in the table below) have already been approved in Decision G-36-09. There is a slight difference of $1,000 in the budget amount presented below for 2010, and that presented in Table C-3-2, which is due to rounding.

	2010		2011	
EEC Funding Sought (000's)	**Incentives**	**Non-incentive costs**	**Incentives**	**Non-incentive costs**
EEC Programs - Approved in G-36-09				
Residential Energy Efficiency	2,818	1,257	2,818	1,257
Commercial Energy Efficiency	10,471	4,292	10,471	4,292
Residential Joint Initiatives (Low Income)	1,010	337	1,010	337
Conservation Education and Outreach	0	2,890	0	2,890
New Programs in this Application				
Interruptible Industrial	0	435	1,750	125
Innovative Technologies	1,800	534	3,600	1,069

27.2 What is the anticipated TRC test ratio for each of 2010 and 2011 EEC portfolio as proposed in the Application?

Response:

The table below provides the TRC test ratio for years 2010 and 2011 for the EEC portfolio as proposed in this Application. Note that this aggregate TRC reflects proposed costs but no savings (benefits) associated with EEC for Interruptible Industrial Customers. As noted in the response to BCUC IR I.29.3.2, the TRC for Interruptible Industrial cannot be calculated at this time as incremental cost for efficiency upgrades for large Interruptible Industrial customers, and associated savings will become available only once any individual customer projects are developed. As can be seen from the table below, the portfolio TRC is significantly above 1, meaning that the benefits significantly exceed costs on a portfolio basis, despite the fact that the costs but no benefits are included for an industrial EEC programs.

Year	Portfolio TRC Ratio
2010	2.7
2011	2.5

28.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section C, Tab 3, pp. 228-229

Energy Efficiency and Conservation Programs

Please forecast data in the following format based on O&M and Total Proposed EEC Expenses for 2010 and 2011 in Tables C-3-1 and C-3-2.

TGI - EEC Expense for All Programs

	2008	2009P	2010F	2011F
Deferral ($000,000)	0.74	7.26	25.85	29.62
O&M ($000,000)	1.74	1.62		
Total EEC Expense	**2.48**	**8.88**		

Source: Table C-3-1 and Table C-3-2

Response:

The table below details the forecast EEC expenditures for 2010 and 2011, broken out into O&M and deferral. Pursuant to Commission Order No. G-36-09, effective 2010 all EEC expenditures (both O&M expenses and incentives) are capitalized by way of a regulatory asset deferral account and as such are not broken out between O&M and incentives. TGI believes it is appropriate to continue this approved accounting treatment for EEC funding for 2011, including Innovative Technologies and Interruptible Transportation programs.

TGI - EEC Expense for All Programs

	2008	2009P	2010F	2011F
Deferral ($000,000)	0.74	7.26	25.85	29.62
O& M ($000,000)	1.74	1.62	0	0
Total EEC Expense ($000,000)	**2.48**	**8.88**	**25.85**	**29.62**

29.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Part III, Section C, Tab 3, pp. 232–233

Industrial Energy Efficiency: Stakeholder Consultation

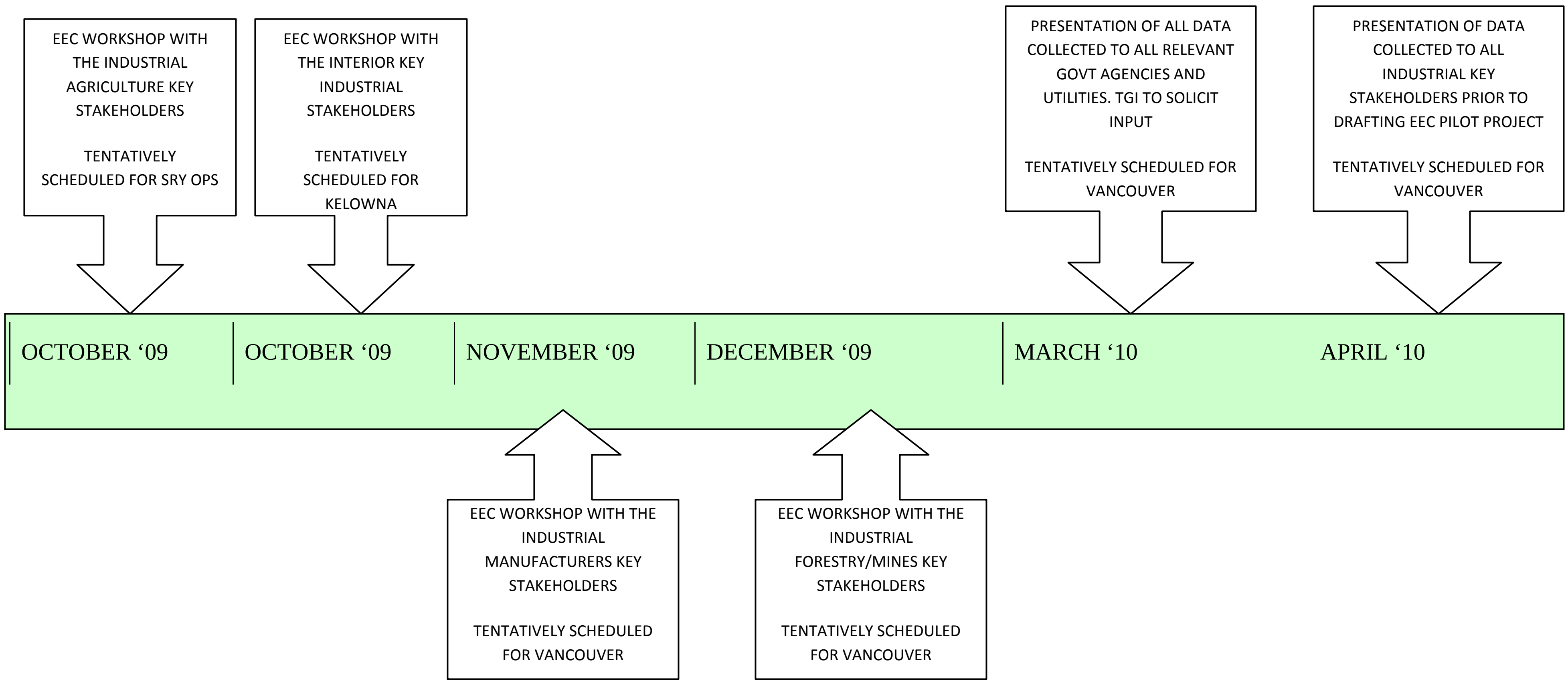
29.1 On page 232 it states: "...TGI must do more work to develop programs to meet EEC needs of this [industrial] group of customers."

29.1.1 Please provide a schedule for the further industry specific workshops and customer meetings that is concurrent with the RRA process and an extended schedule beyond the RRA process, if any.

Response:

The information below provides a proposed timetable for further consultations on Industrial DSM.

FUTURE INDUSTRIAL EEC STAKEHOLDER MEETINGS/WORKSHOPS



29.2 On page 233 TGI budgets for an additional staff member with expertise in the Industrial and Manufacturing Sector.

29.2.1 What is the pay level and affiliation of this new staff member? Is the $120,000 line item in Table C-3-4 the fully loaded cost?

Response:

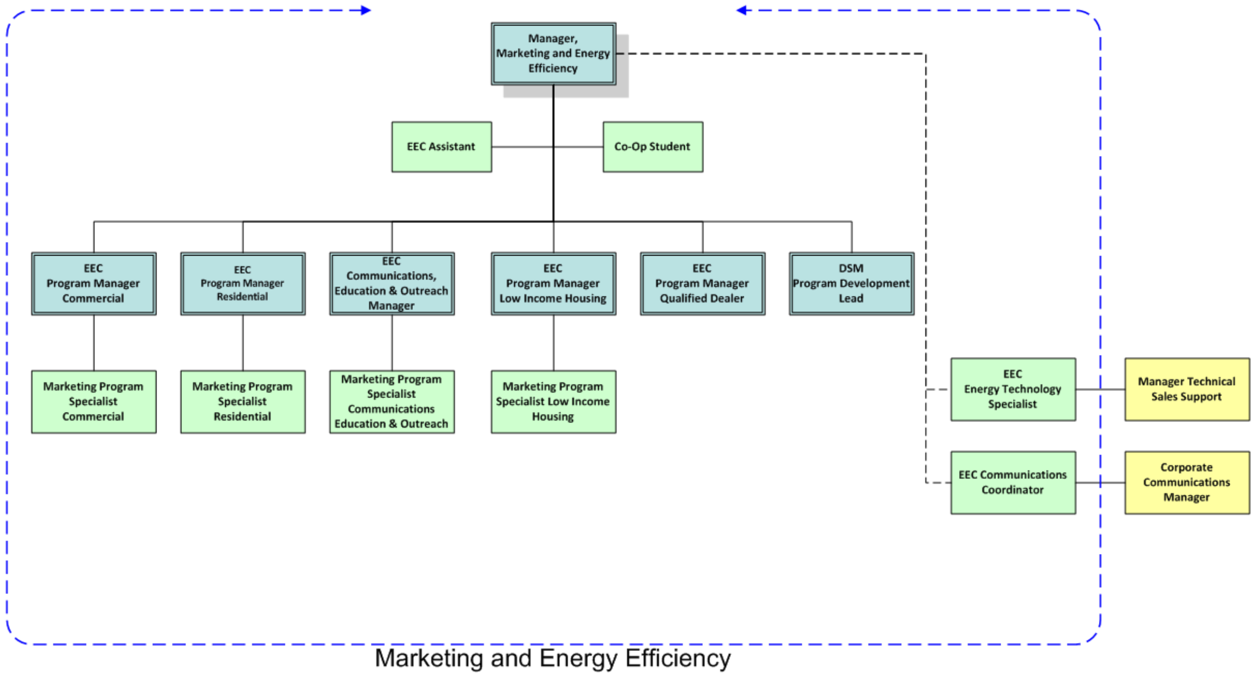
This new staff member will have an M&E affiliation. Other EEC Program Manager roles currently fall into a pay range of $55,700 to $76,600. It is possible that the more complex custom industrial EEC activity will require a higher pay scale; however, this will be assessed once the nature of TGI's program for industrial customers is more developed. The line item is the fully loaded cost.

29.2.2 Please provide an organization chart of the energy efficiency department for years 2009, 2010, and 2011.

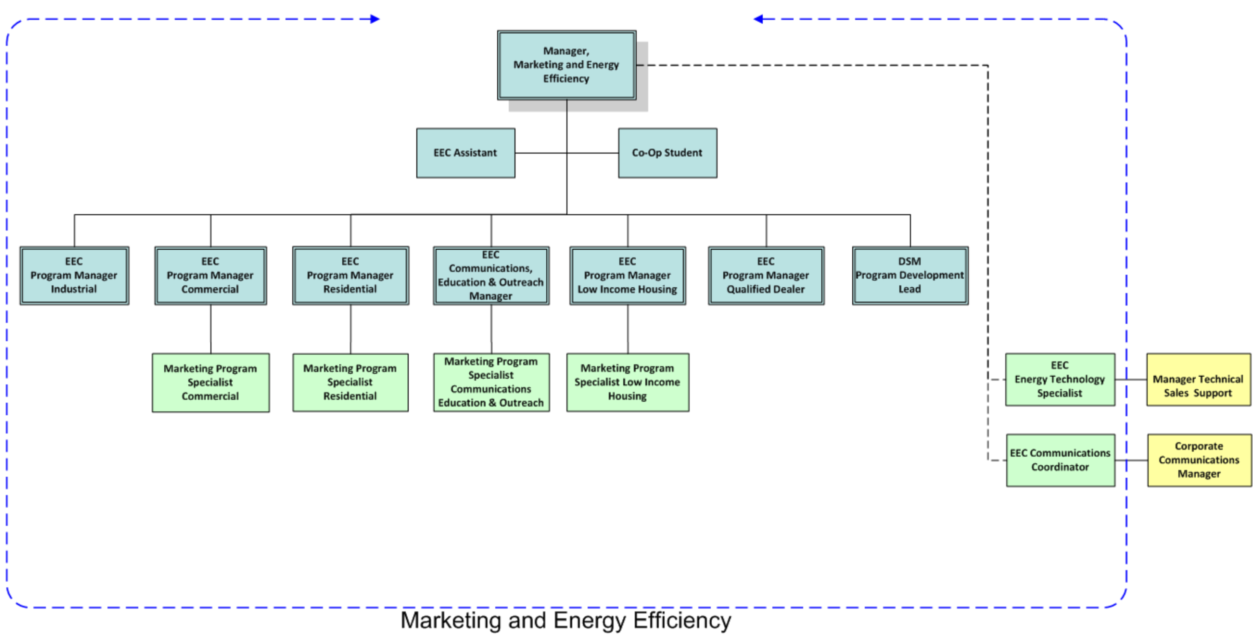
Response:

Organization charts are attached below.

EEC Org Chart - 2009



EEC Org Chart – 2010/2011



29.3 Table C-3-4 on page 233 shows the Industrial EEC Preliminary Budget for $435,000 in 2010 and $1,875,000 in 2011.

29.3.1 What are the low and high ranges for each of 2010 and 2011 budgets and to what level of certainty?

Response:

The budget and request for funding for Interruptible Industrial programs are what TGI expects to spend during the timeframe of the RRA. The budgets were built up based upon specific activities TGI expects to undertake over the course of the RRA. As noted in the Application, these include: in 2010 the addition of a full time staff member to manage and coordinate these activities, a limited number of audits, stakeholder consultations activity and updating a manufacturing sector Conservation Potential Review. In addition in 2011 we estimate that three customers would receive incentives as shown in Table C-3-4 of the Application. We believe that the budgets are small relative to the size of our industrial customer base and as such these amounts will be fully invested to customer benefit over the two year time frame.

At these early stages, TGI is unable to provide a low and high range for these proposed EEC expenditures for Industrial customers, nor an assessment of certainty around ranges. In its Order No. G-36-09, the Commission directed the Terasen Utilities to commence the planning process for the development of an Industrial EEC Program, and to file a report within 90 days; TGI fulfilled this Order by filing its Interruptible Industrial EEC program request as part of this Application. Note that, as per the financial treatment approved in the EEC Decision and proposed in this Application for the incremental expenditures, over time only the actual spend on EEC activities will be charged to the EEC deferral account and ultimately be reflected in delivery rates. For the period of the RRA, customer rates will reflect the approved costs.

Over the course of the RRA, with a dedicated staff person in place for Interruptible Industrial EEC programs, further consultation with stakeholders, risk analysis, program design, and program analysis, TGI will be able to better determine appropriate ranges for future Interruptible Industrial EEC funding.

29.3.2 What is the TRC test ratio for the Industrial EEC?

Response:

The TRC test ratio for Industrial EEC cannot be calculated at this time, since two key inputs to the TRC test, namely full incremental costs for Industrial efficiency upgrades and energy savings available from these upgrades, are not available. As noted in the Application:

"…it became apparent that TGI must do more work to develop programs to meet EEC needs of this group of customers. There was support for additional funding and programs and energy efficiency audits. However participants and the TGI acknowledged:

- *TGI does not have experience with developing industrial programs, and will require further time to develop suitable programs; and*
- *Incentive and program may have to be unique to either the industrial group <u>or in many cases to the individual customer.</u>" [Emphasis added.]*[10]

It is possible that TGI's program for Industrial customers will have to be unique to individual customers, with incentives available on the basis of a dollar amount per unit of energy saved, rather than the more prescriptive residential and commercial programs, where a fixed dollar incentive amount is provided to customers that install a specific natural gas appliance or system. The result of this is that the incremental cost for efficiency upgrades for large Interruptible Industrial customers, and associated savings will become available only once any individual customer projects are developed.

Note, as described on page 228 of the Application, pursuant to the Commission's EEC Application Decision Order No. G-36-09, only the actual spend on EEC activities will be charged to the EEC deferral account, with the result that only the actual spend will be reflected in customers' delivery rates for the years 2012 and beyond. As such, the amounts in C-3-2 represent maximum spending levels.

Due to this unique, individual, customer-by-customer nature of Industrial EEC Programs, TGI believes that it is appropriate to proceed with the Interruptible Industrial EEC programs even though a TRC result will not be available until more is known about individual projects that might be eligible for Interruptible Industrial EEC activity.

The budget amounts put forth in this Application are based upon TGI's best estimates for Interruptible Industrial EEC activity, and despite the lack of information required to calculate a TRC for this budget item, the Company believes that the expenditures requested are reasonable.

[10] Terasen Gas Inc., 2010-2011 Revenue Requirements Application, page 232.

30.0 Reference: Energy Efficiency and Conservation Programs and Alternative Energy Solutions

Part III, Section C, Tab 3, pp. 234-237

Innovative Technologies

The table below summarizes the EEC Innovative Technologies budget request for the various activities.

EEC Innovative Technologies

	$000s	2010	2011	Total	Reference
1	Residential and Small Commercial				
2	Hydroponic Based Heating Systems	$778	$1,600	$2,378	p. 235
3	Integrated Energy Systems (or Combination Systems)	$518	$1,000	$1,518	p. 236
4	Solar Thermal	$518	$1,000	$1,518	p. 236
5	Ground Source Heat Pumps	$518	$1,000	$1,518	p. 237
6	Total (lines 2 to 6)	$2,332	$4,600	$6,932	
7					
8	Innovative Technologies	$2,334	$4,669	$7,003	Table C-3-2, p. 229
9					
10	Difference (lines 8 - 6)	$2	$69	$71	

Please confirm the figures in the above table. If not confirmed, please submit a revised table.

Response:

The discrepancy illustrated in the above table is caused by rounding of the program costs presented on pages 235 and 236 as compared to table C-3-2 on page 229.

The unrounded program cost as outlined in the RRA on pages 235 and 236 and the unrounded cost in table C-3-2 on page 229 are represented in this revised table.

$000s	2010	2011	Total	Reference
1 Residential and Small Commercial				
2 Hydroponic Based Heating Systems	778.125	1556.25	2334.375	p. 235
3 Integrated Energy Systems (or Combination Systems)	518.75	1037.5	1556.25	p. 236
4 Solar Thermal	518.75	1037.5	1556.25	p. 236
5 Ground Source Heat Pumps	518.75	1037.5	1556.25	p. 237
6 Total (lines 2 to 6)	$2,334.375	$4,668.750	7003.125	
7				
8 Innovative Technologies	$2,334.375	$4,668.750	7003.125	Table C-3-2, p. 229
9				

10 Difference (lines 8 - 6)	**$0**	**$0**	**$0**

30.1 The table shows a small difference between the total on page 229 in Table C-3-2 and the itemized activities. Please reconcile the figures.

Response:

The response to BCUC IR 1.30.0 above reflects the reconciled figures.

30.2 Please provide supporting documentation of the market potential for customers taking advantage of the incentives for each Innovative Technology.

Response:

At this time TGI does not have supporting documentation for market potential for customers taking advantage of Innovative Technology programs. However, through discussions with our customers, builders, developers, key stakeholders and innovative technology suppliers (see list of customers seeking Alternative Energy Solutions from TGI in response to BCUC IR 1-23) we know that customers are interested in these solutions. We have determined that the up-front incidental cost deters the installation of innovative technologies for space and water heating systems.

As programs are developed and introduced to the market, we will begin to understand the market potential. As with all EEC programs, we will closely monitor incentive levels and adjust accordingly while also evaluating the TRC levels to ensure that there is customer uptake and the overall aggregate TRC levels meet the aggregate threshold.

30.3 What is the low and high range anticipated for actual spend for each Innovative Technology? Please provide the degree of confidence for the ranges.

Response:

Innovative technologies incentives are pilot programs and, therefore, monitoring participation levels will be critical to gauging if the incentive levels are correct. Anticipating actual spending for innovative technology is difficult to predict; the number of potential participants will be dependent on the number of housing starts for new installations and the number of customers replacing old equipment.

As the table below illustrates, spending in each of the categories will not exceed the proposed program funding levels, TGI is asking for these spending levels to be approved in order to avoid the potential of having to file for more money for incentives. The actual spending level will not exceed the proposed level of spending as indicated in the application[11]. As there is no historical data for a basis for assumptions, we are not able to provide a low range for anticipated spending. As with all Energy Efficiency and Conservation programs, we will closely monitor incentive levels and adjust accordingly while also evaluating the TRC levels to ensure that there is customer uptake and the overall aggregate TRC levels meet the aggregate threshold.

We are not able to provide the degree of confidence for the ranges, as there is no historical data for a basis for these assumptions.

$000s	2010 Proposed, and anticipated, level of spending	2011 Proposed, and anticipated, level of spending
Hydronic Based Heating Systems	778.125	1556.25
Integrated Energy Systems (or Combination Systems)	518.75	1037.5
Solar Thermal	518.75	1037.5
Ground Source Heat Pumps	518.75	1037.5
	$2,334.375	$4,668.750

30.4 What is the TRC test ratio for each of the Innovative Technologies?

Response:

Innovative Technology Measure Name	TRC Ratio 2010	TRC Ratio 2011
Hydronic Baseboards	1.5	1.6
Hydronic Underfloor Systems	0.8	0.8
Combination Systems	1.3	1.4
Solar Thermal	0.3	0.3
Ground Source Heat Pump	0.2	0.2
Overall Innovative Technology Program Area	0.5	0.5

[11] Note that customers will only pay for those EEC costs, including Innovative Technologies and Interruptible Industrial Program, that are actually spent over time. For the period of the RRA, customer rates will reflect the approved costs. If TGI does not spend all amounts for EEC programs, the actual spend will be reflected in customers' delivery rates for the years 2012 and beyond.

The table below details the TRC test ratio for each of the Innovative Technologies in this Application, as well as for the Innovative Technologies Program Area as a whole.

In Decision G-36-09 (the EEC Decision), the Commission affirmed the portfolio approach for assessing TRC. It provided direction with respect to individual measures that have a TRC less than one:

> *"The Commission Panel accepts the portfolio level approach based on achieving a portfolio TRC level…of 1.0 or greater provided that program areas, initiatives or measures with an individual TRC of less than 1.0 are proactively designed and sufficiently support social or environmental objectives…. The Commission Panel directs that Terasen …provide justification for continuing with any measures or groups of measures which have a TRC of less than 1.0."*

Please see the response to BCUC IR 1.27.2: the overall Portfolio TRC, including the Innovative Technologies expenditure, is 2.7 for 2010 and 2.5 for 2011. As the table below indicates, hydronic underfloor heating, solar thermal and ground source heat pumps all have a TRC ratio of less than 1.0, requiring TGI to provide a justification.

TGI believes that by providing incentives for these technologies, we are promoting future proofing of buildings with space and water heating systems that are enabled to integrate these in-building systems with District Energy or other energy sources as they become available. The systems themselves are easily adapted to be combined with one or more other energy sources to create a hybrid system. Although the TRC of some of the technologies in this program area is not favourable today, these future environmental benefits must be considered. As with all new technologies, initial costs are prohibitive to most consumers. However over time market share for these new technologies increases and costs for them come down.

Innovative Technology Measure Name	**TRC Ratio 2010**	**TRC Ratio 2011**
Hydronic Baseboards	1.5	1.6
Hydronic Underfloor Systems	0.8	0.8
Combination Systems	1.3	1.4
Solar Thermal	0.3	0.3
Ground Source Heat Pump	0.2	0.2
Overall Innovative Technology Program Area	0.5	0.5

30.5 For a number of the Innovative Technologies, TGI proposes to provide 25 percent of the total cost of the technology. What is the rationale for the 25 percent? Why should it not be a higher or lower percentage, and what would the impact be if different?

Response:

TGI has operated DSM programs since the 1990's and has found that an incentive level of 50 per cent of the incremental cost is generally effective at getting the desired level of customer participation. However, the initiatives outlined in the Innovative Technologies section of this Application are considered pilot programs, thus the Company felt that setting incentives lower, at 25 per cent of the total cost of hydronic baseboard, under floor piping material or combination systems was more prudent and reasonable. The maximum incentives for these technologies were are also limited; to a maximum of $500 for hydronic baseboard material and $1000 for hydronic under floor piping material and for condensing hot water tanks. In the case of solar thermal and GSHP, the incentives were not set at around 25% of the incremental cost, but rather as a contribution to the overall cost of the technology in question, as the Company feels that fixing incentive amounts for solar thermal and GSHP was the appropriate approach due to the variable cost associated with retrofit installations for solar thermal and drilling cost for GSHP.

As with all EEC programs, TGI will monitor incentive levels and adjust them accordingly while also evaluating the TRC levels to ensure that there is adequate customer uptake and that overall aggregate TRC levels for the EEC portfolio remain above 1.0, consistent with the Commission's EEC Decision.

31.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section C, Tab 3, pp. 229-237

EEC Programs

As stated on page 228: "For TGI in 2010, these new programs add $2.8 million to the amount approved by BCUC Order No. G-36-09. An additional $6.5 million for 2011 is being sought for Interruptible Industrial programs and Innovative Technologies."

31.1 As it relates to the $2.8 million incremental funding for TGI's EEC projects in 2010:

31.1.1 Please describe in detail the specific programs or types of activities for which the $2.8 million additional funding is being sought, and provide relevant timelines, key milestones and completion dates for them.

Response:

More detail regarding the specific types of activity for which additional funding is being sought can be found in Section 3.a.3 on pages 230-234 – Industrial Energy Efficiency Activity – which comprises $435,000 of the incremental $2.8 million requested for EEC funding in 2010, and $1.875 million of the incremental $6.5 million requested for EEC funding in 2011; and in Section 3.a.d and 3.a.e on pages 234-237 – Innovative Technologies, Residential and Small Commercial – which comprises the remaining $2.334 million of the incremental $2.8 million for 2010 and the remaining $4.669 million of the incremental $6.5 million for 2011.

A schedule of upcoming consultations on the Industrial Energy Efficiency activity has been provided in response to BCUC IR 1.29.1. TGI proposes that the Innovative Technologies programs be run as pilots that would subsequently provide data to enable the Company to establish the appropriate timelines, key milestones and completion dates for activity in the Innovative Technologies area. TGI will be in a better position to provide information as to the appropriate timelines, key milestones and completion dates for future programs after the Innovative Technologies pilots outlined in this Application are completed.

31.1.2 Please outline the performance metrics that will be used to assess the social, economic and environmental impacts from incremental funding in 2010 for TGI's customers and the Province of British Columbia.

Response:

TGI proposes that the incremental funding referred to in the Information Request be incorporated into the EEC Portfolio, and that the performance metric for the overall EEC Portfolio would be a Portfolio Total Resource Cost (TRC) test result of 1.0 or greater, consistent with the Commission's Decision dated April 16, 2009 on TGI and TGVI's EEC Application (the "EEC Decision").

A discussion of the various benefit-cost tests that are used to assess EEC initiatives, including the the TRC test, can be found on pages 33 and 34 of the EEC Decision. An alternative to the TRC test is the Societal Test which, as defined by the California Standard Practice Manual, attempts to look at social and environmental impacts from EEC activity. The Commission's determination on this issue, found on page 34 of the EEC Decision, was as follows:

> *"The Commission Panel acknowledges the Societal test as one which addresses a broader spectrum of factors not included in the TRC test. While recognizing that societal factors have significance, the Commission Panel views many of these factors as being rather subjective and difficult to measure. The Commission Panel also takes note of the DSM Regulation which will apply to Terasen as of June 01, 2009 requiring the Commission to use, in addition to any other test it considers appropriate, the TRC test in determining whether a demand-side measure is cost-effective...the Commission Panel does consider the TRC test to be appropriate and adequate for the purposes of this Application and accepts it as such."*

31.2 As it relates to TGI's request for $29.6 million of further EEC funding in 2011 (consisting of $23.1 million for the extension of Commission Order No. G-36-09, plus an additional $6.5 million in new programs):

31.2.1 Please describe in greater detail the specific programs or types of activities for which the $6.5 million new program funding being sought, and provide relevant timelines, key milestones and completion dates for each.

Response:

Please see the response to BCUC IR 1.31.1.1.

31.2.2 Please outline the performance metrics that will be used to assess the social, economic and environmental impacts that the $29.6 million of funding in 2011 will have on TGI's customers and the Province of British Columbia.

Response:

Please see the response to BCUC IR 1.31.1.2.

32.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Economic Assessment Model

Part III, Section C, Tab 3, pp. 268-270 and Appendix C-27

Appendix C-27, presents two samples of TGI's Economic Assessment Model.

32.1 Please provide fully functioning electronic spreadsheets of Tables 1 thru 7 found in Appendix C 27.

Response:

Attachment 32.1 includes two fully functioning electronic spreadsheets, "A" and "B". Spreadsheet "A" contains the economic assessment model for the solar-thermal example of a discrete energy system. This model is based on a *hypothetica*l solar-thermal project as described in Appendix C-27 project. Please note the following changes to Table 3 in the spreadsheet versus that submitted in Appendix C-27:

- Line 3 changed from negative to positive for years 2010-2017 to correct a display error (that did not affect the NPV result).
- Line 6, Title "PV Cash Flow" changed to "NPV Cash Flow" to clarify the terminology.

The revised table is included below:

Table 3 - Cash Flow Summary: Discrete Energy Systems Example

Solar Thermal System; 40-unit residential
Cash Flow Summary ($'000)

Calendar Year	2010 1	2010 2	2011 3	2012 4	2013 5	2014 6	2015 7	2016 8	2017 9
1 Solar Thermal Equipment	43.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2 Terminal Value									
3 Operating & Maintenance	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4 Taxes	0.0	(1.9)	(2.9)	(1.9)	(1.4)	(1.0)	(0.7)	(0.5)	(0.3)
5 Total Cash Flow ('000$)	43.2	(1.8)	(2.9)	(1.9)	(1.3)	(0.9)	(0.6)	(0.4)	(0.3)
Cash Flow Summary (continued)	2018 10	2019 11	2020 12	2021 13	2022 14	2023 15	2024 16	2025 17	
1 Solar Thermal Equipment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
2 Terminal Value								0.0	
3 Operating & Maintenance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	
4 Taxes	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	(0.0)	
5 Total Cash Flow ('000$)	(0.2)	(0.1)	(0.1)	(0.0)	(0.0)	0.0	0.0	0.0	

6 NPV Cash Flow (2010-25)	6.2% 34.3

Spreadsheet "B" contains the economic assessment model for the Dockside Green example of a district energy system. This model was originally filed with the BCUC as part of the Dockside Green CPCN Application. No changes have been made to the model except for the addition of the summary tables contained in the tab "CPCN Summary TGI".

32.2 Please provide details regarding the underlying assumptions used in developing the economic assessment models presented in Table 1 thru 7. For example, please indicate what solar energy levels were used to calculate the amount of energy produced in line 8 of Table 2; what is TGI's weighted average cost of capital (WACC) and what impact does this have on the economic model; what is the assumed interest rate; has the rate of inflation been taken into consideration; and what year dollars do Tables 1, 2, 4 and 5 assume?

Response:

The following assumptions and details underlie the example economic analysis contained in Tables 1 through 7 of Appendix C-27.

Discrete Energy Example (Solar-thermal project) – Tables 1, 2 and 3:

- Capital costs are in "as spent" or 2010 dollars and it is assumed that capital will enter the rate base in July 2010. Annual O&M estimates have been adjusted at 2% per year.
- Depreciation: 15 yrs at 6.67% per year
- Income Tax Rate: 2010 = 28.5%, 2011 = 26.5%, 2012+ = 25.0%
- Interest Rate: 6.72%
- Solar Energy: The solar energy amount input into the economic model was developed using NRCan's RETScreen Clean Energy Project Analysis Software. The solar intensity data used to calculate the amount of energy produced is from weather data from the YVR weather station. Using the weather station's daily solar radiation data works out to be 3.69 kWh/m²/yr.
- TGI WACC: 2010 = 6.09%, 2011 = 6.17%, 2012+ = 6.24% (see also TGI's Response to BCUC IR 1.32.3)
- Allowed ROE: 8.47%
- Inflation: Both O&M and Capital inflation are assumed to be 2% annually.

- Debt to Equity Ratio: Debt - 65%: Equity - 35%

<u>District Energy Example (Dockside Green) – Tables 4, 5, 6 and 7:</u>

- Capital costs are in "as spent" or 2008 dollars and it is assumed that capital will enter the rate base in late 2008.
- Depreciation: 50 years (or 2% per year) beginning in year 8 to reduce the revenue requirements to be recovered from customers during the build-out and market development period, as described in the Dockside Green CPCN.[12]
- Interest Rate: 6.50%
- ROE: 9.62%
- Income Tax Rate: 31%
- WACC: 6.54%
- Inflation:

  On plant operating costs: 2%

  On electricity, natural gas, biomass (after 10 years): 3%

  On future capital: 2.3%

- Debt to Equity Ratio: Debt - 60%: Equity - 40%

---

[12] From the Dockside Green CPCN Application: DGE is proposing to defer depreciation expense for the initial 7 years of operations. This will reduce the revenue requirements to be recovered from customers during the build-out and market development period. Deferring depreciation in this way more equitably allocates costs between generations of customers as the plant has been sized to serve the load associated with customers served at build out. The plant is expected to last for 50 years and, since wear and tear on the plant will be minimal during the initial 7 years, DGE proposes to record depreciation of the plant over a 50 year period beginning in the eighth year of operation. DGE believes that this approach to depreciation also better reflects the actual wear and tear experienced by the utility in the earlier years of system operation relative to full build out after year 7.

32.3 Please confirm whether the PV calculated in line # 6 of Table 3, Appendix C-27, would more accurately be referred to as the net present value (NPV). Please indicate what discount rate was used and whether a risk premium was included in the discount rate.

Response:

Line 6 of Table 3, Appendix C-27 can more accurately be referred to as the net present value. The discount rate is based on TGI's WACC: 2010 (6.09%), 2011 (6.17%), 2012+ (6.24%). The different rates reflect changing income tax rates. The 2010 rate is then adjusted to reflect the mid year (July 2010) timing of the capital or 3.04%. The risk premium implicit in TGI's WACC was included in the discount rate but no additional risk premium was added.

32.4 Please provide details regarding the calculation of Levelized Results for total plant cost and key financial results for both economic models provided in Appendix C-27.

Response:

For the Solar-thermal, discrete energy system example:

A breakdown of the Levelized results contained in Table 2 of Appendix C-27 can be found in Attachment 32.1 A (see 'COS' tab, rows 30-63). The details for the levelized calculation are as follows:

Levelized Revenue Requirement / GJ - The present value (PV) is determined for the revenue requirement and energy produced based on the discount rates listed in IR 32.3. The formula for the levelized revenue requirement per GJ is:

PV Revenue Requirement ($44,734) / PV Energy Produced (4,722 GJ) = Levelized Revenue Requirement ($9.47/GJ).

Levelized Annual Flat Charge ($/Dwelling Unit) - The present value (PV) is determined for the revenue requirement and number of units based on the discount rates listed in IR 32.3. The formula for the levelized annual flat charge is:

PV Revenue Requirement ($44,734) / PV Number of Dwelling Units (411) = Levelized Annual Flat Charge ($109 / Dwelling Unit).

For the Dockside Green District Energy example:

The levelized rates allow DGE to achieve an annualized rate of return over the twenty years equal to its target return over the twenty year period. The initial 2009 on-site rate is based on $26.53 (Table 6 of Appendix C-27) per GJ and is escalated by 3.0% per annum over the 20 year period commencing on January 1, 2009.

32.5 Please provide details regarding the calculation of Levelized tariff (Levelized Revenue Requirement/GJ) for both economic models provided in Appendix C-27.

Response:

Please see the response to BCUC IR 1.32.4 above.

32.6 In addition to revenue requirement, there are several different methods possible for economic analysis of the alternative energy projects. Traditional methods include: payback period, return on investment, discounted cash flow, and cost/benefit ratio. Please discuss the extent to which different methods of economic assessment supplement the analysis provided in Appendix C-27.

Response:

These alternative methods have not been included as supplemental information to the example analysis TGI has provided in Appendix C-27. TGI intends to set the rates for alternative energy customers on a cost of service basis so the solar-thermal example provided in Exhibit C-27 is illustrative of the rates that would be charged if that configuration was to occur as an actual situation. TGI has chosen a revenue requirement or cost of service method of economic analysis as TGI believes it to be the most appropriate mechanism to determine rates for this type of project in establishing rates for which the customer signs a contract. A cost of service test, or revenue requirement, will determine a rate that the customer will pay for the service. If this rate was then entered into a DCF test, such as a main extension test, the Profitability Index would be 1, which therefore confirms that the rates recover all costs and other customers are not being harmed by the addition of the new customers. As such we believe that the cost of service test is the most appropriate test.

A further discussion is below:

- Payback period and ROI - Provides an indication of the profitability of a project as a longer payback, or lower ROI, will be less economic than a shorter payback. However, payback period and ROI analysis will not generate a rate that can be charged to the customer. Further, as the customer does not own the equipment, payback period is only relevant to TGI. Further, as a rate must be generated and will be based on a set depreciation rate and regulated return on rate base, the payback period and ROI would be similar between alternative energy projects once a rate has been determined. Note that in each project agreement, TGI would require clauses in the agreement that allow it to change the return on rate base to be adjusted to reflect approved changes in ROE and debt costs and subsequently flow through these changes into rates.

- Discounted Cash Flow – the TGI and TGVI MX tests are good examples of a DCF test. This test requires a rate to be in place prior to being used. For this reason, a DCF/MX test is an appropriate test to use for Main Extensions and for NGV Compression Service as in both of these examples a rate is already available to be used to determine revenue over the life of the test. For the other alternative energy systems, a rate will need to be determined in order for a DCF test to be performed. Performing a DCF test after determining a levelized rate under a COS model would be redundant.
- Cost/Benefit Analysis – is similar to both the DCF test and ROI/Payback analysis in that the incremental and ongoing costs for the product and service are compared to the benefits (provision of heat and the rate paid for such a service). This is also similar to a profitability index or revenue to cost ratio type of test. However, similar to both DCF tests and ROI/Payback period, a rate is required to perform a Cost/Benefit analysis. Without a rate, one can not perform this analysis. The COS/revenue requirement test will generate a rate that when levelized will result in a one to one revenue to cost ratio or cost and benefit results that are equal.

TGI expects the determining factor for pursuing a particular project will continue to be the customer's willingness to purchase alternative energy services through a long-term contractual arrangement at a specified rate (as generated by the COS test). In other words, the customers of these alternative energy projects will be paying for the costs of those services in their rates. In the utility context, the use of other economic analysis methods such as the DCF test and cost/benefit analysis is frequently employed to confirm whether new customers are paying an appropriate amount for the service received and are not being unduly subsidized by existing customers. Since the rates for alternative energy customers will be based on their cost of service the concern with regard to cross-subsidization by natural gas customers will be minimal.

It is important to note that once a rate is determined and a customer has signed a contract agreeing to pay, the customer has implicitly agreed that the rate is appropriate. It is also important to note that experience on alternative energy projects and proposals by the Terasen Utilities to date indicates that a customer's decision is not always based on the lowest cost alternative. TGI expects that a certain portion of customers, both commercial and residential, are willing to pay a premium for low carbon, alternative energy solutions provided by a trusted and well established utility, for a range of reasons potentially including reducing their carbon footprint and resource impact, reducing potential future carbon costs, competitive positioning and personal preference (customers of Dockside Green are an example). In many cases, TGI will not know the customer's reasons for adopting an alternative energy system. For this reason, and additional reasons as stated above, the suggested methods of evaluation may not have the same relevance as they have had in the past.

33.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Economic Assessment Model

Part III, Section C, Tab 3 (p.269) and Appendix C-27

33.1 Since Dockside Green is a standalone utility project, please explain why this is a suitable comparison for TGI considering that district energy should be operated as part of a natural gas utility?

Response:

The Dockside Green economic analysis results in Appendix C-27 are included as an example of an economic assessment model and not as a comparison to any other utility. Whether standalone or operated within another utility, Dockside Green and similar district energy systems are subject to regulation by the Commission (please see also TGI's response to BCUC IR No. 1.24.3). The *Utilities Commission Act* does not require Terasen Gas to be strictly a natural gas utility, nor does it restrict any utility from undertaking other regulated activities outside its traditional business activities.[13]

Since Dockside Green is an example of an approved district energy system and economic model, TGI believes it is a relevant economic model for this type of alternative energy system. TGI believes that using an existing and approved example is the best way to demonstrate such an approach, particularly since each system is unique and the possible variations of energy sources and model inputs are numerous. TGI recognizes that some of the inputs, such as the company's cost of capital and return on equity, would reflect TGI's capital structure and other regulatory requirements if undertaken by TGI.

[13] There are circumstances that would restrict a utility's ability to offer a new service such as, for example, where another utility has franchise rights to provide that service in a particular area.

33.2 Please confirm that a separate economic assessment is proposed to be completed for EACH customer requesting service under an alternative energy solution. In essence, each customer could have a separate cost of service calculation and hence a separate contribution calculation?

Response:

Confirmed. Yes, each customer or the group of customers for a particular alternative energy project will have a separate cost of service, rate and if applicable contribution calculation, thus a separate rate category or sub-category. Preparing a separate rate category or subcategory, and accounting for cost of service of an alternative energy project via the proposed economic tests, protects customers that are not being served by the alternative energy project from being unduly impacted by costs associated with the project and leads to just and reasonable rates for both gas and alternative energy customers. Alternative energy customers must agree by contract to the service costs of the project.

At some point in the future, TGI may examine the potential to create postage stamp rates for alternative energy projects for categories of similar alternative energy systems. TGI does not expect that such a study of rates for alternative energy systems could take place until many more projects are completed and operating. For this reason, such a study would not take place until sometime after the 2010-11 Revenue Requirement period.

33.3 Does TGI forecast any issues with charging a levelized service rate for alternative energy services (for example, unexpected long-term O&M costs, capital replacement requirements) given that the technology in this area is generally untested?

Response:

TGI is aware that potential issues could arise in regard to the levelized rate that is charged to customers in relation to a specific alternative energy project. TGI intends to address such issues through appropriate provisions in the energy purchase or service agreement with the customer. For example, the energy purchase contract would allow for the opportunity to revisit and adjust the levelized service rate in the event that unforeseen capital expenditures cannot be recovered at the existing levelized service rate.

TGI disagrees with the characterization of this technology as "generally untested". Both discrete and district energy systems can use technology that, while new and innovative, is not untested. Geo-exchange and solar-thermal energy technologies are examples of known and tested technologies that can be employed in both discrete and district energy systems. Further, it should be noted that in its reconsideration of the Dockside Green CPCN decision, the

Commission agreed with Dockside Green Energy that employing such technologies is consistent with BC energy policy and that within the regulated utility environment the Commission has authority to review any extraordinary incremental costs for prudence in considering whether such costs can be recovered through customer rates. The Commission was thus satisfied with this level of protection of the interests of ratepayers and suggested that using a levelized rate methodology would mute the impact of such incremental costs.

As an aside, the use of a levelized rate approach is expected to be the usual approach for rate setting in the alternative energy projects, but it may not be employed in all circumstances. The customer may have a preference for a different rate structure that TGI also finds acceptable and that appropriately recovers the cost of service for the project. Further, a levelized rate approach may also have varying features such as whether the rate is subject to an inflation allowance or not, or whether the rate is a flat monthly charge or an energy-based charge or combination thereof. The uniqueness of individual alternative energy projects is expected to give rise to some variations in the rate structures to accommodate the particular circumstances. However, the underlying premise is that the cost of service for a project will be recovered from customers of that project.

33.4 Does the economic assessment model take into account the energy savings related to the displacement of conventional energy? Since the conventional energy equipment is not removed, please confirm that the customer would still be held responsible for the fixed costs associated in their tariff relating to this equipment.

Response:

There is no specified credit for displaced conventional energy use included within the economic model. Rather the model produces a service rate which can then be compared against other energy solution options including conventional energy or combined alternative and conventional energy solutions. In some cases, such as with solar thermal water heating, the customer(s) will be both natural gas customers and alternative energy customers, since only a portion of the natural gas load will be displaced. In this case the customer will pay both natural gas rates according to the prevailing natural gas tariff and alternative energy rates specific to the solar thermal installation.

In considering conventional energy equipment, a number of different situations can exist and care must be taken to address the remaining conventional equipment fixed costs according to that specific situation. First, in cases of new development where there is no existing equipment, the alternative and conventional energy equipment that might be part of the project could be owned by TGI or by the customer. If owned by TGI, the costs for that equipment will be included in the cost of service and become part of the customer rates for that project. If owned by the customer, the customer would be responsible for the fixed costs associated with the equipment.

In retrofit situations where conventional energy equipment is already in place, the conventional equipment could be addressed in two different ways. The existing equipment could be purchased by Terasen Gas, in which case the cost of that equipment would be included in the cost of service for that project and would be come part of the customer rates for the project. Alternatively, the customer(s) could retain ownership of that equipment and continue paying the fixed or capital costs associated with it. If the customer(s) retains ownership, the fixed costs would not be included in the cost of service, incorporated in rates, and would be paid by the owner. If the conventional equipment is no longer required, whoever retains ownership could remove and sell it for any salvage value it might have. In all cases, the customer(s) of the new alternative energy system will ultimately pay any outstanding fixed costs remaining on the conventional equipment that existed prior to alternative energy development in a retrofit situation.

34.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section C, Tab 3, page 237-270

Natural Gas Vehicles ("NGV") Rate Offerings

34.1 Why is it necessary for TGI to own the compression and refueling service when this function could be performed by Terasen Energy Services or some other non-regulated business?

Response:

TGI believes that it is appropriate for TGI to own and compression and refuelling service for several reasons.

First, compression and refuelling service equipment is a natural extension of the natural gas service and consistent with service already provided to natural gas customers by TGI under Rate Schedule 6. The compression and refuelling equipment is similar to the equipment required for the natural gas distribution system and TGI possesses the skills and knowledge to operate and maintain such equipment. Further, we believe that TGI providing compression service is consistent with and in the spirit of Commission Order No. C-22-06 (see also BCUC IR 1.24.4). As such it is natural for customers to expect TGI to deliver such a service.

Second, TGI believes that the customer can take comfort in the fact that compression service provided by a major utility like TGI would be proactively regulated by the BCUC and that provides them with the security of price transparency, fair, stable rates of return and price increases. Further, TGI already has a Compression Rate (Rate Schedule 6A), approved by the Commission, and as such the provision of compression as a regulated offering is not new.

Third, all TGI customers will benefit from the addition of load from regulated compression and refuelling service through lower delivery costs. The commitment to stay in the BC market because of this added incentive, should allow for a higher market capture rate because of customer confidence in TGI and the BCUC.

Fourth, through TGI's experience with NGV and demonstration programs we are in a position to assist customers in the selection of appropriate compression and dispensing systems. This will result in a compression and refuelling service that meets customer needs. TGI believes that with its current NGV service, it is in the best position to enhance service in the transportation sector by offering a comprehensive NGV service which includes a complementary compression and refuelling service.

TGI observes that approval of TGI's proposal does not prevent other companies from providing the service to end use customers.

34.2 How does TGI intend to meet the other potential obstacles such as fleet conversion costs and the limited number of OEM vehicles?

Response:

TGI intends to meet the other potential obstacles by providing grants, and ensuring that all available funding opportunities are used. TGI will also provide customers with a detailed value proposition which will clearly indicate how long it will take to pay back incremental costs associated with conversion to natural gas.

TGI will continue to offer grants under Rate Schedule 6 – Natural Gas Vehicle Service and the proposed Rate Schedule 26 – Natural Gas Vehicle Transportation Service. The grants will be available to assist customers with conversion costs.

TGI's sales efforts will focus on vehicle markets where OEM equipment is available or where reliable conversion technology exists. A major focus will be applications that can be serviced with vehicles equipped with the Cummins ISL G series engine (280 to 350 HP range OEM engine specifically designed for natural gas). These engines are well suited for return to base fleet applications such as waste collection, transit bus fleets and moderate duty trucking operations. TGI has also been evaluating conversion technology suitable for the Ford E and F series vehicles commonly used in fleet operations, and forklift applications as well. Such conversions are supplied in BC (Eco Fuel Systems/Techno-Carb/Prins). We also note that Ford has entered into a Qualified Vehicle Modifier arrangement with BAF Technologies to supply AT&T with 8,000 natural gas vehicles for fleet operations signalling renewed interest in this market. We have also observed a rapid growth in NGV OEM equipment in international markets (i.e. General Motors alone offers 18 NGV models in international markets). TGI's knowledge of the OEM market and conversion technology allows the Company to assist customers in assessing the NGV value proposition and help overcome the obstacles noted above.

34.3 Who are the remaining OEM's in the market supplying vehicles? Why have the majority of the OEMs exited the natural gas market?

Response:

The majority of OEM's have not exited the marketplace, rather a few light duty OEM suppliers exited the North America marketplace, but other OEM suppliers in both Light Duty and Mid and

Heavy Duty vehicle markets have entered the marketplace. Further, depending upon the vehicle sector, additional conversion options are now available. The OEM market suppliers are growing and are listed below:

Mid and Heavy Duty Vehicle Market – OEM suppliers of NGV's for the North American market include Kenworth, Mack, Peterbuilt, Sterling and Freightliner, with engines supplied by Vancouver's Westport Innovations and Cummins/Westport. The market for NGV's in North American heavy duty operations is growing rapidly, particularly in waste collection and transit applications. TGI plans on focusing sales efforts on this market.

Light Duty Market – The NGV market is growing rapidly internationally with many major OEM's offering NG vehicles. (i.e. Honda, GM, Fiat, Toyota, Ford etc.). Light duty OEM offerings in North America have been less successful because conventional fuels have been more convenient – especially for non-fleet operations (lack of public natural gas infrastructure), environmental benefits of operating on cleaner fuels were undervalued (externalities), and demand for large numbers of vehicles was not sufficient to justify OEM production line runs. In North America Honda offers the "Civic GX" as an OEM vehicle. This vehicle is not offered in Canada primarily because the market for NGV is mainly fleet and Honda believes that the fleet market would lower their resale value. Toyota also has a NGV Corrolla that is now available in California and may be available in Canada. Ford is presently entering into an agreement to have BAF Technologies modify 8,000 vehicles for AT&T under a Qualified Vehicle Modifier relationship while not directly OEM, from a customer standpoint the relationship is similar to OEM.

34.4 Has TGI established whether a market actually exists through letters of commitment, memorandums of understanding etc. from potential customers?

Response:

Yes, TGI has established that a market exists from potential customers. This is demonstrated through actual customer additions as well as collaboration with equipment suppliers, shippers and carriers and potential customers. Through this business model, TGI is successfully developing the NGV market and is currently evaluating a number of customer projects:

- Conversion of a 25 truck waste hauling fleet to LNG operation.
- Discussions are also underway with municipal trash collection operations to convert the fleets to natural gas. The City of Burnaby has begun experiments with a natural gas fuelled recycling truck and has converted three F -150 pickup trucks to natural gas operation.

- The School District in Kelowna has purchased two natural gas powered school buses and is currently evaluating conversion of their vans and pick up trucks.
- The City of Kelowna has purchased a Ford E-550 dump truck which is being converted to natural gas and is currently evaluating conversion of their vans and pick up trucks.
- EuroAsia Transload has converted 70 lift trucks from propane to natural gas and currently proposals have also been issued to other companies for more materials handling equipment applications.

These discussions have not progressed to the point of customer commitment to date, but TGI feels that there is significant interest.

34.5 Please provide a business case over a 10 year forecast period that would be applied if a non-regulated business assumed the project.

<u>Response:</u>

TGI has not prepared a business case to offer the compression and refueling service through a non-regulated business. TGI believes the compression and refueling service complements the existing regulated NGV delivery service and proposes to offer a complete and complementary NGV Compression and Refuelling service through the regulated business. TGI has not considered offering compression and refuelling service as a non-regulated business for the following reasons:

- TGI has the expertise to advise and offer a complete NGV service.
- Regulation by the Commission provides comfort to customers that over the long term rates will be transparent, fair and reasonable.
- TGI existing customers will benefit by NGV being in the utility through increasing the efficiency of the natural gas distribution system and mitigating upward rate pressure as a result of declining use rates (see also BCUC IR 1.57.1)

Please also see the response to BCUC IR 1.34.1.

34.6 Have any market studies been carried out to determine whether "return to home fleets", school buses or forklifts will support the business case for NGV?

Response:

We have completed our own high level study and business plan, and believe that a large market exists that will support the case for NGV. Our sales model recognizes that each application is different and has different factors that contribute to the overall feasibility. We therefore conduct an analysis on each potential customer recognizing that customer's unique business requirements and a specific business case evaluation is produced ensuring that customers are aware of natural gas benefits relating to emissions and economics.

One example is a potential conversion of 40 lift truck operating at a customer warehouse and shipping location at a port facility. The business case evaluated the cost of operating the fleet on natural gas versus propane. The cost comparison looked at the customer's actual expenses over the previous 17 month period operating on propane versus what the cost would have been operating on natural gas. The 17 month period was chosen by the customer as they had accurate cost data for that period. The timing of the assessment was appropriate because of the wide commodity price fluctuations experienced between January 2008 and May 2009.

The cost of operating on natural gas was calculated using the published rates (Rate Schedule 6 and Rate Schedule 23, and Sumas Monthly Index Pricing) during this time frame and adding in a $5/GJ tariff for compression and dispensing service.

The business case presented the following customer benefits:

- Savings over the 17 month period would have been $155,973 assuming the customer was buying gas at Sumas Monthly Index and delivery under Rate Schedule 23. (Savings of 23% versus propane)
- Savings over the 17 month period would have been $84,683 assuming the customer was buying gas under Rate Schedule 6. (Savings of 12% versus propane) (Note: the incentive grants offered under Rate Schedule 6 were not factored into the savings calculation)
- In both scenarios, the customer investment required to convert the fleet would be recovered in less than two years.

A longer term assessment was also conducted which showed that the cost of natural gas has been substantially below propane for the past 6 years. On average the cost of operating on natural gas was 32.8% lower than operating on propane (Source data www.mjervin.com) which confirmed the value proposition. Lastly, the Westport White Paper, as attached as Appendix G-2 to the Application demonstrates that the business case is there for return to home NGV fleet vehicles.

34.7 Please describe the BC Gas (TGI) historical experience with the NGV program over the years from the original justification (based on increasing the system load factor) that approved acquiring refueling assets to the final outcome which was a disposal of those assets to an independent third party at a loss.

Response:

The original NGV program was approved for Inland Natural Gas Co. Ltd. (a predecessor company) in 1985 under Rate Schedule 14 which offered three options: Option A – Fleet Vehicle Service, Option B – General Vehicle Service, and Option C – Compression Dispensing Service. During the mid-1980's and 1990's the Company installed and owned compression and dispensing facilities at many sites.

The company focused on public refuelling stations and the source of the load was primarily vehicle conversions. At its peak in 1997 BC Gas served 51 public stations and with an annual load of 350,000 GJ.

In the late 1990's, there was a market shift from vehicle conversions to factory built natural gas engines or Original Equipment Manufacturers ("OEM") in which Ford was the leader. Management determined that the compression and dispensing business did not fit into the core operations because of the significant customer management efforts required. Management made a decision to turn the compression and dispensing business over to a non-regulated business. A significant portion of the compression and refueling equipment was sold off to Westport Innovations and Clean Energy (renamed efuels). The British Columbia load started to drop off because the focus was on OEM rather than conversion and lack of government incentives forced efuels to expand into other markets like California where the US Federal Government heavily subsidized the NGV market.

In November 2005, Terasen Inc. after being acquired by Kinder Morgan sold all remaining interest in efuels to Clean Energy. Subsequently Clean Energy has focused its resources in markets such as California where it could maximize value by utilizing extensive government grants to stimulate NGV growth. Terasen Gas continues to offer NGV Service and grants through Rate Schedule 6.

In response to the BC Energy Plan and specifically in support of meeting greenhouse gas reduction targets, the Company proposes to promote natural gas in the transportation sector. The Company will focus on return to home fleets and grow the NGV market by proposing a NGV Transportation Service (T-Service) and a NGV Compression and Refuelling Services to complement the existing NGV service. We believe that we will be successful as a result of our market development focus, the changes in the natural gas vehicle marketplace, newly evolved and supportive BC energy policy and the evolution of and significant developments in NGV technology.

35.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Biogas

Part III, Section C, Tab 3 page 249-250

35.1 If TGI were allowed to expand its core business of providing safe, efficient distribution and transmission service at low cost and enter into areas of alternate energy which are high cost, how will the customers see a benefit in lower natural gas rates?

Response:

The Application page reference in the question above is in regards to biogas costs, however the question also speaks to alternative energy. In response to this question TGI first broadly addresses alternative energy, and then in the last paragraph addresses biogas specifically.

For clarity, TGI is not seeking approval to expand its core business into areas of alternative energy, but rather is seeking approval of appropriate economic tests to address cost allocation issues so that rates for gas customers and alternative energy solutions are just and reasonable. As noted in response to BCUC IR 1.24.3, the *Utilities Commission Act* does not prohibit TGI from providing alternative energy solutions, nor does it give the Commission jurisdiction to prohibit this activity. The proposed economic tests are designed to ensure that alternative energy customers will cover the costs of providing that service so that gas customers are not unduly affected by the addition of new alternative energy customers. TGI believes that the resulting rates for gas and alternative energy customers will be just and reasonable.

TGI disagrees with the assumption in the question that alternative energy is high cost. Alternative energy – solar, geothermal and district energy - is competing with traditional energy forms and so it must deliver value to customers for the product or service provided or it will not succeed. In many cases alternative energy provides a different product or service than traditional energy. For example, in the case of district energy systems the customers are receiving heat energy directly and do not need to have their own furnace or boiler to convert gas to heat energy. The customer avoids the capital and maintenance cost of needing to have their own thermal conversion equipment. Alternative energy may also deliver improved energy efficiency or green benefits that customers value. TGI believes that if full life-cycle costs of alternative energy systems are considered, as well as the nature of the product or service delivered and the benefits derived from that service, then the assertion that alternative energy is high cost is unwarranted. Finally, alternative energy solutions may help customer to avoid future carbon costs increases that may materialize overtime to help achieve GHG reduction targets.

Charging just and reasonable rates for alternative energy solutions under the economic tests proposed can confer a benefit on existing and future gas customers by mitigating the delivery rate increases arising from declining throughput as existing customers become more energy efficient or discontinue their natural gas service, and natural gas captures a declining share of new energy load. As alternative energy load grows it will absorb an increasing share of the common costs of the utility and leave the delivery rates of gas customers lower than they would otherwise be. TGI does not anticipate that adding alternative energy solutions into its portfolio of offerings will result in lower natural gas delivery rates in absolute terms, but rather that the delivery rate increases from declining throughput will be mitigated in part (See also BCUC IR 1. 19.1).

For biogas projects, TGI is embarking on this initiative to be proactive in supporting the Government's Energy Objectives, provincial climate change initiatives and the policy actions of the 2007 Energy Plan. TGI believes that a market exists for biomethane. As stated in the Application, TGI is pursuing in parallel the development of a "green gas" market offering which when developed and in operation will see the costs of biogas and biogas upgrading being borne by the purchasers of "green gas". The option to purchase carbon-neutral or green gas will add value to natural gas customers by becoming another product choice and by serving provincial climate change and energy plan objectives. During the pilot phase while the biogas potential is being developed, natural gas rates will be modestly higher however the Company considers the extra costs to be warranted in view of the longer term benefits to be achieved.

35.2 Why should TGI be allowed to purchase gas at $15/GJ when there is a significant amount of natural gas available to TGI below $5.00/GJ?

Response:

As stated in the Application TGI is seeking to implement a biogas and biogas upgrading pilot program in order to gain knowledge and experience with biogas upgrading technology and with the issues associated with taking upgraded biomethane into its distribution system and to meet provincial energy policy targets. TGI is seeking to begin the development of a carbon-neutral (and possibly carbon-negative) gas resource that can ultimately be a substitute for traditional natural gas. This pilot program is being undertaken in support of the provincial climate change mitigation initiatives, greenhouse gas reduction targets, the Government's Energy Objectives, the BC Bioenergy Strategy and the 2007 BC Energy Plan. TGI believes these policies and objectives are relevant to the Commission's determination of this Application.

It is important to note that concurrent with this Application, TGI is developing a "green gas" offering as noted on page 252 of the Application. It is our intention that the "green gas" offering sold to customer would recover all the costs of acquiring the green gas. If end use customers are willing to pay for "green gas" then the actual price that TGI pays for the biomethane is of less concern to existing natural gas customers who choose not take the "green gas" offering. However, in the short term, there would be limited costs paid for by existing customers, through the MCRA. To lessen this impact, TGI has proposed both a price and volume cap. In other words, the limited additional costs of the biogas pilot phase being paid for by TGI's broader customer base is a temporary measure until the green gas offering becomes available.

With respect to the proposed price cap of $15/GJ, using current market pricing for traditional natural gas is not an appropriate comparison for the pricing of upgraded biomethane. Biomethane is effectively a different product with different attributes than traditional natural gas. First, the biogas product is not subject to the carbon tax that increases to $1.50 per GJ by 2012. In a recent report prepared by the National Round Table on the Environment and the Economy called "Achieving 2050: A Carbon Pricing Policy for Canada" it states on page 30 of the report:

> "A first element of our carbon pricing policy is to identify the carbon prices required to meet the government's 2020 and 2050 targets. Our research suggests that economy-wide carbon prices well need to rise to $100 per tonne of CO2e by 2020 (~$5.00 per GJ) and upward of $300 per tonne of CO2e by 2050 (~$15.00 per GJ)."

Thus, if the cost of carbon compliance trends to these levels after 2012, the difference between the biogas cap prices of $15.00 per GJ and the current natural gas prices of $5.00 per GJ would be substantially eroded.

Secondly, the biogas cap price of $15.00 per GJ is tied to a long-term, fixed-price contract, which is different than natural gas commodities market which is subject to market volatility. For example, in July 2008 the Sumas monthly gas price was $11.69/US MMBTU. If prices were in this range, the difference between the proposed price for biogas and the market rate would drop significantly.

In addition to the strong alignment with provincial policy imperatives described above, there are two other considerations as to why TGI believes the biogas pilot phase and the pricing proposed is appropriate:

- The limit on the proposed annual volumes to be eligible for the biogas pilot phase is 0.5 PJ per year, which is a relatively modest amount at less than 0.5% of TGI's core market throughput. The cost exposure is limited by this volume cap.
- By using the BC Hydro RIB Step 2 rate in the derivation of the $15/GJ cap for upgraded biomethane, the maximum price was established with reference to BC-based energy supply contract pricing that has been approved by the Commission. The RIB Step 2 rate was derived from the average plant gate price for volumes from BC Hydro's 2006 Call for Power. It should be noted that since the average call price was used meaning that some of the contracts approved in the 2006 Call for Power were priced above the

average. In other words, the $15/GJ price cap is below recently approved energy supply contract pricing in BC.

35.3 Since TGI can set the specifications for the pipeline quality gas they purchase why is it necessary to require a greater understanding of the full cycle of upgrading and injection of biomethane into the TGI system?

Response:

TGI's reasons for stating that it is necessary to gain experience with biogas upgrading through a full cycle are set out on Pages 251 and 252 of the Application. Biogas and biogas upgrading are new areas of business involving new technologies, multiple possible supply sources and different parties and stakeholders interested in the advancement of the industry. The qualities and delivery profile of the upgraded biomethane are not known with certainty and may vary from one project to the next. Biomethane quality is only one of several matters that will be studied during the pilot. In addition to gaining experience in biogas upgrading, TGI must acquire technical experience in the areas of biomethane measurement, quality monitoring and receiving biomethane into the gas distribution system. Acquiring experience and knowledge in all these areas is necessary and valuable in order to facilitate the effective development of biomethane as a new renewable supply resource in BC.

Moreover, with respect to the issue of biomethane quality, TGI does not believe it is prudent to simply rely on contractual specifications to ensure a reliable, high quality biomethane supply. The third parties that are likely to be involved in raw biogas generation and capture are not parties that will have expertise and experience in gas distribution, measurement or quality monitoring nor in many instances are they interested in gaining such expertise and experience. In the natural gas business gas producers, gas plant operators and transmission companies all have the production and delivery of natural gas as the central focus of their business. Biogas, on the other hand, will be a by-product from wastewater treatment plants, landfills and agricultural contexts for which the primary business interest of the operation is unlikely to be the production of biogas. TGI intends to take the necessary precautions and to have appropriate terms and conditions in its biogas supply contracts to protect its interests and the interests of its customers, but, if small scale biogas producers are expected to have the same level of technical and professional expertise and to adhere to the same contractual terms and conditions as natural gas producers, processors and midstream operators, these requirements may prove to be too onerous and place unnecessary roadblocks in the development of a fledgling industry. It should be noted that even in the case of the natural gas business where TGI deals with large sophisticated commercial enterprises as counterparties there are instances where the gas deliveries do not meet contractual specifications. For biomethane TGI believes it has a critical role in promoting the safe and efficient development of the industry and does not consider it appropriate to leave this in the hands of new inexperienced operators.

35.4 Why does the pilot phase have to be undertaken before the "green" gas offering as a market study would determine if demand for this alternative energy supply actually exists?

Response:

As indicated in the Application and in the response to BCUC IR 1.35.1, the pilot serves multiple purposes, and is not limited to permitting a market assessment. For instance, TGI believes that it must develop a biomethane resource portfolio of reasonable size in order to have enough biomethane to supply interested customers. In addition, TGI needs experience with the costs of developing biomethane supplies and a diversity of biomethane supply sources in order to inform the price it must charge. A diversity of supply will also help to stabilize the price of biomethane.

TGI has already begun development of a “green gas” offering and is currently meeting with customers to understand their desire for such a product. TGI believes that a market review will demonstrate that a market does exist for a “green” gas offering. This is based on the knowledge that the general public in BC displays a strong environmental ethic and also on the experience with “green offering” initiatives in other jurisdictions.

In short, TGI believes that the proposed phased approach, involving a limited pilot and leading to a “green” gas offering that is already in development is prudent and in the interest of customers.

However, even before the “green” gas offering is made available and sold to interested customers, TGI’s natural gas customers will also receive benefits from the development of biomethane supply sources by virtue of the public good achieved from GHG emission reductions and participation in the development of a new renewable source of energy in the province, and through the contribution to achieving provincial energy policy and climate change objectives.

On page 257 TGI states that: "We will also apply to the Commission to move out of the ... if a targeted "green" gas market offering is adequately developed and is ready for implementation"

35.5 When will the TGI customer base be surveyed to determine if there is interest in a "green" market offering?

Response:

TGI has already begun planning for initial market research and customer surveys related to the "green gas" offering. TGI intends to carry out the development of the green gas market offering as quickly as possible but it may not be practical to proceed to full implementation until several biogas upgrading facilities and/or biomethane supply contracts are in place and operating. Sufficient supply will need to be available to make an offering worthwhile and to establish a biomethane cost base from an adequate pool of resources. The level of demand for biomethane will be affected by the price that has to be paid. Follow-up customer research will be necessary in later stages of developing the green gas market offering to assist in a successful product launch. TGI will also be seeking to develop green gas marketing arrangements with specific customers. If an opportunity arises before the green gas market offering is implemented where TGI finds a customer or customers interested in obtaining biomethane or a "green" gas product on an expedited timeline and on acceptable terms and pricing, TGI will bring forward a separate application for that specific situation.

36.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Part III, Section, Tab 5

Financial Treatment of Pilot Phase, page 259-261

36.1 TGI indicates that the company's investment in biogas upgrading equipment as well as O&M and other costs will be tracked in a separate account. Should not all costs including TGI staff time be tracked and assigned to this separate account for these projects as well?

Response:

There are two aspects to the staff time used for the development of biogas projects and supply, which will be discussed separately.

The first is identification of potential projects, their evaluation and investigations required to determine if the project or supply should be undertaken or acquired. These costs are marketing and sales costs related to providing customers with the service they request (which include both conventional gas and alternative energy) and, in addition, providing energy efficiency education and information. As such, these costs are no different than any other sales, marketing, and development costs that are spread across all customers and as such these costs should not be segregated. Also see TGI's response to BCUC IR 1.19.1.

The second aspect is project development. Once a specific biogas project has been identified and has received spending approval from TGI's capital planning committee (the Utility Operating Committee Capital Group) staff resources will be assigned to the project and tracked in the same way that other TGI projects are tracked. The tracking of these costs will allow them to be included in the project costs which, during the pilot phase, TGI proposes to include in the midstream cost recovery mechanism. If the pilot phase of TGI's biogas initiative were to indicate that fewer biogas projects are available than initial indications suggest, these staff resources would be directed to other TGI projects or initiatives.

36.2 Why is it necessary to build a pilot project when there are similar projects that already have been studied in different parts of the world?

Response:

Although biogas has successfully been captured and used to generate electricity or fire boilers for heating applications in numerous projects around the world, the upgrading of biogas to pipeline quality for injection into the distribution system is somewhat newer and has seen fewer applications within North America. While biogas upgrading for pipeline injection has been undertaken in enough circumstances to give TGI confidence that the practice can be successfully done, differences in pipeline quality standards, project specifics and cost implications of each individual project and location are sufficient to require TGI's own investigations into the viability of biogas for pipeline injection here in BC.

The pilot phase will help to establish whether or not an appropriate balance can be found (within a range of potential prices) between the price paid for upgraded biogas and the ability to incent developers to undertake biogas projects. An important aspect in the study of biogas projects is the ability of TGI to acquire a sufficient supply to create a green gas or carbon neutral market offering without paying more than a green electricity project equivalent using the same resource. The pilot phase will also improve the knowledge base of TGI staff in the planning, design and operation of upgrading equipment and potential equipment variations between upgrading projects. These initiatives are best undertaken as part of a pilot project or phase that examines project viability in circumstances specific to BC and the markets in which we operate.

The capture of useful bioenergy that would otherwise be wasted through biogas upgrading is of sufficient interest to the Province that it is referenced in the Bioenergy Strategy and two biogas upgrading projects were recipients of grants from the Innovative Clean Energy (ICE) Fund in the first round of grant awards. The pilot phase of TGI's biogas initiative is needed to advance early projects such as these in BC to kick start the development of biogas upgrading locally. A pilot phase is a logical initial stage in the sequential development of a new green supply resource and market.

36.3 How large is the "alternate energy" portfolio expected to be?

Response:

The question preamble is making reference to the Biogas portion of Section C, Tab 3; therefore, the response will discuss biogas as the alternative energy for which the question is intended.

While some studies have been done on total potential for biogas in BC, there are no definitive inventories available that can confirm the amount of biogas potential that exists throughout BC.

BC's Bioenergy Strategy suggests that between municipal solid waste and agricultural biomass resources, the energy potential of BC's biomass (non-wood) is approximately 67 Petajoules (PJs) annually. Some of the municipal solid waste could be considered appropriate for anaerobic digestion if it is separated from other solid waste, which is not a common practice as yet in BC. Much of the agricultural biomass, if utilized for energy production, may be directed to production of liquid fuels rather than biogas.

Statistics provided by the Ministry of Agriculture and Lands suggests that the biogas potential from readily available agricultural residues in BC is 81 million m3 annually, or the equivalent of heating and electricity for 40,000 homes. This does not include the potential to grow energy crops on marginal lands and may not include all of the fats, oils and greases from food processing industries and restaurants in the province. A feasibility study completed for the BC Bioproducts Association (now the Bioproducts and Bioenergy Sector of Life Sciences BC) focusing on the Fraser Valley identified approximately 2.5 PJ of potential biogas energy from readily available organic waste sources.

Terasen Gas received positive feedback, including 9 potential project submissions, as part of its Request for Expressions of Interest for Biogas projects and continues to receive inquiries and project proposals. This positive feedback and the Province-wide potential identified above must be balanced, however, against the realization that it will be difficult to recover all organic wastes for potential energy production. Based on our learnings from the Request for Expressions of Interest process, we believe that a reasonable range of 1.5 to 3.0 PJ of renewable natural gas produced in BC and injected into Terasen pipelines is possible. These are very preliminary estimates, however, and TGI cannot say at this time if this amount will be reached or how long it will take to fully develop the potential biogas resource in BC.

36.4 Will all the alternate energy projects be interruptible supply?

Response:

Referring specifically to biogas, which is only one type of the alternate energy initiatives that TGI is pursuing, it would be reasonable at this early stage of development to consider the biogas projects as an interruptible supply source. TGI will be seeking firm contract minimum amounts of supply with biogas producers but the proportion of the total supply that is firm will vary from project to project. It is expected that biogas production will fluctuate within a reasonable range around the average energy production levels. However, this will not be confirmed until TGI has some operating experience with biogas projects of varying types. Amounts that TGI can accept above the minimum firm amount would be considered interruptible supply. During the pilot phase, biogas supply amounts are expected to be small enough to have little or no impact on TGI's gas supply portfolio. TGI expects that as more biogas producers come on line beyond the pilot phase, the diversity of projects supplying biogas will result in a more secure supply of biogas backed up by conventional natural gas service. TGI will protect itself and its customers from lost biogas resources if producers do not meet their minimum volume commitments through specific provisions in the biogas purchase agreements. TGI expects that the pilot phase of biogas projects should provide additional information into how firm these resources are, both above and below the minimum or firm production amount.

37.0 Reference: Energy Efficiency and Conservation and Alternative Energy Solutions

Integrated Energy Solutions: Geo-exchange, Solar Thermal, and District Energy Systems, Part III, Section, Tab 5

37.1 TGI intends to provide financing for Alternative Energy Services (page 265). Why should TGI provide this financing and on what terms does TGI intend to provide financial support to third party projects?

Response:

Financing would be the last option offered to customers since TGI would rather own and operate the equipment than simply provide financing for a project. However, in the case that the only option a customer wishes to pursue is a financing option, TGI would come to an agreement with the customer on the structure of the financing after which the contractual agreement would be submitted to the Commission for approval at that time. This is similar to the TGI Tariff General Terms and Conditions Section 15 Promotions and Incentives, whereby TGI "may promote, sell, lease or finance natural Gas vehicle equipment, Gas appliances and related services on a cash or finance plan basis".

38.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 272

Energy Forecast Methodology

"The forecast of demand for natural gas included in the Application is based upon a methodology that is consistent with that used in prior years, and provides a reasonable estimate of future natural gas demand."

38.1 Please provide historical data, methodology, and assumptions made to obtain estimates of future gas demand. What are the supporting references and data?

Response:

Although TGI typically provides only the "weighted" data used to obtain estimates of future natural gas demand, the data for each region and customer class has been provided in Appendix D-1 of the Application.

The methodology is consistent with that used in prior years, with the demand forecast being comprised of three components – Customer Additions, Average Use Per Customer, and Industrial Demand.

The customer additions forecast is based upon the forecast of housing starts provided by CMHC, given the housing market is highly correlated to growth in TGI's customer base. At the time of the forecast, TGI was assuming that housing starts in B.C. in 2009 would be 34% lower than what was realized in 2008, and a further reduction would occur in 2010 before seeing some growth again in 2011.

The forecast of average use per customer was based upon trending analyses, and supported by analyses of factors such as efficiency improvements and the shift towards more multi-family dwellings in the housing mix. The general assumption is that the recent trends experienced by TGI will continue over the Forecast Period.

The industrial demand forecast was based upon the sector analyses illustrated in the Application, and is expected to be validated by the industrial survey once completed.

Each of the components are discussed in the Application itself, and supporting references regarding the reasonableness are the fact that historical Annual Reviews, Resource Plans, and Revenue Requirement Applications have been approved. The supporting data includes that found in Appendix D-1, the economic reports found in Appendix C, and also in TGI's response to BCUC IR 1.38.2 below.

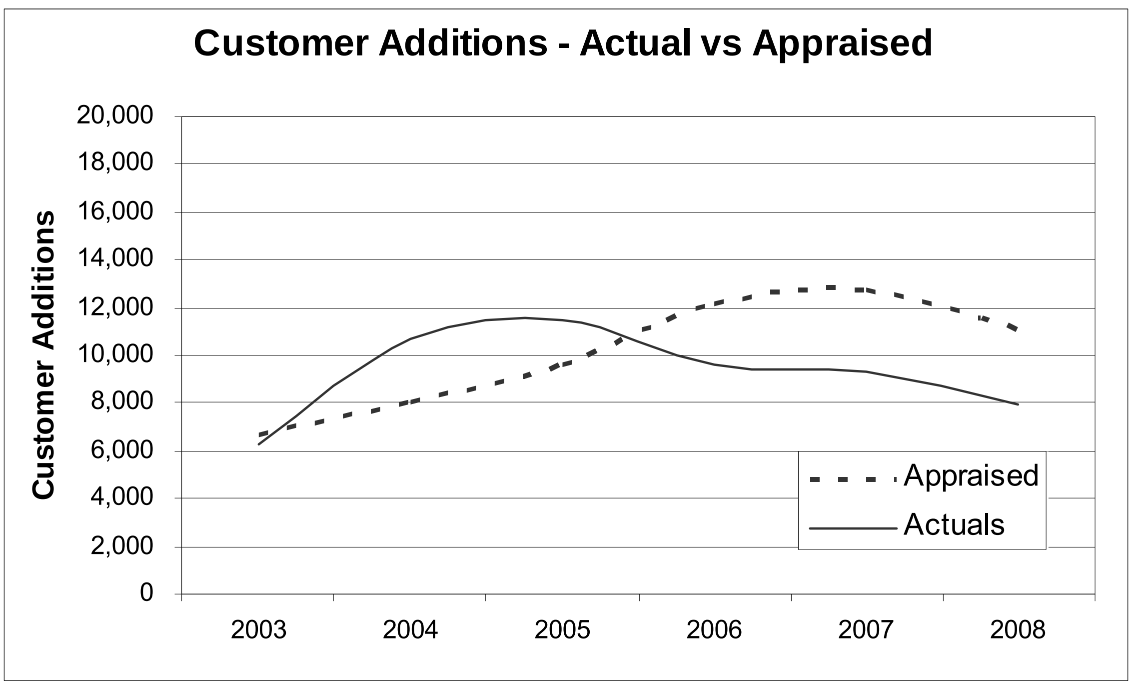
Overall, the forecast was prepared using a methodology that is consistent with that used in prior years, has been reviewed and accepted both internally and by the BCUC, and incorporates the best available information when developed. Additionally, a comparison of appraised to actual results, as found below in TGI's response to BCUC IR 1.38.2 supports the reasonableness of the forecast. And therefore, the forecast is both reasonable and appropriate for use in this Application.

38.2 For 2003 to 2008, please provide the appraised and actual results, and the differences between the two for the following economic indicators:

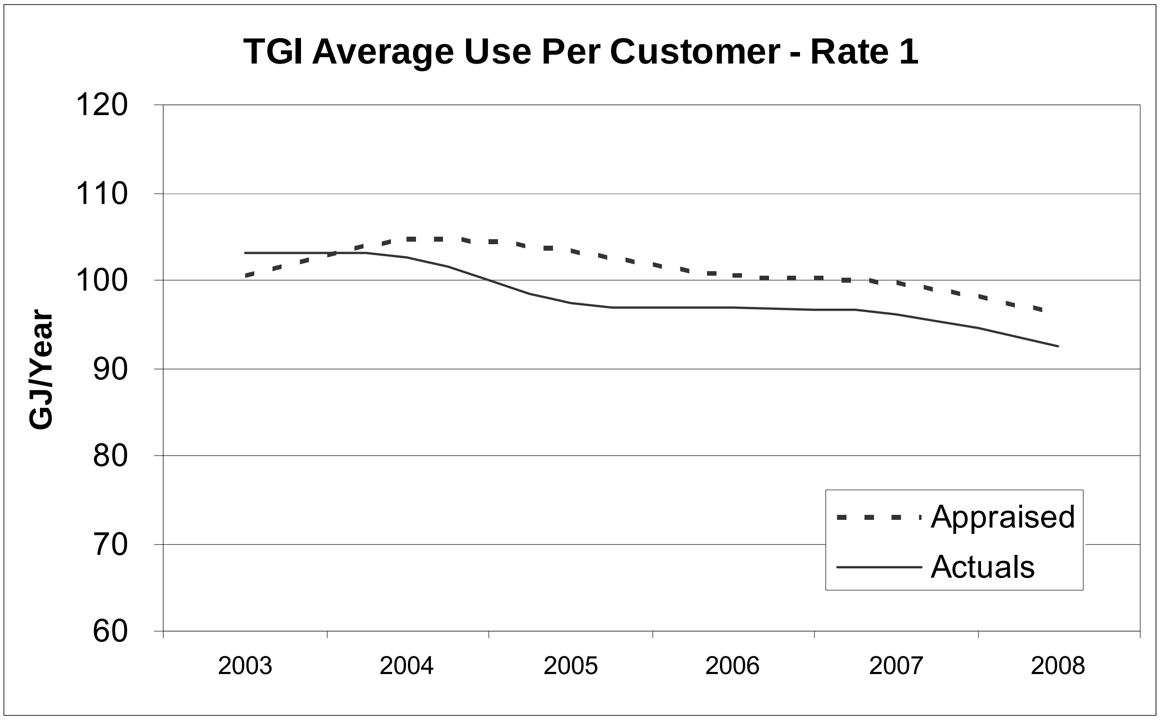
- Customer Additions;
- Use per Customer, by rate class; and
- Total Energy Demand, by rate class.

Response:

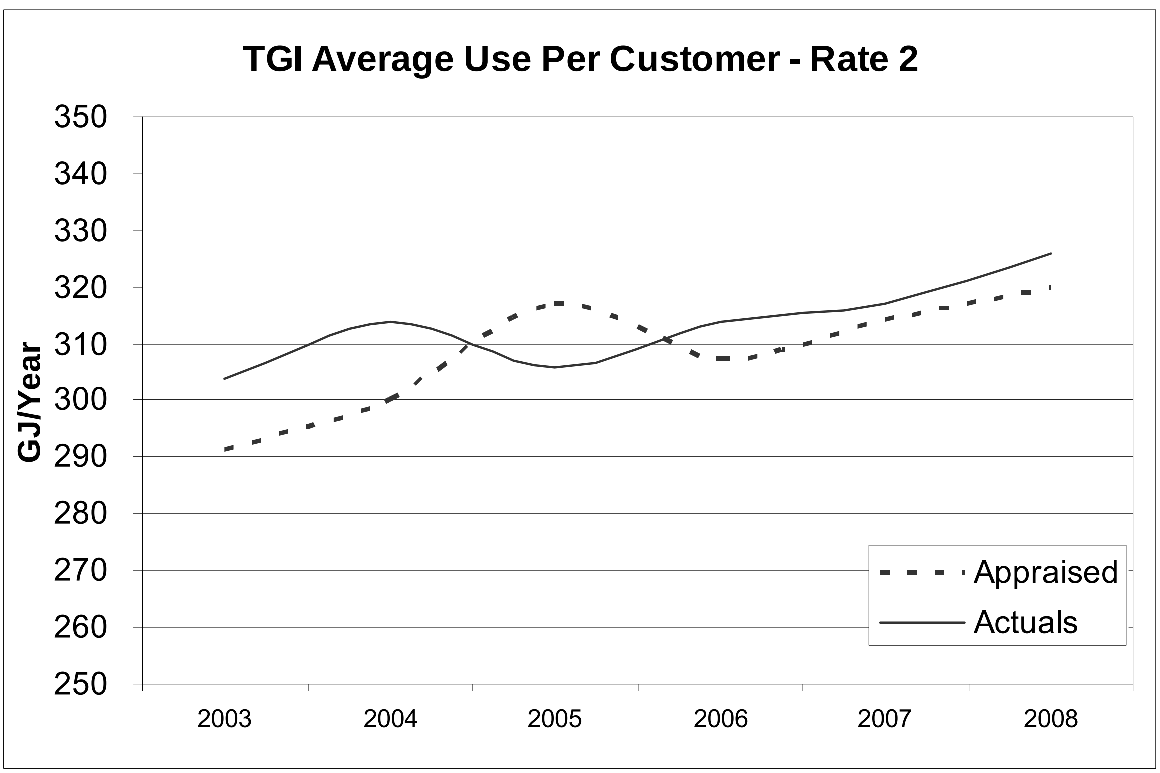
The following chart illustrates the appraised and actual results for Customer Additions over the period 2003 to 2008.



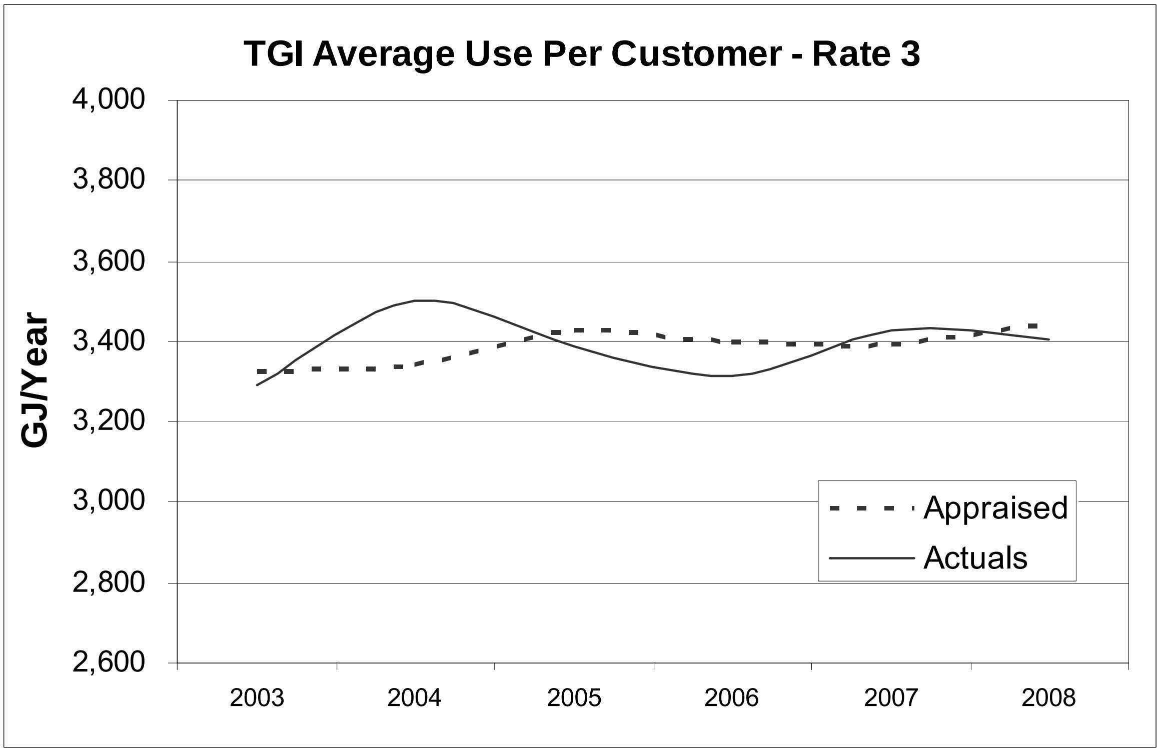
The following chart illustrates the appraised and actual results for Average Use Per Customer over the period 2003 to 2008, for Rate 1, 2, 3, and 23 customers.



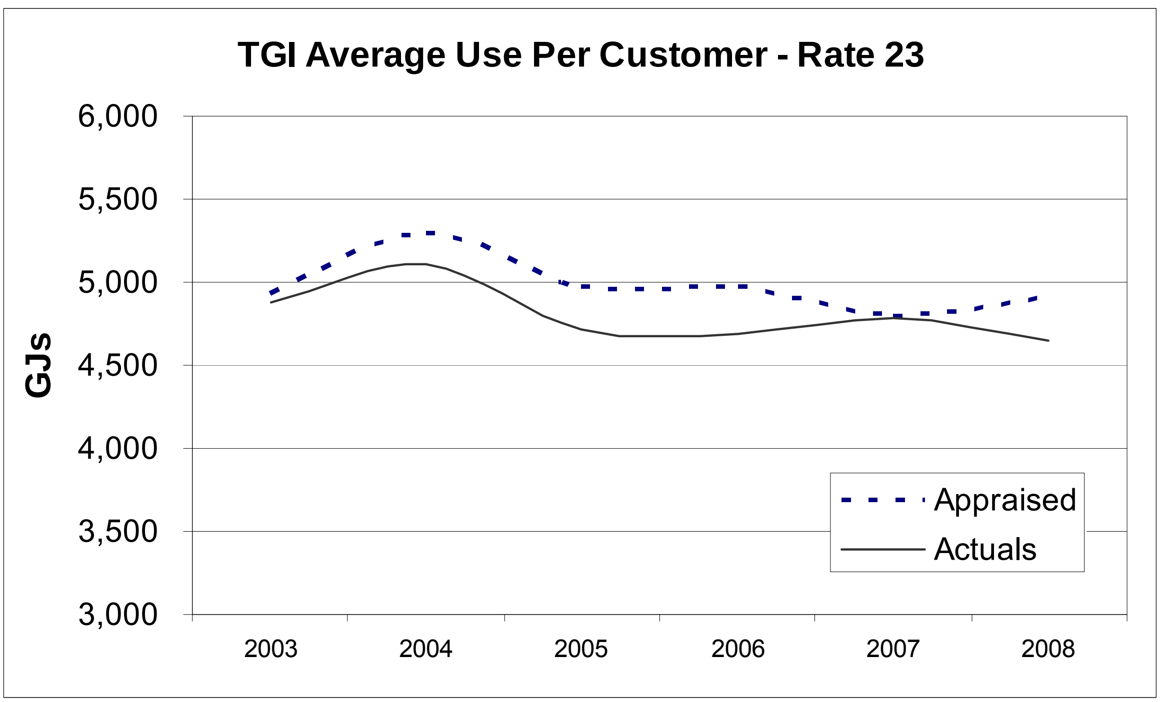
TGI Average Use Per Customer - Rate 1
120
110
100
90
80
70
60
GJ/Year
Appraised
Actuals
2003
2004
2005
2006
2007
2008



TGI Average Use Per Customer - Rate 2
350
340
330
320
310
300
290
280
270
260
250
GJ/Year
Appraised
Actuals
2003
2004
2005
2006
2007
2008

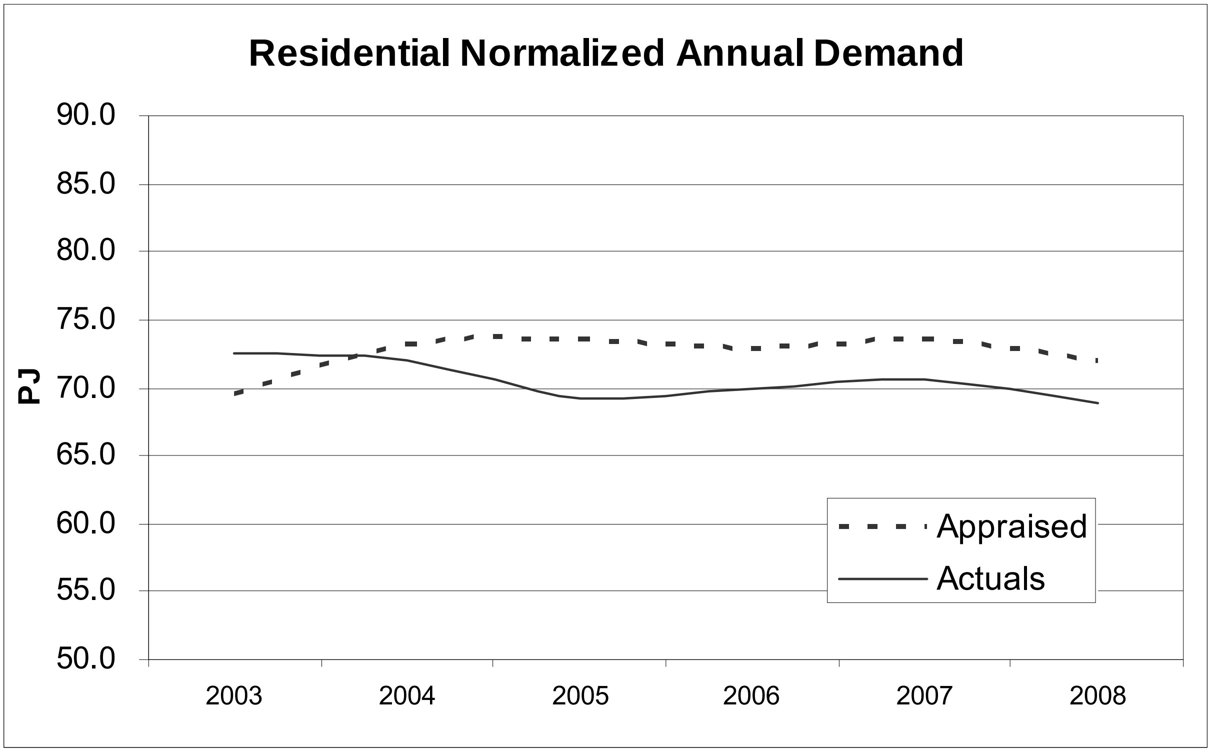


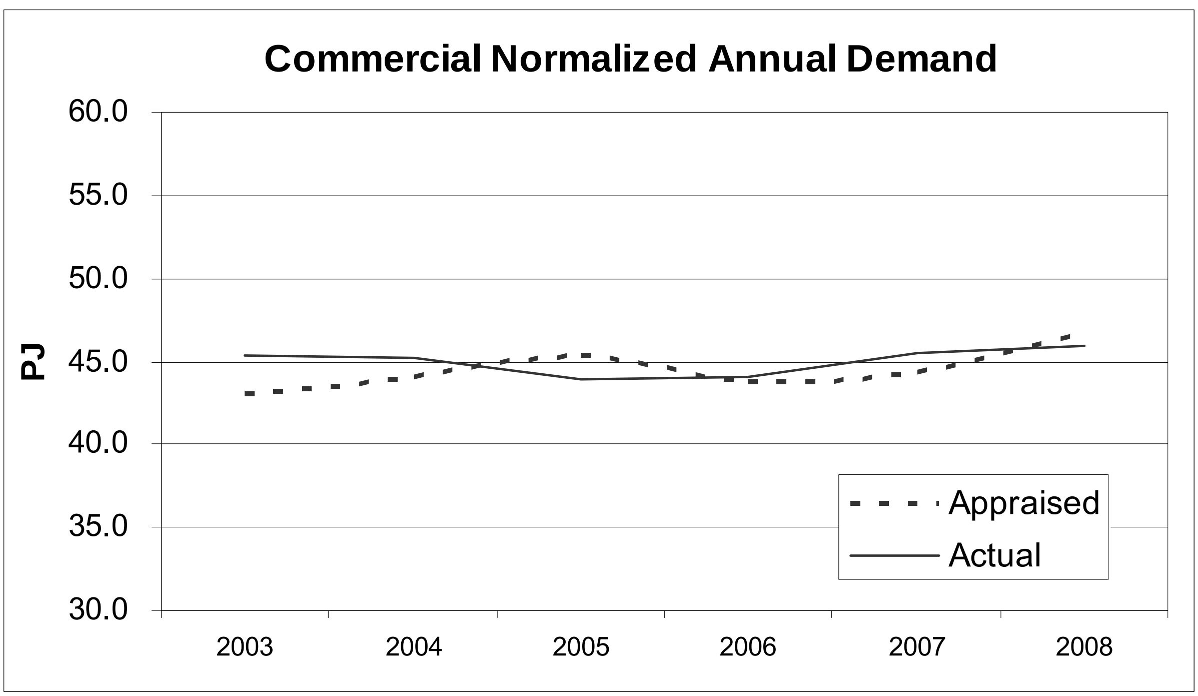
TGI Average Use Per Customer - Rate 3
GJ/Year
4,000
3,800
3,600
3,400
3,200
3,000
2,800
2,600
2003
2004
2005
2006
2007
2008
Appraised
Actuals

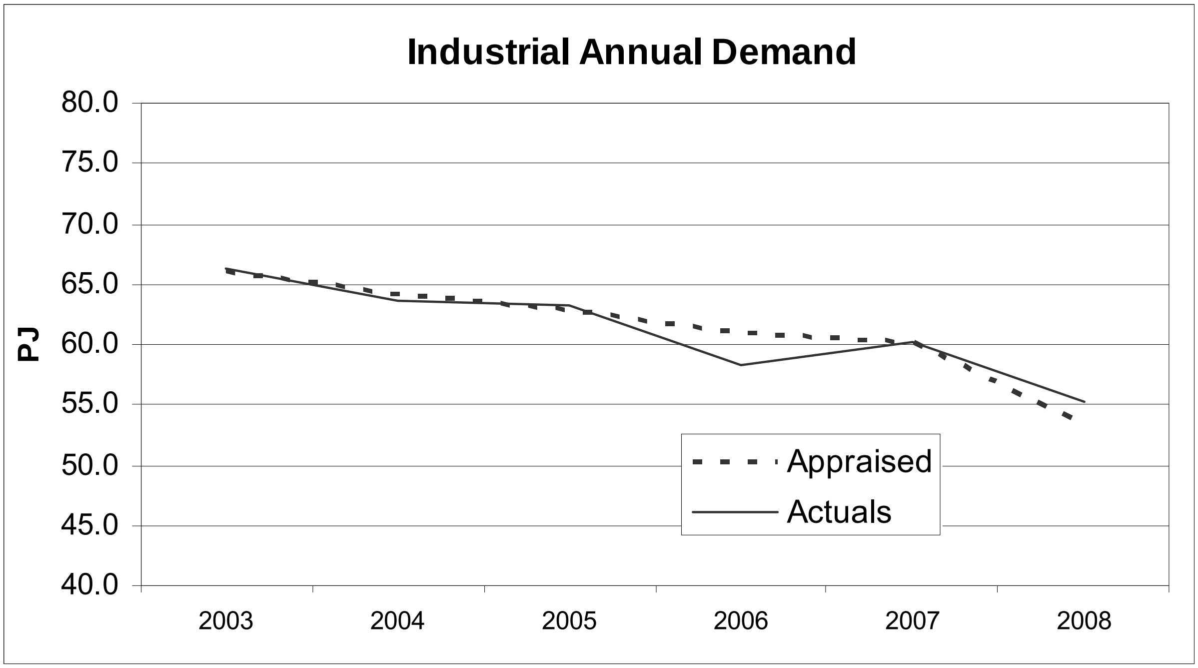


TGI Average Use Per Customer - Rate 23
GJs
6,000
5,500
5,000
4,500
4,000
3,500
3,000
2003
2004
2005
2006
2007
2008
Appraised
Actuals

The following charts illustrate the appraised and actual total energy demand over the period 2003 to 2008 for Residential, Commercial and Industrial customers.







Industrial Annual Demand
PJ
80.0
75.0
70.0
65.0
60.0
55.0
50.0
45.0
40.0
2003
2004
2005
2006
2007
2008
Appraised
Actuals

39.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 272

Energy Forecast Methodology

As stated on page 272: "The methodology has been reviewed and accepted by the BCUC and stakeholders at the Company's annual reviews, which were conducted under the PBR Period."

39.1 Please describe any material changes in the methodology or underlying assumptions used in forecasting demand for residential, commercial, and industrial rate classes over the period 2003 to 2011.

Response:

The only material change in the methodology or underlying assumptions used in the forecast of demand for residential, commercial and industrial rate classes over the period 2003 to 2011 is with regards to the industrial customer classes. This year, the industrial forecast is based primarily on sector analyses, and will be validated later in the summer of 2009 by using the industrial survey , as discussed on page 300 of the Application. Typically, the industrial forecast would be prepared based primarily on the industrial survey and then validated through sector analyses. And although the process is reversed, both methods are still employed and result in a forecast that is both prudent and reasonable.

40.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274

Underlying Assumptions

"One of the steps involved in developing the demand forecast is to identify the main factors that influence the demand for natural gas, and then develop assumptions regarding the impact those factors will have in the future. As with prior years, the factors considered in developing the energy demand forecast for this Application include current economic conditions, the housing market, government policies and programs, and also general trends regarding efficiency improvements."

40.1 Are there additional factors beyond those stated that impact demand forecast? Would the increasing size of new homes or alternative energy sources be considered as significant factors? Please comment.

Response:

Yes, there are additional factors beyond those stated in the Application that impact the demand for natural gas. The increasing size of new single family dwellings is a factor that impacts the demand for natural gas; however, this factor needs to be considered together with other characteristics of the home in order to determine whether or not there is a significant impact to the demand for natural gas. TGI is currently investigating those characteristics, through the 2008 Residential End Use Study ("REUS"), in order to better understand the factors that impact the demand for natural gas. Furthermore, by increasing the frequency of future REUS's (as proposed in the Application), TGI will be in a better position to identify trends and more importantly their impact on the demand for natural gas.

Alternative energy sources are relatively new and are part of a growing market segment, but at this time TGI does not consider them to be a significant factor in the demand for natural gas for the period of the RRA. This is because alternative energies in large impact only newly constructed homes or buildings, whereas people in existing homes and buildings would make use of existing energy delivery systems until those existing systems require replacement or more efficient options are desired. TGI is closely monitoring this segment of the market, and as customers become more aware of the options available to them and are incented to incorporate alternative energies to improve efficiencies, TGI believes alternative energy sources will certainly become a significant factor in the demand for natural gas.

40.2 Please reference any economic or other studies which support the effects of the stated main factors on the demand of natural gas. What were the magnitude and sensitivity of the effects?

Response:

TGI reviewed a number of studies, included in Attachment 40.2, which were found to support the effects of the main factors on demand for natural gas, which included preliminary results from the 2008 Residential End Use Study ("REUS"), a number of studies from the American Gas Association ("AGA"), Canadian Gas Association ("CGA") and external consultants, as well as TGI's own internal analyses based on furnace stock and housing data from Natural Resources Canada.

The 2008 REUS includes analyses regarding changes in both penetration and saturation rates for various natural gas (and propane) end uses, trends in the housing mix (building type), appliance efficiency, and also socio-demographic characteristics of TGI customers that may be impacting the demand for natural gas. Preliminary data supports the assumption that two significant drivers of declining average use per customer are the construction of smaller, multi-family dwellings and also improvements in the efficiency of natural gas end uses (furnaces, water heaters, fireplaces).

The presentation "Factors Influencing Natural Gas Markets 2009", published in December 2009 by the AGA, illustrates the fact that not only is natural gas the cleanest burning fossil fuel, but when considering energies from source, natural gas is significantly more efficient than electricity for certain end use applications. This presentation also discusses declining residential average use per customer, which is estimated to have declined by 32% over the period 1980 to 2007, attributed to efficiency improvements.

The study "Declining Average Customer Use of Natural Gas: Issues and Options", published in December 2006 by Indeco Consulting for the CGA, provides a number of insights into natural gas usage. This study identified the fact that across Canada, natural gas utilities are experiencing declining average use per customer rates, and this is attributed to energy efficiency improvements in new construction and turnover in stock to higher efficiency natural gas furnaces. Average use per customer, across all customer sectors, is estimated to be declining by 1.9% per year, and the study suggests that we could be at a turning point with respect to accelerated declining average use per customer rates over the future.

A study by the American Gas Foundation, "Natural Gas Outlook to 2020", published in February 2005, also identifies declining residential average use per customer, and attributes most of this decline to tighter homes and more efficient appliances. The study illustrates the fact that although the number of natural gas customers has increased by 33% over the period 1980 – 2001, overall consumption has increased very little, again because of increased energy efficiency. The study further suggests that declines in residential average use per customer can be expected to continue over the foreseeable future.

An older study, "Patterns in Natural Gas Consumption Since 1980", published in February 2000, identifies declining use per customer rates and attributes this to efficiency improvements and housing characteristics (responsible for 76% of the declines). This study also indicates declining average use per customer rates are likely to continue over the next ten to fifteen years (today, this would imply over the next six years, given the study was published in 2000).

The above mentioned studies, together with a number of the reports included in Appendix C of the Application, support the effects of the stated main factors on the demand of natural gas. Furthermore, the magnitude and sensitivity of the effects each of these factors has on the demand for natural gas is significant. Current economic conditions impact both industrial volumes and also overall customer growth. Although difficult to quantify, current economic conditions are assumed to be the primary driver of declining industrial volumes, and are therefore significant to the demand forecast. The housing market has a direct impact on customer growth, and as discussed in the Application, also impacts average use per customer rates. The magnitude of this impact is estimated to be a 0.1-0.2 GJ per year reduction in average use per customer rates, as discussed in greater detail below in TGI's response to BCUC IR 1.40.3. Government policies and programs dictate minimum acceptable levels of efficiency around building envelopes and appliance efficiency, which impact average use per customer rates. Government policies also influence customer behaviours and perceptions, which influence overall conservation efforts as well as decisions regarding the appropriate energy source to use. The magnitude of government policies and programs is difficult to quantify, but is certainly significant. General trends regarding efficiency improvements, as indicated in the above studies, are considered to have the most significant impact on the demand for natural gas, and are estimated to be resulting in an approximate 0.9 GJ per year reduction in average use per customer rates. This is also discussed in greater detail below in TGI's response to BCUC IR1.40.3.

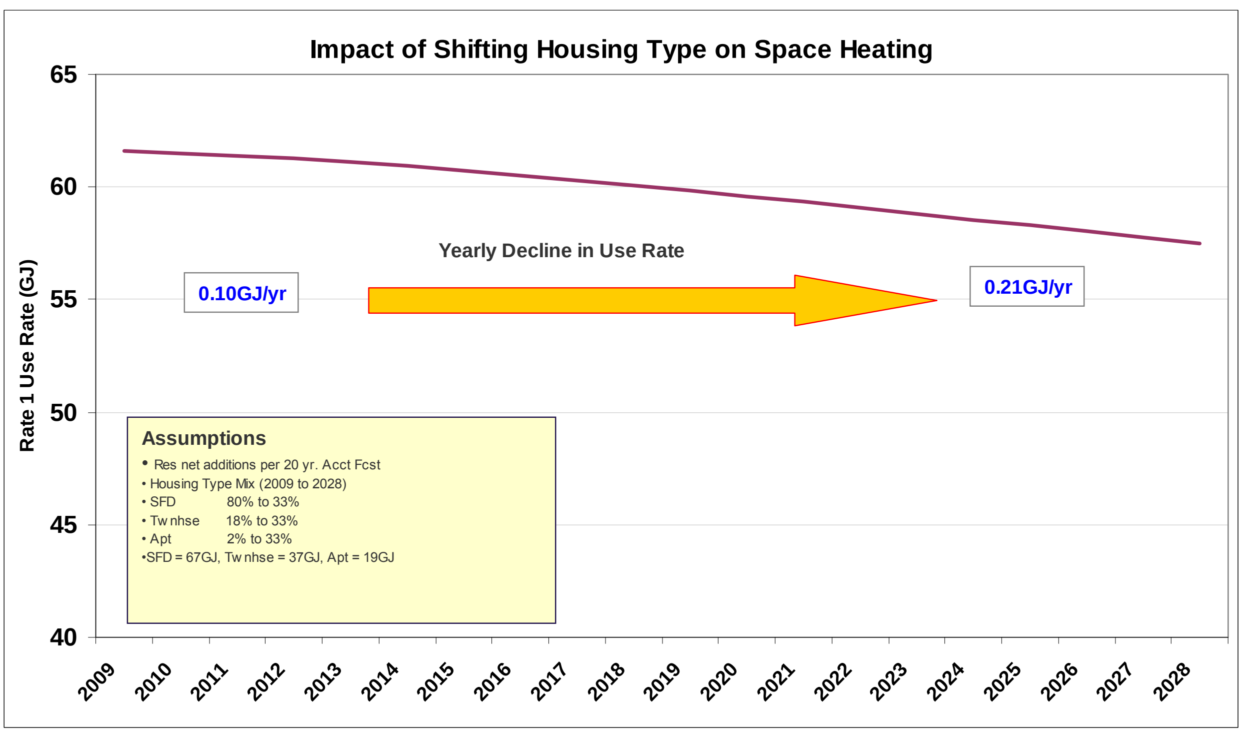
In conclusion, the stated main factors of demand for natural gas are supported by a number of external studies, and provide a reasonable basis from which to develop the forecast of demand for natural gas. And as discussed above, each of the factors significantly impacts one or more component of the demand forecast, and therefore ultimately impacts the overall demand for natural gas.

40.3 Please describe the rationale and assumptions TGI applied to these factors in order to forecast the future demand of natural gas. What data and studies support this, and why?

Response:

As discussed in TGI's response to BCUC IR 1.48.4, the incremental impact of the forecasted customer additions is an approximate 0.6% increase in the overall demand for natural gas. As customer additions are highly correlated to the housing market, fluctuations in the housing market can be expected to impact the overall demand for natural gas. To gauge the sensitivity, if a 10% error margin was assumed for the forecast of housing starts, the overall demand for natural gas would then range from a 0.54% growth to 0.66% growth.

As discussed in TGI's response to BCUC IR 1.41.1, 1.41.2, and 1.41.3, the condition of the B.C. economy significantly impacts the industrial demand for natural gas, as well as influencing the housing market. Quantifying the magnitude and sensitivity that economic growth has upon industrial demand is challenging, although it is reasonable to assume it is significant. As TGI recognizes the condition of the economy to be significant, yet is challenged to quantify the impact/sensitivity, this factor is used as a validation tool on the results of the industrial survey and sector analyses, thereby adding to the reasonableness of the forecast.



Statistics for space heating in various housing types in B.C. together with housing stock data from Natural Resourced Canada formed the basis for the above estimated impact of more multi-family dwellings in the housing mix. With the current housing mix estimated to be approximately 80% single family dwellings and 20% multi-family dwellings, by assuming over time that the mix shifts to 33% single-family dwellings and 67% multi-family dwellings, the estimated impact on average use per customer is an annual reduction of approximately 0.1-0.2 GJ.

41.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274

Underlying Assumptions

The Application states that the underlying assumptions for future forecasts of natural gas take into consideration a number of external influences which include: the condition of the B.C. economy; the housing market; energy efficiency, and the global economic crisis.

41.1 Please describe the methods used to determine the impact that each of these external influences have on the demand of natural gas.

Response:

The external factors that have been incorporated into the demand forecast include GDP, the housing market, and energy efficiency behaviour. Although the global economic crisis has certainly influenced these variables, it is not itself a factor.

The methods used to determine the impact each of the external factors have on the demand for natural gas vary. These methods include incorporating external influences as a proxy for growth in TGI's customer base or overall demand, as a validation tool on other analyses, and are also incorporated as part of detailed analyses so as to estimate the direct impact on average use per customer rates.

For example, GDP growth, which provides a measure of the overall condition of the economy, is typically used to validate the forecast of industrial demand, which itself is typically developed through direct customer feedback and sector analyses. This is also discussed in TGI's response to BCUC IR 1.44.1.

The housing market, more specifically the expected growth in the housing market, is considered a proxy for future customer additions. It is also analyzed in greater detail with regards to the housing mix, to estimate the impact more multi-family dwellings in the housing mix have on average use per customer rates.

Energy efficiency, more specifically the retrofitting of low efficiency furnaces to high efficiency units, has also been analyzed in great detail to estimate the impact on average use per customer rates, as discussed in TGI's responses to BCUC IR 1.41.2 below and also BCUC IR 1.44.2.

By incorporating external factors that influence the demand for natural gas into the forecast, using a number of methodologies, TGI adds a level of rigor and reasonableness to the demand forecast. TGI continues to monitor external factors that influence the demand for natural gas, and anticipates tools such as the Residential End Use Study becoming even more important in expanding on those factors in the future.

41.2 Please indicate the relative magnitude, impact and sensitivity that each of these external variables have on the future demand of natural gas.

Response:

The external variables that have been incorporated into the demand forecast include GDP, the housing market, and energy efficiency behaviour. These variables each have significant impacts upon the future demand for natural gas, as they impact each of the components of the total demand forecast: Customer Additions, Average Use Per Customer, and Industrial Demand.

GDP growth impacts TGI's industrial demand for natural gas. As industrial consumption is heavily weighted towards process-oriented end uses, it is ultimately tied to output or production levels. And, given fluctuations in GDP growth rates are reflective of changes in output or production in the various industry sectors TGI's industrial customers are in, it follows that GDP significantly influences industrial demand for natural gas. Quantifying the magnitude, impact and sensitivity that GDP growth has upon industrial demand is challenging, although it is certainly reasonable to state qualitatively it is significant. As TGI recognizes GDP growth to significantly impact the demand for natural gas, it is incorporated into the demand forecast as a validation tool, and is also used when performing scenario analyses in longer-term forecasts for resource planning purposes.

The housing market is also considered to be a highly significant variable in the forecast of demand for natural gas. The rate of growth in TGI's customer base is strongly correlated to the rate of growth in the housing market, and as such TGI considers the forecast rate of growth in the housing market to be a good proxy for future growth in its customer base. At the same time, the continued shift towards more multi-family dwellings in the housing mix contributes to declining average use per customer rates. Therefore, the housing market impacts both customer additions and also use per customer rates. Customer additions, as discussed in TGI's response to BCUC IR 1.48.4, are estimated to be increasing overall demand by 0.6% over the Forecast Period. At the same time, the impact of more multi-family dwellings in the housing mix is estimated to be resulting in an approximate 0.1 to 0.2 GJ per year decline in average use per customer.

Energy efficiency, or customer behaviour towards such, is considered to be the primary driver behind declining residential average use per customer rates. There are many aspects of energy efficiency, such as building shells, insulation levels, the level of technology employed, and overall comfort levels with respect to heating levels and hot water consumption. But the most significant aspect is with regards to the retrofit of low efficiency furnaces to higher efficiency units. TGI estimates the independent impact of retrofit activity to be an approximate 0.9 GJ per year decline in residential average use per customer rates, and this is expected to continue well beyond the 2010-2011 Forecast Period.

41.3 What result would a 1 percent increase in Real GDP during the Forecast Period have on the corresponding change in demand for natural gas? Please calculate and discuss.

Response:

As stated in TGI's response to BCUC IR1.41.1, GDP is typically viewed as a variable that validates or supports the forecast demand for natural gas. Directionally, TGI can state that a 1 percent increase in Real GDP would likely also influence the demand for natural gas upward, but as GDP is not formally modeled as an independent variable with respect to the demand for natural gas, the estimated impact is unknown.

42.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274, Appendices C-34 and C-37

Underlying Assumptions

42.1 Data provided in Appendix C-34 show that the economy in British Columbia is predicted to expand by 2.4 percent in 2010 and 2.6 percent in 2011. Please describe the method used by TGI to apply this data in forecasting demand of natural gas for the Forecast Period.

Response:

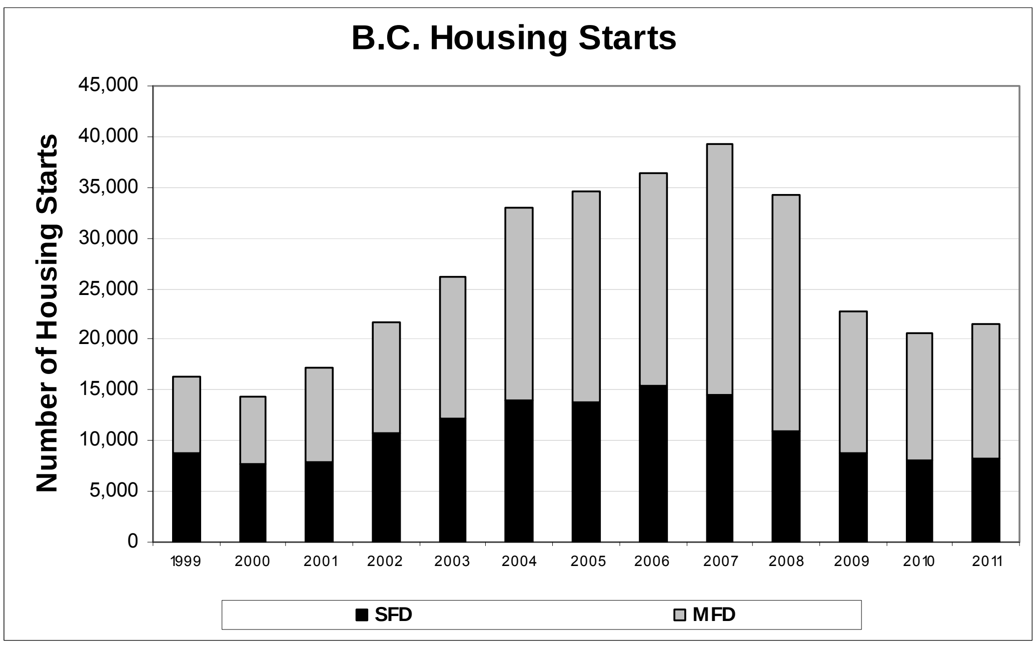
Although the forecast of economic growth provides a high level indication of the environment in which TGI can expect to be operating in over the Forecast Period, the rate of GDP growth does not correlate well to the individual components of the demand forecast. Given that, and also the availability of other economic indicators (such as housing starts) that do correlate well to individual components of the demand forecast, GDP growth is used as a validation tool when forecasting the demand of natural gas over the Forecast Period. More specifically, as discussed in TGI's response to BCUC IR 1.41.1, GDP growth is used as a validation tool for the industrial demand forecast.

42.2 Appendix C-34 presents data indicating that housing starts in British Columbia will increase in 2010 and 2011 by 5.1 percent and 3.7 percent respectively resulting in a total of 54,600 new housing starts over the Forecast Period. Please provide housing start data for the past 10 years in tabular and graphical formats. Based on these data please describe what impact housing starts have had on the number of residential customers and the demand for natural gas on a year-over-year basis. Please provide all data in a fully functioning electronic spreadsheet.

Response:

The following table and chart illustrate the housing starts in B.C. over the period 1999 to 2008, including the projection for 2009 and forecast for 2010 and 2011. This data is also included in Attachment 42.2, as requested.

BC Housing Starts (CMHC)				
Year	SFD	MFD	Total	TGI Year-End Customers
1999	8,731	7,578	16,309	751,893
2000	7,717	6,701	14,418	758,437
2001	7,862	9,372	17,234	763,302
2002	10,730	10,895	21,625	769,908
2003	12,252	13,922	26,174	775,454
2004	14,056	18,869	32,925	786,958
2005	13,719	20,948	34,667	799,378
2006	15,433	21,010	36,443	812,683
2007	14,474	24,721	39,195	822,598
2008	10,991	23,330	34,321	831,845
2009	8,800	14,000	22,800	837,965
2010	8,000	12,700	20,700	843,565
2011	8,300	13,170	21,470	849,415



As discussed in TGI's response to BCUC IR1.41.2, the housing market is considered to be a highly significant variable in the forecast of demand for natural gas. Housing starts and TGI's customer base are highly correlated (there is a 92% correlation over the period 2003 to 2008), and as such TGI considers the forecast of housing starts to be a good proxy for future growth in its customer base. The housing market is also impacting average use per customer rates. As the shift towards more multi-family dwellings in the housing mix continues, there is downward pressure placed on average use per customer rates. Therefore, the housing market is impacting both customer additions and also average use per customer rates, and can be said to be a significant variable impacting the overall demand for natural gas.

42.3 For housing starts that have occurred over period of 1999 to 2008, what is the capture rate into single family detached dwelling and multi-family dwellings?

Response:

The ability to distinguish between single family and multi-family dwelling types within TGI's customer base was gained when the CAFÉ (Customer Attraction Front End) Reporting tool was implemented in 2006. As such, capture rates are estimated for 2007 and 2008 only, and those estimates indicate that TGI has been capturing virtually all single family dwellings and approximately 20% of multi-family dwellings over that period.

42.4 Please provide data for housing starts segmented between detached single family dwellings and multi-family dwelling historically between 1999 and 2008. Please also provide similar data for the forecast period 2010 and 2011. Please provide tabular data and graphical representations in the form of a fully functioning electronic spreadsheet.

Response:

Please see TGI's response to BCUC IR 1.42.2 and the attachment for that response, as the data presented there illustrates the single and multi-family dwelling segments.

42.5 Data included in Appendix C-37 omit housing market data for 2011. However, on page 275 TGI makes reference to 21,475 housing starts in 2011. Please identify the source of data used to estimate housing starts in 2011.

Response:

The 2011 housing starts were estimated by applying the 2010-2011 growth rate derived from the forecast of housing starts in the 2009 B.C. Budget and Fiscal Plan (published by the B.C. Ministry of Finance in Q1 2009) to the 2010 forecast housing starts from the CMHC forecast. The CMHC forecast, given it provides the distinction between single and multi-family dwellings, and also greater detail with regards to the number of housing starts, is the preferred forecast. However, the CMHC only provides a projection for the current year-end and a forecast for the following year. So, in cases where TGI requires an additional forecast year, the growth rate from the B.C. Ministry of Finance forecast is incorporated to derive that estimate.

43.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274

Underlying Assumptions

TGI states that energy efficiency and conservation ("EEC") programs will reduce the demand of natural gas. Please provide a spreadsheet to show the predicted average annual decline rate in natural gas demand resulting from increases in efficiency and conservation during the Forecast Period. Please clearly state the method and assumptions used in the calculations.

Response:

The annual savings resulting from energy efficiency and conservation measures (EEC) are primarily driven by residential new construction and retrofit programs. TGI estimates the decline in residential average use per customer resulting from increases in efficiency and conservation over the Forecast Period to be an approximate 0.3 GJ decline. The calculations and assumptions are illustrated in the spreadsheet provided in Attachment 43.0.

44.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274

Underlying Assumptions

44.1 TGI assumes that "Key industrial sectors will continue to experience adverse conditions as a result of the global economic crisis." Please quantify the impact of the economic crisis on industrial demand for natural gas in the Forecast Period.

Response:

The global economic crisis has resulted in declining demand for manufacturing exports, falling commodity prices and volumes, and also significant volatility in the financial markets. This, in turn, has led to significant declines in output and investment in British Columbia, as well as contractions in consumer spending, rising unemployment levels, and dramatic declines in the housing market. As a result, industrial demand has been significantly impacted. And although TGI attributes most, if not all, of the declines in industrial demand to the global economic crisis, given the many factors that have contributed to the overall downturn in the economy, the impact is not readily quantifiable. Rather, TGI can qualitatively state the global economic crisis has had a significant negative impact on industrial demand.

44.2 Please comment on the extent to which the current economic downturn and associated tighter credit markets will have on delaying the deployment of more efficient burner-tip appliances among residential, commercial and industrial customers. Also, please describe the impact this will have on customer demand volumes.

Response:

At the time of writing, TGI is in the process of ramping up staffing levels in order to implement the programs approved in the EEC Decision, and at this time does not have sufficient data on participation rates for programs intended to speed up the deployment of more efficient burner-tip appliances among residential, commercial and industrial customers. Anecdotal evidence, from TGI's own Commercial/Industrial Account Managers and Builder/Developer Account Managers, as well as from other sources such as the article included in Attachment 44.2, would indicate that market demand for energy efficiency and conservation programs remains strong despite economic circumstances. However, TGI will not have empirical data regarding demand for efficient appliances until after the incremental EEC programs resulting from the EEC Decision are actually developed and deployed into the marketplace, which is expected to commence in early Fall 2009. The Company expects to have more solid data about market demand for energy efficiency programs by the end of Q1, 2010.

45.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 274

Underlying Assumptions

"As with prior years, the factors considered in developing the energy demand forecast for this RRA include current economic conditions, the housing market, government policies and programs, and also general trends regarding efficiency improvements."

45.1 Please provide details of the factors used in developing the energy demand forecast for 2010 and 2011. For example, what specific economic conditions are TGI relying upon in developing its forecast?

Response:

Overall, TGI is expecting the B.C. economy to be in a recessionary period through 2009, but then show signs of stability in both 2010 and 2011. This is expected to result in a dramatically declining housing market in 2009, with a further decline in 2010 before stabilizing in 2011. As well, the shift towards more multi-family dwellings in the housing market is expected to continue, driven by high building material and land costs and declining affordability. It is further expected that TGI's customers will continue to increase conservation efforts, so as to reduce energy expenditures and also as a result of public policies that are targeting reduced GHG emission levels.

Details of the factors used in developing the energy demand forecast for 2010 and 2011 are also described/explained in TGI's response to a number of the BCUC IR's, including 1.11, 1.38, 1.40, 1.41, and 1.44.

45.2 Please provide a regression analysis of demand relationships for residential, commercial and industrial users that compare the demand for natural gas with relevant factors ("independent variables") that TGI is relying upon in the forecast. Please indicate whether the independent variables are significant. For example:

Regression Analysis for Natural Gas Demand (example only)

Variable	Coefficient	Statistically Significant (Yes/No)
Natural gas demand in previous year	0.67	Yes
Natural gas price in previous year		
Electricity price in current year		
Electricity price in previous year		
Income in current year		
Income in previous year	0.07	No
GDP in current year		
GDP in previous year		
Population in current year		
Population in prevoius year		
Additional customers in current year		
Additional customers in previous year		
Climate - heating degree days	0.27	Yes

Also, please provide graphs and supporting tabular data in the form of an electronic spreadsheet that illustrate the relationship between the demand for gas and statistically significant independent variables provided in the above table.

Response:

TGI has performed regression analyses for residential and commercial customers to assist in identifying demand relationships against a number of variables, including GDP Growth, Heating Degree Days, Commodity Prices, Account Additions, Electricity Prices, and Population Growth, and for those independent variables has also included analyses of the lag effect.

The following table summarizes the regression results for TGI Residential customers.

Variable	Coefficient	R Square	Statistically significant
Vs GDP Growth in current year	-56,799.8	-8%	No
Vs GDP Growth in previous year	48.9	-9%	No
Vs HDD	27.0	88%	Yes
Vs Commodity prices in current year	-719.9	-9%	No
Vs Commodity prices in previous year	1.1	59%	No
Vs Account additions in current year	-0.3	-10%	No
vs Account additions in previous year	0.6	3%	No
Vs Electricity prices in current year	183,118.6	-13%	No
vs Electricity prices in previous year	760,424.4	4%	No
Vs Population growth in current year	605,524.2	22%	No
vs Population growth in previous year	1,069,032.7	65%	No

As can be seen from the above table, the only regression showing statistical significance is that which relates Demand to Heating Degree Days. Regression analysis is used in developing the forecast; however, it is used to normalize consumption data (remove the weather effect) before that data is analyzed. Each of the other regressions show either a very poor model fit (low R-square values) or the p-values for the test statistics show they are not significant. TGI has in the past investigated combinations of the above variables (and others), but has not been successful in identifying a relationship with acceptable levels of significance and goodness of fit that also provide reasonable estimates of future levels of residential demand.

The following table summarizes the regression results for TGI Commercial customers.

Variable	Coefficient	R Square	Statistically significant
Vs GDP Growth in current year	-52,524.2	-3%	No
Vs GDP Growth in previous year	-5,386.4	-14%	No
Vs Heating Degree Days	18.0	86%	Yes
Vs Commodity prices in current year	-161.9	-14%	No
Vs Commodity prices in previous year	-127.4	-13%	No
Vs account additions in current year	1.7	10%	No
vs account additions in previous year	2.2	28%	No
Vs electricity prices in current year	5,722.4	-5%	No
vs electricity prices in previous year	11,877.8	20%	No
Vs Population growth in current year	540,819.3	52%	No
vs Population growth in previous year	723,232.6	68%	No

The above table indicates that, similar to the residential analysis, the only regression showing statistical significance is that which relates Demand to Heating Degree Days. TGI does use regression analysis to normalize consumption data for commercial customers, to allow for trending that excludes impacts due to variations in weather. Similar to the analysis for TGI Residential customers, TGI has in the past investigated combinations of these variables (as well as others) when analyzing commercial consumption, but has not been successful in identifying a relationship that provides reasonable estimates for future levels of commercial demand.

For industrial customers, TGI does not incorporate regression analysis into the forecast, for the following reasons. The industrial rate classes are based on consumption levels, and as a result there are a variety of industries represented within each class that makes formal modeling a challenge. But more importantly, TGI believes the individual customers within this customer segment are the best source of estimates for future demand, and therefore implemented an annual customer survey to develop the industrial forecast.

Given the above, and the fact that econometric models are not very well equipped to handle significant economic changes such as those experienced during the latter part of 2008, TGI does not believe a regression-based approach to forecasting demand for natural gas is reasonable at this time. TGI does, and will continue to, monitor those variables considered to be impacting demand for natural gas, and if/when relationships are identified that are deemed reasonable, they will be incorporated into the forecast.

Please see Attachment 45.2 for the spreadsheet that provides graphical representation and the tabular data.

46.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 276

Customer Additions

46.1 TGI states that the capture rates for multi-family dwellings are lower than for single-family dwellings. Please provide a table showing the average capture rates for multi-family dwellings and single-family dwellings for the period 2003-2008.

Response:

As discussed in TGI's response to BCUC IR 1.42.3, the ability to distinguish between single family and multi-family dwelling types within TGI's customer base was gained when the CAFÉ (Customer Attraction Front End) Reporting tool was implemented in 2006. As such, capture rates are estimated for 2007 and 2008 only, and those estimates indicate that TGI has been capturing virtually all single family dwellings and approximately 20% of multi-family dwellings over that period.

46.2 Also, please comment on the effect that reduced capture rates for multi-family dwellings will have on forecasted demand during the Forecast Period.

Response:

Although capture rates for multi-family dwellings are significantly lower than for single family dwellings, they are not declining at this time. As compared to forecast, reduced capture rates for multi-family dwellings, should they occur, will negatively impact forecasted demand over the Forecast Period. Given the trend towards more multi-family dwellings in the housing mix, reduced capture rates imply lower overall growth in customer additions, which ultimately diminishes the growth expected for the overall demand of natural gas.

47.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 277

Forecast Customer Growth

"No growth is assumed for industrial customers unless known at the time of the forecast."

47.1 Please explain why TGI has assumed no growth for industrial customers during the Forecast Period.

Response:

It has been TGI's practice for some time now to assume no growth for industrial customers (unless specifically known) when developing the forecast. Industrial customer growth does not follow similar patterns as for the residential and commercial customer segments. That is, industrial customer growth is not correlated to the housing market, nor does it correlate well to overall economic indicators such as GDP. In the absence of either quantitative or qualitative models to assist in better predicting industrial customer growth, TGI employs an annual survey for industrial customers, and validates the results of this survey through sector analyses. At the same time, TGI has also adopted a policy of assuming no industrial growth until such time that it has been experienced. This is supported by the historical data, as discussed below in TGI's response to BCUC IR 1.47.2.

47.2 Do historical data for industrial customer growth over the past five years support the assumption that there will be no new industrial customers added during the Forecast Period? Please explain why, or why not.

Response:

Yes, over the past five years historical data does support the assumption that there will be no new industrial customers added during the Forecast Period. Over the past five years TGI has experienced both additions and losses to its industrial customer base, although TGI has seen a net loss of 108 customers over the entire period, representing 0.2% of TGI's total customer base. As discussed above in TGI's response to BCUC IR 1.47.1, in the absence of formal models to better predict industrial customer growth, and with recent history showing no real trend, the assumption of no growth for industrial customers is reasonable.

48.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 277

Forecast Customer Growth

48.1 Please extend Table C-4-1 in the same format to include the historical data for residential, commercial and industrial customers from 2003 to 2008.

Response:

The following table illustrates the net customer additions for residential, commercial, and industrial & transportation customers, the total gross customer additions, year-ending number of customers, and housing starts over the period 2003 through 2008, a projection for 2009, and the forecast for 2010 and 2011. Please note that the requested data for the 2003 through 2008 period was included in the same format in Table B-1-1 on page 104 of the Application.

TGI Customer Growth[1]

	2003 Actuals	**2004** Actuals	**2005** Actuals	**2006** Actuals	**2007** Actuals	**2008** Actuals	**2009** Projected	**2010** Forecast	**2011** Forecast
Residential[2]	6,306	10,716	11,427	9,595	9,277	7,959	5,213	4,777	4,983
Commercial[3]	(762)	756	1,002	655	694	1,294	907	823	867
Industrial & Transportation[4]	2	32	(9)	(69)	(56)	(6)	-	-	-
Total Net Additions	**5,546**	**11,504**	**12,420**	**10,181**	**9,915**	**9,247**	**6,120**	**5,600**	**5,850**
Total Gross Additions	**12,837**	**15,549**	**12,770**	**13,338**	**15,533**	**14,566**	**9,600**	**8,784**	**9,176**
Year-Ending Customers	775454	786,958	799,378	812,683[4]	822,598	831,845	837,965	843,565	849,415
Housing Starts[5]	24,050	32,925	34,667	36,443	39,195	34,321	22,800	20,700	21,500

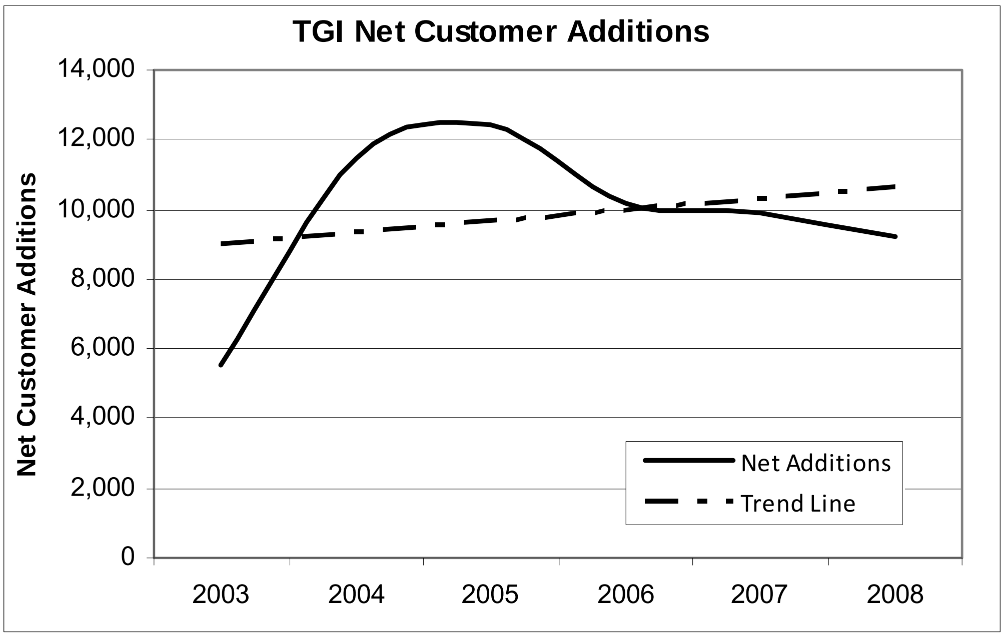
Notes

1. Includes Lower Mainland, Inland, Columbia and Revelstoke service regions only.
2. Rate 1
3. Rates 2, 3 & 23
4. Rates 4, 5, 6, 7, 22, 25 & 27
5. Source: CMHC
6. Includes 3,124 additional customers due to amalgamation of Squamish customers

48.2 Please also provide a plot of the data along with linear regression algorithms used to forecast customer growth in the Forecast Period. If linear regression was not used to forecast customer growth, please explain what analytical methodology and assumptions were used.

Response:

The following chart illustrates the annual net customer additions from 2003 through 2008, along with the trend which was determined through regression analysis.



Although the above graph illustrates a trend line over the period 2003 through 2008, the R-square value associated with that trend line is only 6.5%, indicating it is a very poor fit. Furthermore, the trend indicates growth in customer additions of approximately 330 per year since 2003, which does not appear reasonable to TGI given the current economic state and significant slowdown in the B.C. housing market.

TGI considers the forecast of housing starts, more specifically the yearly growth rate of housing starts, to be a more reasonable indicator of future customer additions, as discussed in TGI's response to BCUC IR 1.42.2 and 1.42.5. There is a fairly strong correlation between the growth rate of housing starts and the growth rate of customer additions (from 2000 to 2008, the correlation is 77%). The assumptions regarding growth in housing starts were based upon the CMHC's Housing Market Outlook, Canada Edition, released in the first quarter of 2009.

48.3 Please describe the process used to make the adjustments between gross additions and net additions. Please provide underlying assumptions and data used to derive the adjustment between gross additions and net additions.

Response:

The adjustment between gross and net additions is based on an analysis of the historical ratio of gross to net customer additions. The following table illustrates the gross and net customer additions, as well as the ratio of net to gross customer additions for TGI over the period 1999 through 2008, as well as the projection for 2009 and forecast for 2010 and 2011.

	1999	2000	2001	2002	2003	2004	2005
Total Net Additions	13,663	6,544	4,865	6,606	5,546	11,504	12,420
Total Gross Additions	15,450	7,400	5,300	8,300	12,837	15,549	12,770
Ratio (Net/Gross)	88%	88%	92%	80%	43%	74%	97%

	2006	2007	2008	2009P	2010F	2011F
Total Net Additions	10,181	9,915	9,247	6,120	5,600	5,850
Total Gross Additions	13,338	15,533	14,566	9,600	8,784	9,176
Ratio (Net/Gross)	76%	64%	63%	64%	64%	64%

Although the ratio of net to gross customer additions has fluctuated over the historical period shown above, the more recent two years suggest more stability. For this reason, and in the absence of more recent data to suggest otherwise, TGI has assumed the current ratio of net to gross additions will remain stable throughout the forecast period.

48.4 Please summarize as a percentage of total forecasted demand in 2010 and 2011, the incremental impact that the forecasted additional customers will have on demand during the Forecast Period.

Response:

The total forecasted demand in 2010 and 2011 is 162.0 PJ and 161.8 PJ, respectively, as illustrated on table C-4-8, page 311 of the Application. The estimated incremental demand as a result of the 5,600 forecast customer additions in 2010 is approximately 1.0 PJ, and the estimated incremental demand resulting from the 5,850 forecast customer additions in 2011 is approximately 1.1 PJ. Therefore, the incremental demand arising from the forecast customer additions represents 0.64% and 0.67% of the total forecast annual demand for 2010 and 2011, respectively.

49.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 277

Customer Growth Issue

"Over the past several years, TGI experienced an increase in the net turnover of its customer base, which has negatively affected our customer growth."

49.1 For the various user classes, please provide tabular data and a corresponding graphical representation of the net turnover of TGI's customer base from 1999 to 2008. Please provide in the form of an electronic spreadsheet.

Response:

The reporting of customer turnover is provided through Accenture Business Services for Utilities ("ABSU"), and does not contain a breakdown by customer class. The report originally only provided company-wide figures, but was revised in 2005 to include a regional breakdown between the Lower Mainland region and Interior regions. Going forward, TGI has requested additional details behind the current reporting structure so as to allow for a greater breakdown, such as by customer class and region, but currently this data is unavailable.

Please see Attachment 49.1 which provides a graphical illustration of the net turnover of TGI's entire customer base from 1999 to 2008 as well as an illustration of the net turnover by region from 2005 to 2008. The data is also illustrated in tabular form.

49.2 Please confirm what turnover rates TGI has assumed in the demand forecast for 2010 and 2011.

Response:

Net turnover is measured as the difference between gross and net customer additions, and represents meters locked off as a result of customers who fall into arrears, meters removed due to a premise becoming vacant or customers moving, and also meters being reconnected as a result of customers returning to the system. For example:

2008 Gross Customer Additions = 14,566

2008 Net Customer Additions = 9,247

2008 Net Turnover = 14,566 – 9,247 = 5,319

The turnover rate is expressed as the ratio of net customer additions to gross customer additions, and for 2008 calculates to 63%, with the 2007 & 2008 average being 64%. For the reasons described in the response to BCUC IR 1.49.3 this turnover rate is expected to continue through the 2010 and 2011 forecast period, resulting in net turnover of approximately 3,200 customers in 2010 and 3,300 customers in 2011.

49.3 Do these turnover rates apply equally for both 2010 and 2011? If so, please explain why.

Response:

Given that the 2008 data indicates the trend towards higher levels of customer turnover has stabilized, and in the absence of information to suggest otherwise, TGI is assuming the ratio of net to gross additions remains stable for both 2010 and 2011. Although the ratio of net to gross additions is expected to remain stable, the actual net turnover is expected to grow slightly from 2010 to 2011 (from 3,200 to 3,300 customers), as a result of an expected increase in housing starts over that period.

50.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 277, Figure B-1-3

Customer Growth Issues

"The issue with customer turnover is the fact that for the past several years TGI has experienced an increase in the net turnover in its customer base, which has resulted in significantly fewer net customer additions than forecast. This is illustrated in Figure B-1-3 of Part III, Section B."

50.1 Figure B-1-3 on page 105 contains projected data for 2009. Please provide year-to-date data upon which the 2009 forecast is based. If no data are available for 2009, please provide a description of the assumptions used to make the 2009 projection for New Customer Additions.

Response:

The 2009 projection for Customer Additions was based upon the Canada Mortgage Housing Corporation ("CMHC") forecast of housing starts (2009 Q1 Forecast), the 2008 year-end actual customer additions, and was compared to the April year-to-date results to ensure reasonableness.

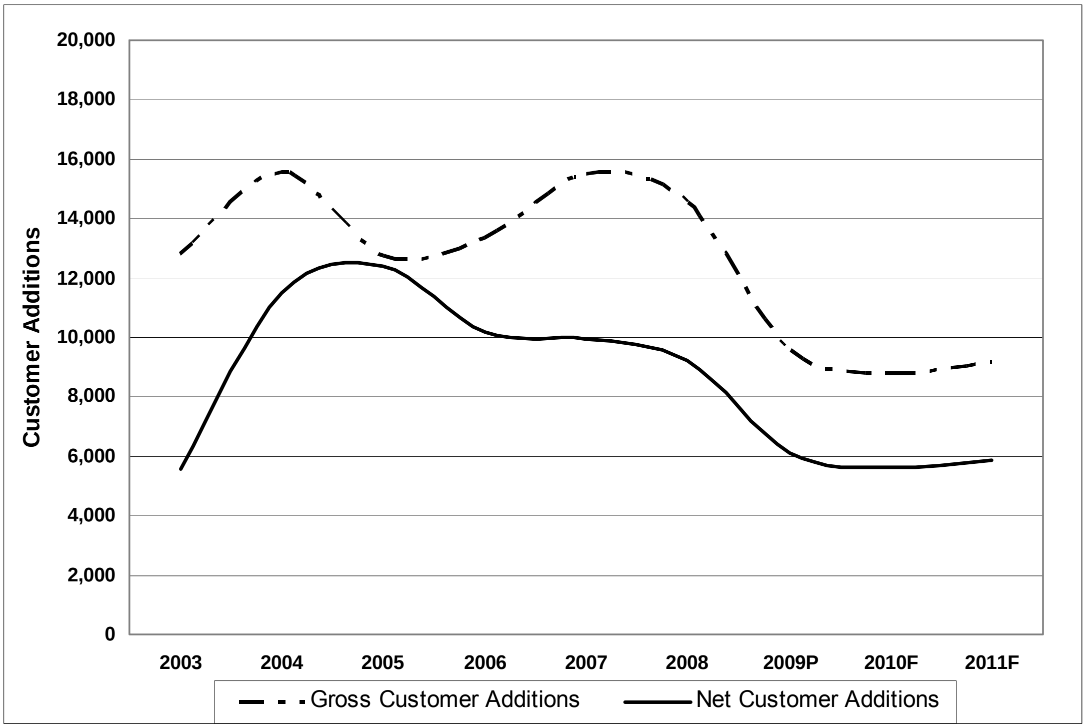
The first quarter forecast of housing starts from the CMHC indicated an expected 34% decline from 2008 actual results (34,321 housing starts were realized in 2008 and 22,800 were projected for 2009), with the Interior (represented by the Kelowna Census Municipal Area) declining at a slightly greater rate than the Lower Mainland (represented by the Vancouver Census Municipal Area).

The April year-to-date results indicated customer additions were approximately 38% lower than what was experienced over the same period in 2008 (April 2009 year-to-date net customer additions were 1,083 as compared to 1,756 in 2008). And, the April 2009 year-to-date ratio of net to gross customer additions was 45%, as compared to 46% over the same period in 2008). This supported the projection that was based upon the CMHC forecast of housing starts, and therefore formed the basis for the 2009 projection of Customer Additions.

50.2 Please extend Figure B-1-3 to include projected Net New Customer Additions for 2010 and 2011.

Response:

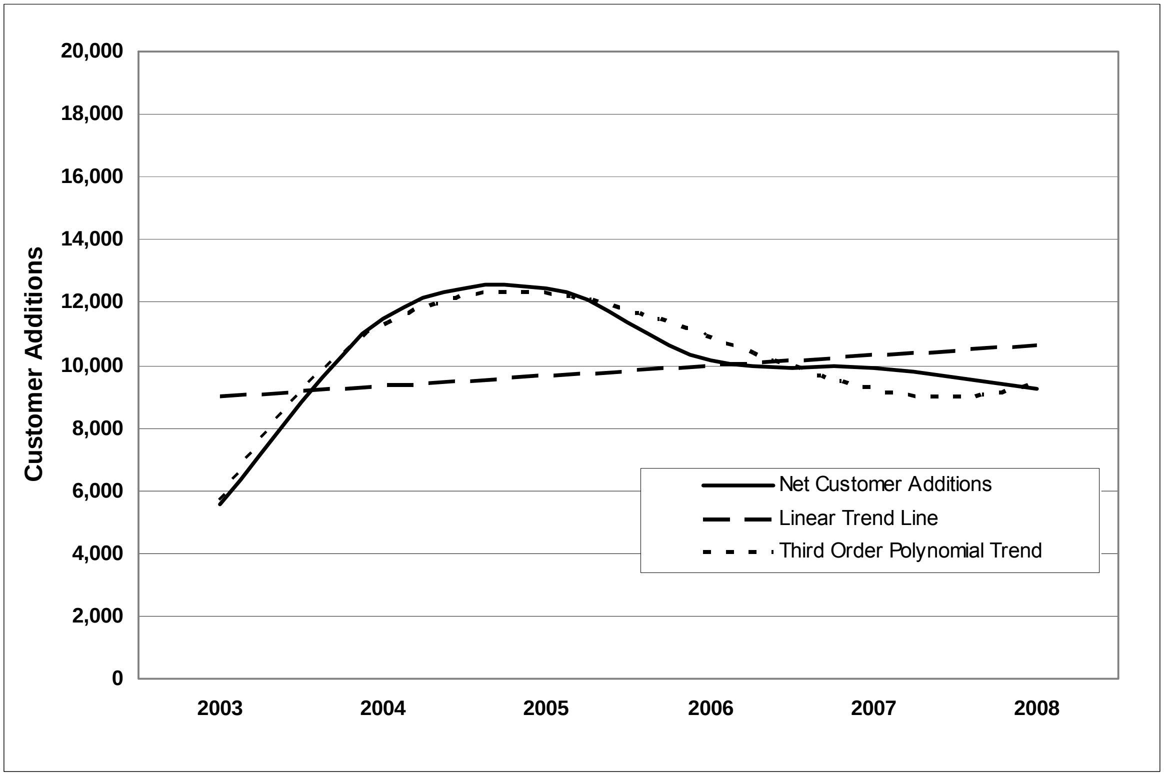
The following chart illustrates the Gross and Net Customer Additions over the period 2003 through 2008, a projection for 2009 and forecast for 2010 and 2011.



50.3 Please provide the linear regression algorithm for Net New Customer Additions over the period 2003 to 2008, and show a graphical representation of the regression curve on Figure B-1-3. Wherever possible, please provide supporting data in the form of an electronic spreadsheet.

Response:

Linear regression was not applied in the development of the forecast for Net New Customer Additions, and therefore there is no algorithm to provide. The following chart illustrates the Net New Customer Additions over the period 2003 to 2008, and includes trend lines based upon both linear and non-linear (third order polynomial) regression.



As can be seen, the linear trend does not provide a good fit to the data. In fact, the R-square value of this trend is only 6.5% which implies a very poor fit. The third order polynomial trend line does show a good fit, with an R-square value of 96%, however as can be seen the trend is showing upwards for 2009, which is not consistent with the slowdown in the B.C. housing market. Given this, it did not seem reasonable to pursue a trending analysis when preparing the forecast of Net New Customer Additions. In prior years, regression analysis has been employed in an attempt to model Customer Additions, but these have resulted in either low R-square values or predicted Customer Additions that were inconsistent with other available data. Therefore, the most reasonable approach at this time is to model Customer Additions to housing starts, more specifically the growth rate of housing starts. Attachment 50.3 includes a fully functioning spreadsheet.

50.4 Please confirm whether the data represented in Figure B-1-3 are a combined summary for residential, commercial, and industrial customer classes. If yes, please also provide tabular data and graphical plots of the historical Gross Customer Additions and Net Customer Additions for residential, commercial and industrial customer class from 2003 to 2008.

Response:

TGI confirms the data represented in Figure B-1-3 are a combined summary for residential, commercial and industrial customer classes. As discussed in BCUC IR 1.49.1, the data is not available on a customer class basis. The data that is available has been provided in Attachment 49.1.

50.5 Please state the turnover rate TGI has assumed in the demand forecast for each customer class in 2010 and 2011.

Response:

The turnover rate TGI has assumed in the demand forecast is discussed in TGI's response to BCUC IR 1.49.2.

50.6 Does this turnover rate apply for both 2010 and 2011? If so, please explain the reason(s).

Response:

Please see TGI's response to BCUC IR 1.49.3.

51.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 278

Demand Intensity

51.1 For residential customers, the intensity (gas demand per person) has decreased by approximately 9 percent from 1999 to 2008 (please see the following table). Despite the decrease in demand intensity, the overall demand for residential gas in 2008 remains essentially the same as the demand in 1999. Please explain the relationship between the volume and intensity of demand for residential gas. Wherever possible, please use graphical representations of to illustrate the relationships between volume and intensity of demand.

Residential: Demand and Intensity, 1999 to 2008

		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
[1]	Residential Gas Demand (PJs)	77.5	76.5	69.1	74.7	68.4	66	69	68.4	74.6	78.2
[2]	Population ('000)	4,001.3	4,039.2	4,078.4	4,115.4	4,155.4	4,203.8	4,260.2	4,320.3	4,380.3	4,442.1
[3]	Intensity - Gas demand per person (GJs/person)	19.37	18.94	16.94	18.15	16.46	15.70	16.20	15.83	17.03	17.60

Notes:
[1] Source data from Appendix D-1
[2] data from Appendix C-1
[3] Gas demand / population (GJs/person)

Response:

TGI does not believe the data illustrated in the above table is representative of the demand intensity of its customers. The population figures include all people living in B.C., and even with population estimates for those areas within TGI's service territories (as illustrated in TGI's response to BCUC IR 1.14) there would still be people that are not currently customers of TGI included in those figures. Given that, analyzing demand intensity as illustrated in the table accompanying this IR could lead to misleading results. A better gauge of the demand intensity is the average use per customer rate, which is analyzed for residential and commercial customer classes, and discussed starting on page 278 in the Application.

With regards to the overall demand for residential gas in 2008 being essentially the same as the demand in 1999, that is only the case for actual demand. And, as discussed in TGI's response to BCUC IR 1.4.2, normalized annual demand is the more appropriate variable to consider when comparing year over year changes (as weather fluctuations are removed from the equation). When considering normalized residential demand, there has been a decline from 77.8 PJ in 1999 to 68.8 PJ in 2008, which is consistent with the experienced decline in average use per customer rates. As volumes are essentially the product of the number of customers and average use per customer, although TGI has continued to add customers to its system, this has only partially offset the more significant declines seen in average use per customer rates over the period 1999 to 2008.

52.0 Reference: Gas Sales and Transportation Demand

Appendix D-1

User Per Customer Forecast - TGI Weather Data

52.1 Data presented in Appendix D-1 indicate that heating degree days (HDD) are based on an 18 degree Celsius control point. Please explain the method used to calculate HDD, including an explanation of whether HDD was calculated using a simplified daily average temperature or another method.

Response:

Heating Degree Days (HDD), when based on a control point of 18 degrees Celsius, are calculated based upon the following mathematical expression:

HDD_{18} = Maximum (0, 18-Temperature)

Where the temperature represents the average of hourly temperature reads, over a gas day (7am to 7am PST), from a particular weather station.

52.2 Please indicate whether the method used for calculating HDD has remained constant over the period 1999 to 2008. If not, please identify and explain any changes.

Response:

TGI confirms that no changes have been made to the methodology for calculating HDD over the period 1999 to 2008.

52.3 Please provide data and the methodology used to normalize the Actual Energy Demand and Use Per Customer provided in Appendix D-1.

Response:

TGI normalizes annual demand and use per customer rates for residential and commercial customers on a regional basis, including rate classes 1, 2, 3, and 23. Normalization, with respect to weather, is accomplished through the following steps:

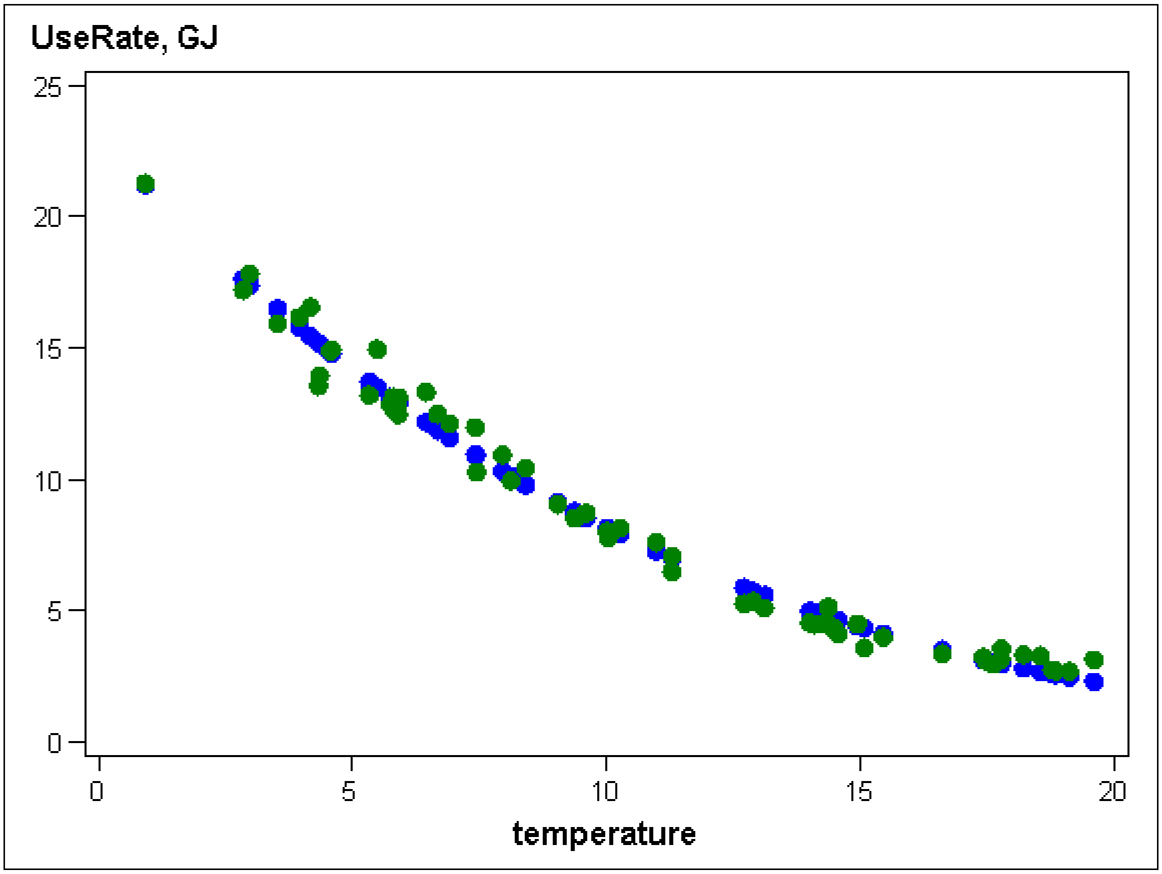
1) Determine the relationship between weather and consumption using non-linear regression analysis, where monthly actual use per customer rates are regressed against average actual monthly temperatures over a rolling five-year period
2) Once the relationship between weather and consumption has been determined, actual and normal monthly weather is then applied to the regression parameters, which results in estimated actual and normal consumption. Normal weather is defined as the average weather experienced over a rolling ten-year period.
3) The ratio of the normal use per customer estimate to the actual use per customer estimate represents the normalization factor for that particular region, rate class, and month.
4) The normalization factor is applied to the actual use per customer, resulting in normalized use per customer rates.

This methodology is illustrated for Lower Mainland Residential (Rate 1) customers, for 2008 use per customer.

Model: Gompertz (non-linear model)

Specification: Monthly Avg Use Per Customer = β1*EXP(-EXP(-β2*(Avg Monthly Temp - β3)))

The following graph illustrates the actual data together with the regression curve that is fitted to the data, which includes average actual use per customer and average monthly temperature over the period January 2004 to December 2008.



The regression analysis resulted in the following estimates for the parameters:

$\beta_2 = 0.0$

$\beta_3 = -28.7$

Using January 2008 as an example, given the average monthly temperature in the Lower Mainland region during January 2008 was 2.84 degrees Celsius, and the normal average daily temperature for January 2008 is 4.66 degrees Celsius, by applying the above model specification the estimated actual use per customer rate for January 2008 is 18.2 GJ per customer and the estimated normal use per customer rate for January 2008 is 15.3 GJ per customer. Therefore, the ratio of 15.3 / 18.2 = 0.84 is the normalization factor for Lower Mainland Residential customers, January 2008. Finally, since the actual use per customer rate for January 2008 was 17.2 GJ per customer, the normalized use per customer rate for January 2008 becomes 17.2 X 0.84 = 14.5 GJ per customer.

This process is repeated for each month of the year, for each region and rate class, and then the sum of the monthly normalized use per customer rates becomes the normalized annual use per customer rate.

52.4 As it relates to the data presented in Appendix D-1, please identify and explain any changes in methodology used by TGI to normalize the Actual Energy Demand and Use Per Customer since 2003.

Response:

Since 2003, the methodology used by TGI to normalize the Actual Energy Demand and Use Per Customer has remained unchanged.

53.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 278

Use Per Customer Forecast

Page 278 states: "The analysis of historical normalized use per account indicates a downward trend in residential average use per customer, while commercial average use per customer is proving to be more stable."

53.1 Under the sub-heading "TGI Consolidated – All Regions" found in Appendix D-1, please provide totals for the following tables:

- Actual Use Per Customer Rates 2003 – 2008; and
- Normalized Actual Use Per Customer Rates 2003 – 2008.

Response:

The following table illustrates the overall TGI Actual Use Per Customer Rates over the period 2003 to 2008. These figures were developed by calculating the weighted average Use Per Customer Rates for the Rate 1, 2, 3, and 23 customers in each of TGI's service territories. Given the data is available by customer class, and there are differences in consumption patterns for each of the above stated customer classes, the overall weighted average use per customer (actual or normal), from TGI's perspective, is not a variable that would be considered when developing the demand forecast. A more meaningful approach would be to consider each customer class individually, which TGI does when developing the demand forecast.

Actual Use Per Customer Rates 2003 - 2008 (GJ/yr)

	2003	2005	2006	2007	2008
Total	143.6	138.9	140.6	139.7	149.6

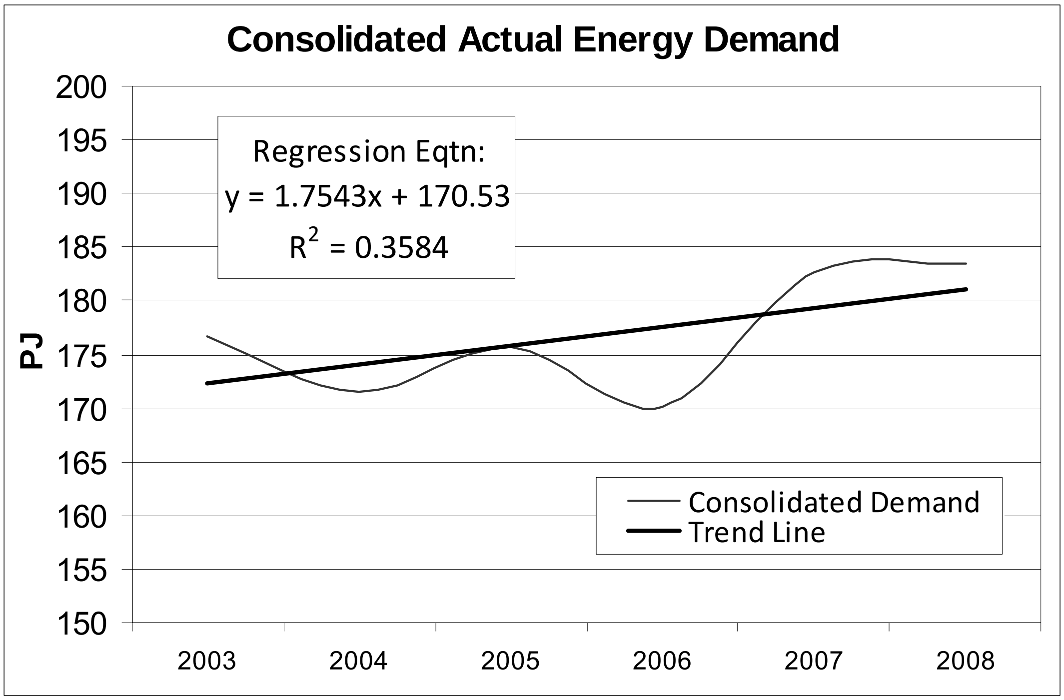
The following table illustrates the overall TGI Normalized Actual Use Per Customer Rates over the period 2003 to 2008. As with the actual use per customer rates above, these figures were developed by calculating the weighted average Use Per Customer Rates for the Rate 1, 2, 3, and 23 customers in each of TGI's service territories.

Normalized Actual Use Per Customer Rates 2003 - 2008 (GJ/yr)

	2003	2005	2006	2007	2008
Total	148.7	150.4	142.6	142.4	142.5

53.2 For the period 2003 to 2008, please provide a consolidated summary figure of the Actual Energy Demand and the Actual Use Per Customer. Please provide the supporting data, linear regression equation, and graph.

Response:

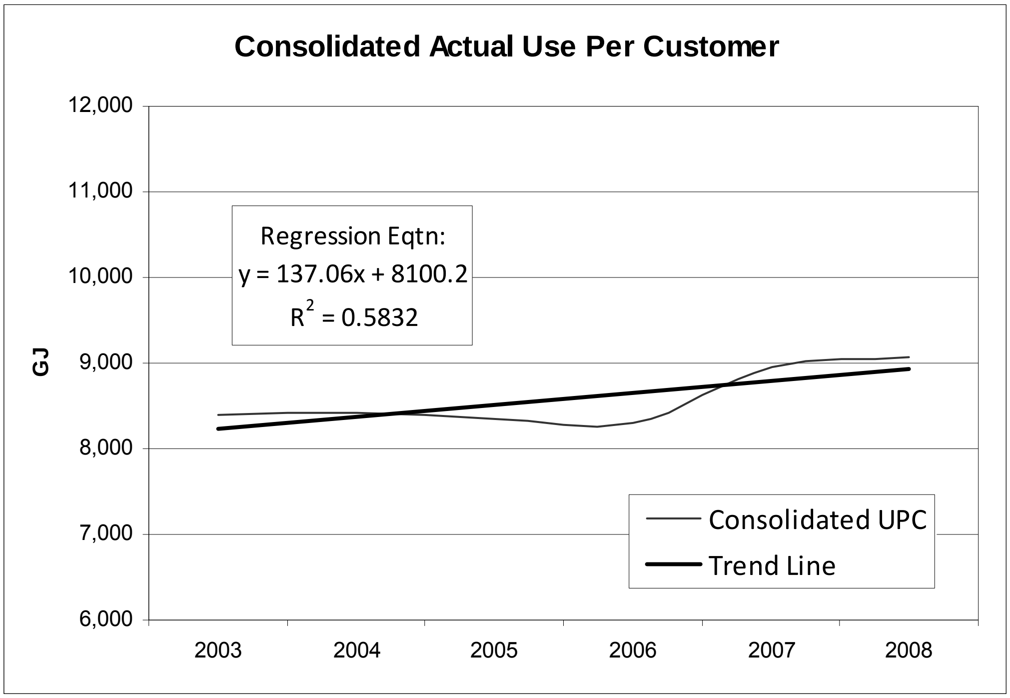


As can be seen from the above graph, the trend line does not show a good fit over this period (with an R-square of only 36%). Also, given that there are distinct customer segments included in these figures, and the patterns of natural gas demand over time are different for those customer segments, TGI would not consider an analysis of this data to be appropriate in preparing the demand forecast. Rather, a more reasonable approach would be to analyze the data for each particular customer segment to arrive at a total.

The following table and graph illustrate the consolidated summary TGI Actual Use Per Customer over the period 2003 to 2008. Included is the linear regression of the time series along with the regression equation and associated R-square value.

TGI Consolidated Actual Use Per Customer (GJ/Year)

	2003	2004	2005	2006	2007	2008
Total	8,407	8,426	8,342	8,291	8,953	9,060



The above graph, as with the Actual Energy Demand graph previously illustrated, does not show a good fit between the trend line and Actual Use Per Customer results, with an R-square of only 58%. Although this is slightly better than the results for Actual Energy Demand, an analysis of this data by customer segment is more appropriate, given the distinct usage patterns seen amongst residential, commercial, and industrial customers.

53.3 For the customer history data provided in Appendix D-1, please provide a table of the Number of Customers per User Class summarized for residential, commercial and industrial customer classes in the following format:

Number of Customers per User Class

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009(P)	2010(F)	2011(F)
Residential													
Commerical													
Industrial & Transport													
Total Number of Customers													

Response:

The following table illustrates the year-ending Number of Customers per Rate Class for the Residential, Commercial and Industrial customer classes, as per the above format.

Number of Customers per Customer Class

	1999	2000	2001	2002	2003	2004	2005
Residential	673,026	678,712	683,547	690,907	697,213	707,929	719,356
Commercial	77,851	78,626	78,642	77,839	77,077	77,833	78,835
Industrial & Transportation	1,016	1,099	1,113	1,162	1,164	1,196	1,187
Total Number of Customers	751,893	758,437	763,302	769,908	775,454	786,958	799,378

Number of Customers per Customer Class

	2006	2007	2008	2009 (P)	2010 (F)	2011 (F)
Residential	731,899	741,176	749,135	754,126	758,903	763,886
Commercial	79,666	80,360	81,654	82,783	83,606	84,473
Industrial & Transportation	1,118	1,062	1,056	1,055	1,055	1,055
Total Number of Customers	812,683 [1]	822,598	831,845	837,964	843,564	849,414

1 Includes 3124 additional Squamish customers who were part of the LML amalgamation

53.4 Please summarize the Customer History provided in Appendix D-1 in a table with the following format:

	A	B	C	C/B	E	(((C x E)/1,000,000) / A)
	Total Energy Demand in the Class (PJs)	Total Number of Customers in the Class	Net Customer Additions (Losses)	% Change in # of Customers	Use Rate (GJs)	% Change in Voume (PJs)
2003						
2004						
2005						
2006						
2007						
2008						
2009 (P)						
2010 (F)						
2011 (F)						

Response:

The following tables provided the information requested above. TGI would like to clarify the data being presented in the last column, as the title may lead to confusion for some readers. The last column, "% Change in Volume (PJs)" is not the year over year change in annual volumes, but rather an illustration of the portion of volumes (for that particular year) that can be attributed to new customer additions. This is not the same as the annual change in volumes.

Given the formula was provided, TGI assumes the portion of volumes (for that particular year) that can be attributed to new customer additions is the desired response, and the figures have been calculated accordingly.

Residential Customer Class

	A Total Energy Demand in the Class (PJs)	B Total Number of Customers in the Class	C Net Customer Additions (Losses)	C/B % Change in # of Customers	E Use Rate (GJs)	(((C x E)/1,000,000)/ A) % Change in Volume (PJs)
2003	72.6	697,213	6,306	0.90%	103.1	0.90%
2004	72.0	707,929	10,716	1.51%	102.6	1.53%
2005	69.3	719,356	11,427	1.59%	97.4	1.61%
2006	70.0	731,899	9,595	1.31%	96.8	1.33%
2007	70.6	741,176	12,003	1.62%	96.0	1.63%
2008	68.8	749,135	7,959	1.06%	92.5	1.07%
2009 (P)	71.0	754,126	5,213	0.69%	84.2	0.62%
2010 (F)	67.8	758,903	4,777	0.63%	89.4	0.63%
2011 (F)	67.2	763,886	4,983	0.65%	88.0	0.65%

Commercial Customer Classes

	A Total Energy Demand in the Class (PJs)	B Total Number of Customers in the Class	C Net Customer Additions (Losses)	C/B % Change in # of Customers	E Use Rate (GJs)	(((C x E)/1,000,000)/ A) % Change in Volume (PJs)
2003	45.3	77,077	(762)	-0.99%	587.7	-0.99%
2004	45.2	77,833	749	0.96%	580.7	0.96%
2005	43.9	78,835	978	1.24%	556.9	1.24%
2006	44.1	79,666	655	0.82%	553.6	0.82%
2007	45.5	80,360	1,092	1.36%	566.2	1.36%
2008	45.9	81,654	1,294	1.58%	560.6	1.58%
2009 (P)	47.5	82,783	907	1.10%	574.4	1.10%
2010 (F)	47.3	83,606	823	0.98%	566.1	0.98%
2011 (F)	47.9	84,473	867	1.03%	567.6	1.03%

Industrial Customer Classes

	A Total Energy Demand in the Class (PJs)	B Total Number of Customers in the Class	C Net Customer Additions (Losses)	C/B % Change in # of Customers	E Use Rate (GJs)	(((C x E)/1,000,000)/ A) % Change in Volume (PJs)
2003	66.2	1,164	2	0.17%	85.4	0.00%
2004	63.6	1,196	(23)	-1.92%	80.8	0.00%
2005	63.3	1,187	16	1.35%	79.2	0.00%
2006	58.3	1,118	(69)	-6.17%	71.7	-0.01%
2007	60.1	1,062	(52)	-4.90%	73.1	-0.01%
2008	55.3	1,056	(16)	-1.52%	66.5	0.00%
2009 (P)	48.7	1,055	5	0.47%	58.1	0.00%
2010 (F)	46.8	1,055	0	0.00%	55.5	0.00%
2011 (F)	46.7	1,055	0	0.00%	55.0	0.00%

53.5 Please provide a similar summary table Consolidated For All Classes and All Regions in the following format:

Consolidated For All Classes and All Regions:

	A Total Energy Demand (PJs)	B Total Number of Customers	C Net Customer Additions (Losses)	C/B % Change in # of Customers	E Net Gain (Loss) of Volume (PJs)	E / A % Change in Voume (PJs)
2003						
2004						
2005						
2006						
2007						
2008						
2009 (P)						
2010 (F)						
2011 (F)						

Response:

The following tables provided the information requested above. As indicated in the response to BCUC IR 1.53.4 above, TGI would like to clarify the data being presented in the last column, as the title may lead to confusion for some readers. The last column, "% Change in Volume (PJs)" is not the year over year change in annual volumes, but rather an illustration of the portion of volumes (for that particular year) that can be attributed to new customer additions. This is not the same as the annual change in volumes. Given the formula was provided, TGI assumes the portion of volumes (for that particular year) that can be attributed to new customer additions is the desired response, and the figures have been calculated accordingly.

Consolidated For All Customer Classes

	A Total Energy Demand in the Class (PJs)	B Total Number of Customers in the Class	C Net Customer Additions (Losses)	C/B % Change in # of Customers	E Use Rate (GJs)	(((C x E)/1,000,000)/A) % Change in Volume (PJs)
2003	184.1	775,454	5,546	0.72%	237.4	0.72%
2004	180.8	786,958	11,504	1.46%	229.7	1.46%
2005	176.4	799,378	12,420	1.55%	220.8	1.55%
2006	172.4	812,683	10,181	1.25%	212.1	1.25%
2007	176.2	822,598	9,915	1.21%	214.2	1.21%
2008	170.0	831,845	9,247	1.11%	204.4	1.11%
2009 (P)	167.3	837,964	6,125	0.73%	199.6	0.73%
2010 (F)	162.0	843,564	5,600	0.66%	192.0	0.66%
2011 (F)	161.8	849,414	5,850	0.69%	190.5	0.69%

As mentioned in TGI's response to BCUC IR1.53.2, there are distinct consumption patterns seen in the residential, commercial and industrial customer segments. Given those distinctions, TGI believes a more reasonable approach in analyzing the above data would be to consider the tables provides in response to BCUC IR 1.53.4, which illustrates the same data by customer segment.

54.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 279

Use Per Customer Forecast

54.1 Please explain how a 0.3 GJ decline in residential average use per customer was determined.

Response:

The 0.3 GJ decline in residential average use per customer discussed on page 279 (as referenced above) is the maximum expected decline that is attributed to TGI's EEC programs, and the manner in which this was determined is explained in TGI's response to BCUC IR 1.43.

"All of these factors are contributing towards a downward trend in average use per customer."

54.2 Please provide the data used to calculate the average use per customer.

Response:

Average Annual Use Per Customer is calculated by summing the Average Monthly Use Per Customer for a particular rate class and region. Using the Lower Mainland Residential (Rate 1) 2008 actual results, the following illustrates the calculation:

Month	Volume (GJ)	Month-End Customers	UPC (GJ/Customer)
Jan-08	8,894,485	517,232	17.2
Feb-08	6,831,775	517,477	13.2
Mar-08	6,794,179	517,709	13.1
Apr-08	5,324,973	517,819	10.3
May-08	2,775,751	518,118	5.4
Jun-08	2,657,724	518,118	5.1
Jul-08	1,837,119	518,075	3.5
Aug-08	1,635,252	518,276	3.2
Sep-08	2,140,401	518,898	4.1
Oct-08	4,163,832	519,584	8.0
Nov-08	5,173,517	520,185	9.9
Dec-08	8,973,002	521,437	17.2
Annual Average Use Per Customer Rate			**110.3**

54.3 What are TGI's assumed Use Per Customer Rates for the Forecast Period 2010 and 2011? Please identify what customer rates were used for 2010 and 2011.

Response:

TGI's assumed Use Per Customer Rates for the Forecast Period 2010 and 2011, by region and rate class, are as follows:

Lower Mainland (GJ/Customer)

	2010	**2011**
Rate 1	96.7	95.3
Rate 2	332	332
Rate 3	3,322	3,322
Rate 23	4,615	4,615

Inland (GJ/Customer)

	2010	**2011**
Rate 1	73.2	71.8
Rate 2	278	278
Rate 3	3,426	3,426
Rate 23	4,998	4,998

Columbia (GJ/Customer)

	2010	**2011**
Rate 1	80.8	79.7
Rate 2	340	340
Rate 3	3,720	3,720
Rate 23	4,550	4,550

Revelstoke (GJ/Customer)

	2010	**2011**
Rate 1	49.2	49.2
Rate 2	301	301
Rate 3	3,651	3,371

TGI Consolidated (GJ/Customer)

	2010	**2011**
Rate 1	89.7	88.3
Rate 2	318	318
Rate 3	3,346	3,346
Rate 23	4,680	4,680

54.4 For new TGI residential customers attached in 2005, what has been their average use in 2006, 2007 and 2008.

Response:

The ability to distinguish between customers new to the system and customers that simply moved premises was gained when the CAFÉ (Customer Attraction Front End) Reporting tool was implemented in 2006. Given that, TGI has identified those customers new to the system from approximately June 2006 through December 2007, and has found their average annual normalized use per customer rate to be 81.2 GJ per customer for 2008. Comparing this to the overall 2008 TGI Residential Use Per Customer Rate of 92.5 GJ per customer shows that Average Use Per Customer for new customers is approximately 12% lower than that for the typical TGI Residential customer. This is incorporated in the forecast of Average Use Per Customer rates, as a portion of the decline seen in recent historical Use Per Customer Rates can be attributed to new customers who use less natural gas (as a result of having higher efficiency rated appliances, and with more MFD's being in the customer mix).

55.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 279

Annual Consumption by Housing Type

55.1 For Table C-4-2, what sample size for each housing type was considered in the 2008 Residential End Use Study? Also, please provide the statistical confidence level associated with the survey.

Response:

For Table C-4-2, the sample size for each housing type was as follows:

Housing Type	**Sample Size**
Single Family Dwelling	729
Multi-Family Dwelling	343
Vertical Subdivision	176
Total	**1,248**

The 2008 Residential End Use Study was conducted using a statistical confidence level of 95%.

56.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 280

Annual Consumption by Housing Type

56.1 What analyses support the forecasted impact of efficiency improvements during the Forecast Period?

Response:

The analyses that support the forecasted impact of efficiency improvements during the Forecast Period are described in TGI's response to BCUC IR 1.40.3, which discusses the rationale and assumptions regarding both efficiency improvements and the shift towards more multi-family dwellings in the housing mix. But more generally speaking, the trending analyses TGI has performed on normalized actual use per customer rates provides an overall indication of the decline which can be attributed to non-weather related factors, the most significant of which being efficiency improvements (as discussed in TGI's response to BCUC IR 1.40.2).

57.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 281

Commercial Sector Analyses

57.1 Please confirm whether the historical data used to assess the consumptions patterns on a sector-by-sector basis are the same data presented in Appendix D-1.

Response:

The historical data used to assess the consumption patterns on a sector-by-sector basis is slightly different from the data presented in Appendix D-1. The data presented in Appendix D-1 is from monthly reports for each rate class sent to TGI's Finance Department for monthly, quarterly, and annual reporting purposes. The data used to assess the consumption patterns on a sector-by-sector basis required reports for individual customers, and therefore was obtained from a data extract reporting meter reads for the commercial customer classes. The two data sets provide similar information, but due to timing differences in reporting, the structure, and also cycle billing, they do not typically reconcile.

58.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, pp. 280-299

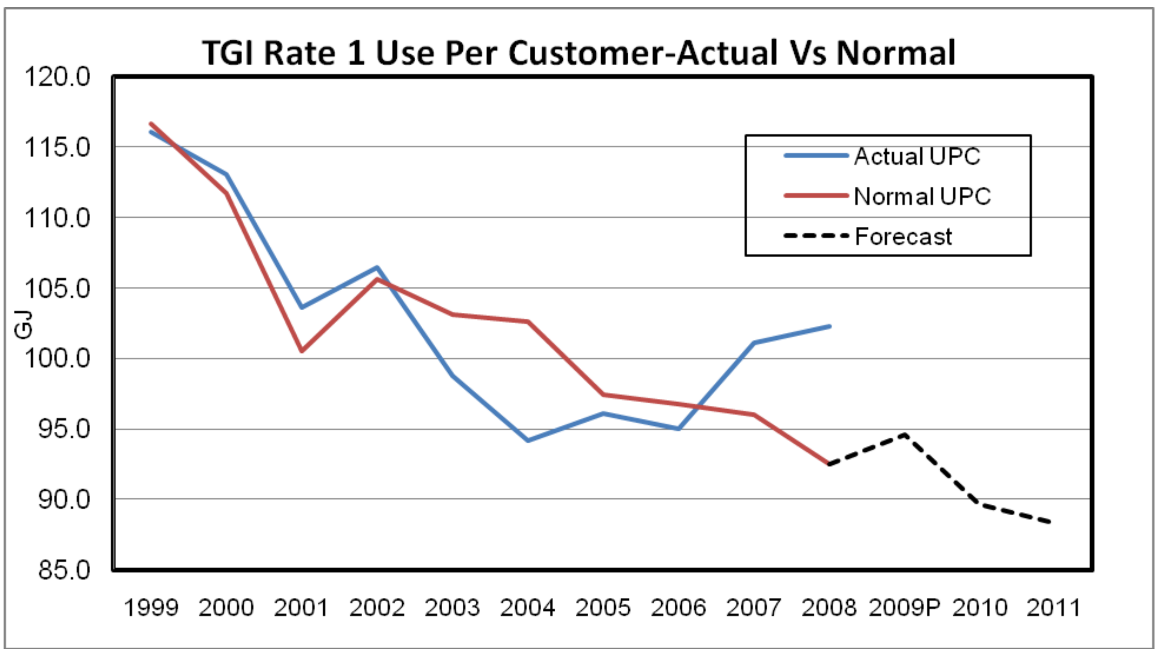
Use Per Customer Forecast

Throughout the RRA, TGI relies upon normalized historical and base year data to forecast Use Per Customer Rates ("UPC"). TGI's use of normalized data is consistent with previous submissions to the Commission.

58.1 Appendix D-1 presents normalized UPC and actual UPC data. For the period 1999 to 2008, please provide a linear graph that illustrates the relationship between normalized and actual UPC data for residential rate 1. Based on the data provided in Table C-4-6 (page 299), please include residential data for 2009, and forecasted data for 2010 and 2011.

Response:

The following graph illustrates the relationship between normalized and actual UPC data for Residential Rate 1 customers over the period 2003 to 2008, including a projection for 2009 and forecast for 2010 and 2011.



Given that normalized UPC is simply the actual UPC with the weather effect removed, a comparison of the actual to normal UPC only illustrates the effect weather has on consumption and does not provide any other meaningful information.

58.2 Please describe the process used to make the adjustment between actual and normalized data.

Response:

The process used to make the adjustment between actual and normalized data is described in detail in TGI's response to BCUC IR 1.52.3.

58.3 Please explain any significant differences between normalized and actual UPC over the period 2003 to 2008. How would TGI explain, for example, a graphic indication that over this time period there is a general trend of increasing actual UPC, whereas the normalized data suggest the opposite trend?

Response:

As discussed in TGI's response to BCUC IR 1.4.2, the differences between normalized and actual Use Per Customer are strictly weather related. It is more appropriate to consider trends seen in normalized Use Per Customer, as it is through analyzing this variable that impacts on usage due to factors other than weather can be identified.

The following table illustrates the Actual and Normal Use Per Customer, Annual Heating Degree Days, and variance of Normal to Actual Use Per Customer over the period 2003 to 2008.

	2003	2004	2005	2006	2007	2008
Actual Use Rate (GJ/Customer)	98.8	94.2	96.1	95.0	101.1	102.3
Normal Use Rate (GJ/Customer)	103.1	102.6	97.4	96.8	96	92.5
Variance (Normal to Actual)	4%	9%	1%	2%	-5%	-10%
Annual HDD	2,667	2,525	2,664	2,714	2,889	3,043

There are two years where there is a significant difference between Normalized and Actual Use Per Customer Rates, in 2004 and in 2008. As can be seen, in 2004 the Annual Heating Degree Days were the lowest over that period, and in 2008 they were highest over that period. Given that, and the fact that normalization removes the weather influence from actual data, the differences between the two figures is attributed to differences in annual weather patterns.

59.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, pp. 294-310

Use Per Customer Forecast

59.1 Graphs presented on pages 294 to 310 represent a different time period, 2005 to 2008, as opposed to the years 2003 to 2008 used in other sections of the RRA. Please explain why TGI has selected different time periods.

Response:

TGI has more historical data available, on a per customer and sector basis, for small and large commercial customers than for industrial and commercial transportation customers, and that is why the additional two years of data was provided for small and large commercial customers. The industrial and commercial transportation data was migrated to ABSU in the second quarter of 2004, and therefore the first full year of data available from that system is 2005. Other data was available for industrial customers by sector, but it was only available at the aggregate level for each sector and was therefore excluded from the analysis. The additional data, for industrial customers, does appear in response to BCUC IR 1.60.2, and also in response to BCUC IR 1.62.1. However, the additional data for commercial transportation customers is unavailable.

60.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 301, Table C-4-7 and Schedules 5, 7, 22, 25, & 27

Industrial Demand Forecast

60.1 Please compose a table in a format comparable to Table C-4-7 that provides normalized and actual Industrial energy consumption data for industrial customers in the top energy consuming sectors including pulp & paper, wood products, greenhouses, mining, apartments and condominiums, chemical manufacturing, and food and beverage for the years 2003 to 2008 plus 2009 Projection and 2010 and 2011 Forecasts.

Response:

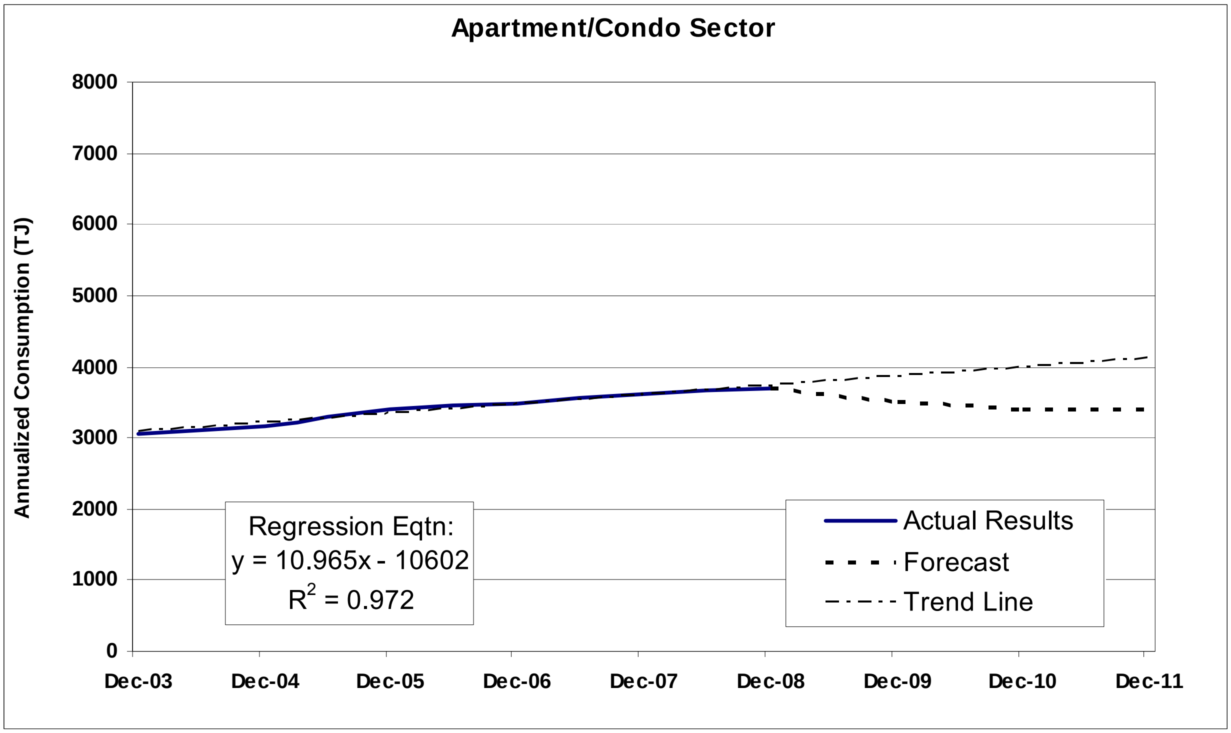
Industrial volumes are more closely tied to production levels, and are therefore considered to be primarily process loads which do not fluctuate with changes in weather patterns. Therefore, TGI does not normalize consumption for the industrial customer classes, and instead relies upon both direct customer feedback and also sector analyses in preparing the industrial demand forecast. The actual demand in a table similar to Table C-4-7 is provided in TGI's response to BCUC IR 1.62.1.

60.2 Please prepare a graph of the actual and normalized subtotals for Energy Consumption in the years 2003 to 2011. Please include the linear regression curves and equations.

Response:

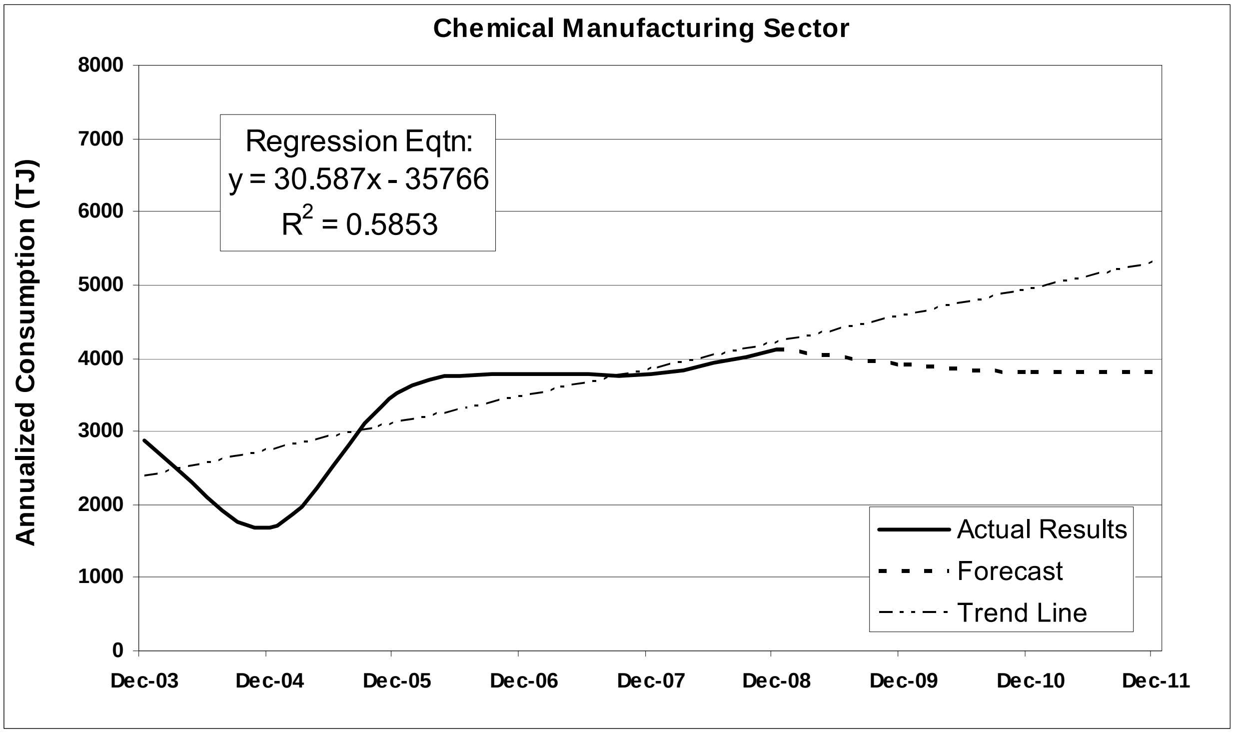
As normalized consumption is not available for the industrial customer classes, the following graphs illustrates only actual demand for each of the top consuming industrial sectors from 2003 through 2011, including the 2003-2008 trend line developed through linear regression. The linear regression equation and R-square value is also illustrated.

Apartment/Condominium Sector:



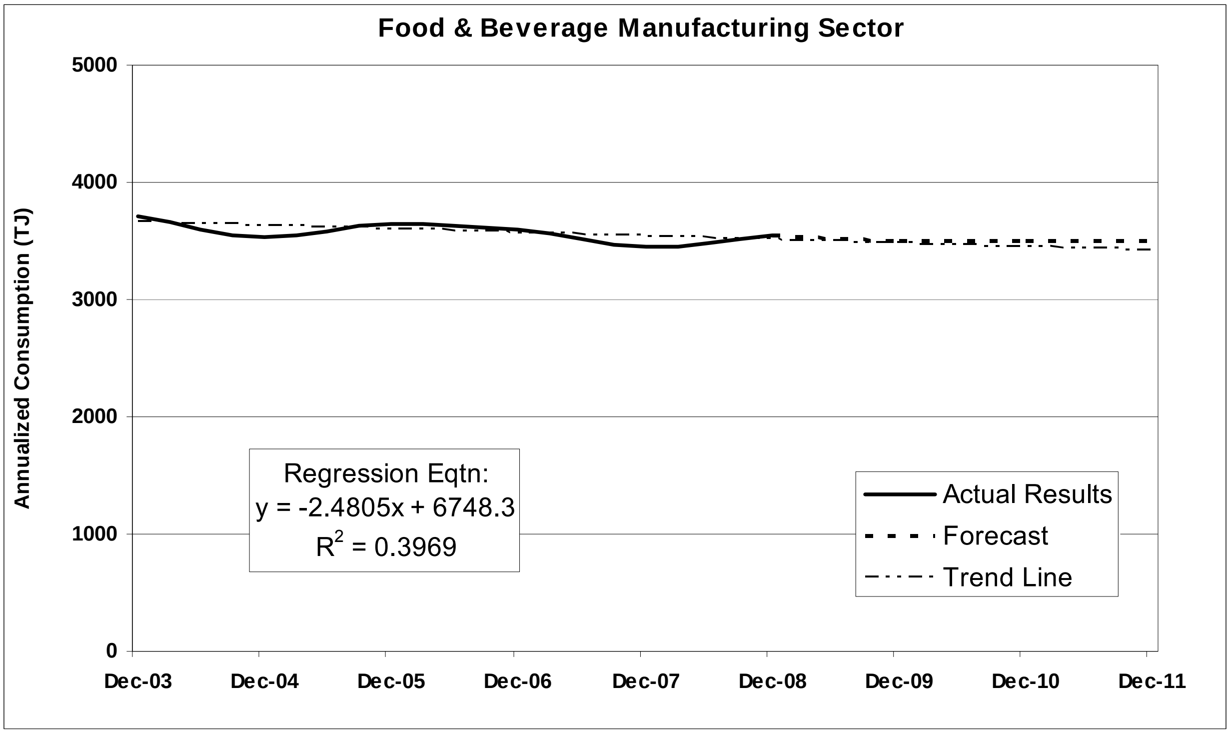
Although the trend line from 2003 through 2008 shows a good fit to the data points (with an R-square value of 97%), TGI does not believe this trend will continue. Given this sector is comprised of larger apartment or condominium buildings, and are essentially residential customers, there are similar opportunities for efficiency gains to be made as there are for this sector in the small and large commercial customers classes, and also the residential customer class. Therefore TGI expects to see a moderate decline in consumption over the Forecast Period.

Chemical Manufacturing Sector:



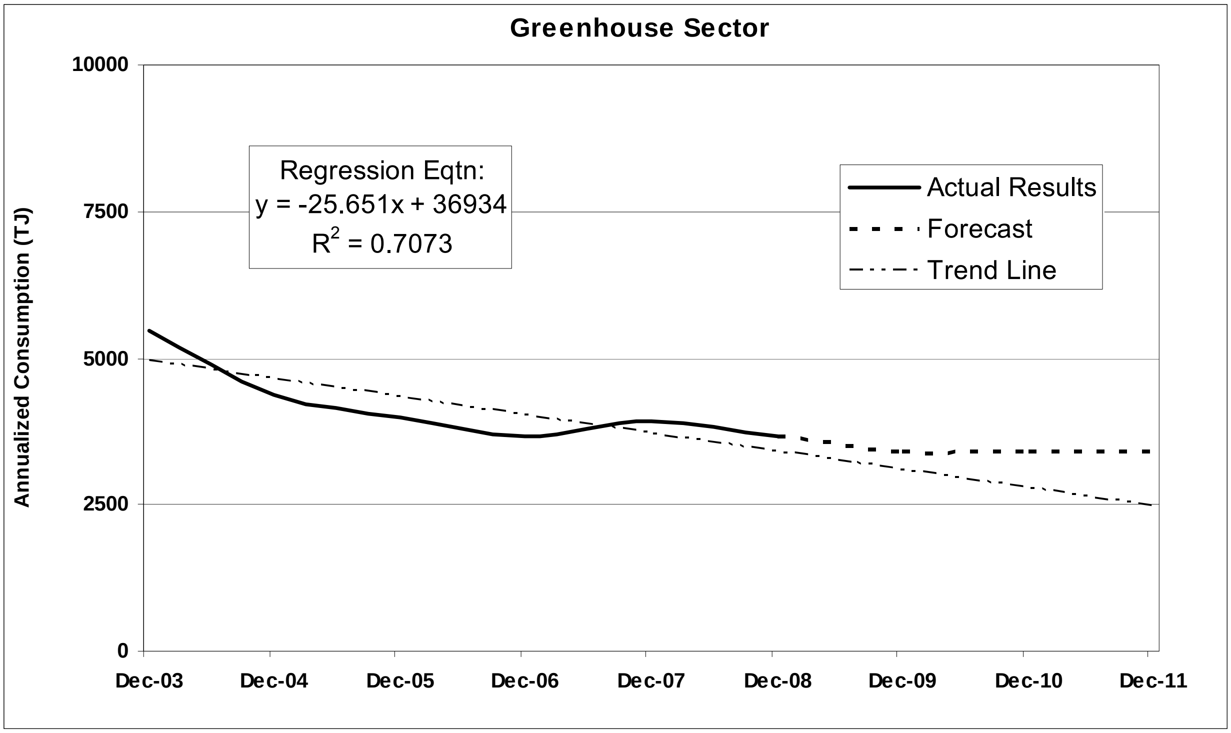
The trend line from 2003 through 2008 does not show a very good fit to the data, with the R-square value being only 59%. Additionally, there are only 23 customers in this sector, which means changes in individual customers' consumption patterns can significantly impact the overall consumption patterns for this sector. For example, the growth seen from 2007 through 2008 is directly related to a single customer installing additional equipment. Absent that single customer's growth in consumption during 2008, there would have been a moderate decline in consumption seen that year. Given that, TGI expects consumption in this sector to moderately decline over the Forecast Period.

Food & Beverage Manufacturing Sector:



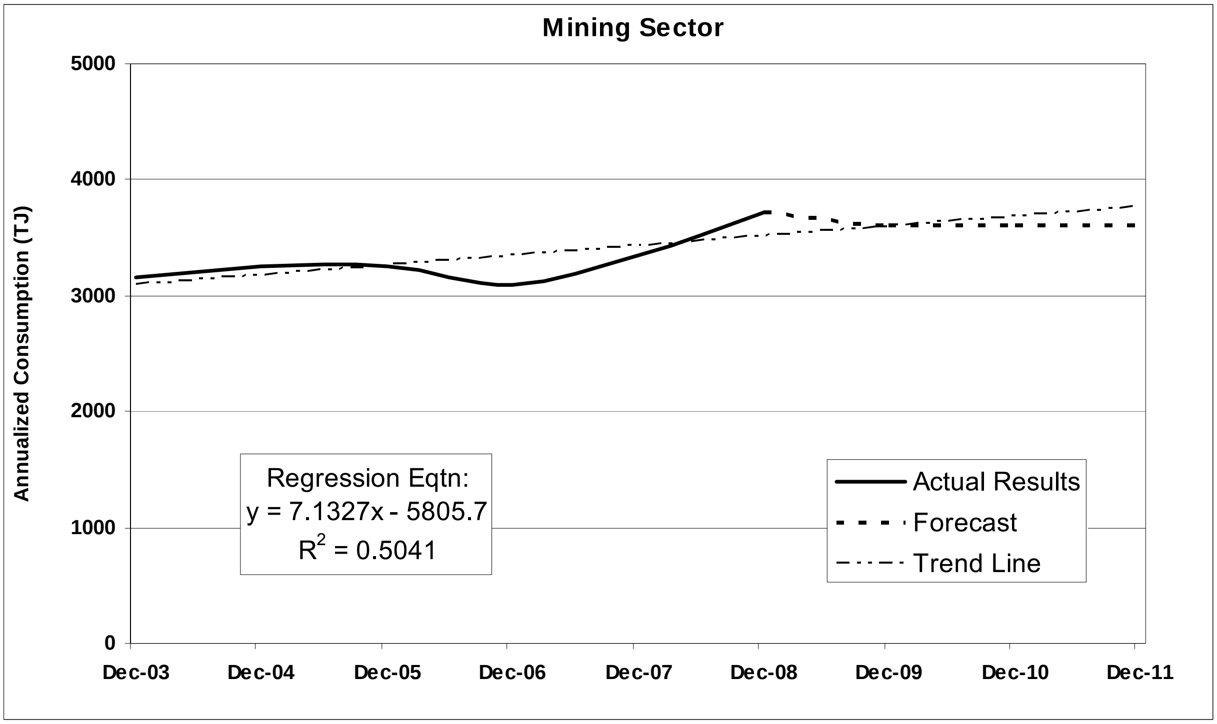
Although the trend line from 2003 through 2008 shows a poor fit (with an R-square of only 40%), the trend going forward is in line with TGI's expectations. There has been some volatility with this sector over the past few years, but TGI's analysis indicates this is due to a handful of customers whose consumption is expected to stabilize over the future. Therefore, TGI is forecasting relatively stable consumption for this sector over the Forecast Period.

Greenhouse Sector:



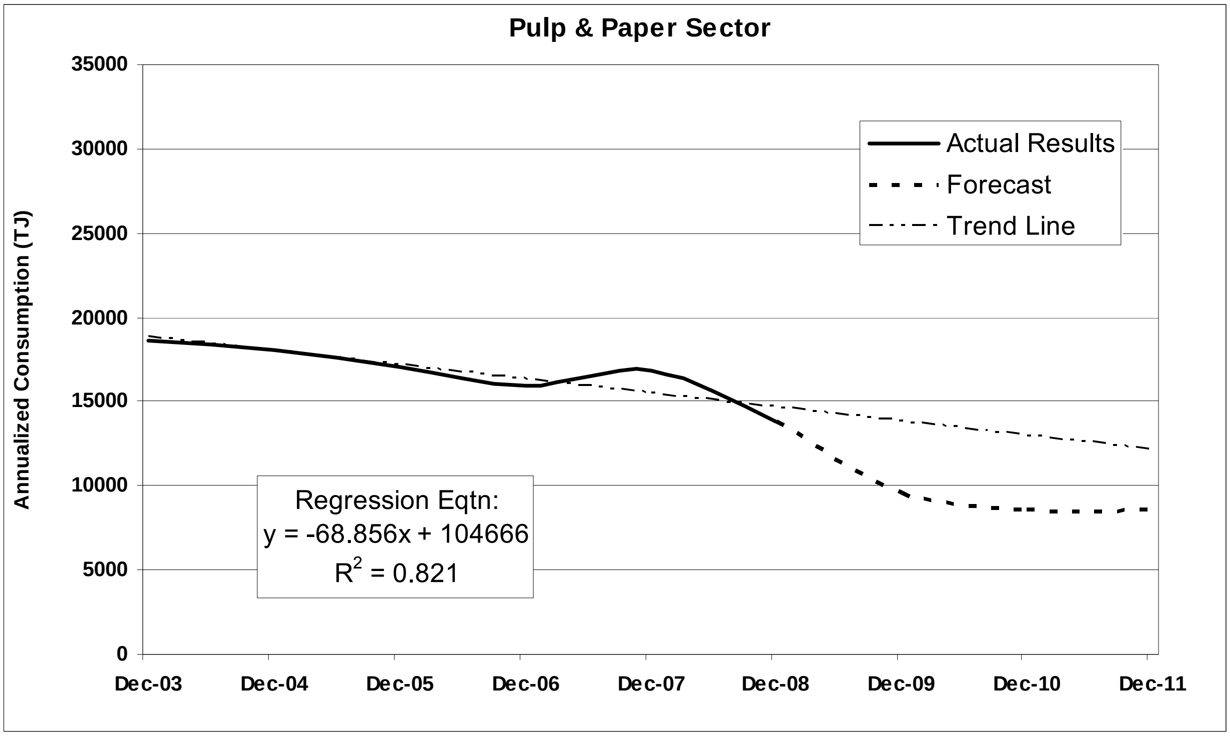
Although the trend line from 2003 through 2008 shows an acceptable fit (with an R-square value of 70%), TGI does not believe consumption will continue to decline over the Forecast Period. This sector has fuel switching capabilities, which implies these customers have the ability to respond to conditions in the spot market. TGI is forecasting a moderate decline in consumption during 2009 and then slight growth over the Forecast Period.

Mining Sector:



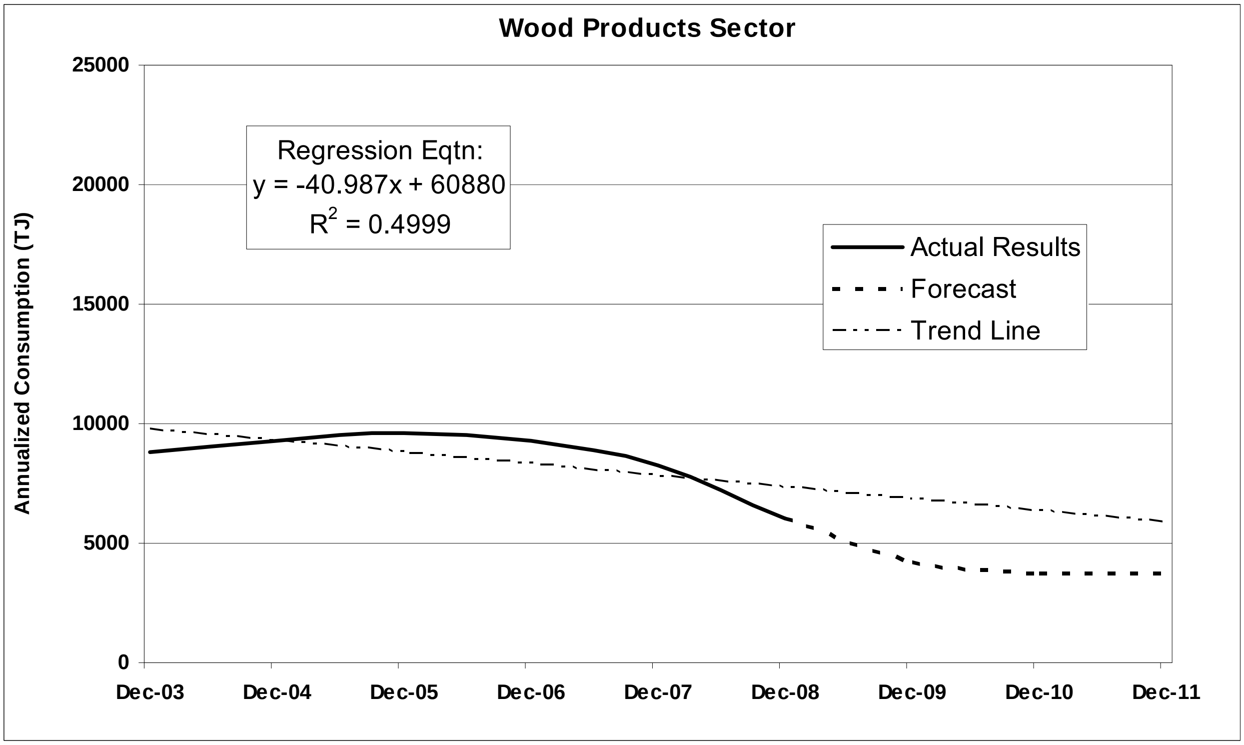
The trend line from 2003 through 2008 does not show a very good fit to the data, with an R-square value of 50%. Given there are only 22 customers in this sector, as with the Chemical Manufacturing sector, changes in consumption for individual customers can lead to significant changes in the overall consumption levels in the sector. TGI's analysis indicates the growth seen over the past two years is not likely to continue, and therefore TGI is forecasting relatively stable consumption over the Forecast Period.

Pulp & Paper Sector:



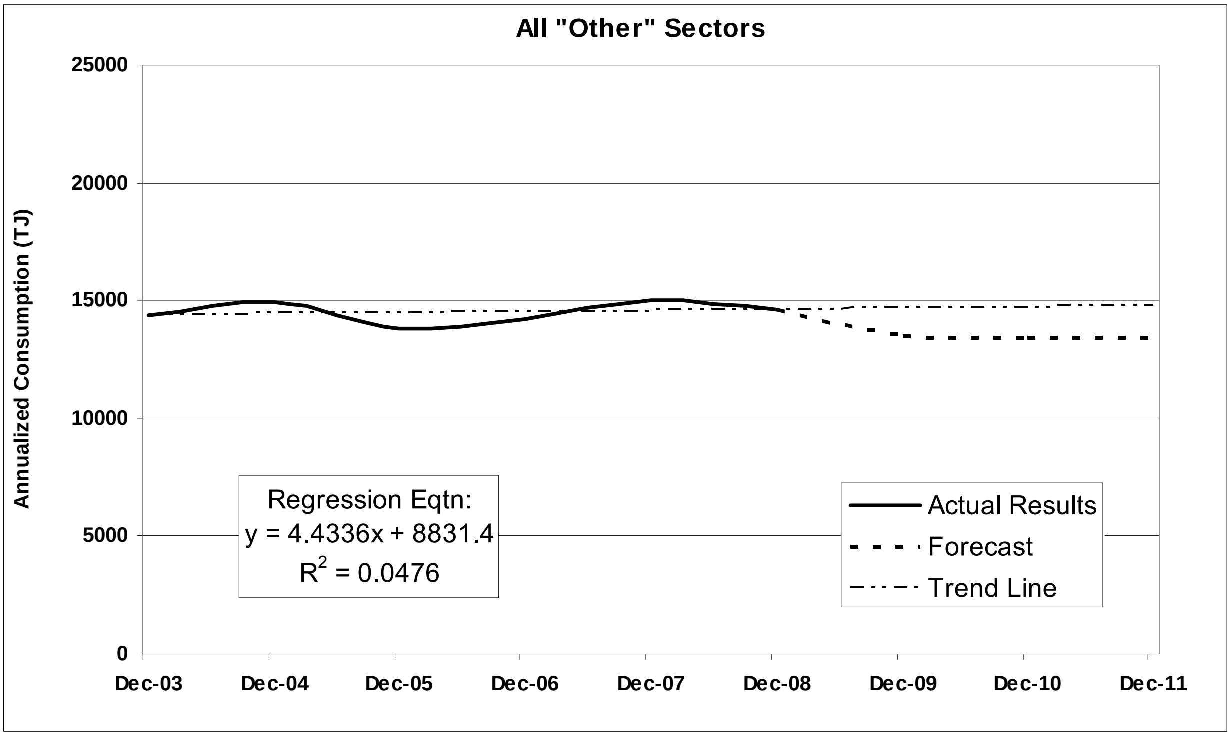
Although the trend line from 2003 through 2008 shows a good fit to the data (with an R-square value of 82%), the trend line going forward does not incorporate the more recent historical downward trends. TGI, based on its analysis of these customers, is forecasting the more recent downward trend (2007-2008) to continue through 2009, but then stabilizing over the Forecast Period. It is important to note that the majority of customers in this rate class are under bypass tariff supplements which include fixed rates that are independent of actual consumption levels. Therefore, consumption patterns that differ from expectations for this sector do not have a significant impact on revenues.

Wood Products Sector:



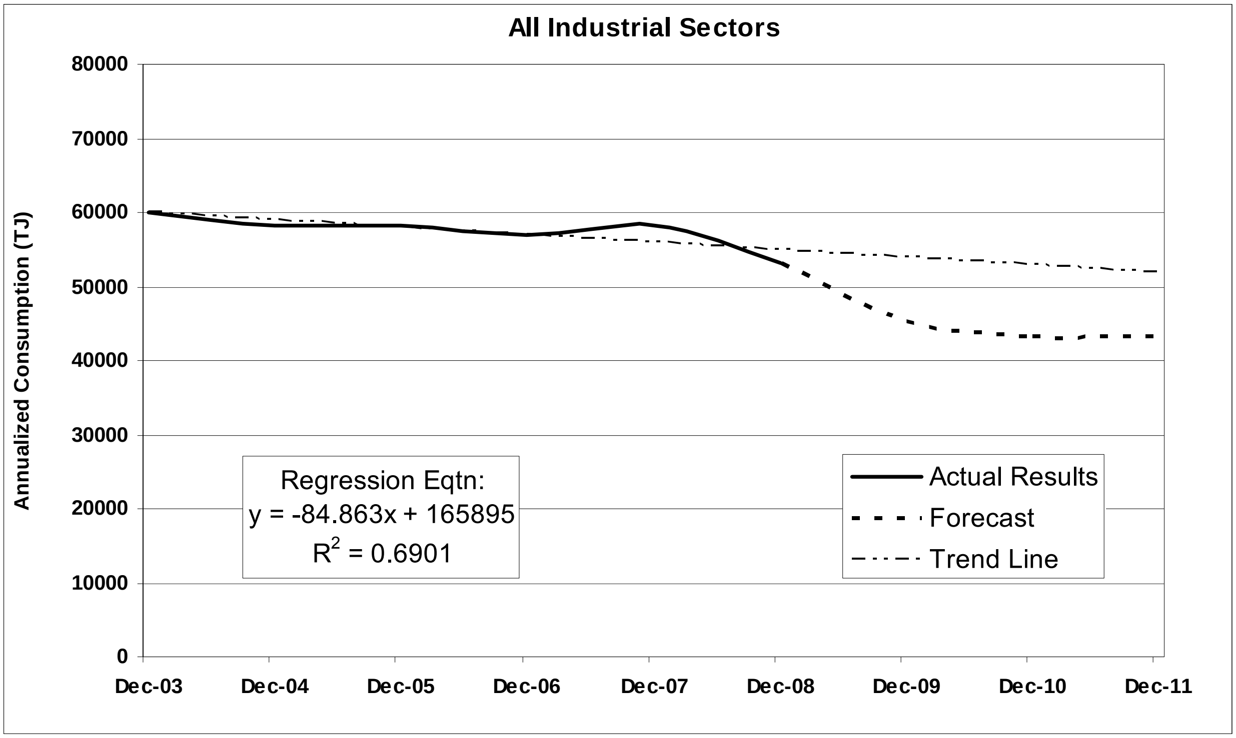
The trend line from 2003 through 2008 is a poor fit to the data (with an R-square value of only 50%), nor does it incorporation more recent downward trends. TGI's analysis indicates the more recent downward trend (mid-2006 through 2008) to be more reflective of consumption levels that can be expected in 2009. Therefore, TGI is projecting significant declines in consumption for 2009, followed by stabilization throughout the Forecast Period. As with the Pulp & Paper sector, the majority of customers in this sector are under bypass tariff supplements which include fixed rates that are independent of actual consumption levels. Therefore, consumption patterns that differ from expectations for this sector do not significantly impact revenues.

All "Other" Sectors:



The trend line from 2003 through 2008 shows a very poor fit to the data (with an R-square value of only 5%). The more recent trend downwards (mid-2008) is forecast to continue through 2009, in line with the economic downturn, and is then expected to stabilize throughout the forecast period.

All Industrial Customers:



The overall trend line shows an acceptable fit to the data (with an R-square value of 69%), although as discussed with the individual sectors, does not incorporate some of the more recent downward trends. TGI is forecasting the more recent downward trend to continue through 2009, before stabilizing throughout the remainder of the Forecast Period.

61.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 310, Figure C-4-30

Industrial Consumption

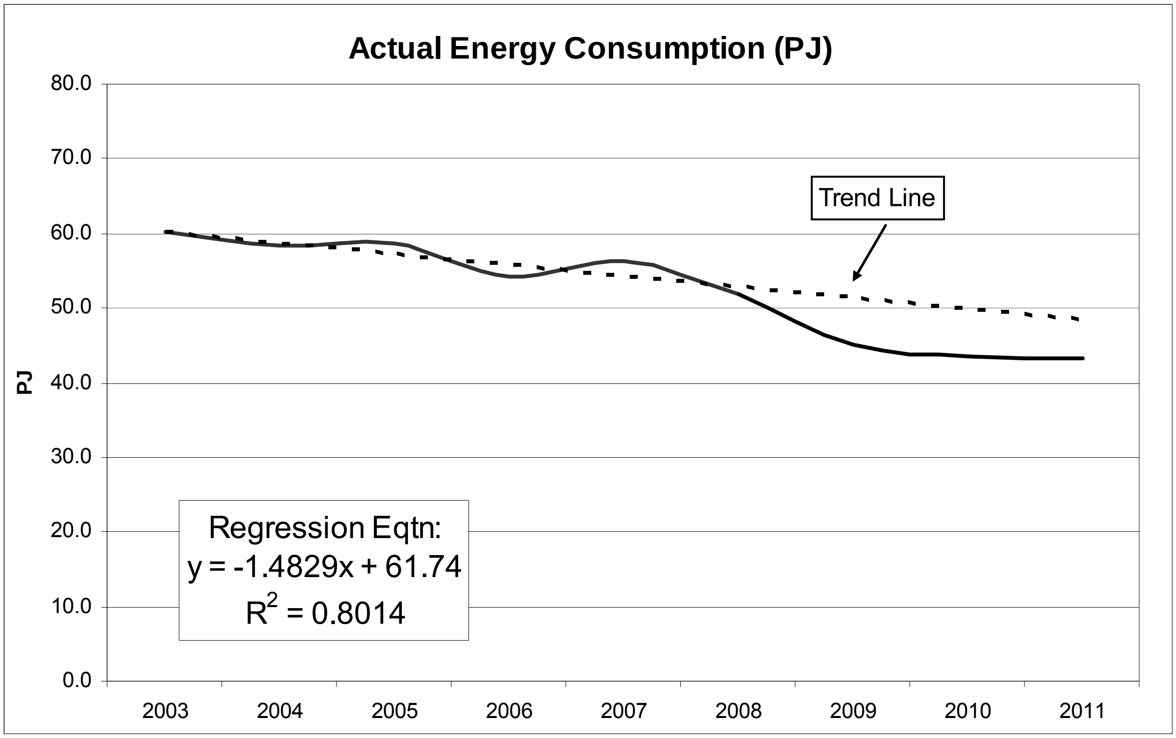
61.1 Please include the following additional information for Figure C-4-30 on page 310:

- Normalized and actual historical Energy Consumption for the period 2003 to 2008;
- Projected and forecasted Energy Consumption for the period 2009 to 2011; and
- Linear regression curves for normalized and actual Energy Consumption for the period 2003 to 2008.

Response:

As discussed in TGI's response to BCUC IR1.60.1, with industrial volumes being more closely related to production levels they are considered to be primarily process loads that do not fluctuate with changes in weather patterns. Given that, TGI does not normalize industrial volumes, and only normalizes volumes for residential and commercial customers.

Therefore, the following graph illustrates the actual historical Energy Consumption for the Industrial Sector for the period 2003 to 2008, the projection for 2009 and forecast for 2010 and 2011, and also includes the linear trend over the 2003 to 2008 period.



Although the linear regression trend does show a relatively good fit, with an R-square of 80%, an extension of the trend into 2010 and 2011 does not provide a reasonable enough response to the economic downturn that has taken place, beginning in the latter part of 2008. A more reasonable approach is to analyze each of industrial sectors individually, and then validate the results through direct customer feedback, which TGI is in the process of completing.

62.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, pp. 310,

Industrial Energy Forecast

Figure C-4-30 on page 310 shows a downward trend. TGI projects "a significant decline in 2009 followed by a further decline in 2010 before stabilizing in 2011."

62.1 Please provide tabular data for historical, projected and forecasted industrial consumption of natural gas for the years 2003 to 2008 plus 2009 Projection and 2010 and 2011 Forecasts.

Table C-4-6:
Industrial Customers Top Energy Consuming Sectors (PJs)

	2003	2004	2005	2006	2007	2008	2009(P)	2010(F)	2011(F)
Pulp & Paper						13.4			
Wood Products						5.9			
Greenhouses						3.6			
Mining						3.6			
Apartment/Condo						3.6			
Chemical Manuf.						4.0			
Food & Beverage						3.5			
Other						14.2			
Subtotals	-	-	-	-	-	51.8	-	-	-

<u>Response:</u>

The following table provides the above requested data.

Industrial Customers Top Energy Consuming Sectors (PJs)

	2003	2004	2005	2006	2007
Pulp & Paper	18.6	18.1	17.1	15.2	16.3
Wood Products	8.8	9.3	9.7	8.8	8.0
Greenhouses	5.5	4.4	4.0	3.5	3.8
Mining	3.2	3.2	3.3	2.9	3.2
Apartment/Condo	3.1	3.2	3.4	3.3	3.5
Chemical Manuf.	2.9	1.7	3.6	3.6	3.7
Food & Beverage	3.7	3.5	3.7	3.4	3.3
Other	14.4	14.9	13.9	13.5	14.5
Total	**60.1**	**58.3**	**58.6**	**54.2**	**56.3**

	2008	2009(P)	2010(F)	2011(F)
Pulp & Paper	13.4	9.6	8.6	8.6
Wood Products	5.9	4.2	3.7	3.7
Greenhouses	3.6	3.4	3.4	3.4
Mining	3.6	3.6	3.6	3.6
Apartment/Condo	3.6	3.5	3.4	3.4
Chemical Manuf.	4	3.9	3.8	3.8
Food & Beverage	3.5	3.5	3.5	3.5
Other	14.2	13.5	13.4	13.4
Total	**51.8**	**45.2**	**43.4**	**43.3**

63.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, pp 310, Figure C-4-30

Energy Consumption for Industrial Customers

"In considering the trends seen in the various sectors illustrated above, TGI is projecting a significant decline in 2009 followed by a further decline in 2010 before stabilizing in 2011."

63.1 Please provide tabular data for 2003 to 2008 actuals, 2009 projected and 2010 and 2011 forecasted industrial consumption of the demand for natural gas in the following format:

Industrial Consumption (TJs): Rate Schedules 5, 7, 22, 25, and 27

	2003	2004	2005	2006	2007	2008	2009(P)	2010(F)	2011(F)
Total for All Regions									

Response:

The following table illustrates the total energy consumption for all industrial customers from 2003 to 2008, including the projection for 2009 and forecast for 2010 and 2011, in the requested format.

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009 (P)**	**2010 (F)**	**2011 (F)**
Total All Regions	65,800	63,150	62,950	58,000	59,800	55,150	48,400	46,500	46,400

TGI would like to note that on Page 310 of the Application, the bullet associating the customer rate classes for Industrial Customers incorrectly references Customer Rate Class 5 (i.e. it should only refer to Rate Class 7, 22, 25 and 27). Customer Rate Class 5 is reported with the Firm Sales customer segment, not with the Industrial customer segment. Table C-4-8 on Page 311 of the Application correctly identifies the Customer Rate Classes included in each customer segment.

64.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, p. 311

Energy Forecast for All Customer Rate Classes

The data in the following table were compiled from Appendix D-1, Appendix F-1 and Table C-4-8.

Historical and Forecasted Gas Demand for All Customer Classes

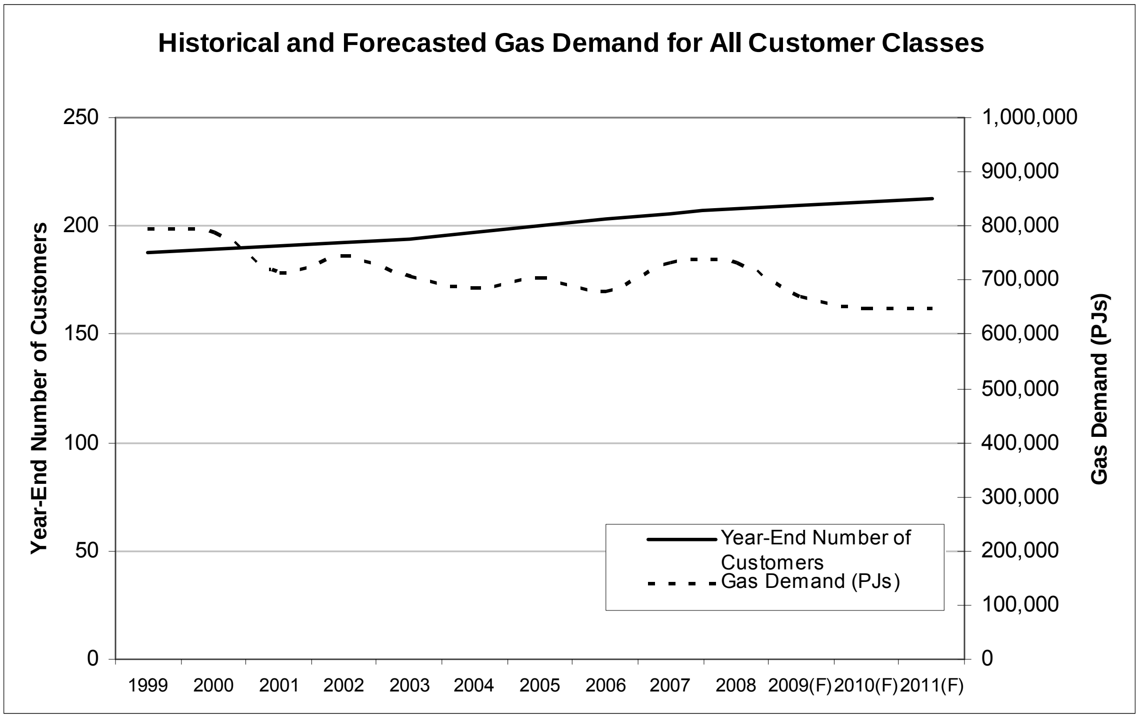
		1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009(P)	2010(F)	2011 (F)
[1]	Year-End Number of Customers	751,893	758,437	763,302	769,908	775,454	786,958	799,378	812,683	822,598	831,845	837,965	843,565	849,415
[2]	Actual Gas Demand (PJs)	198.9	196.7	178.5	186.5	176.6	171.7	175.7	170.1	182.7	183.4			
[3]	Forecasted Gas Demand (PJs)											167.3	162	161.8

Notes:
[1] - source data from Appendix D-1
[2] - source data from Appendix F-1
[3] - source data from Table C-4-8

64.1 From the data, please prepare a linear graph comparing Year-End Number of Customers to Actual Gas Demand for natural gas for the period 1999 to 2008. Please extend the graph to include Forecasted Gas Demand (ref. Table C-4-8) for 2009, 2010 and 2011.

Response:

The following graph illustrates the Year-End Number of Customers and Actual Gas Demand over the period 1999 to 2008, the projection for 2009 and the forecast for 2010 and 2011.



64.2 Please explain the decrease in gas demand over the period 2009 to 2011.

Response:

The decrease in demand for natural gas seen between 2008 and 2009 in the above table is largely attributed to the fact that actual demand is illustrated rather than normalized demand. Given that 2008 was colder than normal, actual demand was higher than normal demand. Normalized annual demand for 2008 was 170.0 PJ as compared to the 183.4 PJ illustrated above. If normalized annual demand was illustrated above, the change from 2008 to 2009 would be a 1.6% decline rather than the 8.7% decline that is currently illustrated. As TGI forecasts demand based on the assumption of a normal year, normalized historical demand is a more appropriate comparator than is actual demand.

As can be seen from the tables and graphs provided in TGI's response to BCUC IR1.64.3, the decrease in demand for natural gas from 2009 to 2011 is attributed to the industrial and residential customer segments. Industrial volumes are expected to decline through 2010 before stabilizing, as the economy begins to recover. At the same time, the downward pressure on residential demand for natural gas is resulting from declining customer additions, which are no longer offsetting the decline in average use per customer rates (attributed to ongoing conservation efforts and more multi-family dwellings in the housing mix). Given relatively stable average use per customer rates, commercial demand for natural gas is expected to grow in accordance with the overall customer growth, but this growth is certainly not enough to offset the declining demand for natural gas in the residential and industrial sectors.

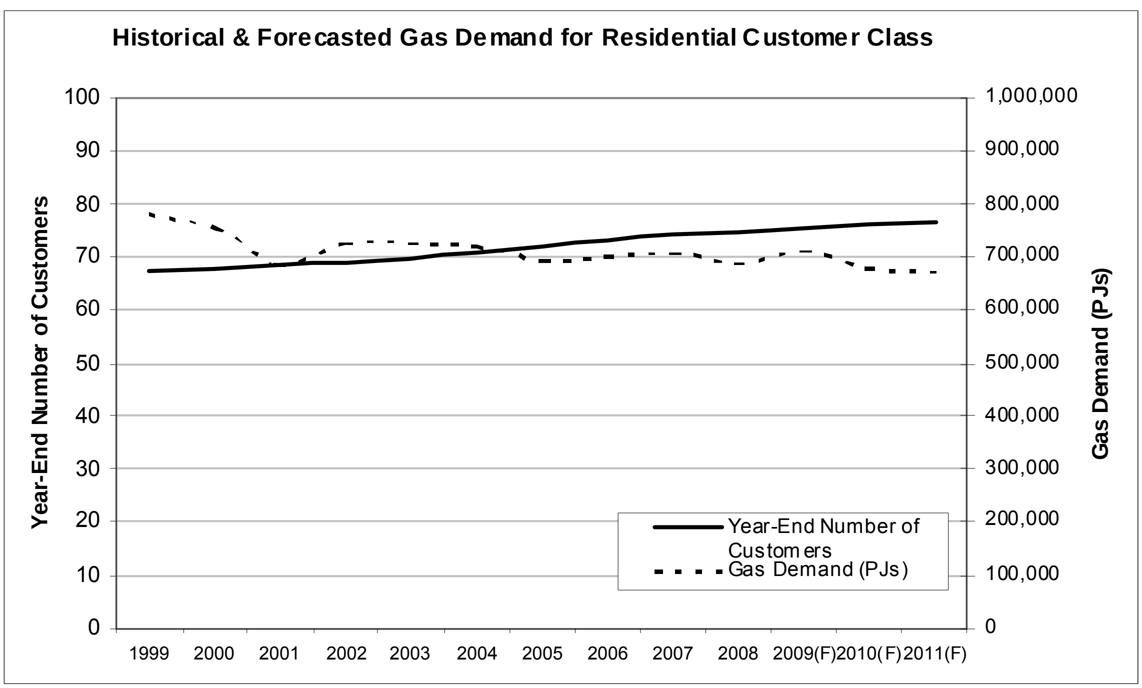
64.3 In the same format as above, please prepare individual tabular and graphical data for residential, commercial and industrial customer classes. Please provide an analysis of the demand in gas as a function of the number of customers for each user class. Please provide all data and graphical results in a fully functional electronic spreadsheet.

Response:

An analysis of the demand for natural gas, as a function of the number of customers in each customer class, is not materially different from the analysis of average use per customer rates which is included in the Application (Pages 278 – 299).

The following tables and graphs illustrate the number of customers and normalized actual demand, by customer segment, over the period 1999 to 2008, including the projection for 2009 and forecast for 2010 and 2011. The data and graphs are included in Attachment 64.3.

Residential Customers:

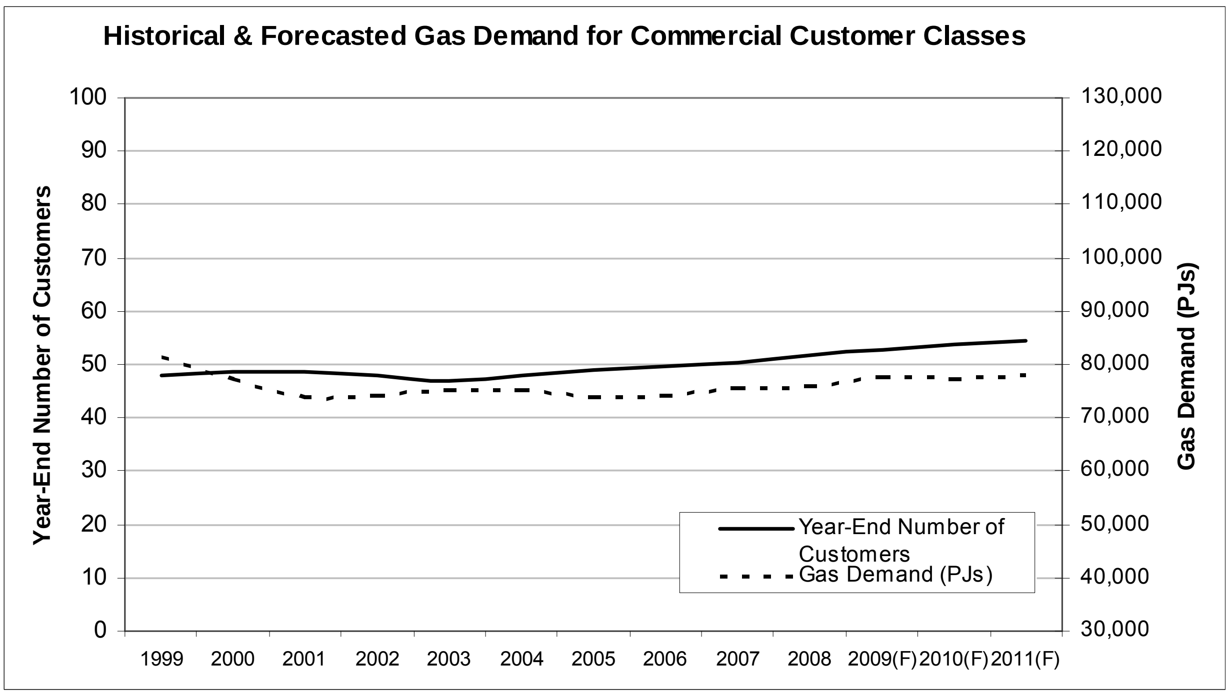


Historical and Forecasted Gas Demand for Residential Customer Class

	1999	2000	2001	2002	2003	2004	2005
Year-End Number of Customers	673,026	678,712	683,547	690,907	697,213	707,929	719,356
Gas Demand (PJs)	77.8	75.4	68.4	72.6	72.6	72	69.3

	2006	2007	2008	2009(F)	2010(F)	2011(F)
Year-End Number of Customers	731,899	741,176	749,135	754,126	758,903	763,886
Gas Demand (PJs)	70.0	70.6	68.8	71.0	67.8	67.2

Commercial Customers:

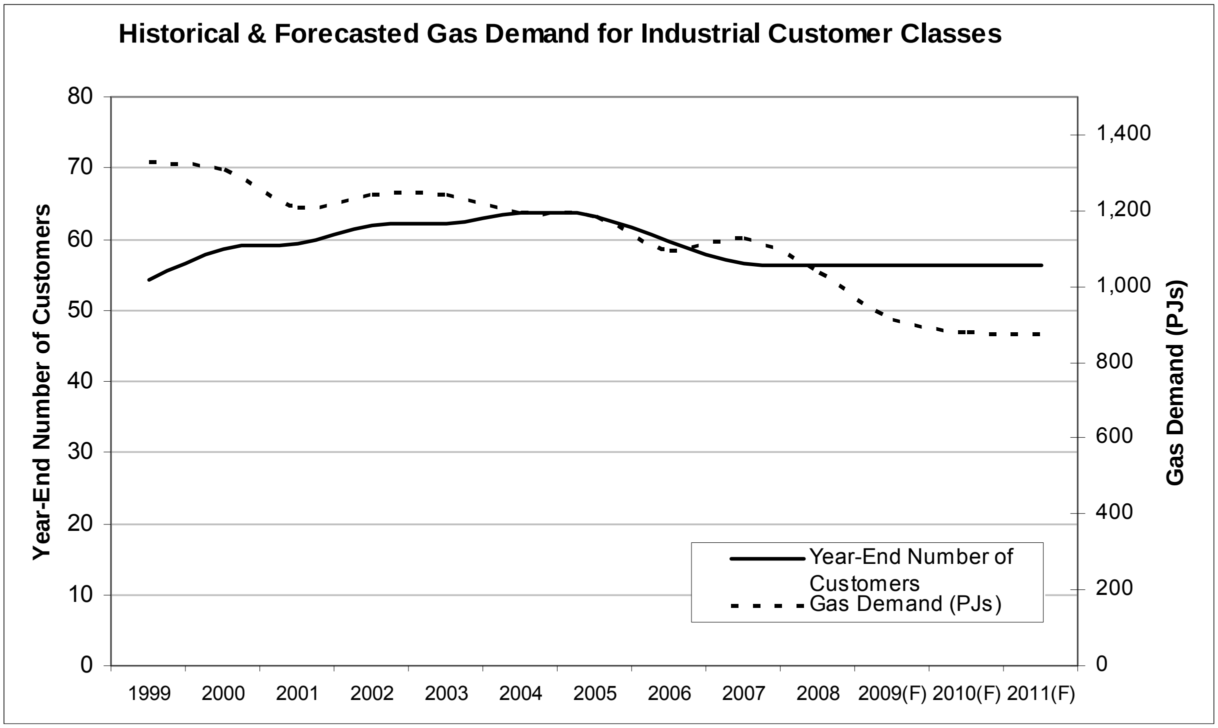


Historical and Forecasted Gas Demand for Commercial Customer Classes

	1999	2000	2001	2002	2003	2004	2005
Year-End Number of Customers	77,851	78,626	78,642	77,839	77,077	77,833	78,835
Gas Demand (PJs)	51.5	47.3	43.9	44.3	45.3	45.2	43.9

	2006	2007	2008	2009(F)	2010(F)	2011(F)
Year-End Number of Customers	79,666	80,360	81,654	82,783	83,606	84,473
Gas Demand (PJs)	44.1	45.5	45.9	47.5	47.3	47.9

Industrial Customers:



Historical and Forecasted Gas Demand for Industrial Customer Classes

	1999	2000	2001	2002	2003	2004	2005
Year-End Number of Customers	1,016	1,099	1,113	1,162	1,164	1,196	1,187
Gas Demand (PJs)	70.8	69.8	64.5	66.3	66.2	63.6	63.3

	2006	2007	2008	2009(F)	2010(F)	2011(F)
Year-End Number of Customers	1,118	1,062	1,056	1,055	1,055	1,055
Gas Demand (PJs)	58.3	60.1	55.3	48.7	46.8	46.7

65.0 Reference: Gas Sales and Transportation Demand

Part III, Section C, Tab 4, pp. 311-313

Burrard Thermal

65.1 Please explain why Burrard Thermal is not included in the data presented in Tables C-4-8, C-4-9, and C-4-10.

Response:

Burrard Thermal has not been included in the data tables illustrating Forecast Energy Consumption (Table C-4-8), Forecast Margin (Table C-4-9) and Forecast Revenue (Table C-4-10) tables as it has been TGI's practice for a number of years now to report Burrard Thermal in the Other Revenue section of the Application.

Revenues from Burrard Revenue are determined through contractual agreements, and are entirely fixed in nature – they do not vary according to consumption levels. Revenues from residential, commercial, and industrial (to some extent, as approximately 55% of industrial margins are fixed in nature) customers do vary according to consumption levels, and are therefore viewed differently than those for Burrard Thermal.

65.2 To the best of TGI's knowledge, please confirm whether BC Hydro has filed operational plans for Burrard Thermal such as in the BC Hydro 2008 Long Term Acquisition Plan. If so, please provide any forecasts and adjustments to projected natural gas demand for that facility over the Forecast Period 2010 and 2011.

Response:

To the best of TGI's knowledge, BC Hydro's most recently filed future plans for Burrard Thermal were included as part of the BC Hydro 2008 Long Term Acquisition Plan. These plans were considered in TGI's 2008 Resource Plan, for capacity planning purposes. More recently, TGI has received indication from BC Hydro (through the industrial survey) which indicates expected consumption for Burrard Thermal will be lower than what has been included in the demand forecast. However, as discussed in TGI's response to BCUC IR 1.65.1, given revenues do not vary with fluctuations in consumption levels, there is no material impact to the demand forecast.

Recently, the Commission issued its Decision on the BC Hydro 2008 LTAP, in which it did not accept all of BC Hydro's requests with respect to Burrard Thermal. The Commission approved BC Hydro's request to include Burrard Thermal as a capacity resource of 900 MW in its capacity resource stack, but the Commission did not accept BC Hydro's request to reduce the energy contribution from Burrard Thermal (for planning purposes only) from 6,000 GHh per year to 3,000 GWh per year. It is TGI's understanding that the Commission's LTAP Decision does not change how much BC Hydro expects to run Burrard Thermal since the Decision affects the designation of Burrard Thermal for planning purposes only. Burrard Thermal will only run as an emergency backup or peaking resource, or in the occasional circumstances where market electricity prices are high enough for Burrard to be economically dispatched. From a revenue perspective, TGI has more of an interest in the capacity planning for Burrard Thermal, since TGI must reserve enough space on its own transmission system to meet Burrard Thermal's requirements when all six generating units are operating. With the Commission's approval to keep Burrard Thermal at a capacity rating of 900 MW there is very little likelihood that BC Hydro will seek to terminate or renegotiate its fixed price transportation contract with TGI during the 2010-2011 RRA Period.

66.0 Reference: Cost Of Gas - Gas Cost Deferral Mechanisms

Part III, Section, Tab 5, pages 317-345

66.1 Why is it necessary to have a hedging program in place when the three deferral accounts accomplish the same objective?

Response:

The three gas cost deferral accounts utilized by TGI include the Commodity Cost Reconciliation Account ("CCRA"), the Midstream Cost Reconciliation Account ("MCRA") and the Revelstoke Propane Cost Deferral Account. These deferral accounts capture variances between the actual gas costs and the forecast gas costs as recovered in rates and the deferral mechanisms, which are reviewed quarterly enable these variances to be recovered from, or refunded to, customers as part of future rates forecast over a twelve month period. These deferral accounts ensure that 100% of the actual gas costs are passed through to customers, including any costs above or savings below forecasted gas costs. The quarterly review mechanism with the twelve month future outlook also helps to reduce the volatility in rates. However, these deferral accounts do not affect the underlying commodity prices embedded in the cost of gas, which the hedging program does.

The objectives of the hedging program are to moderate the volatility of market prices and the resultant effect on rates, improve the likelihood that natural gas remains competitive with electricity, and reduce the risk of regional price disconnects. The hedging program accomplishes these objectives through layering in hedges over a 36 month horizon per a predefined schedule, but the implementation also includes accelerated hedging when favourable price targets are reached. The result is that the hedging implementation affects the underlying commodity cost of gas which is flowed through to customers via rates.

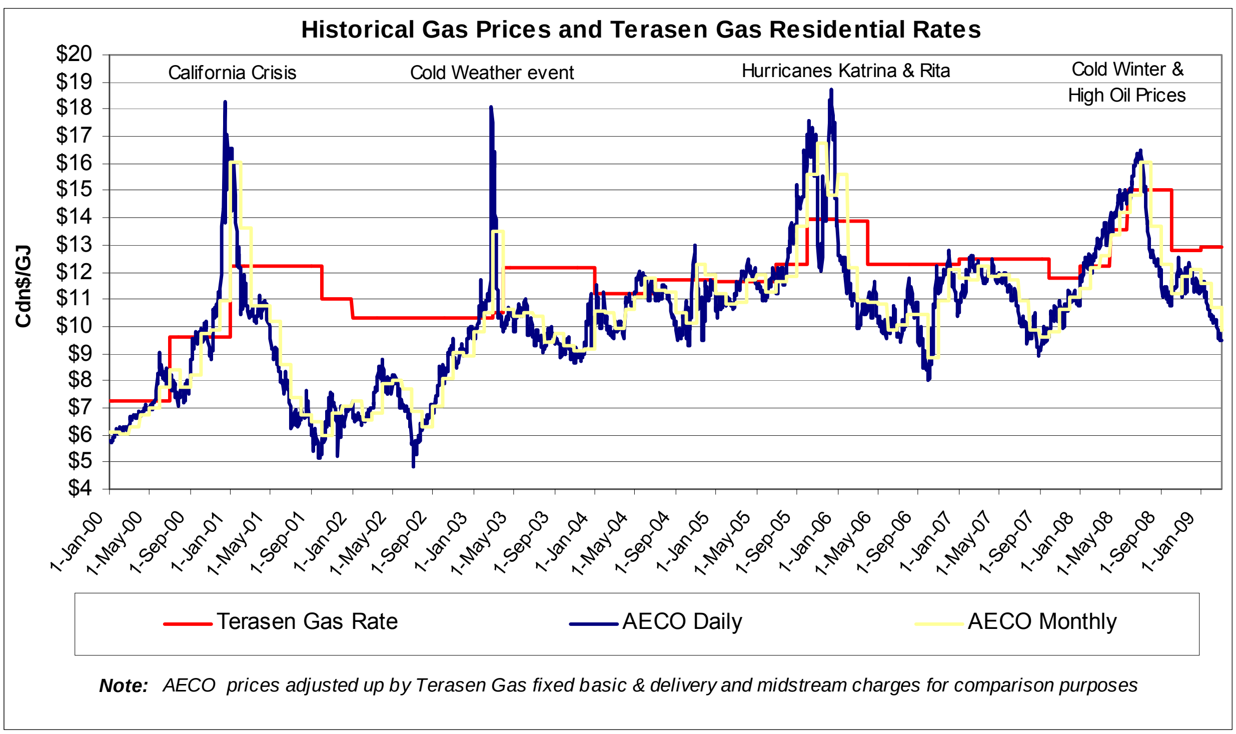
Therefore, Terasen Gas believes that the hedging program and the deferral accounts work in a complimentary manner, rather than as substitutes, in reducing rate volatility for customers.

66.2 Are regulatory Commissions in Canada generally ending hedging programs for utilities that they regulate?

Response:

Terasen Gas does not agree that regulatory Commissions in Canada are generally ending hedging programs for utilities that they regulate. Terasen Gas is only aware of the cancellation of the hedging programs in Ontario which occurred over the past two years. In July 2008, the Ontario Energy Board ("OEB") effectively cancelled the Union Gas Limited ("Union Gas") hedging program (decision dated July 31, 2008). While Union Gas maintained its risk management activities had provided material rate volatility reduction for customers at a minimal cost, the OEB disagreed and argued that the quarterly rate adjustment mechanism process and the equal billing plan provided sufficient rate smoothing effects. This decision came one year after the OEB cancelled the Enbridge Gas Distribution Inc. ("Enbridge") hedging program on the basis that Enbridge had failed to demonstrate rate volatility reduction to customers as a result of its hedging program. Terasen Gas demonstrates material rate volatility reduction through its hedging program at a minimal cost to customers as illustrated in the following graph (where AECO prices have been adjusted up by the Terasen Gas fixed basic and delivery charge and midstream rate for proper comparison to the Lower Mainland Rate Schedule 1 for residential customers).

Figure 1.66.2: Volatility Reduction Provided by the Terasen Gas Rate



Terasen Gas believes that quarterly rate adjustment mechanisms and equal billing plans should be complimentary to a hedging program and not as substitutes for hedging. Furthermore, Terasen Gas faces challenges unique to British Columbia, including high Sumas volatility, lack of significant market area storage, historically low electricity rates and the B.C. carbon tax on natural gas usage all of which create the need for an effective hedging program.

The hedging programs of the other major Canadian utilities, such as Manitoba Hydro, Gaz Metro Limited Partnership and SaskEnergy, continue to exist.

Furthermore, according to RMI Consulting, Inc.'s Customer Hedging Survey conducted in the fall of 2006 (presented in their Commodity Risk Management Report in October 2007 as part of the Union Gas hedging program evaluation), commodity risk management programs amongst utilities are a prevailing trend and becoming even more widely used in recent years given the increased volatility in the natural gas marketplace. The results showed that 100% of those surveyed exercised risk management programs. Another recent survey was performed in the United States by the American Gas Association ("AGA") for the winter 2006/07 season which showed that 88% of utilities surveyed had financial hedging programs compared to only 55% in winter 2000/01. Of the western U.S. utilities surveyed, 100% used financial hedging to manage price risk.

67.0 Reference: Cost of Gas - Unaccounted for Gas

Part III, Section, Tab 5, page 319

67.1 Please provide the actual UAF percentages for each service area for the last 5 years.

Response:

The table which follows provides the actual UAF percentages for each service area for the last 5 years.

TGI - Historical Actual Annual UAF by Service Area

	2004	2005	2006	2007	2008
Lower Mainland Service Area	-0.52%	0.22%	1.16%	-0.10%	-0.33%
Inland Service Area	0.44%	0.39%	0.22%	-0.44%	0.56%
Columbia Service Area	-0.80%	1.02%	3.72%	1.03%	0.16%

67.2 Please explain any abnormalities that occurred during the year that impacted the percentage.

Response:

Terasen Gas cannot identify any specific abnormalities that occurred, and that directly correlate to the variances in the actual UAF percentages experienced during the past five years.

UAF refers to gas that is not specifically accounted for in a gas energy balance of receipts, deliveries, and operations use. Some UAF is to be expected in any system and gas measurement variances are a major factor to UAF. Normal operating tolerances on equipment, differing operating environments, and technology used in measurement all contribute to measurement related variances. In addition, other factors such as billing cycle effects, flaring of natural gas, and gas lost due to the intentional or unintentional release of gas (which includes venting, system damage and leakage) contribute to UAF.

68.0 Reference: Cost Of Gas -Treatment of Costs within the MCRA Related to Southern Crossing Pipeline ("SCP")

Part III, Section, Tab 5 p.319-320

On page 310 TGI states that:

"The Commission approved an annual allocation of $3.6 million to be debited against the MCRA with an equal and offsetting allocation to be credited o the delivery margin revenue account for the period ending November 1, 2010 corresponding to the primary term under the former BC Hydro Agreements."

68.1 The rationale for debiting the MCRA and crediting the delivery margin revenue was in recognition that the BC Hydro agreements would have ended by November 1, 2010. What is the rationale for extending this arrangement to November 1, 2020?

<u>Response:</u>

Terasen Gas believes it appropriate to extend debiting the MCRA and crediting the delivery margin revenue to November 1, 2020 for two main reasons.

The first lies in the fact that SCP is an important part of the Terasen Gas resource portfolio over the long term, enabling reliable and cost effective gas supply service for core customers.

The second reason for this extension lies in the terms of the original Transportation Service Agreement and Peaking Gas Purchase Agreement between Terasen Gas and BC Hydro (the "BC Hydro Agreements") based on 52.2 MMcfd of Southern Crossing Pipeline ("SCP") capacity. Under this arrangement, the initial term of the agreements expired November 1, 2010. However, BC Hydro held the option to extend the term for a maximum of an additional 10 years through to November 1, 2020.

Terasen Gas believes the ten year extension is not an unreasonable period of time to allocate to long term portfolio resources.

69.0 Reference: Cost Of Gas - Company Use Gas

Part III, Section, Tab 5, Figure C-5-1, p.320-323

69.1 Why is it more appropriate for the variances between actual and forecast company use gas volumes to be absorbed through MCRA rather than be apportioned both in MCRA and CCRA? Are not both accounts affected by Company Use Gas?

Response:

Terasen Gas believes the variances between actual and forecast company use gas volumes should be absorbed through MCRA rather than be apportioned both in MCRA and CCRA. This is in recognition of the fact that the primary differences between actual and forecast company use gas volumes are related to core customer load requirements resulting from changes in temperatures. The MCRA is essentially designed to handle fluctuations in core load requirements while the CCRA relates to unchanging baseload requirements. Therefore, Terasen Gas believes it appropriate for variances between actual and forecast company use volumes to be absorbed through MCRA. This is consistent with how the MCRA currently absorbs variances between normal forecast baseload core load requirements and the actual core load requirements resulting from actual weather and temperature changes.

69.2 What range of volume variances are expected to be absorbed by MCRA?

Response:

The range of volume variances from forecast that would be absorbed by MCRA are largely driven by weather conditions which are very difficult to predict. In the recent past, actual volumes have differed from forecast volumes by as much as 25 percent. It is reasonable to expect that in a warmer than normal winter, actual company use gas volumes to come in below forecast, with the savings flowing through to customers via the MCRA. In a colder than normal winter, actual company use gas volumes would be expected to come in above forecast, thereby appropriately increasing MCRA costs for core customers as they consume more than expected. As the variances are driven by throughput volume, on average the per unit (ie. $ per GJ delivered) impact would be negligible.

69.3 Please provide a history of the transition from the GCRA account to the split into MCRA and CCRA accounts and describe what this arrangement was originally designed to accomplish?

Response:

The division of the Gas Cost Reconciliation Account ("GCRA") into the Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") was needed to help establish the Essential Services Model, which forms the basis for which the Commercial Commodity Unbundling Program approved by BCUC Order No. G-25-04. In November, 2007 this program was extended to residential customers with the Customer Choice Program.

Starting in 2004, these two new gas cost related deferral accounts are used to accumulate the difference between the costs incurred by Terasen Gas to purchase the gas commodity and midstream services and the revenue collected by Terasen Gas through the gas cost recovery component of rates. The CCRA is designated to capture and account for costs and recoveries associated with the baseload supply through gas commodity rates whereas the MCRA is associated with the midstream function required to meet design peak day through midstream rates.

Commodity rates (CCRA) are reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold. Generally, when commodity rates are reset, the new rate is designed to recover, or refund, over the next 12 months any existing CCRA account balance, along with any under or over recovery of commodity costs forecast to occur over the next 12-month period.

Midstream rates (MCRA) are reviewed on a quarterly basis and, under normal circumstances, are adjusted on an annual basis with a January 1 effective date. Generally, when midstream rates are reset for the upcoming calendar year, the new rate is designed to recover, or refund, over the next 12 months any existing MCRA account balance, along with any under or over recovery of midstream costs forecast to occur over the next 12-month period.

TGI customers continue to benefit from these two deferral accounts by reducing volatility in commodity rate changes and volume related variances.

69.4 As shown in Figure C-5-1 (Company Use Gas Volumes), what accounts for the increase volumes in the components of Company Use; Compressor, LNG and Facilities?

Response:

Pressure reducing stations in the Distribution system require line heater fuel to maintain gas temperatures above the freezing point. Through the deployment of high efficiency line heaters during the PBR period, consumption increases due to system growth have been largely offset.

For Compressors, there were three main reasons for increased fuel usage:

1. There was a change in the gas supply portfolio where some supply for the Interior load was switched from Savona (via Westcoast T-South capacity) to EKE (via TCPL). This was due to BC Hydro giving back its share of the SCP transport capacity. The resulting increase in EKE flows from TCPL to meet core demand meant more compression requirements at Kitchener and Kingsvale (on the SCP system).
2. Mitigation activities in winter 2007/08 had an effect on fuel requirements. Although the mitigation fuel is not included in Company Use fuel, the increase in system throughput means incremental fuel requirement for compressors which the core shares.
3. There is also a weather component that resulted in increase fuel requirement for 2008 due to colder winter temperatures than previous years.

LNG fuel usage is primarily based on peak day requirements, emergency usage (such as due to third party pipelines constraining supply) and commissioning (i.e. testing requirements). From 2003 to 2008, due to weather and operations, forecast peak day loads were not realised , so less volume was required. The projected 2009 and forecast 2010 and 2011 volumes are based on peak day requirements.

With regard to Facilities fuel usage, the volumes for 2003 to 2007 as presented in Figure C-5-1 have been incorrectly understated. The actual usage for this period was approximately 28 TJ per year, rather than approximately 9 TJ per year as presented. Usage for 2008 has increased by about 14 percent to approximately 32 TJ per year based on cooler temperatures during the winter months than in prior years. Facilities usage variations are primarily driven by weather.

69.5 In the 2009 Price Risk Management Plan dated May 4, 2009 page 7, TGI planned to hedge 100 percent of MCRA Sumas exposure through basis swaps to avoid price extremes that may take place at Sumas. In fact, TGI states that:

"Given the volatility in the natural gas marketplace in recent years, Terasen Gas believes it prudent and appropriate to continue to hedge the pricing associated with company use gas through Sumas fixed price swaps to provide protection against unfavorable movements in natural gas prices in the future."

Considering this position, why is the Sumas price appropriate to calculate the cost of Company Use Gas?

Response:

Terasen Gas believes the Sumas price is appropriate to calculate the cost of Company Use Gas and has hedged the price for 2010 and 2011 to provide protection against unfavourable movements in natural gas prices in the future.

Terasen Gas has used the Sumas price at the Huntingdon market hub in the interests of simplicity and transparency and believes it to be reasonable as representative of where the gas is ultimately delivered for consumption. As Company Use Gas occurs throughout the Terasen Gas system, as compressor, line heater and LNG fuel as well as to heat facilities, it would be a complicated exercise to cost certain portions of Company Use Gas based on its proximity in the Terasen Gas system to the various market pricing hubs, such as Station #2, AECO/NIT or Sumas. This pricing mix would also likely change over time, depending on weather and operating conditions in different regions in which Terasen Gas operates. Furthermore, it would be necessary to allocate some portion of midstream costs to these market hub prices as the Company Use Gas is not consumed right at the market hubs but rather further downstream. Therefore, in the interests of simplicity and transparency, the Sumas price is a reasonable proxy to cost Company Use Gas.

In order to provide protection against future unfavourable movements **in the Sumas price,** Terasen Gas has hedged the Company Use Gas price for 2010 and 2011 with fixed price swaps. Given that current market natural gas prices are depressed relative to recent historical averages, Terasen Gas believes this to be a favourable time to hedge the pricing related to company use gas costs. Terasen Gas requested Commission approval to hedge company use gas in its letter dated May 29, 2009 and obtained Commission acceptance for hedging company use gas for 2010 and 2011 on June 11, 2009 per Letter No. L-44-09. The hedge price of the Sumas fixed price swap Terasen Gas has subsequently implemented for the company use gas forecast volumes is $6.44 US/MMBtu. This compares favourably to the historical five year average price of $6.90 US/MMBtu and the historical five year high price of $8.02 US/MMBtu. While the actual index prices for 2010 and 2011 could ultimately settle lower than the hedge price achieved, Terasen Gas believes that, given the volatility in the natural gas marketplace and potential for prices to move up in the future, this is a prudent approach in managing costs on behalf of customers.

69.6 Instead of applying a Sumas price, why should the pricing not be based on a weighted price of gas based on the locations where gas is purchased; AECO (70 percent) Station 2 (15 percent) and Sumas (15 percent) with the price based on forecast volumes?

Response:

As stated in the response to the previous BCUC IR 1.69.5, Terasen Gas believes it appropriate to use the Sumas price to calculate the cost of Company Use Gas. Pricing based on a weighted price of gas based on the locations where gas is purchased (i.e. AECO, Station 2 and Sumas) does not include a component of transportation required to move the gas from these locations to where it is used for compressors, line heaters, LNG and facilities fuel. Furthermore, the weighted price of gas based on the locations where gas is purchased (i.e. AECO, Station 2 and Sumas) is reflective of the Terasen Gas baseload annual purchases relevant to the CCRA rate and is not representative of the seasonality associated with Company Use Gas volumes.

69.7 Does TGI believe that it should be at risk for Company Use Gas volume variances above forecast? If not, why not?

Response:

Terasen Gas believes that it should not be at risk for Company Use Gas volume variances above forecast. Volume variances above forecast are primarily due to changes in core customer load requirements resulting from changes in weather, which is largely beyond Terasen Gas' control. This is also consistent with volume variances that occur within the MCRA, whereby costs associated with changes in the utilization of various midstream resources due to changes in core load volume requirements are flowed through to customers via the cost of gas embedded in MCRA rates.

Conversely, if Company Use Gas actual volumes are lower than forecast, then the benefit of the lower costs is also flowed through to customers via the cost of gas embedded in MCRA rates.

69.8 Does TGI believe that the inclusion of volume variances within MCRA absolve TGI of being at risk for Company Use Gas above forecast?

Response:

Terasen Gas believes that the inclusion of volume variances within MCRA is appropriate for the reasons explained in the response to BCUC IR 1.69.7. The effect of doing so is to remove the forecast risk for Company Use Gas for an uncontrollable factor, namely weather variations. It should be noted that if Company Use Gas actual volumes are lower than forecast, then the benefit of the lower costs also goes directly to customers.

70.0 Reference: Cost Of Gas - Core Market Administration Expense ("CMAE")

Part III, Section, Tab 5, pages 326-327

70.1 According to Table C-5-2: CMAE Historical and Projected Costs ($ millions) the CMAE rate between 2004 and 2009 has increased by 4.06 percent/year, since this is well above the inflation rate what accounts for this substantial increase?

Response:

According to Table C-5-2: CMAE Historical and Projected Costs ($ millions), Total CMAE increases between 2004 and 2009 by $447 thousand or 4.4 percent per year. The increase is primarily related to four cost components.

The first cost component relates to labour costs which have increased by approximately $124 thousand or about 1.5 percent per year from 2004 to 2009, in line with inflation.

The second cost component relates to increases in subscriptions and memberships of approximately $105 thousand since 2004. Other than inflation, this includes the addition since 2004 of membership in the Northwest Gas Association ("NWGA"), which is a trade organization serving the Pacific Northwest natural gas industry. Terasen Gas is a member along with six natural gas utilities and three transmission pipelines serving communities throughout Idaho, Oregon, Washington and British Columbia. The NWGA's annual Outlook Study provides a consensus industry perspective of the Pacific Northwest's current and projected natural gas demand, supply, delivery capability and prices and enables Terasen Gas to effectively plan for resource requirements for the future. Also included is a subscription to Cambridge Energy Research Associates ("CERA") which provides up-to-date research regarding the energy industry, which enables Terasen Gas to stay on top of the latest developments affecting natural gas supply, demand and pricing. This cost component also includes the addition since 2004 of a pricing data feed subscription service which provides Terasen Gas with real time pricing and information necessary for trading natural gas.

The third cost component relates to increases in IT costs of approximately $99 thousand since 2004. Other than inflation, the increases are primarily related to IT support for Gas Supply systems, license costs associated with the Nucleus product and the inclusion of costs for a risk management package in 2009. This risk management package was budgeted to provide enhanced risk management functionality, such as the measurement of credit exposure risk, reducing the reliance on time consuming spreadsheets, given the importance of effective risk management in light of the recent events in the financial marketplace and the effects on counterparties' credit ratings.

The last and most significant component contributing to the increase in CMAE since 2004 is the decline in EMS revenues of approximately $168 thousand. This is due to the reduction in EMS customers, from three in 2004 (including Calpine Corporation, Methanex Corporation and Pacific Northern Gas ("PNG")) to just PNG in 2009.

When EMS revenues are excluded from CMAE, the increase in CMAE from 2004 to 2009 is approximately $280 thousand or only 2.3 percent per year. Terasen Gas believes the increases in costs are prudent and appropriate in providing core customers with reliable and cost effective supply.

70.2 What causes an 8.6 percent increase in CMAE between 2007 and 2008 (page 327)?

Response:

The 2008 actual CMAE was $20,000 under the budget amount granted by Commission Order No. G-150-07. CMAE increased by approximately $185 thousand or 8.3 percent between 2007 and 2008. The primary drivers for this increase are related to increases in training and travel costs and legal and consulting expenses, which can vary from year to year depending on staff turnover and upstream regulatory hearings. Terasen Gas endeavours to keep CMAE costs as low as possible.

Increases in training and travel costs from 2007 to 2008 amounted to approximately $86 thousand. This was primarily the result of several new employees joining Gas Supply in 2008 (replacing employees who left the Gas Supply department), who required natural gas industry-related training, and associated travel, as part of their development and knowledge base.

Legal and consulting expenses increased by approximately $89 thousand from 2007 to 2008. This was primarily the result of increased regulatory activity for Nova Gas Transmission Limited ("NGTL"), the pipeline system on which Terasen Gas contracts for service to supply core customers. Terasen Gas participated in the NGTL natural gas liquids inquiry (affecting shippers ability to capture revenues from liquids extracted from the gas flowed) and the North Central Corridor hearing (related to the expansion of pipeline infrastructure to supply the oil sands market) with the objective of maintaining reasonable pipeline costs and liquids revenues for shippers and the benefit of its core customers. Other consulting cost increases relate to the mapping of Gas Supply processes as part of the pre-work required for the transition from the Nucleus product (no longer supported by the vendor after 2009) to the Entegrate system in 2009. The Nucleus product, and its successor Entegrate, provide Gas Supply with an integrated system capturing deal entry through to invoicing, reporting and cost management.

Terasen Gas believes increases of this nature are prudent and appropriate in providing core customers with reliable and cost effective supply.

70.3 What were the cost components (itemized) and items included as part of the CMAE in 2005 and list and explain the cost components that have been added to the CMAE over the period of 2003 to 2009?

Response:

The cost components included as part of CMAE in 2005 have not changed from 2003 to 2009 and are itemized as follows:

Table 1.70.3 – 2005 CMAE Costs

Labour	$	1,824,524
Training/Travel	$	145,576
Consulting/Legal	$	139,107
Sundries/Subscriptions	$	165,649
IT	$	223,414
EMS Revenue	$	(328,321)
Total	$	2,169,950

Costs related to labour represent the largest component of CMAE costs. IT costs primarily relate to annual license fees and database and server support related to the Nucleus product, which enables Gas Supply to operate efficiently and generate necessary reporting and invoicing. Consulting and legal costs (provided by external parties) arise primarily from contracts review, participation in pipeline companies' regulatory applications and proceedings and external regional resource studies, which allow Terasen Gas to help reduce portfolio costs and provide reliable and cost-effective resources over the long run for core customers. Sundries and subscriptions costs are primarily related to natural gas pricing information and market research subscriptions, including credit monitoring services, as well as memberships in natural gas associations, such as the Northwest Gas Association. Training and travel expense covers costs for Gas Supply employees traveling to and attending industry courses and conferences and developmental or management courses. This enables employees to stay on top of the latest industry developments and develop their management and communication skills and industry knowledge. Lastly, EMS revenue is shown as a revenue stream and relates to providing energy services to third parties, such as PNG, and serves to reduce CMAE costs for core customers. TGI considers its expenditures relating to these components to be prudent and appropriate.

70.4 What were the numbers of FTE's included in CMAE in 2003 and show the increase in FTE's for each year up to and including 2009?

Response:

As identified in our response to BCUC IR 1.19 for the 2004 PBR Application, headcount for 2003 was 19. This included 16 TGI staff and 3 TGVI staff. As part of the Utilities Strategy Project, the projected headcount for the combined CMAE function for 2004 and 2005 was 17. This reflected a 2 headcount efficiency gain which reduced gas costs for all Terasen Gas Utilities. As shown in table C-5-3 of the Application, actual FTE for the 2004 to 2009 timeframe has been slightly under the 17 budgeted due to maternity leaves and other departures.

Table 1.70.4: CMAE Historical and Projected Full Time Equivalents

	2004	**2005**	**2006**	**2007**	**2008**	**2009**
Full Time Equivalents	15.8	16.3	16.3	16.6	16.6	16.7

70.5 Please provide the cost components included in Gas Cost Reconciliation Account ("GCRA") before it was split between into two gas deferral accounts; MCRA and CCRA?

Response:

The cost components included in the Gas Cost Reconciliation Account ("GCRA") before it was split into two gas deferral accounts, MCRA and CCRA, in April 2004 are the same cost components as included after the split into MCRA and CCRA. These cost components are labour, IT, consulting and legal, sundries and subscriptions, training and travel and EMS revenue. Commission Order No. G-25-04, and the Reasons for Decision attached as Appendix A to Order No. G-25-04, approved the CMAE allocation of 30% to the CCRA and 70% to the MCRA based on the level of administrative activity required to support the Commodity and Midstream functions.

70.6 What were the individual cost components (itemized) and items included as part of the CMAE in 2004 and list and explain the cost components that have been added to the CMAE over the period of 2005 to 2009?

Response:

As described in the response to BCUC IR 1.70.3, the cost components included in CMAE have not changed over the period from 2004 to 2009. They include labour, IT, consulting and legal, sundries and subscriptions, training and travel expenses and EMS revenues.

70.7 As indicated by TGI, "*Overtime the Gas Department has evolved into commodity, midstream, compliance and credit, back office support and resource management groups* (page 335)."

If CMAE costs are included in the MCRA account, does not this hide expenses from operating and maintenance accounts and therefore artificially lower the O&M category of costs?

How would this affect the performance based rate making formula and what adjustments to the formula would have to be implemented?

Response:

As outlined in the Application, Terasen Gas believes it is appropriate to continue to allocate the total CMAE costs to the three Terasen Gas Utilities consistent with the allocation which has been in effect since January 1, 2005 and was approved by the Commission in Order No. G-112-04, and the Reasons for Decision attached as Appendix A to Order No. G-112-04. TGI's portion is then allocated 30% to the CCRA account and 70% to the MCRA account, consistent with the allocation which has been in effect since April 1, 2004 and was approved by the Commission in Order No. G-25-04, and the Reasons for Decision attached as Appendix A to Order No. G-25-04. This allocation of CMAE to the CCRA and MCRA accounts serves to appropriately allocate costs associated with activities performed on behalf of core sales customers to these customers via the cost of gas.

Allocation of CMAE costs to Gas Costs ensures that the right customers are paying for the administrative activities required to support the Commodity and Midstream functions within the Gas Supply department. It is not "hiding" expense from operating and maintenance accounts, and is not "artificially lowering" the O&M costs. If these costs remained in O&M, they would be inappropriately allocated to both core sales customers as well as transport customers and only to TGI customers. Accordingly, there has been no affect on the PBR formula and there has been no need to adjust the formula.

70.8 Please provide the costs that have been included in CMAE costs for "green" energy management for 2010 and 2011 as described on pages 329-330.

Response:

As outlined in the Application, in the future, the gas supply portfolio may include natural gas "green" energy sourced downstream of the typical resource mix procured by Gas Supply. Gas Supply's role may include contract management, supply management (incorporating new supply sources into the Annual Contracting Plan) and invoice verification and payments. While Terasen Gas anticipates these new sources of supply could be significant in the longer term and important for the company to continue customer growth, the costs for "green" energy management are not expected to be material in 2010 and 2011 and will be absorbed into the Gas Supply activities through synergies with existing processes. Therefore, no costs have been included in CMAE costs for "green" energy management for 2010 and 2011 within the Application.

70.9 What were the costs included in CMAE cost category for the Lions Gate Waste Water Treatment Plant Biogas Upgrade Project and does TGI believe that it should be at risk for these costs since the project was cancelled and never received a CPCN?

Response:

There were no costs included in the CMAE cost category for the Lions Gate Waste Water Treatment Plant Biogas Upgrade Project. As discussed in the response to the previous BCUC IR 1.70.8, the costs for "green" energy management are not expected to be material in the initial years and will be absorbed into the Gas Supply activities through synergies with existing processes.

70.10 What revenue does TGI expect to receive from Terasen Gas Energy Services in 2010 and 2011 for the management of propane supply for TES customers at Furry Creek and Sun Peaks?

Response:

TGI expects costs to be recovered from Terasen Gas Energy Services in 2010 and 2011 for the management of propane supply for TES customers at Furry Creek and Sun Peaks. For the management of propane supply for TES customers at Furry Creek and Sun Peaks, time spent on this activity is converted to dollars and charged from TGI Gas Supply to TES, based on reimbursement for costs incurred. The costs are recovered through direct charges to TES (through time-sheets) and the forecast cost recovery from TES is based on booking 78 hours per year for 2010 and 2011 for TES. This equates to approximately $5 thousand for each of 2010 and 2011. This is consistent with the pricing of services as defined in the Terasen Gas Transfer Pricing Policy.

70.11 What revenue does TGI expect to receive for the management of contracts (page 333) related to third party shippers on the Terasen Gas Southern Crossing Pipeline System?

Response:

Terasen Gas currently provides transportation service for Northwest Natural Gas Company ("NWN") on its Southern Crossing Pipeline system. The revenue received from NWN for this service is forecast to be $7,580,692 in 2010 and $8,993,991 in 2011 and is allocated to the Southern Crossing Pipeline Revenues account, as detailed in Table C-4-11: Southern Crossing Pipeline Revenues on page 314 of the Application. The year over year increase in revenue is associated with the monthly demand charge, increasing from Cdn $15.18 per 10^3m^3 per day up until October 31, 2010, to Cdn $18.71 per 10^3m^3 per day from November 1, 2010 to the end of the contract term. The costs incurred by the Gas Supply department for contract management are not material.

70.12 The CMAE increases for 2010 and 2011 relate primarily to labour inflation and benefit cost increases (page 337). Please itemize the individual cost components.

Response:

	2009	2010	2011
Salary	$ 1,443,473	$ 1,442,609	$ 1,489,735
Inflation	$ 38,548	$ 45,707	$ 41,520
Benefits	$ 337,297	$ 322,129	$ 340,125
Total Labour	$ 1,819,318	$ 1,810,445	$ 1,871,380
Legal/Consulting	$ 189,944	$ 289,500	$ 310,600
Total Labour + Legal/Consulting	$ 2,009,262	$ 2,099,945	$ 2,181,980
Changes from 2009	$ -	$ 90,682	$ 172,718

As discussed on page 337 of the Application, costs related to labour represent the largest component of CMAE costs. However, the base CMAE increases for 2010 and 2011 (from 2009), excluding the appropriate transfers from O&M related to the Gas Accounting group, Gas Supply incentive compensation and shared services, relate primarily to labour inflation and benefit cost increases as well as increases in legal and consulting expenses. These increases from 2009 are $91 thousand for 2010 and $173 thousand for 2011. Total base CMAE costs for 2010 and 2011 increase by $120 thousand and $205 thousand, respectively, from 2009. The changes for 2010 and 2011 from 2009 are as follows:

Changes in Base CMAE Costs from 2009:

	2009	2010	2011
Salary	$ 1,443,473	$ 1,447,976	$ 1,489,735
Inflation	$ 38,548	$ 40,341	$ 41,520
Benefits	$ 337,297	$ 322,129	$ 340,125
Total Labour	$ 1,819,318	$ 1,810,445	$ 1,871,380
Legal/Consulting	$ 189,944	$ 289,500	$ 310,600
IT	$ 257,230	$ 279,407	$ 282,022
Sundries/Subscriptions	$ 186,543	$ 192,853	$ 193,841
Training/Travel	$ 204,510	$ 209,565	$ 213,535
EMS Revenue	$ (168,152)	$ (171,400)	$ (176,580)
Total Base CMAE	$ 2,489,393	$ 2,610,370	$ 2,694,799
Changes from 2009	$ -	$ 120,976	$ 205,406
Changes from 2009 related to Labour and Legal/Consulting	$ -	$ 90,682	$ 172,718

70.13 On page 339, TGI indicates that it believes that the time has come to realign costs between TGI O&M and CMAE to ensure the appropriate costs to core customer of Gas Supply services. Why does TGI consider that this is the appropriate time when allocation of costs is usually more effectively done in a cost of service study?

Response:

The scope of costs being considered with the realignment of certain costs between O&M and CMAE is sufficiently narrow that an embedded cost study such as a Fully Allocated Cost of Service (“FACOS”) study is not required. Terasen Gas believes that it is important to deal with this relatively narrow issue at this time so that costs that are presently accounted for in O&M are appropriately accounted for in CMAE so that recovery of these costs will occur for whom the costs are incurred, i.e. sales customers. A FACOS study is not needed to address this issue..

70.14 The costs of the Gas Accounting group primarily consist of labour costs and are forecast to be $433 thousand and $456 thousand in 2011. Please separate these amounts inflation and benefits?

Response:

The labour costs for the Gas Accounting group for 2010 and 2011, showing the inflation and benefits cost components, are presented below.

Gas Accounting Group Forecast Costs:

	2010	2011
Salary	$ 355,607	$ 366,135
Inflation	$ 7,812	$ 8,010
Benefits	$ 69,729	$ 82,071
Total Labour	$ 433,149	$ 456,216

70.15 How are the incentive payments for Gas Supply staff determined (page 340) that result in incentive pay of $243 thousand and $251 thousand in 2010 and 2011 respectively?

Response:

The Gas Supply Employee Incentive Program (EIP) payments referred to above follow the same methodology to the EIP payment program which exists for all Terasen Gas employees: they are based on alignment of interest of customer, shareholder & employee, providing employees with a direct stake in results produced. Employees are eligible to earn an incentive amount depending on results achieved and their relative impact in achieving these results. All personnel are required to have personal performance plans in place each year and payout is based on a combination of the employees' personal performance as well as corporate performance. A minimum threshold level of corporate financial performance must be achieved before the incentive payments are awarded.

Where performance is achieved or exceeded, total direct compensation (base salary plus annual incentive) is targeted at the 50^{th} percentile of the external comparator group. Budgets are set based on the previous EIP payouts anticipating similar overall performance.

70.16 On what basis are 50 percent of the credit risk management costs shared between the Gas Supply department and Terasen Gas allocated to CMAE? Why is the allocation of $65 thousand and $67 thousand in 2010 and 2011 respectively appropriate?

Response:

Terasen Gas has allocated 50 percent of the credit risk management costs associated with a new Credit Risk Manager role within Terasen Inc. to CMAE via the shared services fee methodology. This represents $65 thousand and $67 thousand in 2010 and 2011, respectively. This is based on the estimated requirements for incremental credit risk management for the Gas Supply function related to credit evaluation and analysis work to ensure physical and financial counterparties, necessary to providing reliable and cost effective supply for core sales customers, are sound. Given the financial and credit crisis that has occurred over the past year, resulting in many companies having their credit ratings downgraded and in certain instances, going bankrupt, Terasen Gas believes this incremental credit risk management is appropriate and prudent in ensuring core sales customers interests in cost effective and secure supply are protected. As this credit risk management is done solely on behalf of core sales customers, and not transportation customers, it is appropriate to include the costs in CMAE rather than O&M.

71.0 Reference: Operations and Maintenance Expenditures

Part III, Section C, Tab 6, p.347

71.1 Please recalculate Table C-6-2 by using 2008 Actual O&M as a starting point to determine the 2009, 2010, and 2011 formula O&M. Please compare these results to the total forecast O&M in Table C-6-3 (p.348) for 2010 and 2011 and discuss the variances.

Response:

Under the terms of the 2008 – 2009 extension of the 2004 – 2007 PBR Settlement Agreement, current and forecast year's O&M is derived by applying the formula for customer growth and inflation to the prior year's Approved O&M expense. Substituting prior year's Approved with prior year's Actual as the starting point is a deviation, as well as unreasonable to TGI. 2008 actual O&M is not an appropriate starting point in the aforementioned formula because operating environment and activities, management initiatives in 2008 would not be indicative of the same in 2010 and 2011. Therefore, its derived O&M is not an approximation of TGI costs for the forecast period.

To construct the requested table, a modification is required to remove the productivity factor. This factor represents a negotiated adjustment on CPI reducing variances between Actual and Formula O&M derived from the 2003 Decision over the term of the PBR. Using 2008 Actual O&M instead of 2008 Approved O&M as the starting point in the O&M formula would have effectively eliminated the forecasting variance on the 2008 Approved O&M.

As the table below displays, the variance between the restated formula and forecast can be largely attributable to the exogenous factors identified in Table C-6-3. When adjustments to make the forecast comparable in 2009 dollars are taken into consideration, the variance between the restated formula and forecast reiterates the prudent and reasonable nature of the forecast O&M expenses as discussed in the Application.

Calculation of Formula Gross O&M for 2009-2011 with 2008 Actual Gross O&M as Base

(Amounts in $000s)	**2009**	**2010**	**2011**
Prior Year Gross O&M	186,480	192,263	197,362
Customer Growth Factor**	0.98%	0.74%	0.68%
CPI	2.1%	1.9%	2.0%
Adjustment Factor	0.0%	0.0%	0.0%
Formula Gross O&M	192,263	197,362	202,671
Pension & Insurance Variance	1,753	3,766	4,765
Vehicle Lease Reclass	(2,050)	-	-
Ft Nelson	(778)	(678)	(696)
Calculated Formula Gross O&M	191,189	200,450	206,740
Projected and Forecast Gross O&M (Table C-6-3)	195,079	209,590	219,149
Less: Vehicle Lease Reclass	(1,804)	-	-
Less: Exogenous Factors (Table C-6-1)	-	(2,800)	(4,500)
Less: Adjustment to 2009 Dollars	-	(3,856)	(8,133)
Comparable Projected and Forecast Gross O&M (Table C-6-1)	193,275	202,934	206,516
Variance	(2,086)	(2,485)	224

**Customer Growth based on projected amounts (approved customer growth is 1.01% for 2009)

71.2 Please provide the data in Table C-6-2 using Net O&M figures and also in the format requested in the above question.

Response:

As stated in the response to BCUC IR 1.71.1, using 2008 Actual O&M as the starting point in the O&M formula as the derived 2010 and 2011 O&M is not an approximation of TGI's costs for the forecast period. Nevertheless, the information requested is set out below.

Calculation of Formula Net O&M for 2009-2011 with 2008 Actual Gross O&M as Base

(Amounts in $000s)	2009	2010	2011
Prior Year Gross O&M	186,480	192,263	197,362
Customer Growth Factor**	0.98%	0.74%	0.68%
CPI	2.1%	1.9%	2.0%
Adjustment Factor	0.0%	0.0%	0.0%
Formula Gross O&M	192,263	197,362	202,671
Formula Overhead Capitalized	(28,113)	(15,789)	(16,214)
Pension & Insurance Variance	1,753	3,766	4,765
Vehicle Lease Reclass	(2,050)	-	-
Ft Nelson	(778)	(678)	(696)
Calculated Formula Net O&M	163,076	184,661	190,527
Projected and Forecast Gross O&M (Table C-6-3)	195,079	209,590	219,149
Less: Forecast Overhead Capitalized	(28,113)	(16,767)	(17,532)
Less: Vehicle Lease reclass	(1,804)	-	-
Projected and Forecast Net O&M	165,162	192,823	201,617
Less: Exogenous Factors (Table C-6-1)	-	(2,800)	(4,500)
Add: Capitalized Overhead on Exogenous Factors	-	224	360
Less: Adjustment to 2009 Dollars	-	(3,547)	(7,482)
Comparable Projected and Forecast Net O&M	165,162	186,700	189,995
Variance	(2,086)	(2,039)	532

**Customer Growth based on projected amounts (approved customer growth is 1.01% for 2009)

71.3 "The most significant offsetting factor in the 2010 and 2011 revenue requirements is savings resulting from the rebasing of the benefits achieved through the PBR Period. These savings total approximately $22.4 million and are composed of $6.7 million related to net O&M savings <u>as TGI moves from a formula-based to a cost-driver approach</u> to the O&M requirements, and a total of $19.3 million related to capital savings through reduced rate base and the tax-adjusted effects of reduced depreciation expense." page 217, par. 3

71.3.1 Given the above statement, please explain why it is appropriate the compare the forecast O&M for 2010 and 2011, as calculated using a cost approach, to a formula based O&M, as calculated in Table C-6-2.

<u>Response:</u>

It is appropriate to calculate the formula based O&M and compare it to the forecast in order to establish the reasonableness of the forecast cost-driver based O&M.

TGI has been successful in keeping its operating costs below the formula based amounts throughout the PBR Period, despite the inclusion of a significant productivity improvement factor in the formula.

When the PBR Settlement Agreement was reached, the parties to that Agreement considered that the formula based approach would provide a reasonable level of O&M to include in rates. Even though we have reached the end of the PBR Period, the formula continues to provide a good approximation of what would be an acceptable level of O&M that TGI would incur in providing service to its customers. As such, it is appropriate to compare the forecast O&M to the formula based O&M in establishing that the forecasts included in the RRA are well within the range of reasonableness.

72.0 Reference: Operations and Maintenance Expenditures

Table C-6-3, Part III, Section C, Tab 6, p.348

72.1 Please identify what portion of the forecast O&M costs in 2010 and 2011 relate to customer growth and what portion is related to general CPI inflation.

Response:

Approximately $1.5 million of the forecast O&M costs in 2010 relate to serving customer growth. Of the $1.5 million, $0.25 million is for an increase related to the Customer Care (CWLP) contract to serve additional customers in 2010 (RRA reference page 380). The remaining $1.25 million is for Distribution operations costs in support of customer related activities such as meter exchange, meter to cash support, etc. (RRA reference page 364).

In 2011 (2011 vs. 2010), additional customer growth related O&M costs included amount to approximately $0.7 million. Of the $0.7 million, $0.4 million is for an increase related to the Customer Care (CWLP) contract to serve additional customers in 2011 (RRA reference 380) . The remaining $0.3 million is for Distribution operations costs in support of customer related activities such as meter exchange, meter to cash support, etc. (RRA reference page 364).

Inflation Related

Inflation related increases including in the forecast O&M costs in 2010 and 2011 include allowances for vehicle inflation, price related contract increases and general inflation on materials, expenses, etc.

Vehicle inflation included in O&M costs for 2010 total to approximately $0.25 million in 2010 and an additional $0.25 million in 2011, primarily in the Distribution Services department for operations vehicles.

Price related contract increases in 2010 total to approximately $0.6 million, including $0.5 million for CWLP contract increase to serve existing customers and $0.1 million primarily related to facilities leases and service contracts and inflation for IT support contracts. In 2011, an additional $0.5 million has been included for the CWLP contract to serve existing customers and less than $0.1 million has been added for IT support contract inflation related increases.

For other general inflation, approximately $0.1 million has been included added in each of 2010 and 2011 to reflect general inflation pressures on materials, expenses, etc. in the various departments.

In preparing the 2010 and 2011 O&M budgets, following a zero based approach, inflation allowances are not automatically applied and instead requires review of specific circumstances before an allowance is included in the O&M budgets. Not listed here are labour inflation and benefits related increases which are discussed on page 349 of the RRA.

72.2 Please identify what portion of the forecast O&M costs in 2010 and 2011 relate to new service offerings (such as geo-exchange, solar, biomass, thermal).

Response:

Of the $4.5 million noted in 2010 in Table C-6-3 under the heading "Customer / Stakeholder Behaviours and Expectations", $3 million is required for additional sales and development staff to support offerings for natural gas and also new services offering such as geo-exchange, solar, biomass or other thermal energy sources.

TGI is not able to accurately estimate the allocation of the $3 million incremental funding between natural gas offerings versus new service offerings (i.e. geo-exchange) as customer requirements are evolving. As indicated in the Application, customers (including those noted in response to BCUC IR 1.23.1) of TGI are increasingly looking for assistance and information in not just natural gas but also information on options for alternative energy solutions, partners in alternative energy solutions, detailed information on gas and GHG emission. It is this requirement to support our customers' evolving energy use and management needs that TGI is seeking funding for.

However, as noted in response to BCUC IR 1.19.1, and on page 267 of the Application, TGI believes it is important to allocate a portion of overhead costs, including Marketing related costs, to the customers who would receive alternative energy solutions. As part of the economic tests for the alternative energy solutions including biogas, DES, solar and geo, customers will be allocated a fair portion of these costs and as the alternative energy business grows and more customers are added, the overall share of these costs allocated to AES customers will grow accordingly. As discussed in BCUC IR 1.20.1 the costs included in the economic tests for AES customer will include an overhead allowance, similar to the overhead allowance included in TGI's main extension test, so that AES rates will recover more than the direct costs of the particular project only.

A further incremental $0.6 million to the $3 million in 2010 for additional sales and development staff related to supporting gas and new service offerings has been included for 2011.

72.3 Please present the data in Table C-6-3 (p.348) without accounting changes. Please also show the percentage increase from 2009 on the total forecast O&M for 2010 and 2011, without accounting changes.

Response:

Following is Table C-6-3 updated without the accounting changes.

Year	*Prior Year*	Labour Inflation and Benefits	Government Policy	Code and Regulations	Customer / Stakeholder Behaviours and Expectations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Total Forecast
2010	195,079	2,816	592	5,297	4,526	817	-	3,604	17,652	212,731
2011	212,731	5,344	113	2,059	599	216	-	1,734	10,065	222,796

(amounts in $ thousands)

The 2010 forecast O&M of $212.7m (without accounting changes) represents a nine per cent increase from 2009. The 2011 forecast O&M of $222.8m (without accounting changes) represents a 13 per cent increase from 2009.

TGI believes the 2010 and 2011 O&M incremental funding requests excluding the accounting changes are still necessary and required to enable it to continue providing safe, reliable and cost efficient service to its customers.

73.0 Reference: Operations and Maintenance Expenditures

Part III, Section C, Tab 6 and Appendix F.1

73.1 Please provide in table format the actual gross O&M dollars for 2006-2008, projected O&M for 2009, and the forecast O&M for 2010 and 2011. Please include the change in dollars and percentage from year to year. Please also include the average number of customer and end of year number of customers. Please use the table provided below:

	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Gross O&M						
Increase / Decrease $'000						
Increase / Decrease %						
Net O&M						
Increase / Decrease $'000						
Increase / Decrease %						
Average # customers						
End of Year # customers						
Gross O&M per Ave # customer						
Net O&M per Ave # customer						

Response:

The requested table is provided below. Although the percentage increase in O&M is higher in 2010 than it has been historically, the requirements for the projected O&M are fully explained in the Application. The Net O&M is significantly impacted by the change in overheads capitalized policy proposed in the Application.

	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Gross O&M	179,206	178,973	185,740	195,079	209,590	219,149
Increase/Decrease $'000		- 233	6,767	9,339	14,511	9,559
Increase/Decrease %		-0.1%	3.8%	5.0%	7.4%	4.6%
Net O&M	150,223	149,564	156,208	165,162	192,823	201,617
Increase/Decrease $'000		- 659	6,644	8,954	27,661	8,794
Increase/Decrease %		-0.4%	4.4%	5.7%	16.7%	4.6%
Average # of customers	803,686	817,480	825,957	833,798	839,949	845,633
End of Year # customers	812,683	822,598	831,845	837,965	843,565	849,415
Gross O&M per Ave # customer	223	219	225	234	250	259
Net O&M per Ave # customer	187	183	189	198	230	238

74.0 Reference: Operations and Maintenance Expenditures

Part III, Section C, Tab 6

74.1 Please summarize all requests for O&M increases by functional department, including increases in headcount and dollar amount in a table format, providing 2006-2008 actuals, 2009 projection, 2010 and 2011 forecasts, for comparative purposes. An example is provided below for Distribution. Please ensure the totals dollars reconcile to the summary on Table C-6-10 (p.357) and Table C-6-11 (p.358).

Function:	2006A	2007A	2008A	2009P	2010F	2011F
	($'m)	($'m)	($'m)	($'m)	($'m)	($'m)
Field Work				20.115	23.17	25.169
Operations Centre				6.375	7.466	8.032
Asset Mgmt, Regional Mgrs, Process Support				7.113	8.288	9.050
Vice President				4.005	4.418	4.504
Total Distribution (including Vehicle Lease and Fort Nelson)				37.608	43.342	46.755
*Vehicle Lease					(1.612)	(1.977)
**Fort Nelson				(0.656)	(0.676)	(1.696)
Total Distribution (excluding Vehicle Lease & Ft. Nelson)				**36.952**	**41.054**	**43.082**
Headcount	xx	xx	xx	xx	xx	xx

Response:

Provided below is the information as requested beginning with the year 2006 to provide context to the 2010 and 2011 O&M forecasts. However, TGI does not believe 2006 actuals is the appropriate starting baseline for comparison of 2010/2011 O&M forecasts. Instead, TGI believes the starting point should be the 2003 allowed O&M base that was approved by the Commission and adjusted annually using the approved formula, as it is the allowed O&M that has been used for purposes of rate setting. It then follows that an appropriate and reasonable level of base expenditures for 2010/2011 for comparison purposes would be the 2009 O&M projection, as it is the most recent and given it has been shaped by benefits associated with performance based incentives.

Distribution ($ millions)	Actual 2006	 2007	 2008	Projection 2009	Forecast 2010	 2011
Field Work	16.7	17.8	20.2	20.1	23.2	25.2
Operations Centre	6.4	6.2	6.5	6.4	7.5	8.0
Asset Mgmt, Regional Mgrs, Process Support	5.9	6.5	6.5	7.1	8.3	9.1
Vice President	3.4	3.6	4.3	4.0	4.4	4.5
Total Distribution (including Vehicle Lease & Fort Nelson)	32.4	34.1	37.6	37.6	43.3	46.8
Vehicle Lease [1]	0.0	0.0	0.0	0.0	(1.6)	(2.0)
Fort Nelson [2]	(0.7)	(0.7)	(0.6)	(0.7)	(0.7)	(0.7)
Total Distribution (excluding Vehicle Lease & Fort Nelson)	**31.7**	**33.4**	**37.0**	**37.0**	**41.1**	**44.1**
FTE [3]	491	504	526	545	574	577

Notes:
1. Vehicle lease expenses previously recorded as an operating lease are classified as a capital lease effective 2010
2. Fort Nelson expenses are removed to create a more accurate view of TGI Distribution O&M Costs
3. The FTE count includes 23 dependant contractors

Gas Supply and Transmission	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
Transmission	12.7	12.9	14.0	16.0	16.4	17.4
Gas Supply-Transpportation Services	0.0	0.0	0.0	0.2	0.2	0.2
Vice President	1.0	0.9	0.7	0.8	0.7	0.7
Total Gas Supply and Transmission	**13.7**	**13.7**	**14.7**	**16.9**	**17.3**	**18.3**
FTE	80	81	80	90	96	96

Marketing and Development	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
Customer Contact - ABSU contract	44.2	45.4	46.4	46.8	48.5	49.4
Bad Debt Expenses	4.3	3.4	3.7	5.0	4.9	4.9
Other	12.5	11.9	13.0	14.8	18.8	19.9
Total Marketing & Business Development	**60.9**	**60.7**	**63.1**	**66.6**	**72.2**	**74.2**
Headcount	75	80	80	112	127	131

Business and Information Technology Services	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
IT and Business Services	19.3	20.7	20.5	22.4	27.8	28.7
Operations Engineering	7.7	8.0	8.3	9.2	11.2	12.0
Operations Support	6.6	6.7	6.8	7.5	8.3	8.7
Total B&ITS	**33.7**	**35.4**	**35.7**	**39.1**	**47.3**	**49.3**
FTE	293	300	311	357	370	377

Human Resources and Operations Governance	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
Human Resources	5.1	5.8	6.1	6.8	8.3	8.6
Environment & Occupational Health & Safety	1.2	1.1	1.2	1.5	2.4	2.5
Engineering Governance & Fleet Services	0.1	0.1	0.0	0.1	0.1	0.1
Total Human Resources and Operations Governance	**6.4**	**7.0**	**7.3**	**8.4**	**10.7**	**11.2**
FTE	85	84	87	76	85	88

Finance and Regulatory Affairs	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
Finance and VP	4.6	5.0	5.2	5.6	6.2	6.4
Regulatory Affairs	2.5	2.8	3.6	3.9	3.5	3.5
Total Finance and Regulatory Affairs	**7.1**	**7.8**	**8.7**	**9.6**	**9.6**	**10.0**
FTE	59	58	63	68	67	67

President and CEO Office	Actual			Projection	Forecast	
($ millions)	2006	2007	2008	2009	2010	2011
Total President & CEO	**25.7**	**21.1**	**19.3**	**17.5**	**11.3**	**11.9**
FTE	2	2	2	2	2	2

75.0 Reference: Operations and Maintenance Expenditures

Maintenance Deferred during PBR

Part III, Section C, Tab 6, p. 357, par. 1

"To continue to fulfil our recognized role as a respected and trusted operator providing safe, reliable and cost effective utility service to customers, Terasen Gas forecasts additional O&M funding required for its ongoing operations and activities. These include ... maintenance which has been pragmatically deferred during the PBR Period but cannot be deferred any longer."

75.1 Please provide details of the maintenance activities and related costs deferred, indicate which will now be required in the 2010 or 2011 period, and detail the reference in this Application.

Response:

O&M maintenance activities and related costs deferred from the PBR period into the 2010 period total to approximately $870K with none in 2011. Maintenance activities pragmatically deferred during the PBR period but that cannot be deferred any longer include:

1. $200K - Valve and maintenance repairs
2. $170K – Station heater maintenance
3. $30K - Bridge and aerial cross repairs
4. $25K - Station ground maintenance
5. $160K - Tools and equipment maintenance
6. $285K – Building maintenance

$870K – Total Deferred and Requested in 2010

Item numbers 1 to 4 are listed on page 362 of the Application in table C-6-16. During the PBR period, there were no changes in survey or inspection procedures. All regularly scheduled preventive maintenance, surveys and inspections were completed as per Code and Terasen Gas requirements. No work was deferred that was considered critical to the ongoing safe operation of the natural gas distribution system. Maintenance expenditures were managed and prioritized based on a corporate risk profile with higher risk items addressed first. Please refer to TGI's response to BCUC IR 1.8.2 for further discussion of this approach.

Item number 5, tools and equipment maintenance is referenced on page 390. Maintenance on tools and equipment used in field operations has been deferred during the PBR period without impact to operations. However, much of this maintenance work is directed toward industry specific tools and equipment that would otherwise be expensive to replace through purchase or manufacture. As such, these additional maintenance activities are prudent and required in order to continue providing tools and equipment to our field employees in a cost effective manner.

Item number 6 is listed on page 390 of the Application. The additional facilities maintenance comprised of activities such as painting, fence replacement, maintenance on roofs, etc is not in essence deferred expenditures but more cyclical activities in nature that have varying frequencies. In 2011, there is reduction of ($160K) reflecting the completion of maintenance completed in 2010.

TGI continues to defer low risk or low priority items as it has done during the PBR period as part of its prudent management of expenditures.

76.0 Reference: Operating & Maintenance

Budget Prioritization

Part III, Section B, Tab 1, p. 85

"Requests for O&M funding are assessed against safety and reliability requirements and prioritized to ensure that funding is put to its best use …" Ref: Part III, Sec B, Tab 1, p. 85, par. 4

76.1 Please expand on the budget prioritization process, particularly with reference to funding for code compliance, safety communication, maintenance, and marketing & business development.

Response:

Requests for incremental O&M funding are considered and prioritized with the focus on achieving Operational Excellence and the alignment of the interests of ratepayers, stakeholders and the shareholder. To ensure optimal allocation of resources, all departments are first required to scrutinize their existing O&M budgets before seeking incremental funding. Funding requests are then brought forward before the Utility Operating Committee and Executive Leadership Team who have the experience and understanding of the business priorities to make effective prioritization decisions. The total incremental funding requests approved and the needs that they meet are balanced against the need to minimize the impact on the cost of service and the financial impact on the Company.

For a discussion of the prioritization process for Code Compliance and related Maintenance funding, please refer to BCUC IR 1.8.2.

For a discussion of the prioritization of Safety Communication funding, please refer to BCUC IR 1.127.1 and 1.127.2. Information available now indicates TGI must increase it activities in this area in response to customer needs and new Oil and Gas Commission regulations on public awareness as a way to prevent damage.

Customer satisfaction is an important aspect of Terasen Gas' commitment to Operational Excellence. Providing appropriate Market and Business development funding is important in ensuring customer expectations are met and satisfied, particularly now given the impact of government policy and TGI's competitive situation.

TGI believes it proposed O&M funding are required to meet the needs of our customers and stakeholders and to maintain its profile as an efficient and effective utility.

77.0 Reference: Operating & Maintenance

Non-Maintenance Deferrals during BPR

Part III, Section B, Tab 1, p. 161, par. 1

"Deferring activities and related costs where safe and prudent to do so, particularly where the activities were of a cyclical nature."

77.1 Please provide details of the non-maintenance activities and related costs deferred, indicate which will now be required in the 2010 or 2011 period, and detail the reference in this Application.

Response:

Non-maintenance activities pragmatically deferred during the PBR period but that cannot be deferred any longer include:

1. $250K - Vegetation ($150K) and pipeline identification ($100K)
2. $150K - Data integrity improvements
3. $120K - Class location study

$520K – Total Deferred and Requested in 2010

The above items are listed on page 362 of the Application in table C-6-16. These non-maintenance expenditures were managed and prioritized based on a corporate risk profile with higher risk items addressed first, and Terasen Gas intends to continue with this prudent management of these types of expenditures. Please refer to TGI's response to BCUC IR 1.8.2 for further discussion of this approach.

78.0 Reference: Operations and Maintenance Expenditures

Budget and Planning Process

Part III, Section C, Tab 6, p. 346, par. 2

"To ensure an optimal allocation of financial resources at Terasen Gas, O&M budgets are reviewed, updated and approved annually. Forecasted O&M expenditures by departments are developed on a trended and zero-based approach where appropriate. Departments review their existing budgets and identify incremental funding requests with supporting justification provided."

78.1 Please provide the total O&M dollars and percentage for 2010 that were zero-based budgeted and which were trend budgeted.

Response:

Terasen Gas follows a comprehensive approach to budgeting to ensure an appropriate allocation of resources amongst various departments. As part of the annual budget development process, departments are asked to first review their O&M budget allocation to ensure existing funding available is still required and justified (zero based approach). Departments then are required to identify incremental changes to their existing budgets with supporting justification required. To assist in the validation process of the required funding, departments depending on the nature of the expenditure compare the history of actual spending to that forecasted (trend based approach).

TGI does not separate its O&M budget development into zero based and trend based. The two approaches, zero based and trend based, are not mutually exclusive and instead complementary to one another.

78.2 Please provide the number of historical years used for the trend analysis in the budget process.

Response:

Please refer to the response to BCUC IR 1.78.1.

As a minimum, year-to-date spending and the most recent complete year of historical expenditures are used to validate 2010 and 2011 funding requests. Where applicable (i.e. Distribution Services - gas odour calls expenditures), a longer period ranging three to five years of historical data is used in the validation process.

78.3 Please comment on the Terasen Gas processes to identify items for reduction and/or elimination.

Response:

As part of its focus and commitment to achieving Operational Excellence, TGI continuously looks for ways to prudently manage costs and increase the efficiency of its operations for the benefit of ratepayers and the shareholder. Cost saving initiatives are identified from a number of ways including process reviews and those opportunities that are identified by managers for their areas of responsibilities.

When the reduction items are confirmed, they are reflected in the current year forecast and incorporated into the development of the annual budgets. Please refer to the response to BCUC IR 1.78.1 for a description of the development of O&M budgets at TGI.

As part of the annual budget process and reflective of a zero-based approach, items for reduction and elimination are identified and reflected in the budget. Examples of reductions/eliminations include those for Distribution Service referenced on page 364 of the RRA (i.e. Emergency Management, Distribution Apprentice Training). The decreases are incorporated into the funding requirements identified as part of the budget preparation process.

79.0 Reference: Operations and Maintenance Expenditures

Labour Inflation and Benefits

Part III, Section C, Tab 6, p.349

79.1 Please explain why the COPE increase in 2010 is based on negotiated contract increases while the increase in 2011 is based on estimates?

Response:

Since April 2002, the company and union have negotiated the final year salary adjustment to be based on a guaranteed minimum percentage or market median derived from a joint market comparator survey. This has been a consistent practice when negotiating multiple year contract settlements for COPE that expire after the term of the IBEW contract. The COPE negotiated rates up to 2010 are aligned with the IBEW contract settlement which expires March 2011. The current COPE agreement covers the period April 2007 through to March 31, 2012.

The negotiated collective agreement language states "Effective April 1, 2011, salaries and bi-weekly salary scales shall be adjusted by an amount that will re-establish their relationship to market median as determined by the survey, and in any event not less than 2.50%."

The The COPE 2011 3% estimate for the salary increase for 2011 is based on the anticipated market median. for our salary survey comparator groups. The negotiated salary increases have averaged 3% for the years 2008 and 2009.

79.2 Please file the negotiated union agreements for IBEW and COPE which supports the forecasted contract increases for 2010 and 2011.

Response:

A complete copy of the current COPE agreement is included in Attachment 79.2. The IBEW collective agreement is still in draft form as there are outstanding housekeeping changes still pending. However, all wage increases have been finalized. This document is also included in Attachment 79.2.

79.3 Please discuss Terasen Gas' bonus / merit structure for each category of employees (M&E, IBEW, COPE) and explain where these costs are captured in O&M.

<u>Response:</u>

The Employee Incentive Plan (EIP) is an opportunity available to eligible employees to share in the company's success and be recognized for their contributions in achieving the outcomes in the performance year. This program emphasizes and encourages excellence, growth and development which provide incentive opportunities for all employees that are linked to individual and company performance. The EIP is paid in February following the performance year (equivalent to a calendar year). Each affiliation has unique guidelines outlining the methodology for processing EIP. The IBEW and COPE incentives are governed by the guidelines set out in their respective collective agreements.

M&E:

The Employee Incentive Program introduced in 1996 provides management and exempt employees a direct stake in the results they produce. Employees are eligible to earn an incentive amount depending on their ability to impact outcomes and results which align with the Scorecard Objectives. All personnel are required to have personal performance plans in place in the first quarter of each year. Actual payout is based on the employees' personal performance as well as Company performance. A minimum threshold level of corporate financial performance must be achieved before the plan pays out.

The general formula used to calculate an M&E EIP amount is as follows:

Annual Salary x Personal Performance x Corporate Scorecard

IBEW:

There are two components to the EIP calculation for IBEW:

1. <u>Corporate Scorecard:</u> $1,000 times the Scorecard multiplier; this amount will be prorated if an employee's annual absences exceed 20 days in the performance year;
2. <u>Individual Performance Measures:</u>
    a. <u>Lost Time Accidents:</u> an additional $300 if the employee maintains zero lost time accidents in the performance year
    b. <u>Motor Vehicle Accidents:</u> an additional $300 if the employee maintains zero motor vehicle accidents in the performance year; and
    c. <u>Attendance:</u> an additional $300 provided no more than two paid medical/dental appointments <u>AND</u> total paid sick leave is less than 50% of the bargaining unit average for the performance year. The employee must meet both attendance criteria to be eligible.

Sample IBEW Calculation:
Assumptions:

Scorecard Multiplier: 1.05

Employee had no lost time accident and no motor vehicle accident

Employee had less than 50% of the bargaining unit's average sick leave and not more than 2 paid medical/dental appointments

Corporate Scorecard Factor: 1,000 x 1.05 = $1,050

Individual Performance Measures:

Lost Time Accidents: $300

Motor Vehicle Accidents: $300

Attendance: $300

Total EIP Payment: $1,950.00

COPE:
All employees have a personal performance plan and behavioural goals developed for the reporting year. There are three components to the EIP calculation:

1. Corporate Scorecard Factor: 1% of an employee's actual earnings times the Scorecard Multiplier;
2. Employee Performance: 1% of an employee's actual earnings provided the employee has met both the behavioural goals and 3 out of 4 of their performance goals as identified in their performance plan; and
3. Total Sick Leave: 1% of an employee's actual earnings provided the employee's total paid sick leave (including sick leave and paid medical appointments) is less than 75% of the bargaining unit average.

Sample COPE Calculation:
Assumptions:

Scorecard Multiplier: 1.05

Actual Annual Earnings: $40,000

All performance and behavioural goals were met

Employee had less than 75% of the bargaining unit's average sick leave

Corporate Scorecard Factor: 40,000 x 1% x 1.05 = $420

Employee Performance Factor: 40,000 x 1% = $400

Sick Leave Factor: 40,000 x 1% = $400

Total EIP Payment: $1,220.00

The costs for all 3 Employee Incentive Plans are captured under Operation and Maintenance expenses. Please refer to: Financial Schedules, Part III, Section C, Tab 13, Schedule 28. line items 1-5 and Appendix F 1(a), line items 1-5. A detailed breakdown of labour costs including EIP is explained in detail in response to BCUC IR 1.85.1 Labour – Compensation and Benefits.

80.0 Reference: Operations and Maintenance Expenditures - Demographics

Table C-6-8, Part III, Section C, Tab 6, p. 353

80.1 What are the expected immediate and long term benefits arising from these enhanced training efforts?

Response:

We are increasing our investment in Training and Employee Development to ensure that our current workforce remains competent, to build leadership capacity to replace older retiring workers, and to improve our training programs to ensure we are providing the best possible outcomes for our new (younger) employees and their changing learning styles. Immediate and long term benefits are summarized as follows

- Engineers in Training (EITs) benefit our business immediately by providing cost effective resources to undertake lower level technical work, while at the same time learning from our seasoned Professional Engineers. In the long term, we are growing our future Professional Engineers internally by providing training that is specific to our industry. We are a somewhat unique industry in BC, and hiring qualified engineers has been a challenge over the past several years: our EITs will help fill this void. We have a successful EIT program that has been in place for well over 20 years and several of our current senior managers have come through this program. We have requested funding to add capacity for one more EIT in 2010.

- We currently have two Sr. Instructional Designers that are focused on developing training material for our field/trades workforce. As we shift to a competency based learning model, these positions will be essential to ensure there is alignment between the competencies our employees must have, the assessments we use to validate these competencies, and the training that is delivered to close any competency gaps. In the short term these requirements are driven by the Asset Integrity Management Program. As we expand the competency based learning model to all areas of our company, the Sr. Instructional Designer that we plan to hire in 2011 will ensure that these processes are applied similarly the non-field/trades areas. The immediate benefit will be the standardization of training processes that will allow for easy updating and re-usability of curriculum. In the longer term we will see a continual improvement in the effectiveness of our training programs for our new employees. This includes the development of learning content and delivery methods that are consistent with the learning styles of younger employees as well as the ability to capture the knowledge of our existing long term employees.

- As discussed in Part III, Section C, Tab 6, pages 396-397, employee and leadership development is a key pillar of Terasen Gas' long term HR strategy and our response to the looming demographic challenge. In addition to the need to enhance traditional training and development opportunities for field and office workers, TGI has recently renewed its emphasis on leadership development across the organization by focusing on the development of both managers and emerging leaders who have been identified through the succession planning process. The funding requested for 2010-2011 will also be directed to the development of new programs in support of the Core Leadership Competencies, including enhanced funding for tuition support and professional development delivered at semi-annual Management Forums.

Terasen Gas intends to maintain and enhance its strong focus on employee development and training in its commitment to the pursuit of Operational Excellence.

81.0 Reference: Headcount History

Appendix F.2

81.1 Please re-categorize the data in the first table in Appendix F.2 (Employees Historical Comparison "Headcount" as at December 31st for the Year 2003 to 2008) to show employees by the 3 categories of M&E, COPE, IBEW. Please show actuals in each year for 2006-2008, projected 2009, forecast 2010 and 2011.

Response:

As requested, the data found in the first table (titled "Headcount During the PBR Period Has Remained Below 2003 Levels") in Appendix F.2 has been reproduced in the table included in the response to 81.2 below by employee affiliation (i.e. M&E, COPE, and IBEW) and by department.

For reference, "headcount" includes all active full-time regular, part-time regular, and temporary employees. Headcount does not include dependent contractors.

81.2 Please also present the headcount data by department for each of the years as requested in the above question.

Response:

The requested date is in the following table.

BCUC IR No. 1, Questions 81.1 & 81.2

TERASEN GAS INC.
EMPLOYEES HISTORICAL COMPARISON
HEADCOUNT AS AT DECEMBER 31ST
FOR THE YEARS 2003 TO 2011

Line No.	Particulars		2003	2004	2005	2006	2007	2008	2009 Forecast	2010 Proposed	2011 Proposed
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Distribution										
		COPE	271	178	146	148	148	142	147	155	157
		IBEW	401	389	285	261	286	308	292	292	292
		M&E	114	64	56	54	58	60	66	67	68
			786	**631**	**487**	**463**	**492**	**510**	**505**	**514**	**517**
2	Finance & Regulatory Affairs										
		COPE	31	34	30	30	38	38	39	40	40
		IBEW	0	0	0	0	0	0	0	0	0
		M&E	16	23	21	25	26	28	29	33	33
			47	**57**	**51**	**55**	**64**	**66**	**68**	**73**	**73**
3	Business & IT Services										
		COPE	21	36	139	136	162	167	184	194	201
		IBEW	4	3	71	69	82	79	90	90	90
		M&E	29	27	56	55	63	71	84	90	91
			54	**66**	**266**	**260**	**307**	**317**	**358**	**374**	**382**
4	Human Resources & Operations Governance										
		COPE	43	139	48	45	38	42	67	67	67
		IBEW	9	8	9	5	8	6	6	6	6
		M&E	38	59	42	47	40	52	62	64	65
			90	**206**	**99**	**97**	**86**	**100**	**135**	**137**	**138**
5	Marketing & Business Development										
		COPE	31	27	21	30	34	30	39	41	41
		IBEW	1	1	1	0	0	0	0	0	0
		M&E	20	37	43	47	50	50	76	91	95
			52	**65**	**65**	**77**	**84**	**80**	**115**	**132**	**136**
6	Gas Supply & Transmission										
		COPE	32	29	52	56	23	23	26	27	27
		IBEW	34	35	54	48	32	32	35	36	36
		M&E	37	32	30	27	26	27	28	30	30
			103	**96**	**136**	**131**	**81**	**82**	**89**	**93**	**93**
7	Corporate										
		COPE	3	-	-	-	-	-	-	-	-
		IBEW	-	-	-	-	-	-	-	-	-
		M&E	62	-	-	-	-	-	-	-	-
			65	-	-	-	-	-	-	-	-
8	Total Headcount										
		COPE	432	443	436	445	443	442	502	524	533
		IBEW	449	436	420	383	408	425	423	424	424
		M&E	316	242	248	255	263	288	345	375	382
			1197	**1121**	**1104**	**1083**	**1114**	**1155**	**1270**	**1323**	**1339**

82.0 Reference: Organizational Chart by Department

Figure B-1-1, Part III: Section B – Tab 1 (p. 87)

82.1 Please provide a more detailed organizational chart including headcount which drills down to the employee level, for end of year 2006, 2007, and 2008.

Response:

More detailed organizational charts as at December 31st for the years 2006 – 2008 are provided in Attachment 82.1.

Headcount totals are included at the departmental level. Please note that these organizational charts do not drill down to the employee level. Efforts were made to create charts to the employee level, but this proved to be a very onerous process as we do not normally maintain corporate organizational charts with that level of detail. It is also exceedingly difficult to reconcile headcount on a departmental basis, when operationally our organizational charts combine Terasen Gas employees with Terasen Inc. and Terasen Gas Vancouver Island, and when the employee landscape is constantly changing, depending on vacancies, temporary backfill, short-term and long-term leaves of absence, as well as regular developmental movement throughout the organization.

82.2 Please provide the same detailed organizational chart (in the previous) as forecasted for 2010 and 2011.

Response:

Forecasted organizational charts for 2010 and 2011 are included in Attachment 82.2.

As with our response in BCUC IR 1.82.1, these charts do not drill down to the employee level. We have included headcounts at the departmental level, and have focussed on identifying new positions (i.e. positions that do not already exist at Terasen Gas) that we plan to add in these years.

83.0 Reference: Operations and Maintenance Expenditures

Business Development – Resource Planning

Part III, Section C, Tab 6, p. 382, par. 3

83.1 Please explain the reasoning for moving the resource planning function from Gas Supply to Business development. Is resource planning no longer required for Gas Supply?

Response:

Resource planning is still required by Gas Supply. Below is a brief explanation of the evolving nature of the Resource Planning function at TGI and the reason for appropriately moving it out of Gas Supply.

When the Resource Planning function at TGI was developed and costs originally allocated to Gas Supply, TGI conducted its own Regional Resource Plan which examined the regional infrastructure planning environment, resource needs and industry response for major supply and transmission issues upstream and downstream of TGI's interconnect with other merchant transmission pipelines. This provided insight into how TGI would need to respond to ensure that the needs of its own customers could be met given these regional planning issues. This work was undertaken in addition to the completion of our own integrated resource planning, which examined future demand and resource needs on our own system.

More recently, the Northwest Gas Association has assumed the role of undertaking a regional planning study - the NWGA's Outlook Study (www.nwga.org) - into which all of the member companies, including utilities and pipeline transport companies, provide input. TGI's Resource Planning function still includes participation in the outlook study, but since the NWGA manages the process, completion and publishing of the study, the time spent on this activity by TGI is much less than it was when TGI undertook its own Regional Resource Plan.

In addition to the change in Regional Resource Planning, TGI's integrated resource planning process has also evolved. In earlier Integrated Resource Plans, much of the effort focused on physical gas transportation assets - pipe, compression and associated storage - required to meet future expected demand and highlighted the gas supply planning activities that impacted customers. Since gas transportation is largely a Gas Supply function, the resource planning activity was traditionally viewed as supporting the Gas Supply Group.

Since approximately 2004, the Resource Planning function at TGI has been evolving to include a greater focus on energy efficiency and conservation, alternative energy initiatives, regional issues beyond participating in the NWGA, information infrastructure, distribution issues and other inputs in addition to Gas Supply and Transmission Planning. Since Gas Supply is one of many groups providing input into the Resource Planning process today, we believe it is more appropriate to move the Resource Planning function outside of the Gas Supply group. It is important to note, however, that the traditional gas supply planning activities, such as portfolio planning and price risk management, are still carried out by the Gas Supply Group and provide one of many inputs into TGI's Integrated Resource Plan.

84.0 Reference: Operations and Maintenance Expenses

Codes and Regulations - HROG O&M Increases

Part III, Section C, Tab 6, p. 398, Table C-6-33

84.1 Please provide an expanded table from 2006, by year, providing the number of FTE and O&M funding for each of the items in Table C-6-33.

Response:

The following table provides an expanded view of HROG's incremental FTE and O&M funding requirements for the years 2006-2011 to ensure compliance with various codes and regulations:

All dollars expressed in $000's

	2006		2007		2008		2009		2010		2011	
	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M	FTE	$O&M
Public Safety Manager [1]	0	20	0	20	0	20	0	20	1	117	0	117
Business Continuity (Manager, Program, Pandemic Planning) [2]	0	50	0	80	0	150	0	30	1	315	0	225
Environmental Program [3]	0	0	0	0	0	0	0	0	0	90	0	70
Security Management Program [4]	0	0	0	0	0	0	0	30	0	10	0	10
Emergency Preparedness Program [5]	0	0	0	0	0	0	0	0	0	115	0	115
Competency Administrator	0	0	0	0	0	0	0.25	25	1	105	1	105
Web-based Training Modules	0	0	0	0	0	0	0	40	0	100	0	100
Total Code and Regulation ($000s)	0	70	0	100	0	170	0.25	145	3	852	1	742

NOTES:

1. During the PBR period, the Public Safety Awareness Program has been coordinated by the Emergency Preparedness Manager for an average of one day per week. However, in order to raise public safety awareness levels, the Program needs to expand to comply with new Integrity

Management Plan requirements, which requires the addition of a full time resource beginning in 2010.

2. During the PBR period, Terasen Gas assessed and mitigated risks related to business continuity and pandemics by engaging consultants to advise on the adequacy of our disaster recovery capability, perform a business continuity health check, work with the CGA to develop pandemic guidelines for utilities and develop a Pandemic Plan. In 2010 and 2011 Terasen Gas will develop and implement Business Continuity Plans, including Pandemic preparedness and mitigation strategies, and update emergency supplies, such as waterless hand cleansers.

3. While Terasen Gas has spent approximately $1,145,000 on three environmental resources and $340,000 on non-labour environmental programming between 2006 and 2009, the costs required for the 2010 and 2011 period are for initiatives which are new, and for which money has not been previously spent. These initiatives involve ensuring compliance with emerging Federal Species at Risk Legislation, compliance with Provincial General Waste Regulations, and enabling Terasen Gas to participates in land use planning schemes to ensure that land use decisions protect existing and proposed pipeline right of way tenure.

4. The Oil & Gas Commission intends adopting new Security Standard CSA Z 246.1 as a regulatory requirement. In anticipation of this, Terasen Gas performed a readiness assessment in 2009, and will be required to formalize a Security Management System in 2010 and develop a risk analysis tool in 2011.

5. While Terasen Gas has spent approximately $330,000 on one emergency preparedness resource and $620,000 on non-labour emergency preparedness programming between 2006 and 2009, the costs required for the 2010 and 2011 period are for initiatives which are new, and for which money has not been previously spent. These initiatives involve updating the Operations Emergency Centre at Surrey, restocking Emergency Supply Cabinets in the Lower Mainland , and developing contingency office sites in the Lower Mainland.

85.0 Reference: Labour – Compensation and Benefits

Part I, p. 7, par. 2

Part III, Section C, Tab 13, Schedule 28

Appendices F (1) and (2)

"For the purposes of compensation and benefits, Terasen Gas' workforce is separated into three primary groups: executives, management and exempt ("M&E") employees and unionized employees …"

"the actual labour inflation during the PBR Period (approximately 3 percent)" Ref: Part I, p. 8, par. 2

The data from Part III, Sec C, Tab 13, Schedule 28 and Appendices F (1) and (2) do not permit detailed analysis but do indicate an average 5.9 percent increase in total compensation in both 2010 and 2011.

85.1 Please provide for each of the three identified workforce groups (executives, M&E, unionized), by year from 2006 to 2011, a breakdown of FTE and total compensation package (by salary, step increase, short term and long term incentives, benefits, pension, OPEB, other), for all costs recovered as part of rates. Please separate the union data by union. Please confirm that these Total Labour Costs will reconcile to O&M, capital, and deferred costs with referencing to the corresponding financial schedules.

Response:

The attached spreadsheet provides a breakdown of total compensation for Executive, M&E, COPE and IBEW for the years 2006 – 2011. The Executive's post retirement benefits are identical to the M&E and therefore captured under M&E OPEB. Effective July 2007, most executives moved from a defined benefit to a defined contribution pension plan, the total pension expense includes both M&E and Executives. For the years 2006 – 2009 the OPEB for all groups has been reflected in M&E compensation, for the years 2010-2011 OPEB has been allocated into the three workgroup and included in the charge out rates to capital.

The amounts shown as TGI O&M labour reconcile to the following schedules in the Application: the years 2006 to 2008 to Appendix F, Page 1 and 2009 -2011 to Part III, Section C, Tab 13, Schedule 28. Due to the nature of the labour charge-out process, TGI's uses loaded rates to charge to O&M and capital activity, thereby the O&M and Capital amounts are shown as gross compensation and cannot accurately be broken further into the separate components.

The increase in salaries is driven by 3% inflation together with increases in headcount. With respect to the 2010 and 2011 benefit and pension increases, please refer to Part III, Tab C, Section 6 page 349 (Labour Inflation and Benefits) of the Application.

Compensation Package (in millions)

M&E & Executive	Actual 2006	Actual 2007	Actual 2008	Projection 2009F	Forecast 2010	Forecast 2011
Total TGI (including Fort Nelson)						
M&E Salaries	19.3	22.0	22.9	28.4	32.4	34.3
Executive Salaries	1.4	1.6	2.1	1.7	1.7	1.8
Step Increases	0.0	0.0	0.0	0.0	0.0	0.0
M&E Short Term Incentive	2.0	2.2	3.4	4.4	4.7	4.9
Executive Short Term Incentive	0.8	1.2	1.1	1.1	1.1	1.1
M&E Mid Term Incentive	0.8	0.8	0.4	0.2	0.0	0.0
Executive Mid Term Incentive	1.3	1.2	0.6	0.3	0.0	0.0
Benefits	2.3	3.5	3.5	4.5	4.8	6.3
Pension	4.5	3.7	1.5	3.0	3.2	3.2
OPEB	8.2	8.3	7.8	6.0	1.1	1.0
Total Compensation	40.6	44.5	43.3	49.6	49.0	52.6
Total TGI O&M Labour 1 includes Salaries, Incentive, Benefits, Pension and OPEB	37.0	41.1	38.6	43.1	46.5	49.6
Total Labour Charged to Capital, Deferrals and Other includes Salaries, Incentive, Benefits, Pension and OPEB 2	3.6	3.4	4.7	7.1	2.5	3.0
M&E FTE	241	249	265	330	359	370
Executive FTE	7	7	7.7	7	7	7

COPE	Actual 2006	Actual 2007	Actual 2008	Projection 2009F	Forecast 2010	Forecast 2011
Total TGI (inlcuding Fort Nelson)						
Salaries	25.0	25.0	27.1	27.4	30.0	31.2
Step Increases	0.2	0.1	0.1	0.2	0.2	0.2
Short Term Incentive	0.6	0.7	0.8	0.9	0.9	1.1
Long Term Incentive	0.0	0.0	0.0	0.0	0.0	0.0
Benefits	3.3	3.4	3.5	3.8	5.3	6.5
Pension	0.9	-0.1	-0.2	-0.3	0.8	1.2
OPEB	0.0	0.0	0.0	0.0	2.3	2.4
Total Compensation	30.0	29.1	31.3	32.0	39.5	42.6
Total TGI O&M Labour 1 includes Salaries, Incentive, Benefits, Pension and OPEB	22.4	22.0	23.0	24.8	29.6	32.0
Total Labour Charged to Capital, Deferrals and Other includes Salaries, Incentive, Benefits,	7.6	7.2	8.3	7.3	10.0	10.6

IBEW	Actual 2006	Actual 2007	Actual 2008	Projection 2009F	Forecast 2010	Forecast 2011
Total TGI (inlcuding Fort Nelson)						
Salaries	27.5	27.5	31.9	31.8	31.9	32.7
Step Increases						
Short Term Incentive	0.0	0.9	0.9	1.1	1.1	1.1
Long Term Incentive						
Benefits	3.3	4.1	4.2	4.7	5.7	6.5
Pension	0.9	0.2	-0.2	-0.4	0.8	1.3
OPEB	0.0	0.0	0.0	0.0	1.9	1.9
Total Compenstion	31.7	32.7	36.8	37.2	41.4	43.5
Total TGI O&M Labour 1 includes Salaries, Incentive, Benefits, Pension and OPEB	18.6	19.9	21.2	22.3	24.9	26.6
Total Labour Charged to Capital, Deferrals and Other includes Salaries, Incentive, Benefits, Pension and OPEB 2	13.2	12.8	15.6	14.9	16.5	16.9
FTE	398	412	424	458	481	481

Notes

1. These amounts are for TGI 3 division and reconcile to the following schedules:
2006-200:reconciles to : Appendix F Page 1
2009-201:reconciles to Part III, Section C, Tab 13, Schedule 28

2. OPEB is included effective 2010

86.0 Reference: Labour – Full Time Equivalents (FTE)

Appendix F-2, p. 2

"The Company has demonstrated a prudent and reasonable approach in managing overall employee costs, including headcount during the PBR period." Ref: Part I, p. 7, par. 3

86.1 Please explain the 8.3 percent increase in Distribution FTE from 2008 to 2009, and the further 5.3 percent increase from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The headcount and FTE tables in Appendix F2 on both pages 1 and 2 do not include 23 dependent contractors (Lower Mainland backhoe and dump truck operators) for the historical years 2003-2008 to ensure consistency with annual BCUC reporting. However, these individuals have been included in 2009-2011 forecast numbers. Dependent contractors have been part of our employee count since 1984 when they joined the IBEW bargaining unit. Since that time, dependent contractors have been part of the Distribution budget as they are considered to be part of the regular compliment of Distribution resources that form part of the construction crews.

Restating the Distribution historical numbers to include the dependent contractors, for comparative purposes, results in the following FTE numbers for Distribution:

	2003	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Distribution FTE	533	522	511	491	504	526	545	574	577

The increase in Distribution FTE from 2008 to 2009 is 19, or 3.6%, of which 3 are new positions (2 Capital Project Managers and 1 Process Manager) and 16 are unfilled vacancies from 2008 to be filled in 2009. Unfilled vacancies are influenced by turnover, availability of contractors, challenges in attracting new applicants and internal training capacity. The shortfall in positions in 2008 was offset by the use of contractors and internal employee overtime.

The increase in Distribution FTE from 2009 to 2010 is 29, or 5.3 %, of which 9 are new positions and 20 are IBEW unfilled vacancies to be filled in 2010. The 20 vacant positions are in the Lower Mainland construction group. The shortfall in positions in 2009 is being offset by the use of construction contractors not reflected in headcount. However, new construction activity has dropped below the threshold of our ability to assure a baseline of work for contractors so they have downsized considerably, impacting our ability to utilize these resources for peak shave.

The 9 incremental Distribution headcount proposed in 2010 are as follows:

- Operations Centre - 4 COPE Meter Exchange Appointment Setting representatives, 1 COPE Resource Planner (refer p. 367 of Application).
- Asset Mgmt /Integrity Management - 3 COPE employees (refer page 362 and Appendix F-8, page 9-10 of Application).
- M&E Professional Development – 1 Manager in Training position is to assist with demographic challenge in management (refer p. 366 of the Application).

86.2 Please explain the 14.8 percent increase in Business & IT FTE from 2008 to 2009, the further 3.6 percent increase from 2009 to 2010, and the further 1.9 percent increase from 2010 to 2011. Include the references to the appropriate material in the Application.

Response:

The 14.8% increase in Business & IT FTE from 2008 to 2009 is the result of two factors. 10% can be attributed to vacancies that existed in 2008 which were offset by increased overtime and the use of consultants, neither of which are reflected in the FTE calculations. The remaining 4.8% were new positions filled for the reasons stated below.

- 3 FTE in IT to meet the increased demands for support resulting from increased investment in IT applications.
- 4 FTE in Operations Engineering in 2009 to meet the new turnaround requirements of the BC Safety Authority.
- 3 FTE to meet increased workload related to location records and land administration
- 1 FTE to meet new code requirements related to Integrity Management, including maintenance of a new Cathodic Protection Data Management System and implementation of associated analysis and quality assurance processes.
- 3 FTE related to retirement and knowledge transfer transition.
- 1 FTE related to EIT program, employee development and succession planning.

The 3.6% increase in Business & IT FTE from 2009 to 2010 and the 1.9% increase in Business & IT FTE from 2010 to 2011 consist entirely of net new positions required to meet business objectives in 2010 & 2011 respectively (there are no vacancies included in this annual increase). For example, we need to add 2 net new FTEs in 2010 for business intelligence support in the IT group. Similarly, we will need a net new 2 FTE in 2011 in Operations Engineering to continue to be able to meet turnaround requirements for BC One Call tickets. Further details on other net new FTE additions in 2010 and 2011 can be found in *Part III: Section C – Tab 6: Operations and Maintenance Expenses: Business and Information Technology Services: page 383 – 391.*

The overall increase in FTE has resulted from the need to address past vacancy challenges and the need to hire net new staff to meet existing and future strategic business objectives.

86.3 Please explain the 40.0 percent increase in Marketing & Business Development FTE from 2008 to 2009, the further 13.4 percent increase from 2009 to 2010, and the further 3.1 percent increase from 2010 to 2011. Include the references to the appropriate material in the Application.

Response:

TGI views the management of employee costs and headcount from a company wide perspective and in the context of overall cost management. TGI makes changes in headcount within specific departments (upwards or downwards) in order to best meet the needs of our customers while still managing overall costs in an effective manner. The changes proposed in Marketing & Business Development, along with other proposed changes in personnel, will allow us to best meet the needs of our customers over the 2010/11 timeframe and beyond.

The annual increases in the number of Marketing FTE are due to vacancies and net new FTE required to meet strategic business objectives, including those approved as part of Commission Order No. G-36-09. Therefore the increase to staffing is not 40% as indicated; this number must be adjusted by vacancies and already approved expenditures. Vacancies existed in Marketing at the end of 2008 and previous years because of regular turnover and difficulties associated with the hiring of qualified and experienced staff due to the labour and market conditions at the time. Many of these vacancies were offset by increased overtime and the use of consultants, neither of which are reflected in the FTE calculations. (Refer to TGI's response to BCUC IR 1.88.1 for more detail on the current economic situation and its impact on the availability of skilled workers from the oil and gas industry.)

For 2008, the total number of FTE's in Marketing and Business Development including vacancies was 89 staff. An additional 7 staff are being added in 2009 as a result of BCUC Order No. G-36-09 for approved EEC programs (note that all EEC staff costs are capitalized as per Order No. G-36-09). Adding this number to the 2008 FTE number (including vacancies) yields a full staffing complement of 96 for 2009. The forecast FTE for year end 2009 is projected to be 112 (assuming there are no vacancies), representing a 17% increase over 2008

(2008 FTE + vacancies + approved funding for EEC programs). The remaining increase of 16 staff is primarily to address changes in market conditions and customer expectations and is broken down as follows:

By Category	2011 Fcast	2010 Fcast	2009 Proj	2008 Bud		YOY Variance 11vs10	10vs09	09vs08	High level description of changes	Application Reference
Bad Debt Expense	0.0	0.0	0.0	0.0		0.0	0.0	0.0	Bad Debt is managed in Customer Care Admin line item	
Customer Care Contract	0.0	0.0	0.0	0.0		0.0	0.0	0.0	Contract is managed in Customer Care Admin line item	
Customer Care Contract - penalties	0.0	0.0	0.0	0.0		0.0	0.0	0.0		
Research	2.0	2.0	2.0	2.0		0.0	0.0	0.0	No change	
Customer Contact Centre	16.0	16.0	16.0	16.0		0.0	0.0	0.0	No change	
Customer Care Admin	17.1	17.1	13.5	11.5		0.0	3.6	2.0	Increasing staff levels required to manage CWLP performance and to offer improved services to customers	page 376
* Customer Care & Services	35.1	35.1	31.5	29.5	*	0.0	3.6	2.0	See above	
* Customer & Business Facilitation	9.0	9.0	7.0	6.0	*	0.0	2.0	1.0	Policy Analyst, 1st Nations Relns, Municipal Op Agreemnt	page 378
* Customer Solutions & Services	70.0	66.0	56.0	40.0	*	4.0	10.0	16.0	2009: +7 EEC headcount approved by BCUC Order G-36-09 2009: +9 Enhanced sales & business development 2010: +10 enhanced sales & business development 2011: +4 enhanced sales & business development	page 378
* Customer Information & Education	17.0	17.0	17.0	14.0	*	0.0	0.0	3.0	Communications Mgrs x 3	page 382
** Total RRA	131.1	127.1	111.5	89.5	**	4.0	15.6	22.0		

Note, the cells highlighted in pink show staff additions in 2009. In the Application, TGI has asked for funding that would result in the addition of these staff in 2010. However, due to cost savings as a result of CWLP performance penalties, TGI was able to add these staff in 2009.

86.4 Please explain the 12.5 percent increase in Gas Supply & Transmission FTE from 2008 to 2009, and the further 6.7 percent increase from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The table in Appendix F2 entitled "Additional FTE Requirements in 2010 and 2011" contains an error in the 2008 number for GS&T. The actual FTE in 2008 for GS&T was 82, not 80, which means the 2008-2009 increase was 8 FTE or 10%. This includes:

- 5 FTE resulting from numerous vacancies carried throughout the year and part of the year in Transmission departments for difficult to fill positions.
- 2 FTE transferred from Marketing to Gas Supply for Transportation Services. Further details can be found in Part III: Section B, Tab 1, page 90.

- 1 FTE added to LNG Plant Operations to allow for job shadowing and knowledge transfer for a pending retirement.

The 2009-2010 increase in FTE includes:

- 4 FTE transfer from Regulatory Accounting to Core Market Administration Expense to ensure costs are properly allocated to core customers. See Part III: Section C, Tab 5, page 340 for more information.

3 2 FTE additions to Asset Improvement. One of these is the addition of a Transmission Asset Engineer to support the end–to-end Transmission Asset Management and Improvement processes. The overall objective is to manage the capital and O&M expenditures on transmission assets to maintain operational excellence in a safe, reliable, environmentally responsible and cost effective manner. The second position is for an Analyst to provide for the implementation of a more disciplined approach to asset management similar to the Distribution model. Funding for these two positions has been made available by utilizing contractor budget for internal labour and hence is not incremental and therefore not included in the original filing.

87.0 Reference: Labour – Unfilled Vacancies

Part III, Section B, Tab 1, p. 161, par. 1

87.1 Please provide details on the number of unfilled vacancies each year from 2006 to 2008, and on the number expected in 2009, 2010 and 2011. Confirm if all new positions added in 2009 to 2011 will be filled 100 percent in the first year.

Response:

It is very difficult to provide details on actual number of unfilled vacancies. Between 2006 and 2008, the overall vacancy ratio based on total budgeted FTE versus actual FTE has averaged approximately 8%. The forecast vacancy ratio for 2009 is 0%. See table which follows:

Vacancy Ratios (2006-2009)

	2006	2007	2008	2009
Budgeted FTEs	1196	1175	1194	1229
Actual/Forecast FTEs	1062	1087	1127	1226
Difference	134	88	67	3
Vacancy Ratio (%)	11%	7%	6%	0%

The vast majority of the vacancies in 2006 and 2007 can be attributed to the IBEW hiring freeze that was imposed pending negotiation of a new collective agreement. During this period, much of the work was shifted to install contractors (see Part III, Section B, Tab 1, page 149). It is the Company's intent to fill all new positions in 2009-2011 as soon as possible, budget permitting. Other than the addition of new positions, vacancies typically occur in response to voluntary and involuntary turnover, which has been averaging 3-5 % per year (see Table B-1-8 on page 152 of the Application), as well as actual retirements which have averaged 13% during the 2003-2008 PBR period (see Appendix F2). In addition, we are required to accommodate employees on maternity leave and long term disability leave by maintaining open positions for when they return to work. Some positions may take more time to fill than others depending on the required skill level, role complexity, and availability of candidates in the general workforce. In some cases, contractors, consultants and temporary workers are hired to fill vacant positions on an interim basis. As discussed in Part III, Section B, Tab 1, pp 146-157, Terasen Gas has implemented a variety of plans and strategies over the years to effectively manage and mitigate employee turnover and retirement risk.

88.0 Reference: Labour – Replacement Technical Staff

Part III, Section B, Tab 2, p. 210, par. 2

88.1 Please comment on the impact of the current economic situation and its impact on the availability of skilled workers from the oil and gas industry.

Response:

It is reasonable to expect that the current economic downturn and its impact on the oil and gas industry would likely result in increasing numbers of skilled workers from those industries applying for job openings at Terasen Gas. While the economic downturn has resulted in an increase in the number of applications we receive for our posted vacancies overall, this is not necessarily true for positions that require technical or technological training, or skilled trades training. This situation is explored further in our Application at Part III, Section A, pages 74-75, and Part III, Section B, Tab 2, pages 207-208.

Our efforts to recruit for difficult to fill positions requiring engineering and/or technical skill sets have included advertising campaigns targeting numerous professional publications, job boards and newspapers in both BC and Alberta (eg. APEG BC, APEG AB, Calgary Herald, Workopolis, Working.Com). While we have noticed a general increase in the number of applications from Alberta, those applying generally do not have the level of technical qualifications or experience required for the posted positions. In some instances the Terasen Gas Recruiting Services department has taken the initiative to follow up on announcements of plant closures and layoffs with HR counterparts in those organizations to make them aware of needed skill sets and job openings at Terasen Gas. Terasen Gas' Recruiting Services department was also actively involved in government-sponsored job fairs targeting unemployed workers in Prince George and Ontario. In short, Terasen Gas has been actively recruiting in various sectors impacted by the recent economic downturn, but we have not experienced a material shift in the pool of overall talent for difficult to fill positions.

89.0 Reference: Operations and Maintenance Expenditures

Distribution Vice President

Part III, Section C, Tab 6, p. 359, Table C-6-13

89.1 Please provide a breakdown of the $4 million base in 2009, and then explain the 10 percent increase in 2010 and subsequent increase in 2011.

Response:

Several factors contribute to the Distribution Vice President O&M cost increases in 2010 (and 2011) over the 2009 base level of expenditures. The breakdown of costs for 2009 as well as the forecast increases for 2010 and 2011 can be found in the table below. A more detailed explanation for higher dollar value programs follows.

Operations and Maintenance Expenditures; Distribution Vice President, 2010 vs 2009

	2009P	2010F	Increase	Explanation
Labour	$ 2,528,000	$ 2,574,000	$ 46,000	Labour, Benefit inflation
Communications	$ 770,000	$ 900,000	$ 130,000	*See excerpt from p. 367 of application (below)
3rd Party Damage Write-offs	$ 200,000	$ 300,000	$ 100,000	**See excerpt from p. 366 of application (below)
Fees & Admin	$ 139,000	$ 139,000	$ -	
Contractors	$ 115,000	$ 117,000	$ 2,000	Customer Satisfaction Survey inflation
Vehicles	$ 96,000	$ 98,000	$ 2,000	Vehicle inflation
Employee Travel & Expenses	$ 60,000	$ 60,000	$ -	
M&E Development & Relocation	$ 100,000	$ 180,000	$ 80,000	***See excerpt from p. 366 of application (below)
3rd Party Damages	$ 50,000	$ 50,000	$ -	
Employee Safety Recognition	$ -	$ 30,000	$ 30,000	New safety pay recognition program
Fire Department Relations	$ -	$ 25,000	$ 25,000	Training and cost of fuel for fire dept.
Other	$ 17,000	$ 15,000	$ (2,000)	
Recoveries	$ (70,000)	$ (70,000)	$ -	
Total	**$ 4,005,000**	**$ 4,418,000**	**$ 413,000**	

Operations and Maintenance Expenditures; Distribution Vice President, 2011 vs 2010

	2010F	2011F	Increase	Explanation
Labour	$ 2,574,000	$ 2,653,000	$ 79,000	Labour, Benefit inflation
Communications	$ 900,000	$ 900,000	$ -	
3rd Party Damage Write-offs	$ 300,000	$ 300,000	$ -	
Fees & Admin	$ 139,000	$ 139,000	$ -	
Contractors	$ 117,000	$ 117,000	$ -	
Vehicles	$ 98,000	$ 105,000	$ 7,000	Vehicle inflation
Employee Travel & Expenses	$ 60,000	$ 60,000	$ -	
M&E Development & Relocation	$ 180,000	$ 180,000	$ -	
3rd Party Damages	$ 50,000	$ 50,000	$ -	
Employee Safety Recognition	$ 30,000	$ 30,000	$ -	
Fire Department Relations	$ 25,000	$ 25,000	$ -	
Other	$ 15,000	$ 15,000	$ -	
Recoveries	$ (70,000)	$ (70,000)	$ -	
Total	**$ 4,418,000**	**$ 4,504,000**	**$ 86,000**	

*Communications

Communication costs in Distribution are expenditures associated with pagers, satellite phones, cell phones, aircards for mobile laptops, and various other communication devices and systems used across the province. Cost increases are as a result of contract costs, number of users as well as process and technology changes.

**3rd Party Damage Write-offs

Terasen Gas incurs costs to repair damages to its system (meters, services and mains) from 3rd party activities. All reasonable attempts are made to recover these costs from the damager (the excavating community, municipalities, and homeowners) where the damager is culpable and identifiable. Collection of these costs is often protracted and involves legal proceedings and payment settlements. The typical cost to make repairs increased in 2007 due to the addition of an apprentice on most repair crews. The crew composition will continue to contain an apprentice for some time as these individuals gain experience in making repairs to the system. Terasen Gas continues to work with the excavating community, municipalities and homeowners to reduce third party damage through specific damage prevention sessions targeting frequent offenders as well as in promoting BC One Call.

***M&E Professional Development and Relocation Fees

Employee development and training is essential to ensure ongoing safe, reliable and cost effective gas service. The demographics of the Distribution M&E workforce requires additional training and employee development costs to replace cumulative years of knowledge and experience as a significant portion of the workforce had reached retirement age. Additionally, as M&E employees retire, increased relocation costs are anticipated to cover the cost of relocating replacements.

Terasen Gas believes that its focus on employee development and training has been a key contributor to the Company's success over the PBR Period. Distribution intends to maintain and enhance its focus in this area to continue its pursuit of Operational Excellence.

Note: A portion ($50,000 out of a total of $230,000) of the costs for the above noted program, specifically the Manager in Training Program, is budgeted outside of the Vice President's cost centre for 2010 and 2011.

90.0 Reference: Operations and Maintenance Expenditures

Part III, Section C, Tab 6, pp. 353-355

Workforce Profile

TGI is seeking an incremental O&M of $5.1 million for the hire of additional staff over the period 2010 to 2011 citing various demographic reasons for increased workforce funding. As stated on page 353: "Terasen Gas has an aging workforce resulting in a significant attrition risk over the next five years as record numbers of employees become eligible for retirement. This workforce challenge is characterized by a demographic profile which shows that more than 48 percent of current employees become eligible to retire, with either a reduced or unreduced pension, within the next five years."

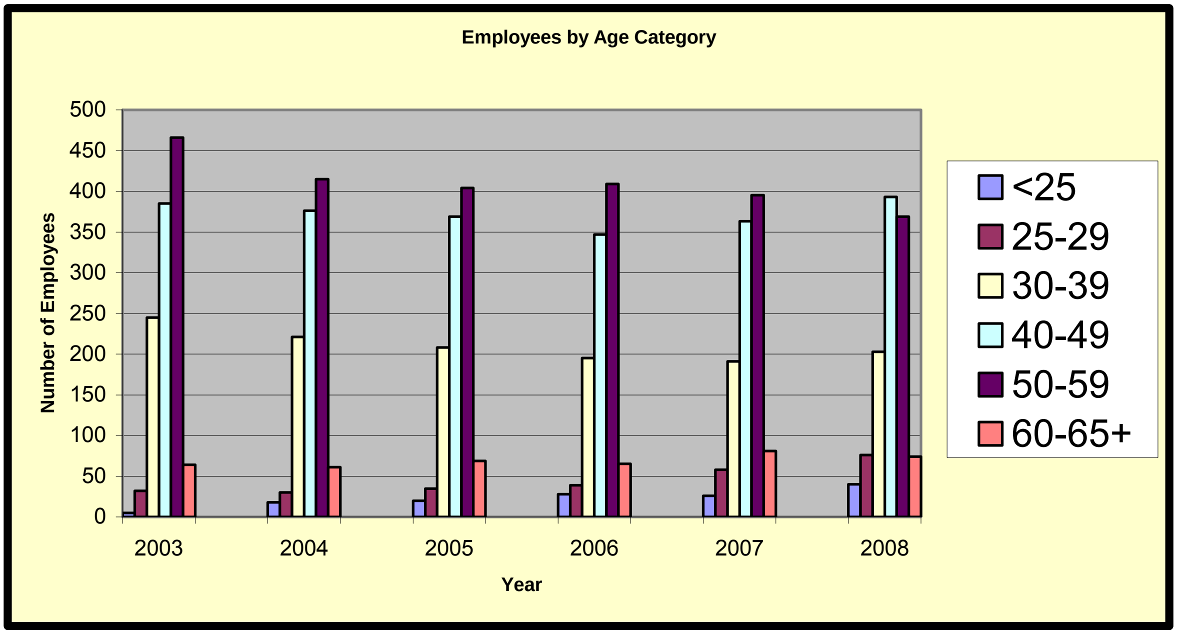
90.1 The following table was compiled from data provided in Appendix F-2. Please provide a graph (stacked area format) that displays the trend of the number of employees in each age category over the period 2003 to 2008.

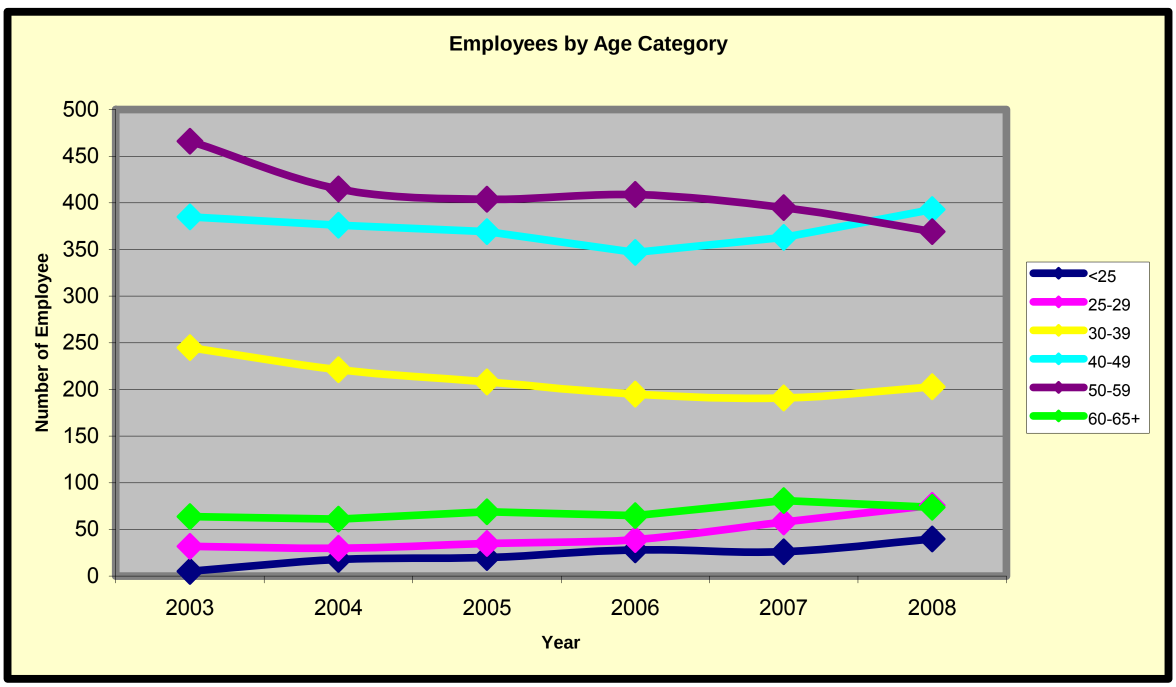
Age Category	2003	2004	2005	2006	2007	2008
<25	5	18	20	28	26	40
25-29	32	30	35	39	50	76
30-39	245	221	238	195	191	203
40-49	305	376	339	347	363	393
50-59	466	415	434	409	395	369
60-65+	64	61	30	66	81	74
Total	1197	1121	1135	1083	1114	1155

Source Appendix F-2

Response:

The following tables show that between 2003 and 2008, 35-45% of TGI's workforce was age 50 or older. While this figure has remained fairly constant, it is important to note that Terasen's demographic risk over the next 3-5 years is linked directly to retirement eligibility, which is a combination of both age and years of service. Age alone does not determine retirement eligibility. This connection is described more fully in the response to BCUC IR 1.90.3).


Employees by Age Category
Number of Employees
500
450
400
350
300
250
200
150
100
50
0
2003
2004
2005
2006
2007
2008
Year
<25
25-29
30-39
40-49
50-59
60-65+


Employees by Age Category
Number of Employee
500
450
400
350
300
250
200
150
100
50
0
2003
2004
2005
2006
2007
2008
Year
<25
25-29
30-39
40-49
50-59
60-65+

90.2 Please analyze the graph and provide commentary on whether the profile of TGI's workforce has changed significantly over the period 2003 to 2008.

Response:

It is important to note that attrition risk resulting from retirement eligibility is based on a combination of age plus years of service, not just age (see response to BCUC IR 1.90.3). The tables provided in response to BCUC IR 1.90.1 above only reflect historical age data for 2003-2008. During that period, 35-45% of Terasen Gas's workforce was age 50 or older. Noticeable increases in the <25 and 25-29 age categories reflect younger people being hired to replaced retiring workers. A 21% drop in the number of employees in the 50-59 age category over this time period is a direct result of employees exercising their options to retire. The slight increase in the number of employees in the 60-65 category suggests the number of people retiring in the 60 to 65 age category is roughly equal to the number in the 50-59 age category who are deferring their retirement options and therefore moving into the next age category.

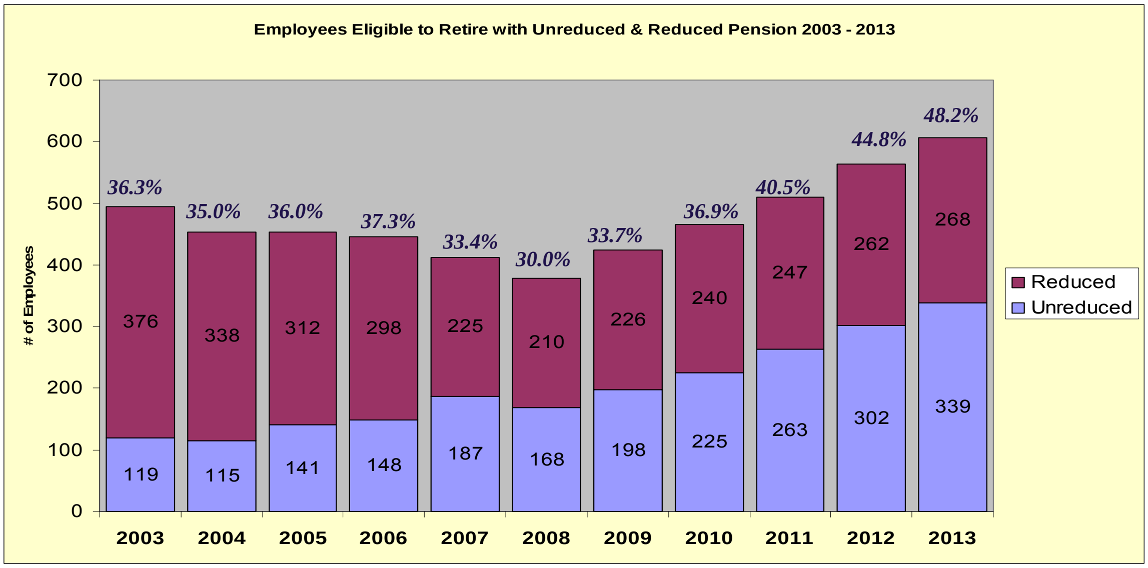
90.3 Please reconcile any differences with the statement quoted above.

Response:

Please note that TGI is seeking $1.033 million to address demographic challenges. Table C-6-3 on page 348 of the Application provides a breakdown of the O&M incremental funding which shows a total request of $1.033 million for "Demographics" over the 2 year period. The $5.1 million referenced in the second paragraph on page 323 is required for other business drivers as identified under "Customer/Stakeholder Behaviours and Expectations".

The statement referenced in IR 90.0 from page 353 of the Application describes the demographic risk looking forward to 2010-2011 and beyond. Terasen Gas' demographic risk over the next 3-5 years is linked directly to retirement eligibility which is a combination of both age plus years of service. By contrast, the data in Appendix F-2, which provides the source data for the table included in the preamble of the question, provides only a historical perspective of age distribution for the period 2003-2008. It does not account for years of service, nor does it depict retirement eligibility. Therefore, the data, and the graphs prepared in the response to BCUC IR 1.90.1, are not an appropriate point of reference for the challenge going forward.

The table below provides a more accurate indication of the trend in retirement eligibility (reduced and unreduced pensions) for the period 2003-2013.

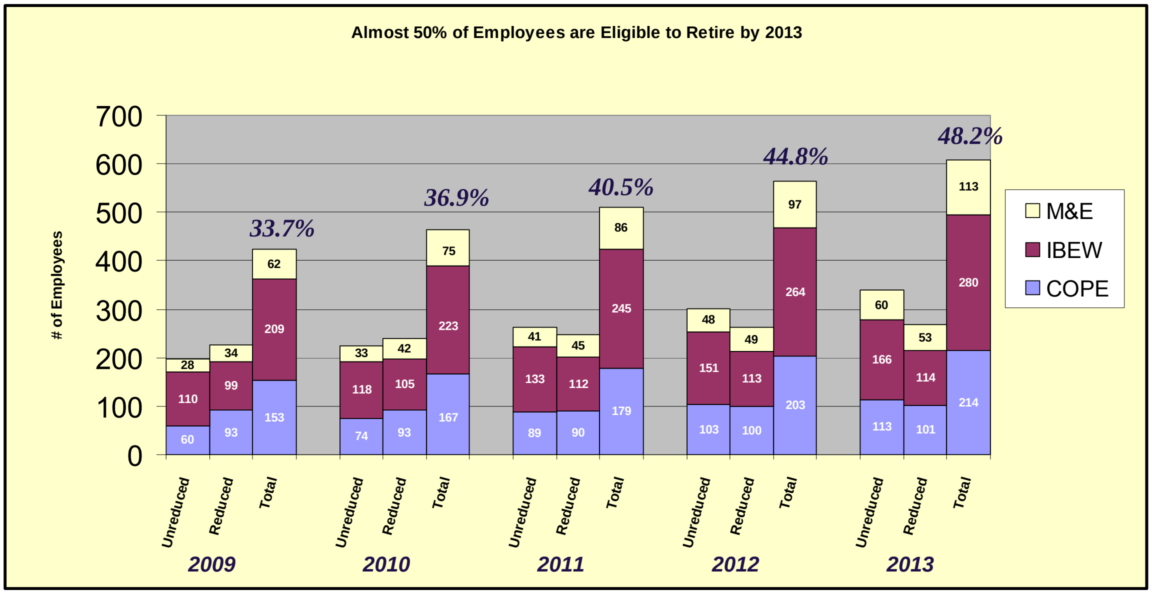


Note: The number of TGI employees who meet the criteria to retire in a given year have been carried forward in subsequent years as some employees are choosing not to retire when eligible.

- For the years 2003 – 2008 % of total workforce is based on FTR headcount for TGI, TGVI and TI as at December 31 of each year
- For 2009 – 2013 % of total workforce is based on December 31, 2008 FTR headcount for TGI, TGVI and TI

Retirement eligibility as a per cent of total workforce remained fairly stable from 2003 to 2006 and then declined slightly in 2007 and 2008. The trend from 2008 to 2013 shows a steady increase in retirement eligibility peaking at 48.2% in 2013. By contrast, the trend for those eligible to retire on an unreduced pension (blue bar) shows a steady and significant increase from 119 employees in 2003 to 339 employees by 2013.

The table below provides additional detail which identifies the increasing retirement risk between 2009-2013, as more and more employees become eligible to retire with either a reduced or unreduced pension.



Note: % of total workforce is based on December 31, 2008 FTR headcount

For example, in 2009, 198 employees or 16% of the workforce becomes eligible to retire with an unreduced pension. This number increases to 424, or roughly 34% of the workforce if those eligible to retire on reduced pensions are taken into account. By 2013, those eligible to retire with an unreduced pension increases to 339 employees or 27% of the workforce. When factoring in those eligible to retire on a reduced pension, the number increases to 607 or 48% of the workforce.

The demographic challenge for 2010-2011 is no less daunting. By 2011, 263 employees or 21% will be eligible to retire with an unreduced pension and the number increases to 510 or 40% if we include those eligible for reduced pension. As mentioned on page 354 of the Application, the Company's actual retirement risk for 2010-2011 has potentially increased as a result of some negotiated changes to post-retirement benefits in the new IBEW and COPE Collective Agreements.

The additional $1 million in funding requested to address the demographic challenge for 2010 and 2011 is reasonable relative to the overall magnitude of the risk.

91.0 Reference: Operations and Maintenance Expenditures

Part III, Section C, Tab 6, pp. 353-355

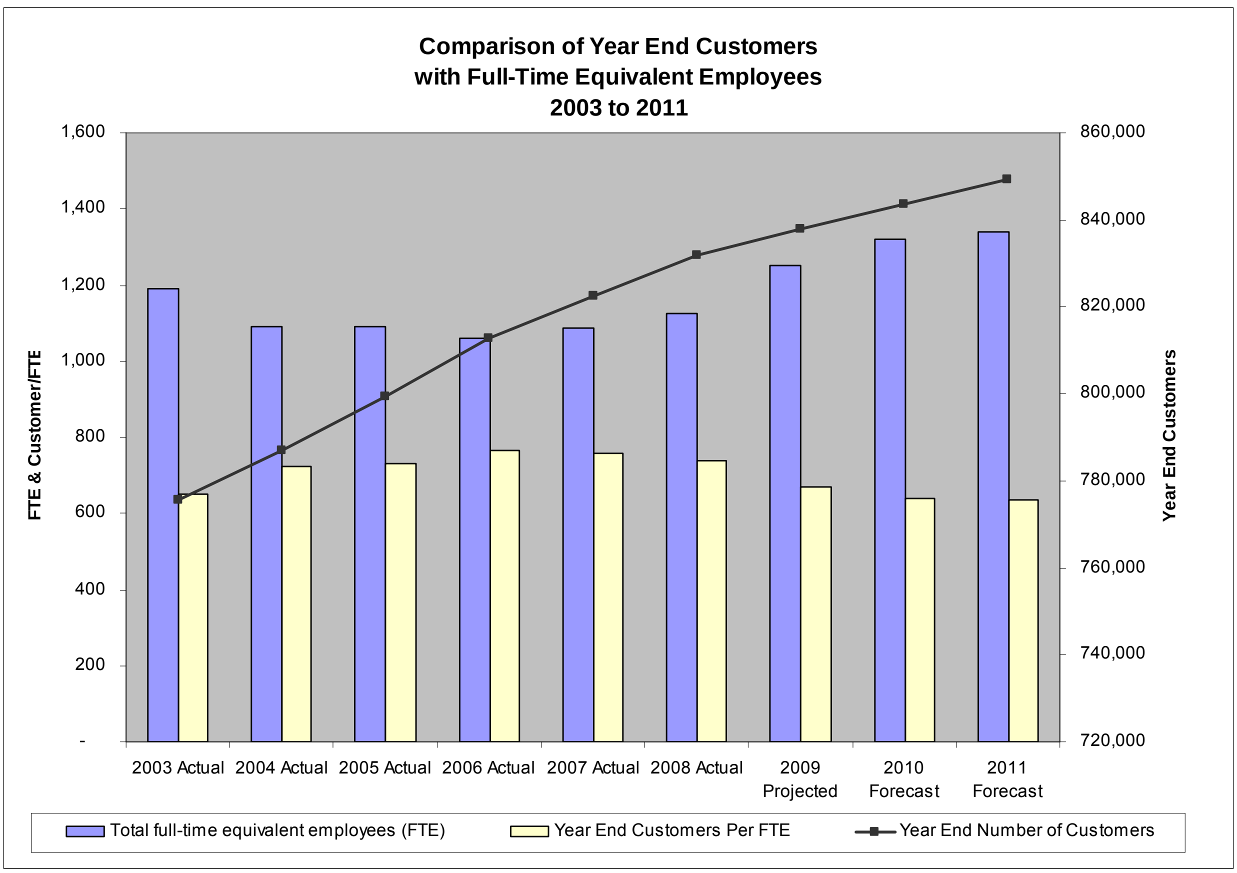
Workforce Head Count

91.1 Please provide tabular and graphical data for the period 2003 to 2011 that compare the total number of FTEs to the Year End Number of Customers. Please provide this data in a fully functional electronic spreadsheet.

Response:

Data Table:

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Year End Number of Customers	775,454	786,958	799,378	812,683	822,598	831,845	837,965	843,565	849,415
Total full-time equivalent employees (FTE)	1,189	1,089	1,092	1,062	1,087	1,127	1,250	1,321	1,338
Year End Customers Per FTE	652	723	732	765	757	738	670	639	635



Please refer to Attachment 91.1.

91.2 Please provide an explanation of the internal and external factors affecting TGI's workforce size. Wherever possible, please provide a description of management policies and supporting data.

Response:

The size of Terasen Gas's workforce is determined by what is required to prudently run the business. Factors that are taken into consideration are core workload, external economic conditions, new business initiatives, the impact of mergers and acquisitions, voluntary and involuntary turnover, and exposure to retirement risk.

In 1998 we started to centralize planning and dispatch and reduced merchandising functions, which resulted in office closures and reduction in field staff through to 2002. The acquisition of Centra Gas, the Utilities Strategy Project (USP), and the acquisition by Kinder Morgan all resulted in business restructuring and workforce reductions between 2003 and 2008. The impact of these events is evident in Table B-1-8 on page 152 of the Application, which shows much higher than average levels of turnover in 2004 (as a result of the Utilities Strategy Project) and 2006 (impact of the acquisition by Kinder Morgan).

During this period, the Company also implemented a Vacancy Management Strategy in anticipation of the negotiation of a new Collective Bargaining Agreement with the IBEW and to accommodate the use of contractors for capital work such as new mains and service installations (see page 149 of the Application). It is important to note that contractors are not included in the total number of FTE reported in Table 91.1.In 2007, with a new contract in place, Terasen Gas established a Distribution Apprenticeship program resulting in two waves of new hires (increasing overall FTE) to fill the gap to mitigate the looming demographic challenge and retirement risk in the IBEW field workforce. These management initiatives are discussed in further detail in Part III, Section B, Tab 1, page 149 of the Application. Terasen Gas' demographic challenge is described in detail in Part III, Section B, Tab 2, pp 207-211 and in the response to TGI BCUC IR 1, 90.0 – 90.3.

Over the next few years we are planning on increasing headcount in order to better respond to changing code compliance needs, as well as adding staff to address the ongoing business needs underpinning customer requests to provide new and enhanced products and services. These business drivers are explained in detail in Part III, Section A, pp 47-51 and Part III, Section C, Tab 3, pp. 227-271.

Terasen Gas has effectively managed overall personnel levels and will continue to do so. The total number of FTE was relatively flat following the USP and in 2008 was still below even 2003 levels. The upward trend from 2007 through 2011 reflects actions taken to manage demographic risk and respond to the changing nature of the business environment.

91.3 During the period of 2003 to 2008 there appears to have been a net decrease in the number of TGI employees despite an increasing trend in the number of customers over the same period. Please explain what the critical factors are that influence TGI's head count.

Response:

Refer to the response to TGI BCUC IR 1.91.2

92.0 Reference: Operations and Maintenance Expenditures - Accounting Changes

Part III, Section C, Tab 6, part (f)

"…$521 thousand is forecasted in 2010 and a further $51 thousand in 2011 in Operations Engineering for costs related to preliminary investigation and training activities which are required to be expensed under the Canadian GAAP changes." p. 387, par. 5

92.1 Please provide a description of the types of preliminary investigation and training activities referred to in the above statement. Please identify whether any of these costs relate to EEC and Alternative Energy Solutions.

Response:

Preliminary investigation activities include the necessary front end engineering and design (FEED) of potential expansion or retrofit projects. Specific FEED activities include defining the project scope, identifying and defining requirements, site visits, identifying and considering of alternatives, developing cost estimates and an economic comparison of the options considered, developing conceptual designs, and producing a technical report that documents the previous items and makes recommendation(s) of the preferred option.

Training activities refer to any courses, conference or seminars that are specifically related to a particular expansion or retrofit project and attended by Operations Engineering staff during the course of the expansion or retrofit project. For example, an Engineer attending a directional drill training session at the design phase of a directional drill project.

We believe that training of Operations Engineering staff on technical matters related to specific expansion or retrofit project is essential to the continued safe and reliable design of our gas assets. Technical training provides four key benefits to the attendee. First, it enhances an individual's depth of understanding of a particular matter related to a project and allows him/her to provide a superior product or design for the project. Second, the training exposes the individual to the most current state of technical content and allows him/her to draw on this current knowledge to provide more innovative solutions to the project. Third, courses and conferences expose attendees to key contacts within a particular technical field. Subsequently, these contacts become resources to an individual at times of difficulty or challenge on a project. Operations Engineering staff receive significant benefit from project specific technical training.

None of these costs relate to EEC and Alternative Energy Solutions.

93.0 Reference: Operations and Maintenance Expenditures

Marketing and Business Development

Part III, Section C, Tab 6, p. 373

"It requires investment in investigating and developing new opportunities and services for customers. This increase in costs has been seen in 2008 and 2009 and Terasen Gas seeing this continuing in 2010 and 2011." Ref: p. 373, par. 3

"Compared to the 2009 Projection, O&M costs for Marketing and Business Development are forecasted to increase in 2010 by $5.6 million and $2.0 million in 2011." Ref: p. 374, par. 1

Marketing & Business Development FTE were 80 in 2007 and then increased by 40 percent from 80 in 2008 to 112 in 2009, followed by a forecast 13 percent increase to 127 FTE in 2010 and a forecast 3 percent increase to 131 in 2011. Ref: Part III, Sec E, Appendix F, p. 2

93.1 Please explain the increase in costs in 2008 given the same 80 FTE in 2007 and 2008.

Response:

Please see response to BCUC IR 1.86.3 regarding staffing numbers.

The three main causes for the increases related to customer care contract of $1.06M, bad debt write off of $.355M, and salary inflation of $.283M. Thus, the increases in the Marketing & Business Development are unrelated to staffing changes in 2007 to 2008 timeframe.

Changes in Expenditures 2007-08	**$(M)**
Nominal 2008 Expenditures	$ 63.1
Nominal 2007 Expenditures	$ 60.7
Difference	**$ 2.4**

Changes in Costs	$(M)
Customer Care increases (~9000 increased customers & 1.5% contract inflation)	1.062
Salary inflation	0.283
Bad debt write off	0.355
Miscellaneous spending increases:	
Newswire service & broadcast monitoring	0.066
Communications (writing services, advertising)	0.221
Sales expenses & customer account admin	0.345
Other	0.068
Total increase over 2007	**2.400**

93.2 Please provide the O&M costs for Marketing & Business Development, by year from 2006 to 2009, separated into the same categories as provided for 2010 and 2011. Please provide explanations for all items that increased more than 3 percent year over year.

Response:

Please see the table below for a detailed breakdown of the O&M costs for the years 2006-2009 to match categories provided in 2010 and 2011. TGI also notes that while the question asks about costs for 2006-2011 and why there were increases, the Marketing costs from 2003-2006 are also relevant. As detailed in the Application on Table B-1-15, B-1-18, and C-6-23, the expenses for the Marketing Department were $68.1 million (in real dollars) in 2003, decreasing to $64.7 million in 2006, increasing to a projection of $66.6 million in 2009, $70.9 million in 2010 and $71.4 million in 2011. This represents a total increase of $3.3 million or 4.8% over 8 years, which is therefore slightly above inflation (if the increases matched inflation, real dollar expenses would not have increased).. In nominal dollars, Marketing expenses were $60.5 million in 2003, $60.9 million in 2006, projected at $66.6 million in 2009 and forecast to be $74.2 million in 2011. Overall this represents a nominal dollar increase of 22% over 8 years. However, of this increase in nominal dollars, $6.9 million is attributable to Customer Care Contract costs resulting from an increase in customer numbers. If this amount is taken out of the analysis, there would have been an increase of $6.8 million in Marketing costs or 10%.

Given the changes the Company has experienced over this time period, TGI believes that these changes are not unreasonable, and represent prudent management of the business to meet changing customer needs and expectations and respond to the evolving business environment.

With respect to the time period requested, the table below provides the detailed breakdown of costs broken into sections described in the Application.

Government Policy, and requests described on page 375 of the Application, includes changes in costs seen in Customer Information and Education as well as Customer Services and Solutions columns in the table.

Codes and Regulations request for $1 million is incorporated into the costs for Customer Information and Education columns in the table.

Customer Stakeholder Behaviours and Expectations requests described on page 376-379 of the Application, encompassed in Customer Care and Services, Customer Services and Solutions, and Customer and Business Facilitation columns in the table.

Accounting Changes, specifically the reduction in $1.6 million in O&M due to the capitalization of EEC spending is encompassed in the Customer Care and Services column.

Service Enhancements are included in the Customer Care and Services (including a column for Bad Debt), and Customer Information and Education column.

By Category	2011 Fcast ($000s)	2010 Fcast ($000s)	2009 Proj ($000s)	2008 Actual ($000s)	2007 Actual ($000s)	2006 Actual ($000s)	Year over Year dollar variance 11vs10 ($000s)	10vs09 ($000s)	09vs08 ($000s)	08vs07 ($000s)	07vs06 ($000s)	2009 % Var	2008 % Var	2007 % Var	High level description of changes greater than 3%
Bad Debt Expense	5,259	5,253	5,253	3,944	3,589	4,459	6	-	1,309	355	(870)	33%	10%	-20%	Economic conditions and fluctuations in cost of gas
Customer Care Contract	49,564	48,608	47,680	46,558	45,570	44,334	956	928	1,123	987	1,237	2%	2%	3%	Contractual obligations to CWLP driven by increase in customer numbers
Customer Care Contract - penalties	-	-	(865)	-	(75)	(35)	-	865	(865)	75	(40)	0%	-100%	114%	CWLP performance penalties
Research	753	741	537	510	504	538	12	204	27	6	(34)	5%	1%	-6%	07 and 08 Research cost-shared amongst other TGI depts
Customer Contact Centre	701	672	620	277	194	278	29	51	343	83	(84)	124%	43%	-30%	O&M increases when capital activity volumes drop. Current economic conditions have caused a decrease in new housing starts. See also explanation on page 381 of the Application
Customer Care Admin	2,094	2,052	1,568	1,169	1,138	1,143	42	484	399	30	(4)	34%	3%	0%	Increased TGI management staff and expenses required to manage/address/mitigate CWLP performance
Customer Care & Services	58,371	57,326	54,793	52,457	50,921	50,717	1,045	2,533	2,336	1,536	204	4%	3%	0%	See above
Customer & Business Facilitation	1,762	1,731	1,425	1,394	1,373	1,359	31	306	31	21	14	2.2%	1.5%	1.0%	Year over year variances are not greater than 3%
Customer Solutions & Services	10,596	9,766	7,673	6,548	5,649	6,190	830	2,094	1,124	899	(541)	17%	16%	-9%	07 vs 06: $(300k) Marketing advertising 07 vs 06: $(115k) reduced Market Development consulting services 07 vs 06: $(95k) incr labour cross charged out to marekting development projects 08 vs 07: $900k return to budgeted spending levels 09 vs 08: $1124k enhanced customer solutions/sales/account management staff including additional headcount
Customer Information & Education	3,672	3,588	2,800	2,857	2,837	2,812	83	788	(56)	20	25	-2%	1%	1%	Year over year variances are not greater than 3%
Adj for Vehicle Lease & Capzd O/H	(129)	(119)	(91)	(156)	(80)	(178)	(10)	(28)	65	(75)	98	-41%	94%	-55%	
Total RRA	74,272	72,292	66,600	63,100	60,700	60,900	1,980	5,692	3,500	2,400	(200)				

93.3 Please provide a table detailing all the staff and funding requests across Marketing & Business Development for 2010 and 2011, balanced to the increase in FTE, and reference each request to the specific category in the table provided in the item above, and reference the specific location in the Application detailing the specifics of each request.

Response:

See TGI's responses to BCUC IR 1.93.2 and BCUC IR 1.86.3.

94.0 Reference: Operations and Maintenance Expenditures - Marketing and Business Development

Part III, Section C, Tab 6, p.373

94.1 Please summarize the total (as opposed to incremental) Marketing and Business Development costs requesting approval relating to the cost drivers below by completing the following table:

Marketing & Business Development Costs
(related to Customer and Stakeholder Behaviours and Expectations)

	2010		2011	
	$m	%	$m	%
Customer Care and Services				
Customer Solutions and Services				
Customer and Business Facilitation				
	$Total		$Total	

Response:

Please see TGI's response to BCUC IR 1.93.2.

94.2 On page 378 of the Application, Terasen Gas states that:

"These staff will not only sell and develop natural gas offerings but will focus on integrated energy solution offerings that may include any of natural gas, geo-exchange, solar, biomass or other thermal energy sources… Terasen Gas has already increased staff in this area for 2009 and proposes to continue adding to this area for 2010 with a further slight increase in 2011."

94.2.1 In Terasen Gas' opinion, is there a difference between the marketing activities described above and the marketing activities of natural gas marketers who operate under a deregulated business segment?

Response:

The activities described above for gas and alternative energy systems are totally unrelated to the activities of gas marketers. The TGI staff will work with customers or customer groups to assess energy needs and options and will then be involved in developing the required capital project as well as the proposed terms of service for that customer or customer group. What TGI is requesting through this Application is for the approval of the regulatory mechanism for cost allocation and rate setting for the provision of heat via a DES, solar or geo application which is owned and operated by TGI.

94.2.2 What is the number and costs of staff that Terasen Gas has already increased in this area for 2009? Furthermore, please identify the number and costs of additional staff that relate to EEC and Alternative Energy Solutions as discussed in Part III: Section C – Tab 3 of the Application.

Response:

Please see TGI's response to BCUC IR 1.93.2 and BCUC IR 1.86.3 for additional information and overall O&M requests.

The table below shows the staffing changes for not only 2009 as requested, but 2010 and 2011 for EEC and those staff who roles fall under the categories Service Enhancements, Government Policy, and Customer Service and Sales (which includes EEC). Note, as per Commission Order No. G-36-09 that EEC costs from April 2009 forward are capitalized not treated as O&M.

			Year over Year					
Business Driver	**Department**	**Application Location**	**Incremental Headcount**			**Incremental O&M Cost**		
			2011 Fcast	**2010 Fcast**	**2009 Proj**	**2011 Fcast**	**2010 Fcast**	**2009 Proj**
Gross								
Service Enhancements	Customer Care and Services	Page 380	0	2	0	$ 8	$ 244	$ -
Government Policy	Customer Service and Solutions	Page 375	0	3	0	$ 9	$ 321	$ -
EEC (no request for O&M)	Customer Service and Solutions	Not Applicable	0	0	7	$ 25	$ 363	$ 240
Sales & Business Development	Customer Service and Solutions	Page 377	4	5	9	$ 561	$ 936	$ 568
Total Year over Year Change			4	10	16	$ 603	$ 1,864	$ 808
Offsets								
EEC offsets (deferred)						$ (25)	$ (363)	$ (240)
Marketing Dept O&M efficiencies								$ (568)
Net Totals			4	10	16	$ 578	$ 1,501	$ -

94.2.3 Please describe the types of activities that were included in the above statement. Specifically, please indicate whether Terasen Gas considers these activities to be *product or service development* in nature.

Response:

Describing the activities as either product or service development is too narrow a description as the activities of these staff may include either product or service development or both, but may also include many other activities that are unrelated to product and service development. In meeting with customers (both potential new customers and existing customers) TGI staff work with the customers to arrive at the best use of gas (which includes sales activities, energy efficiency activities, gas commodity activities, billing questions etc.) as well as responding to inquiries and offering advice about efficient use of energy which can include the mix of gas and alternative energy. Below is a breakdown of the different staffing roles referenced in the quote above and their activities:

- Sales Staff – Sales staff sell both traditional gas applications where the sales staff meets with developers, engineers and architects to encourage the use of natural gas in new developments, as well as advising on options for alternative energy (often in conjunction with natural gas) if the customer desires this option. These activities are neither product or service development; rather they are selling of the benefits of natural gas in a new development. Sales staff also meets with customers who have a desire for alternative energy systems such as DES and geo-exchange. These meetings in part could be termed both product and service development, as the resulting energy system must be developed (product development) and resulting service provide must be determined (service development).

- Account Management – These staff primarily work with existing Commercial and Industrial gas customers and provide account management services related to their natural gas needs which include responding to questions regarding billing, transportation options and energy efficiency etc.). However, many of these same customers are seeking to change the way in which they use energy (see BCUC IR 1.23) and require both product and service development advice similar to those described for Sales Staff.

- Market Development – These staff are primarily developing both services and products to meet our customers developing needs, and to do Resource Planning for TGI, TGVI, and TGW. For example, this group is developing the Biogas offering that is part of the Application, the LNG Tariff 16 Application, the LNG CPCN (Mount Hayes), and the Whistler Pipeline are projects the Market Development group has been engaged in over the last few years. In addition this group recently submitted the LNG Dispensing Application that was recently approved by Commission Order No. G-65-09.

95.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations Public Safety Awareness, Appendix F.8, part (h)

95.1 Please provide the actual dollars spent in the Marketing and Development department for 2006, 2007, 2008, and projection for 2009 pertaining to Public Safety Awareness.

Response:

Actual dollars spent for Public Safety Awareness in Marketing and Business Development for the following years are as follows:

2006 $370,000
2007 $165,000
2008 $342,000
2009 $340,000 (projected)

Each year, safety public awareness activities include radio and newspaper placements. However, the existing budget allows for only infrequent coverage. The budget is further stretched in that the service territory is large requiring a vast number of radio and newspaper outlets to provide information equitably throughout the service region. It is important to note that radio is demonstrated to have greater recall awareness than communications methods such as newspaper placements or bill inserts but needs to be utilized at an appropriate frequency to achieve a level of awareness and then knowledge, contributing to a change in behaviour.

Public information is more frequently distributed via communications activities including: media releases and earned media; brochures; annual letters; damage prevention program; school program and the Terasen Gas website and the TerasenJr. web page. As well, safety messaging is added to all communications materials, where appropriate, to reach as many audiences as possible.

Funds are also required to ensure Terasen Gas is providing safety information to large populations of customers and members of the public who speak Punjabi and Cantonese as a primary language rather than English (currently 25 per cent of the population in the Lower Mainland speaks a language other than English in the home with Punjabi and Cantonese being two of the most frequently spoken.)

Our number of customers has increased since 2003 and current research demonstrates that additional communications efforts are needed to increase our customers' and the public's the level of awareness of key safety messages, particularly gas odour and action and Call Before You Dig. TGI requires the funding for more than one year to be able to assess the effectiveness of the program and ensure that messaging is meeting the projected targets which may lead to alterations in messaging to ensure success. Terasen Gas requires a larger safety communications budget to address these results and increase the opportunities customers have to access information to protect themselves and members of the public.

95.2 Has Terasen Gas tracked the success of safety awareness programs in the past? What is the correlation between the type and volume of safety promotions and the number of reported incidents?

Response:

Through our corporate image and customer satisfaction surveys, customers have indicated that Terasen Gas's safety information is highly-valued by them.

At the same time, Terasen Gas's Residential Safety Survey research has demonstrated that our customers' level of understanding around gas odour and action (what steps to take when they detect a gas odour) is lower than desirable. This survey takes place every three years and is next scheduled for Fall 2009, providing an ideal baseline prior to an increase in targeted activity.

The company also measures and analyzes its third party damage statistics. The underlying factors for damage occurring have remained the same for the past few years. Annually, approximately 70 per cent of all damage occurs because those digging did not obtain location information for gas lines in the prescribed dig area. For the digging community, Terasen Gas participates in workshops in areas that have seen an increase in damages to help reduce future damages.

Safety awareness programs help educate the public about the safe use of natural gas such as appliance safety, meter safety, calling before excavation, and carbon monoxide. Thankfully, serious incidents are rare. While it is difficult to calculate a simple cost / benefit analysis for serious incidents, TGI believes that it is appropriate and in the interests of customers and the public for Terasen Gas to inform the public about the potential for serious situations.

96.0 Reference: Operations and Maintenance Expenses

Customer and Stakeholder Expectations - Significant resourcing requirements

Part III, Section C, Tab 6, p. 353, par. 2

"The majority (over $4 million) is for additional sales and account management staff, additional staff in government relations, business development and analysis staffing, and additional customer advocacy staff. ... In 2011, to meet the customer and stakeholder expectations, TGI requires an additional $0.6 million for additional sales and account management staff in the Marketing Department."

96.1 For each area of growth due to Customer & Stakeholder Expectations, please detail the O&M in 2006 and the increase for each year to 2011.

Response:

Please see the response to BCUC IR 1.93.2. The rows labelled "Customer and Business Facilitation" and "Customer Solutions and Services" are those that make up the changes in Customer and Stakeholder Expectations.

96.2 Please explain why the increases should exceed inflation for each year.

Response:

TGI has allocated funds to the Customer Solutions and Services group in order to meet the changing needs of customers and stakeholders by promoting and maintaining gas load for the benefit of all TGI customers. Also, this group has been proactive in analyzing and developing new service options for TGIs customers. To not do so, in TGI's opinion, would have been imprudent. TGI does not believe that there is any relation to inflation and the number of staff in the Marketing group. Inflation is a broad measure of the economy whereas, staffing requirements address specific customer needs and respond to the changing environment in which TGI operates.

96.3 Please compare the increases in each year to the increase in customers for that year.

Response:

Please see the response to BCUC IR 1.93.2. Please see below a table comparing decreases and increases in spending with increases in customers. Note however that comparing spending in this area to actual customer additions is not a reasonable comparison as there are many other factors that affect or impact the required staffing levels in the Marketing department.. First there is usually a lead-lag from the time of spending increases until the results can be seen. Further, spending increases are not all focused on adding customers. The increases in spending are for staff in Account Management, and Market Development (part of the Customer Solutions and Services Group). While these staff also work to add customers, they also work to keep existing customers by providing service to these customers.

Secondly, the number of customer attachments are primarily driven by housing starts and the associated capture rates in that new housing stock. Lower housing starts will result in fewer customer attachments if capture rates remain constant.

Lastly as has been noted in the Application, customer needs and expectations are changing. This is changing the nature of the interactions that TGI has with builders, developers, engineers and architects (the customer group responsible for housing starts and customer additions). It takes considerable more time to educate and work with this group and encourage the use of gas in a development. Sales and development staff often must change this customer's perception of gas and educate them on the options gas can play in their development. TGI believes that this has resulted in more customer additions than taking a "do nothing" approach and is imperative to maintain and ensure future business success. Further, as TGI moves into Alternative Energy Solutions, the alternative energy solution customer may already be a gas customer and, therefore, gas customer numbers would not increase; rather, the end use customer's energy use and usage would change. This is not reflected in the numbers below. The number of staff therefore relates to the complexity of both the energy systems and the customer needs. There is little correlation to staffing numbers in this area and increase in gas customers.

Increase in Customer Stakeholder and Expectation Spending Ensures Increase in Customer Additions						
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Housing Starts	36,443	39,195	34,321	22,800	20,700	21,500
Total Gross Additions	13,338	15,533	14,566	9,600	8,784	9,176
Year - Ending Customers	812,683	822,598	831,845	837,970	843,565	849,415
Percentage Change In Customers	1.6%	1.9%	1.8%	1.1%	1.0%	1.1%
Customer Stakeholder and Expectations Changes in Spending						
Customer Solutions and Services		-9%	16%	17%	27%	8%
Customer and Business Facilitation		1.0%	1.5%	2.2%	21%	1.8%

97.0 Reference: Operations and Maintenance Expenses

Customer and Stakeholder Expectations - Detailed Customer Information

Part III, Section C, Tab 6, p. 375, par. 1

97.1 Please comment further on the provision of detailed, multi-year customer account and usage analysis and whether this type of service is charged to requestors by other utilities.

Response:

TGI canvassed other natural gas utilities to determine if multi-year customer account and usage analysis is provided to customers by the utility and whether this type of service is charged to customers. TGI received one response from Union Gas confirming that they offer two customer systems – Unionline and MyAccount. Unionline is a system where commercial and industrial have the ability to access historical consumption data back to 1998 or whenever they became a Union Gas customer, whichever is later. The Unionline functionality was implemented in 2003 and was part of an entire system implementation for Union Gas. Customers use Unionline free of charge with overall costs for Unionline the utilities revenue requirement and recovered through delivery rates. The MyAccount system is for residential and small commercial customers allowing them to access 24 months of consumption data history, and is offered free of charge to customers (ie: there are no variable charges for each time a customer requests information), however, costs for this service are recovered in delivery rates.

In addition, TGI understands that BC Hydro also provides consumption information for free to all customers the cost for which is recovered in rates.

TGI's proposed treatment of these costs to provide these services is reasonable and appropriate due to the fact that all customers need to have ready access to their natural gas consumption history to help them understand their usage, given the provincial focus on using energy efficiently. Making information easily available to customers is a critical first step in helping customers finds ways to use natural gas more efficiently and to reduce their energy consumption.

98.0 Reference: Operations and Maintenance Expenditures

First Nations

Part III, Section C, Tab 6, p. 379, par. 3

98.1 Please provide the number of agreements with First Nations renegotiated, by year from 2006 to 2008 and projected for 2009 to 2011.

Response:

TGI negotiated or renegotiated the following agreements:

- 2006= 2 Chemainus First Nation, Cowichan Tribes
- 2007= 1 Skeetchesten First Nation
- 2008= 2 Upper Similkameen IB, Tsawwassen First Nation
- 2009= 2 Canim Lake IB, Lower Similkameen IB
- 2010= 2 Tsleil-Waututh Nation, Kwantlen First Nation
- 2011= 2 Kamloops IB, Penticton IB

Due to the complex nature of First Nation agreements, TGI relies on strong relationships with bands to complete negotiations successfully and without litigation. TGI has been under-resourced to take on the current and projected work load. Although results to date have been favourable, TGI requires streamlined process to ensure that First Nation relationships are fostered and not jeopardized long term. We also expect that in the future the complexity of issues and relationships, and therefore the time required meeting and responding to issues, will continue to grow. Further, as noted in response to BCUC IR 1. 100.1, developments in the law respecting the duty to consult increase both the importance and complexity of TGI's First Nations relationships. It is therefore incumbent upon TGI to ensure that it has the necessary staffing levels and time to devote to First Nations issues going forward. It is for this reason that TGI has requested additional funding for this area.

98.2 Please comment on when Terasen expects the proposed new legislation to be effective.

Response:

Please refer to the response to BCUC IR 1.100.1.

99.0 Reference: External Situational Context

Continuing Complexities in Aboriginal Rights

Part III, Section A – Tab 1:, pp. 55-56

Page 56 states:

"The need to recognize and deal with Tribal Councils flows from the lack of treaties, making it more difficult to identify the appropriate aboriginal representative."

"TGI needs to invest in the necessary resources to address properly the issues presented by asserted claims of aboriginal rights and title and the duty to consult and, if necessary, accommodate."

99.1 How has TGI used resources available on the internet such as the websites of the BC Treaty Commission, BC Ministry of Aboriginal Relations and Reconciliation, and individual First Nations in BC etc. to help identify aboriginal representatives?

Response:

As discussed in the referenced passage in the Application, the challenges associated with identifying aboriginal representatives that are driving the proposed expenditure flow from the challenges associated with identifying the scope of rights and title asserted by many First Nations with overlapping claims. These First Nations may or may not be participating in the Treaty Process, with published claims. Once the First Nations with asserted rights and title in a particular area are identified, it is generally more straightforward to identify the appropriate representatives for each First Nation.

TGI endeavors to use all available resources for information and for identifying the scope of asserted rights and title, and hence the applicable aboriginal representatives with whom TGI must deal. These resources include the Internet and the BC Treaty Commission statement of intent data base. However the information in the databases is incomplete, as all First Nations in BC do not have their interests posted online as they may not be participating in Treaty negotiations. TGI also attends First Nations Summit meetings and the BC Assembly of First Nations meetings in order to better understand and identify aboriginal territorial interests.

The lack of a comprehensive listing of First Nations interests creates considerable uncertainty. In order to ensure that TGI is able to track and be aware of all First Nations issues which may affect the Company, additional resources are required. TGI believes that one existing First Nations relations staff person is insufficient to meet these needs.

99.2 The Province of British Columbia has established FrontCounter BC. To simplify the process for small-to-medium sized natural resource businesses. On the FrontCounter BC website it states: "FrontCounter BC Staff will begin referral processes with First Nations."

99.2.1 How has TGI utilized the services of FrontCounter BC and if so, how long?

Response:

TGI's lands department has contacted FrontCounter BC on approximately 5 occasions in the last year. TGI has directed questions to them regarding crown land issues (new SRW applications, license amendments and renewals) and FrontCounter BC refers the questions to the applicable Integrated Land Management Bureau office. Questions surrounding Crown Land and First Nation boundaries are typically complex and require in depth analysis due to several bands or tribal councils claiming overlapping areas as reserve land. While Front Counter staff typically are familiar with basic processes, in depth questions require technical staff and often require meetings with the Province of BC or INAC (Indian and Northern Affairs Canada).

99.3 On page 379, the Application indicates Terasen is renegotiating agreements with four or more of the 84 First Nations whose land is impacted by Terasen Gas infrastructure.

99.3.1 What information was used by TGI to determine the aboriginal groups that might be affected by TGI infrastructure?

Response:

The Provincial Government administers a central database that is not available to the public, that logs all First Nation land claims within the Province. Once TGI files environmental permits with the Province, the Province will send TGI a list of bands that have made claim on the parcel of land TGI would like to pursue. It is TGI's priority to ensure appropriate consultation with the impacted bands takes place. In order to be proactive and protect relationships, TGI typically collects land claim data from local First Nations bands, regional Treaty negotiating organizations as well as Tribal Councils and begins talks with impacted bands immediately.

99.3.2 How did TGI determine the aboriginal representatives to negotiate with and conclude agreements?

Response:

TGI renegotiates agreements with First Nations in instances where TGI needs to acquire land use rights, such as in instances where the original permit will expire or where TGI wishes to expand the TGI system and therefore acquire additional or new rights.

TGI meets with band administration along with elected officials at the impacted band office. Discussions were conducted giving the band a general overview of the issues. The band gave TGI direction on whom TGI would be negotiating with and the process to conclude the agreements.

100.0 Reference: Customer and Business Facilitation

Exhibit No. B-1, Part III, Section C – Tab 6: Operations and Maintenance Expenses, p. 379

First Nations

On page 379 it states:

"As has been shown in Section 3, we believe that over the period of the RRA, there will be a need for greater First Nations engagement. This is primarily driven by fact that the Province of British Columbia and the First Nations Leadership Council have developed a proposal for provincial legislation to recognize aboriginal title in BC and establish a process for negotiation and implementation of shared decision-making and revenue and benefit sharing agreements. The proposed Act would apply to all provincial ministries and agencies and would take priority over all other provincial statutes and policies. This in turn would, and has already started to, change the way that businesses work with and negotiate with First Nations. The provincial legislation to recognize aboriginal title in addition to increased regulatory requirements will result in an increased need for discussions with First Nations each time Terasen Gas proposes to build new infrastructure on Crown lands or through First Nations lands. Lastly, at any given time we are renegotiating agreements with four or more of the 84 First Nations whose land is impacted by Terasen Gas infrastructure. Terasen Gas believes that it requires one additional staff and associated expenses at a cost of $200 thousand, to meet these needs."

100.1 Please provide further information on the proposed provincial legislation and specifically cite the sections that would affect TGI. When is the legislation to be enacted?

<u>Response:</u>

Terasen Gas' information on the proposed provincial legislation is limited to publicly available documents. In the Throne Speech of 2009, British Columbia pledged to further implement the ideals of the New Relationship by working with First Nations to establish a *Recognition and Reconciliation Act.* The "Discussion Paper on Instructions for Implementing the New Relationship", issued by the Province contains a summary of the proposed elements of the legislation. These include "mechanisms for shared decision making in regards to planning, management and tenuring decisions over land and resources". TGI has no knowledge as to the progress of the proposed legislation that is not publicly available..

Regardless of the status of the proposed legislation and whether it becomes law, Terasen Gas needs and desires to engage with First Nations each time we propose to build infrastructure on Crown Lands. Dealing with First Nations has become an increasingly important aspect of our business. As described in the response to BCUC IR 1.100.2, TGI must typically lead or be significantly involved in undertaking the consultation upon which the Crown must rely to satisfy the duty to consult with First Nations. Customers benefit from careful management of relationships with First Nations as it facilitates the timely and cost effective completion of projects that are necessary for safe and reliable service. Any further movement by the Province towards shared decision making with First Nations as contemplated in the Discussion Paper would add complexity to this process until all the stakeholders in the shared decision making understand any new decision making processes.

100.2 Please confirm whether or not TGI has a legal duty to consult First Nations.

Response:

The Crown has a constitutional duty to consult First Nations. Terasen Gas is not a Crown agent. However, Terasen Gas has a practical need and desire to assist the Crown in discharging its duty to consult First Nations. Consultations undertaken by Terasen Gas assist the Crown in fulfilling its duty to consult. As a project proponent, we are often in the best position to engage in early discussions with the First Nations who may be affected by a project we propose to undertake.

100.3 Are costs related to First Nations discussions capitalized into the project when a new infrastructure project is proposed?

Response:

First Nations discussions related costs including consultant and related expenses are capitalized as part of the development of a new infrastructure project. TGI staff time related to First Nations discussions (i.e. aboriginal relations manager) are not directly capitalized and are accounted for as an O&M cost, subject to the overheads capitalized policy.

100.4 Are the costs of negotiating agreements with First Nations capitalized into a new proposed infrastructure project?

Response:

Similar to the response to BCUC IR 1.100.3, First Nations negotiation related costs including consultant and related expenses are capitalized as part of the development of a new infrastructure project. Not capitalized though are TGI staff time related to First Nations negotiations (i.e. aboriginal relations manager) which are accounted for as an O&M cost, subject to the overheads capitalized policy.

100.5 What is the pay level/affiliation and fully loaded cost for the additional staffing resource? Which department would house this staffing resource be located?

Response:

The pay level for an additional TGI staff member would be approximately $124,000 per year plus job related expenses. The employee would be in the Marketing Department and would be a Management Exempt employee.

100.6 What would be the specific duties of the First Nations resource? Provide a job description, if available.

Response:

Please see TGI's response to BCUC IR 1.104.2.

100.7 Please provide details of the associated expenses of $200,000 by cost element and for which type of activity.

Response:

Description	**Expense:**
Compensation; includes wages, benefits, & inflation	$124,000
Travel; (includes airfare, car rental, personal car use, accommodation & meals)	$42,000
Consultants	$18,000
Advertising & Communications; includes communications materials for consultations, meeting space, etc	$16,000
Total	**$200,000**

101.0 Reference: Marketing

Exhibit No. B-1, Part III, Section B – Tab 1: Respected and Trusted Operator – The Past, pp. 91-92

On page 91 it states: "The Marketing department plays an important role … facilitating business relationships with government and First Nations."

On page 92 it state: "Customer and Business Facilitation – This includes activities such as community and government relations and policy, and First Nations relations."

101.1 Please provide an organization chart of the Marketing's Customer and Business Facilitation activity including the number of positions and position titles

Response:

Please see the response to BCUC IR 1.104.1.

101.2 Please describe how TGI facilitates relationships with First Nations and identify the positions in the organization chart that are involved with this function.

Response:

TGI facilitates relationships with First Nations by participating in local and Provincial events during the year, typically hosted or organized by various First Nations and Tribal Councils throughout BC. These opportunities allow the Aboriginal Relations Manager and local Community Relations Managers to develop relationships with Chief, Council and local Community members. TGI also has partnerships and programs with various groups such as the Terasen Boot Camp, assisting First Nations graduates to develop needed skills to determine their technical education path. An organization chart is provided in response to BCUC IR 1.104.1. The primary staff responsible for relationships with First Nations is the Aboriginal Relations Manager. The Community Relations Managers and the Director of Government and Aboriginal Relations also facilitate relations with First Nations. Members of the executive group and other senior managers are also involved in facilitating First Nations relationships.

102.0 Reference: External Situational Context - BC Energy Plan 2007

Part III, Section A – Tab 1 p.32

102.1 Please provide details on how TGI has participated in the expanded First Nations and Remote Community Clean Energy Program since 2007. Identify activities for this program and the costs involved.

Response:

TGI has not participated in any activities related to this policy objective, as this policy relates specifically to BC Hydro.

103.0 Reference: Business Information and Technology Services

Exhibit No. B-1, Part III: Section B - Tab 1: Respected and Trusted Operator - The Past, pp. 92-94

Operations Engineering: Property Services

On page 93 it states: "Property Services is responsible for managing all land rights and land tenure issues including property taxation, acquisition and disposal, leases, right of way agreements, and for supporting environmental reviews and First Nations negotiations."

103.1 Please explain further the First Nations negotiations undertaken by Property Services. Are these for capital projects, operating projects, or a mix of projects? Please elaborate.

Response:

For clarity, Property Services does not undertake negotiations with First Nations, but rather provides support to the department that handles those negotiations. Property Services supports First Nations negotiations for both capital and operating projects in the following ways:

1) review and recommend appropriate terms in tenure agreements;

2) coordinate survey or right of way by drafting terms of reference for review by First Nations and Canada (INAC) and hiring surveyors;

3) coordinate real estate appraisal for valuation of right of way by drafting terms of reference for review by First Nations and Canada (INAC) and hiring appraisers;

4) coordinate completion of land-related, restoration issues; and

5) coordinate payments for new or renewed tenure agreements.

104.0 Reference: Strategies to Manage Retirement and Recruitment

Exhibit No. B-1, Part III: Section B – Tab 1: Respected and Trusted Operator - The Past, pp. 147-148

On page 148 it states: "Representatives from Terasen Gas Aboriginal Relations and Recruiting Services met with Snuneymuxw First Nation in Nanaimo to discuss employment opportunities and pre-requisites for certain types of positions, available funding for courses, educational opportunities, and types of careers that are available after one or two years of training in the technician and technologist fields. Terasen Gas Recruiting Services also participated in a two-day Career Fair sponsored by the Nuu chah nulth Tribal Council in Port Alberni and another in Kamloops."

104.1 Please provide an organization chart of the Terasen Gas Aboriginal Relations and Recruiting Services group including the number of positions and position titles. Where is the Aboriginal Relations and Recruiting Services group located within TGI's organization?

<u>Response:</u>

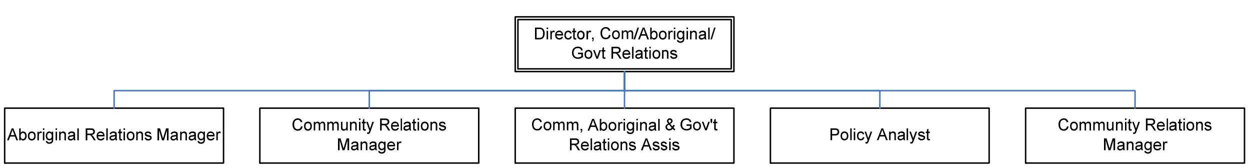
Aboriginal Relations and Recruiting Services are two separate groups that reside in different departments but work closely together on Aboriginal recruiting and training initiatives. Aboriginal Relations is part of Marketing and Business Development, reporting to the Director, Community, Aboriginal & Government & Relations. Recruiting Services is part of Human Resources & Operations Governance, reporting to the Director, HR Strategy & Advisory Services.

Organizational charts for the two departments are included below.

TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

As at July 15, 2009



TERASEN GAS INC.

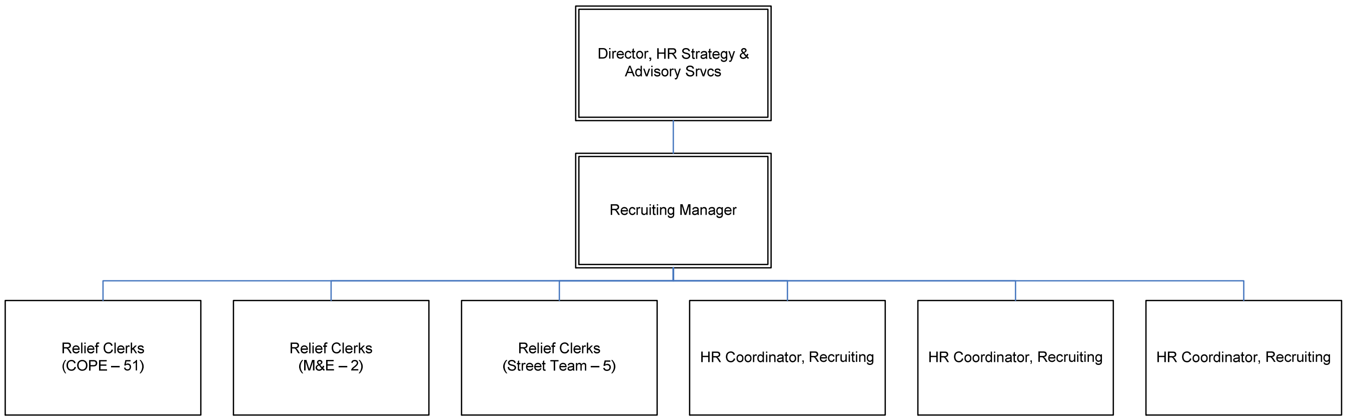
HUMAN RESOURCES & OPERATIONS GOVERNANCE

As at July 15, 2009

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

As at July 15, 2009



104.2 Please provide the job description(s) of the positions in Aboriginal Relations and Recruiting Services.

Response:

Community, Aboriginal & Government Relations includes a total of seven employees, six of whom are employed by Terasen Gas Inc. Those employees hold the following positions:

- Director, Community, Aboriginal & Government Relations
- Aboriginal Relations Manager
- Three Community Relations Managers (one serving the Okanagan, Kootenay & Northern Region, one serving the Lower Mainland, and one serving TGVI & Whistler)
- One Policy Analyst
- One Community, Aboriginal & Government Relations Assistant

Recruiting Services includes a total of four employees:

- One Recruiting Manager
- Three Recruiting Coordinators

The job descriptions of the above-mentioned positions are included in Attachment 104.2.

105.0 Reference: Overall Summary by Business Driver

Exhibit No. B-1, Part III: Section C – Tab 6: Operations and Maintenance Expenses, p. 348

On page 348 it states: "Government Policy funding requests are for additional resources needed to respond to changes in government policy regarding energy efficiency and GHG reduction."

105.1 Are these additional resources incurred fully expensed into operations and maintenance or deferred as capital into the EEC deferral account? Why are these additional costs required?

Response:

Changes in government policy and legislation including the Carbon Tax, Cap and Trade, the Green House Gas Reduction Targets Act, and the British Columbia Climate Action Charter have all caused an increase in demand for consumption information and reporting from the utility and its customers. These additional resources are fully expensed into O&M. Specific positions include forecasting staff to meet requests for consumption information and for additional forecasting analysis to respond to customer and stakeholder requirements as driven by these changes to government policy. In addition, there are staffing in operations governance.

It is appropriate that these costs are incurred in O&M because these staffing requests do not relate to EEC programs and as such a Total Resource Cost (TRC) test cannot be performed. Further, the customers' requests and how they use the data are as a result of government policy changes as opposed to meeting the terms of an EEC program. This is also consistent with Union Gas', and BC Hydro's approach to providing information to customers and having costs recovered through delivery rates, rather than recovering the costs directly from the requesting customer (see TGI's response to BCUC IR 1.97.1).

105.2 If these incremental requests are in addition to the approved costs arising from the TGI Energy Efficiency and Conservation Application, why were they not included in the EEC Application?

Response:

The costs are not related to EEC but are related to work being done in relation to overall government energy and environment policy and business drivers that relate to these initiatives.

In particular, customers are seeking to better understand their consumption behaviour in part to manage costs effectively, in part to meet government policy objectives and in part to reduce energy usage. The desire to understand energy usage is therefore not specifically related to an energy efficient test or desired outcome. TGI believes that these costs are day to day costs that should be recovered through O&M rather than through EEC programs. See TGI's response to BCUC IR 1.105.1

106.0 Reference: Customer and Business Facilitation

Exhibit No. B-1, Part III: Section C – Tab 6: Operations and Maintenance Expenses, p. 378-379

Operating Agreements

On page 379 it states:

"Terasen Gas was successful in negotiating a significant number of operating agreements over the PBR Period. At the end of 2011, the operating agreements on Vancouver Island will expire and will need to be re-negotiated. In addition there are ongoing requirements to renew TGI agreements as they expire and to ensure that there is a concrete strategy and direction for meeting both the TGVI needs and that of TGI. To meet these needs, additional staffing resources and associated expenses are required. A staffing resource and associated expenses to be shared between TGI and TGVI will be added in 2010 to meet this need, at a cost of $145 thousand to TGI."

106.1 During the PBR years how many operating agreements were being negotiated? What level of resources (i.e., positions and associated expenses) were used to negotiate and conclude the operating agreements?

Response:

In order to maintain good relationships with the municipalities within which Terasen Gas operates, significant effort has been made to renegotiate municipal operating agreements prior to their expiry. In this regard, Terasen Gas was successful in finalizing 12 agreements during the PBR period, all of which are with smaller communities located in the Interior of British Columbia. Costs associated with our Community Relations Manager include salary and benefits for three years, non-labour expenses of approximately $140,000, consisting of $25,000 in 2004, $25,000 in 2005 and $90,000 in 2006. In addition to a Community Relations Manager, a Regulatory Affairs Manager and TGI Legal Counsel worked on the file as part of their job duties.

106.2 How many operating agreements are expected to be negotiated in years 2010 and 2011 and from years 2012 to 2020?

Response:

Terasen Gas is committed to working cooperatively with municipalities, and is therefore planning to negotiate several new municipal operating agreements in the regions served by TGI and TGVI prior to 2012 and also before 2020.

For TGI, five operating agreements with municipalities in the Interior of British Columbia expire before 2018 and an additional 18 between 2018 and 2020. We expect that negotiations to renew these agreements will conclude prior to their expiry dates.

On Vancouver Island, seven of our ten operating agreements expire in 2012. We expect to successfully negotiate new agreements with these seven municipalities, and possibly with additional municipalities which have never had operating agreements, but have effectively been governed by a 1991 BCUC decision setting the terms of the operating agreement used by TGVI. TGVI serves approximately 28 municipalities.

In addition to negotiating operating agreements, TGI expects that additional planning time is required to review existing operating agreements and develop a strong rationale and corporate strategy for future operating agreement negotiations.

106.3 Please describe the history of the negotiations and approval process for the PBR Period operating agreements. Are there any synergies or templates that can be used to facilitate easier conclusion of future agreements?

Response:

Negotiations during the PBR period have focused on municipalities located in the Interior of British Columbia, since that is where operating agreements had been expiring. TGI's executives provided overall direction to our Community Relations Manager, who in turn received support from other internal Terasen groups, including Regulatory Affairs, and Senior Legal Counsel.

In order to facilitate an efficient negotiating strategy, and produce operating agreements with consistent terms, TGI successfully negotiated a pro-forma operating agreement with the Union of British Columbia Municipalities' ("UBCM") Operating Agreement Committee in 2006 and, using this agreement as a template, negotiated new operating agreements with ten municipalities located in the Interior of British Columbia. While this template agreement was developed with the intention of being used by these ten municipalities, we anticipate that portions of it, while not binding on either party, will assist in future negotiations with other municipalities. While the achievement of consistent terms and conditions is desirable, flexibility may be necessary to achieve a successfully negotiated agreement that reflects local interests and issues. At the conclusion of the original ten Interior operating agreements signed using the UBCM template, TGI eliminated one staffing position in the Government and Community Relations group. However, while TGI believes that synergies exist as a result of the use of the UBCM template, TGI still requires the replacement of the Government and Community Relations staff in order to develop a corporate strategy regarding future operating agreements including a review of the UBCM agreement to determine its applicability to TGVI, a review of

TGI operating agreements and the long term corporate requirements, and to lead negotiations of both TGI and TGVI.

106.4 What is the pay level/affiliation and fully loaded cost for the additional staffing resource? Which department would this staffing resource be located?

Response:

In order to successfully complete the negotiation of upcoming operating agreements in a timely and efficient manner, an internal management resource funded at a fully loaded annual cost of $145,000, plus additional costs for external support and expenses totalling $100,000 per year will be necessary beginning in 2010. This resource would report into the Community, Aboriginal and Government Relations department.

106.5 In a table format, please show the gross cost segmented by labour and non-labour and the individually allocated cost to TGI and TGVI by segment.

Response:

	2010 Labour	**2010 Non-labour**	**2011 Labour**	**2011 Non-labour**
TGI (30% labour allocation)	$ 45	$ 100	$ 46	$ 100
TGVI (70% labour allocation)	$ 105	$ -	$ 109	$ -

The 70/30 allocation of the costs between TGI and TGVI specifically reflects the expectation that the position will be spending the majority of their time on re-negotiating TGVI agreements which are coming due at the end of 2011.

Note: expenses will be allocated through the Shared Services Agreement

Note: projected spend is expressed in thousands of dollars.

107.0 Reference: Customer and Business Facilitation

Exhibit No. B-1, Part III, Section C – Tab 6: Operations and Maintenance Expenses, p. 379

Government Policy Analysis and Facilitation

On page 379 it states:

"Until the introduction of the 2007 BC Energy Plan, Terasen Gas' interaction with government was primarily with the Ministry of Energy Mines and Petroleum Resources. However, now Terasen Gas interacts with numerous Ministries on both a staff and political level. In order to meet government energy objectives, Terasen Gas must be aware of these objectives and understand both the impact on Terasen Gas and its customers and also determine how Terasen Gas might react to the energy objectives. As such Terasen Gas requires one additional staff and support costs at a cost of $180 thousand in order to meet these changed objectives."

107.1 Who are these "other Ministries"?

Response:

Since the 2007 Energy Plan was announced, the Terasen Utilities have met with government ministries to discuss and advocate solutions to climate change and energy related issues and policies. Although the Terasen Utilities have long been in close association with different ministries (i.e. Ministry of Energy Mines and Petroleum Resources ("MEMPR")) mainly for code compliance purposes, their level of interactions with various ministries has increased significantly due to the fact that recent energy policies affect all sectors of the economy. In addition to MEMPR, the Terasen Utilities have been meeting with staff and elected officials in the Ministry of Environment (compliance and project development), Ministry of Transportation and Infrastructure (for natural gas vehicles and coordinated infrastructure development), Ministry of Education (business development), Ministry of Agriculture and Lands (for biogas), Ministry of Finance, the office of the Premier, and the Climate Action Secretariat and, in addition, with elected officials in both ministerial portfolios and non-ministerial portfolios including the Minister of Healthy Living and Sport, the Minister of Housing and Social Development, the Minister of Small Business, Technology and Economic Development, Aboriginal Relations and Reconciliation, Community and Rural Development, Health Services, Public Safety and Solicitor General, Minister of State for Intergovernmental Relations, and Minister of State for Climate Action.

107.2 Which positions currently interact with MEMPR and these other Ministries?

Response:

TGI has employees from various departments and levels across the organization, interacting with different government Ministries depending on the issue or topic that needs to be discussed with government. Primary responsibility for engagement, coordination and scheduling lies within the Marketing department (principally with Community, Governmental and Aboriginal Relations). The office of the President, Executive Leadership Team members and select subject matter experts engage with government elected officials and staff directly, via their geographic representation in the 125 BC communities that we serve and indirectly via 3rd party events, conferences and working groups. (See the response to BCUC IR 1.107.1 for the list of ministries). The interactions of TGI with different Ministries ensures that the Company takes a proactive part in advocacy of solutions to climate change and energy policy to the benefit of TGI's customers and stakeholders.

107.3 What is the pay level/affiliation and fully loaded cost for the additional staffing resource? Which department would this staffing resource be located?

Response:

The total compensation for the Government Policy Analyst would be $105,000 per year. This includes wages, benefits, bonus and inflation. Job related expenses would amount to $75,000.

The Government Policy Analyst would report to the Director, Community/Aboriginal and Government Relations within the Marketing department (see response to BCUC IR 1.104.2).

107.4 What specifically would be the duties of this government policy analysis resource? Provide a job description, if available.

Response:

Please see the response to BCUC IR 1.104.2.

107.5 What are the incremental duties that are not currently being done?

Response:

The duties outlined in the job description for the government policy analysis position provided in TGI's response to BCUC IR 1.104.2 are duties that are currently required and would not get completed unless the position is filled. See also response to BCUC IR 1.86.3.

107.6 Please provide details of the associated expenses of $180,000 by cost element and for which type of activity.

Response:

Description	**Expense:**
Compensation; includes wages, benefits, & inflation	$105,000
Travel; (includes airfare, car rental, personal car use, accommodation & meals)	$60,000
Advertising & Communications; includes communications materials for consultations, meeting space, etc	$15,000

108.0 Reference: Operations and Maintenance Expenditures Media Monitoring

Part III, Section C, Tab 6, p. 382, par. 1

"We require additional funds to support ongoing media monitoring and newswire services to reflect the increased media interest in energy and the greater requirements on Terasen Gas to provide this information."

108.1 Please provide the costs for this service by year from 2006 through 2011.

Response:

TGI wishes to clarify that TGI does not monitor newswires, nor does it intend to do so. Rather the company uses a newswire service to distribute its news releases to media outlets across the service territory in more than 125 communities. Please see the response to BCUC IR 1.108.2.

Media Monitoring & Newswire Costs 2006 - Estimated 2011

	2006	2007	2008	2009 (year-to-date)	2010 (estimated)	2011 (estimated)
Media monitoring	22,000	43,000	56,000	56,000	60,000	60,000
News wire services	4,000	8,000	23,000	23,000	25,000	25,000
	26,000	**51,000**	**79,000**	**79,000**	**85,000**	**85,000**

108.2 Please explain the benefit to ratepayers of ongoing media monitoring and newswire services, functions usually linked to investor relations.

Response:

TGI wishes to clarify that TGI does not monitor newswires, nor does it intend to do so. Rather the company uses a newswire service to distribute its news releases to media outlets across the service territory in more than 125 communities. Further, this is not investor relations activity; rather, it is activity related to customer and energy issues.

News releases are used to get mass media coverage of information about safety, rates, energy efficiency, community involvement and other topics of value to our customers and the communities we serve. Distributing our news releases throughout our 125 service communities is fundamental to the company being a transparent operator since it allows us to immediately and directly alert the vast amount of media in our service area when new information is available. The media then in turn may elect to report on the information for communication to the public and our customers.

Unlike paid advertising which guarantees publication of content in its entirety on a set date, the release of information to the media provides no guarantee of publication and the content may only be partially covered or subject to interpretation. However, Terasen Gas only prepares releases that are either news (event-driven, such as a rate change) or public awareness or education opportunities (safety, energy efficiency that are timely and are triggered by news event – seasonal safety information supporting a weather-related event or is new information and therefore newsworthy.)

In recent years, energy has become a topic of greater interest to the media and consumers, resulting in the company issuing more news releases. There has also been an increase in media requests that in many cases are not a result of a news release. These requests also result in coverage.

Since it is the media and not Terasen Gas that communicate the information (from either a Terasen News release or a media request) to our customers and the public, it is in the customers', the public's and Terasen Gas's interest that the reporting be monitored for accuracy. When misinformation is reported, Terasen works with the respective media outlet to ensure correct information is published. Media monitoring also allows the company to access *Letters to the Editor* that our customers may have submitted to prepare a response in a timely manner for publication.

109.0 Reference: Operations and Maintenance Expenditures

Business and Information Technology Services

Part III, Section C, Tab 6, p. 384, Tables C-6-28, C-6-29

109.1 Please provide tables for each of the three departments in B&IT, for 2006 by year to 2011, with the base O&M in 2006 and the incremental for each year provided in the same categories as the incremental in the Tables C-6-28 and C-6-29.

Response:

Provided below is the information as requested beginning with the year 2006 to provide context to the 2010 and 2011 O&M forecasts. However, TGI does not believe the 2006 actual O&M spending is the appropriate starting baseline for comparison of 2010/2011 O&M forecasts. 2006 was highlighted by higher allocation of resources for capital projects coupled with staff vacancies which contributed to the lower level of spending. Increasing cost pressures over this time period from a number of sources (i.e. higher lease costs, software licensing fees, odourant costs, etc) have contributed to the existing 2009 projected spending.

Instead, TGI believes the starting point should be the 2003 allowed O&M base that was approved by the Commission and adjusted annually using the approved formula, as it is the allowed O&M that has been used for purposes of rate setting. It then follows that an appropriate and reasonable level of base expenditures for 2010/2011 for comparison purposes would be the 2009 O&M projection, as it is the most recent and reflects the full scope of the benefits associated with performance based incentives.

IT and Business Services

Year	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total Incremental O&M	Total O&M
2006	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	19,315
2007	663	42	42	-	693	1,440	(65)	1,375	20,690
2008	(110)	10	(48)	-	(27)	(175)	-	(175)	20,515
2009	87	18	(35)	-	1,913	1,983	(116)	1,867	22,382
2010	582	116	76	1,000	3,394	5,168	127	5,295	27,677
2011	334	2	-	-	503	839	-	839	28,516

Operations Engineering

Year	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total Incremental O&M	Total O&M
2006	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	7,730
2007	355	111	-	-	(163)	303	-	303	8,033
2008	(245)	383	-	-	175	313	-	313	8,346
2009	486	267	-	-	(22)	731	116	847	9,193
2010	560	1,136	167	363	(200)	2,026	-	2,026	11,219
2011	482	83	183	51	(22)	777	-	777	11,996

Operations Support

Year	Labour Inflation and Benefits	Code and Regulations	Demographics	Accounting Changes	Service Enhancements	Total Incremental	Internal Budget Transfers	Total Incremental O&M	Total O&M
2006	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	Base Year	6,639
2007	131	-	-	530	(646)	15	-	15	6,654
2008	508	-	-	-	(337)	171	-	171	6,825
2009	523	-	-	45	140	708	-	708	7,533
2010	538	25	-	(117)	459	905	(67)	838	8,371
2011	355	100	-	-	-	455	-	455	8,826

110.0 Reference: Operations and Maintenance Expenditures

Right of Way

Part III, Section C, Tab 6, pp. 386-7

110.1 Please expand on the new requirements driving the increased costs.

Response:

The increased costs in Part III, Section C, Tab 6, pp. 386-7 are driven by four factors.

- The first factor to increase costs is the forecast ROW fees for new ROW that is being acquired due to expansion or retrofit type projects. For example, Terasen Gas will be acquiring a second ROW through the Lower Similkameen First Nations reserve which will increase the annual fees paid out by Terasen Gas on an aggregate basis.
- The second factor increasing ROW fees is associated with Terasen Gas performing due diligence on the land and rights to be acquired. For instance, more and more archaeological, environmental, species at risk studies and real estate valuations are required to be performed as part of the acquisition process.
- The third driver of increased ROW fees is related to an increase in permitting fees associated with Provincial noxious weeds regulation compliance.
- Our need to enhance communication with property owners along the ROW is the final driver of costs increases in ROW related fees. We need to implement a formal and effective public awareness program to improve awareness of safety related issues specific to the ROW.

We believe that the increased costs associated with ROW fees are prudent and required in order to secure necessary rights, pay increasing fees associated with existing ROWs, meet Provincial regulatory compliance and enhance public safety awareness specifically along ROW.

111.0 Reference: Operations and Maintenance Expenditures

Sustainability Manager

Part III, Section C, Tab 6, p. 398, par. 2

111.1 Please provide further detail on the job function for the new Sustainability Manager position.

Response:

Terasen Gas has always placed a high priority on the importance of conducting our business in an environmentally responsible manner. By adding this new position, Terasen Gas reinforces the commitment to its Environment, Health and Safety Policy, which drives and defines the Company's strategic response to government and industry objectives. The Company interprets the principle of environmental responsibility as meeting or exceeding government regulations, as evident in our ongoing Operational practice.

This new position will be focused on providing ongoing analysis of corporate greenhouse gas emissions. Responsibilities include working with all Operating groups within the organization to analyze and evaluate reduction measures. The incumbent will implement a new (electronic) emissions inventory program for the organization, and will manage data currently received from various departments within the company that collect and track greenhouse gas source data. In addition, this position will be responsible for developing systems and metrics to support Corporate Responsibility reporting.

111.2 Provide detail on all other positions in the Company that currently perform this type of work.

Response:

The only position currently performing related duties is an Environmental Program Manager, who is responsible for the collection and preparation of information that then allows us to track and report our corporate carbon emissions. Until now this activity has been a technical activity, since external reporting requirements have been voluntary in nature, without incentives to meet targets. However, in order to comply with emerging climate change regulations including the requirements of emerging cap and trade regulations, which will contain emissions targets and incentives for industry, the Company now also needs a Sustainability Manager with the ability to provide broader business guidance and direction to enable the the company to manage carbon emissions targets.

111.3 Provide detail on the time required annually to purchase $60-100 thousand in carbon offsets.

Response:

Terasen Gas demonstrated environmental leadership by voluntarily purchasing carbon offsets in 2000 to reduce the carbon impact of projects such as the Southern Crossing Pipeline Project and the Langley Compressor Station. This experience over the past nine years has positioned Terasen Gas to better prepare for carbon trading needs associated with incoming compliance regimes such as cap-and-trade market which is anticipated due to changing regulation. Until now, our experience with carbon offset purchases has been best served through the services of provided by consultant expertise (that consultant acting as "broker"). We envision that as the offset market evolves Terasen Gas will have more opportunity to work to ensure future offsets are purchased through available providers in a more robust trading environment as the marketplace for these products evolves. While present time commitment is currently limited to a working with one consultant and relates primarily to administrative time managing the current portfolio, we anticipate this increasing in the years ahead due to the complexities and evolving products and services that will enhance and play an important role in the emerging carbon market. Additionally, the time required to enter into purchase agreements and obtain emission reduction credits will partly be influenced by the availability of these credits on the market, the types of projects invested in, and by the structure and demonstration of government compliance mechanisms, once developed.

It should be noted that purchasing carbon offsets is but one component of our carbon management program, which also includes data collection and analysis, establishing emission reduction targets, providing assistance and guidance to the business regarding effective cost / benefit efforts to manage carbon emissions, and making decisions regarding what volumes of offsets or allowances need to be purchased and where they should be sourced. The program also includes governance elements such as monitoring external regulations, ensuring internal policies and standards comply with external regulations, ensuring that employee training programs are available, and monitoring compliance through internal auditing.

The time required to purchase of carbon offsets is but one task and this activity cannot be isolated from other elements of the carbon management program, including having a required understanding of carbon markets, industry leading practices, applicable regulations and how the carbon management program strategically supports other components of the company's overall sustainability program.

112.0 Reference: Operations and Maintenance Expenditures

Regulatory Policy Managers

Part III, Section C, Tab 6, p. 401, par. 4

112.1 Please comment on how this work has been completed since 2007.

Response:

Over the term of the PBR Agreement, the requirements of the Regulatory Affairs department, which it undertakes on behalf of the three Terasen Utilities have increased and changed in response to the evolving regulatory and business conditions. A significant driver of these evolving conditions has been government policy, provincially as well as federally. With the issuance of the Province's Energy Plan in 2007, there has been a sizeable increase in the workload on the Regulatory Affairs staff. The Company expects that the demands on the Regulatory Affairs department will continue to increase in the forecast period in response to these evolving regulatory and business conditions. This is what is driving the need to increase staff in the department in 2010.

The primary purpose of the addition of these two employees in the Forecast Period is to support the Marketing and Business development department address the changing needs of our customers and addressing energy policy initiatives. This will include the bringing forth of applications resulting from energy policies objectives, as well as analyzing the implications of changes to energy policy on TGI's customers. Additionally these employees will support TGI's efforts, on behalf of our customers, in the proceedings of other BC utilities, which has become a significant requirement since the 2007 Energy Plan was introduced. The responsibilities of these two employees will also include assisting with the significant workload that the department expects to continue to increase moving into the forecast period. This significant workload, which the department has been experiencing and expects to continue is otherwise being met by significant overtime on the part of managers, which is not sustainable.

112.2 Please provide the FTE, by job title, and O&M from 2006, by year, for the Regulatory Group.

Response:

	2006	2007	2008	2009P	2010F	2011F
M&E						
Chief Regulatory Officer/Director	1.0	1.0	1.0	1.0	1.0	1.0
Mgr., Regulatory Affairs	-	0.4	1.0	1.0	1.0	1.0
Regulatory Policy Mgr	-	-	0.2	1.0	1.0	1.0
Regulatory Policy Mgr	-	-	-	1.0	1.0	1.0
Regulatory Policy Mgr	-	-	-	-	1.0	1.0
Regulatory Policy Mgr	-	-	-	-	1.0	1.0
Director/Manager, Reg Strategy & Bus Analysis	0.4	1.0	0.8	1.0	1.0	1.0
Cost of Service Mgr	1.0	1.0	1.0	1.0	1.0	1.0
Cost of Service Mgr	0.8	1.0	0.9	1.0	1.0	1.0
Cost of Service Mgr	-	0.2	0.8	1.0	1.0	1.0
Cost of Service Mgr	-	-	1.0	1.0	1.0	1.0
Rate Design & Projects Mgr	0.9	1.0	1.0	1.0	1.0	1.0
Tarriff & Special Contracts Mgr	1.0	0.6	0.9	1.0	1.0	1.0
Rates Design Coordinator	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory Reporting Mgr.	1.0	1.0	1.0	1.0	-	-
Regulatory Goverance Advisor	0.9	1.0	1.0	1.0	1.0	1.0
	8.1	**9.2**	**11.6**	**14.0**	**15.0**	**15.0**
COPE						
Regulatory Affairs Asst	1.0	1.0	1.0	1.0	1.0	1.0
Senior Rates Analyst	-	1.0	1.0	1.0	-	-
Senior Rates Analyst	-	1.0	1.0	1.0	-	-
Financial Accounting Analyst	-	1.0	1.0	1.0	-	-
	1.0	**4.0**	**4.0**	**4.0**	**1.0**	**1.0**
Total FTE for Regulatory Group	**9.1**	**13.2**	**15.6**	**18.0**	**16.0**	**16.0**
Total O&M ($ millions) for Regulatory Group	**$ 2.5**	**$ 2.8**	**$ 3.6**	**$ 3.9**	**$ 3.5**	**$ 3.5**

TGI
BCUC IR 112.2
Regulatory Policy Managers
FTE

	2006	2007	2008	2009P	2010F	2011F
Regulatory Group						
M&E						
Chief Regulatory Officer/Director	1.0	1.0	1.0	1.0	1.0	1.0
Cost of Service Mgrs	1.8	2.2	3.8	4.0	4.0	4.0
Director/Manager, Reg Strategy & Bus Analysis	0.4	1.0	0.8	1.0	1.0	1.0
Rate Design & Projects Mgr	0.9	1.0	1.0	1.0	1.0	1.0
Tarriff & Special Contracts Mgr	1.0	0.6	0.9	1.0	1.0	1.0
Rates Design Coordinator	1.0	1.0	1.0	1.0	1.0	1.0
Regulatory Goverance Advisor	0.9	1.0	1.0	1.0	1.0	1.0
Mgr., Regulatory Affairs	-	0.4	1.0	1.0	1.0	1.0
Regulatory Policy Mgrs	-	-	0.2	2.0	4.0	4.0
	7.1	**8.2**	**10.6**	**13.0**	**15.0**	**15.0**
COPE						
Regulatory Affairs Asst	1.0	1.0	1.0	1.0	1.0	1.0
	1.0	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**
Total FTE for Regulatory Group	**8.1**	**9.2**	**11.6**	**14.0**	**16.0**	**16.0**
Gas Accounting FTE transferred to CORE in 2010						
M&E						
Regulatory Reporting Mgr	**1.0**	**1.0**	**1.0**	**1.0**	**-**	**-**
COPE						
Senior Rates Analysts	-	2.0	2.0	2.0	-	-
Financial Accounting Analyst	-	1.0	1.0	1.0	-	-
	-	**3.0**	**3.0**	**3.0**	**-**	**-**
Total FTE for Gas Accounting	**1.0**	**4.0**	**4.0**	**4.0**	**-**	**-**
Total FTE for Regulatory and Gas Accounting Group	**9.1**	**13.2**	**15.6**	**18.0**	**16.0**	**16.0**
Total O&M ($ millions) for Regulatory and Gas Accounting Group	**$ 2.5**	**$ 2.8**	**$ 3.6**	**$ 3.9**	**$ 3.5**	**$ 3.5**

Note: The Gas Accounting COPE staff, prior to 2007, reported into the Finance group..

112.3 Please explain how the additional two regulatory managers are reflected in the Finance and Regulatory FTE for 2010 and 2011 in the table on p. 2 of Appendix F-2.

Response:

The table on Page 2 of Appendix F-2 shows FTE employees for the Finance & Regulatory Affairs department of 68 for 2009, and 67 for 2010 and 2011.

The change from 2009 to 2010 is a decrease of one FTE. This is broken down as follows:

Transfer of Gas Supply Accounting to CMAE	(4)
Addition of Regulatory Policy Managers	2
Addition of Financial Reporting Manager*	1
Total Decrease	(1)

* This headcount is related to IFRS so the associated dollars are included in the IFRS Conversion Costs Deferral account and not in O&M.

113.0 Reference: Operations and Maintenance Expenditures

Resource View

Part III, Section C, Tab 13, Schedule 28

113.1 Please explain the 34.2 percent increase in Employee Expenses from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 34.2% increase in Employee Expenses from 2009 to 2010 can be explained as follows:

- Roughly 1/3 of this increase is attributable to forecast headcount increases and basic inflation. Part III, Section C, Tab 13, Schedule 28 shows labour costs increasing by 12% in 2010. A similar increase would apply to Employee Expenses.
- The remaining 2/3 of this increase is attributable to additional employee training, developing and transitioning that will be required to educate and enable employees with respect to changes in Government Policy, changes in Codes and Regulations, changes in Accounting Standards and the transition to IFRS, and the looming Demographic Challenges all of which TGI will be faced with going into 2010, as itemized in Part III, Section C, Tab 6, Page 348.

113.2 Please explain the 30.0 percent increase in Materials and Supplies from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 30% increase in Materials and Supplies from 2009 to 2010 totalling approximately $1.6 Million consists of the following:

- $1.0 Million is attributable to Promotion and Advertising costs that rolled up to Materials and Supplies in the Resource View in 2010; whereas in 2009 these costs are included in Fees and Administration in the Resource View.
- $0.6 Million is attributed to increased levels of Distribution activities as described in Part III, Section C, Tab 6, Page 363, and listed in Table C-6-18, and further described in detail in subsequent sections. These are primarily maintenance type activities that were deferred during the PBR period that can no longer continue to be deferred. Materials and Supplies expenses, which include small tools, are allocated based on activity levels to the following: Meter exchange, Regulator stations, General Operations (i.e. replacing line markers, warning signs, etc), Line Heater Overhauls, and First Response Standby.

113.3 Please explain the 47.0 percent increase in Computer Costs from 2009 to 2010, and the further 7.1 percent increase from 2010 to 2011. Include the references to the appropriate material in the Application.

Response:

Increases in Computer Costs from 2009 to 2010 and from 2010 to 2011 can be explained as follows:

- Approximately 35% of the increases can be attributed to Accounting Changes as described in Part III, Section C, Tab 6, Page 387. As part of Canadian GAAP, certain costs relating to IT capital projects that have historically been capitalized are now required to be expensed. This would Include computer costs associated with development of business cases, training, and change management activities.
- Approximately 40% of the increase can be attributed to IT Contract increases as described in Part III, Section C, Tab 6, and Page 388. Additional funding is required for application support, upgrading existing infrastructure capacity, as well as compensation for changes by various vendors in their software licensing models. Vendors, including SAP, Oracle, and GE Smallworld have incrementally increased their software support fees by enhancing or changing their licensing models. Additional funding is also required for the renewal in 2010/2011 of multi year support contracts that Terasen Gas had 'pre-bought' in 2008, thus effectively reducing the 2009 support costs.
- The remainder of the increase as described in Part III, Section C Tab 6, Page 389 can be attributed to computer costs required in 2010 and 2011 to support new IT capital initiatives as well as additional Disaster Recovery Planning.

113.4 Please explain the 8.0 percent increase in Contractor Costs from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 8% increase in Contractor Costs from 2009 to 2010 totalling approximately $4.6 Million consists of the following:

- $0.8 Million applicable to the CWLP contract to cover increases to forecast customers and contract inflation as detailed in Part III, Section C, Tab 6, Page 380.

- $0.5 Million applicable to the Customer Choice Program which is deferred and 100% recovered on Line 14 Recoveries and Revenue, of Part III, Section C Tab 13, Schedule 28.
- $1.5 Million related to Customer and Stakeholder Behaviours and Expectations as discussed in Part III, Section C, Tab 6, Page 376 – 379. This will include: additional support and enhancement to augment the existing Customer Care Management Contract, Account Management and Market Development associated with Customer Solutions and Services, and additional funding for Customer and Business Facilitation which will include renewal of Operating Agreements, increased involvement with First Nations, and increased interaction with Government on Policy Analysis and Facilitation
- $0.9 Million tied to Distribution Code and Regulation Cost Drivers as shown on Part III, Section C, Tab 6, Table C-6-16, Page 362 including Security Risk Assessment, Seismic Mitigation, Class Location Study, Cathodic Assessment, Pressure vessel Inspection, Pipeline Identification, and Vegetation and Station Grounds Management.
- $0.3 Million tied to Business and Information Technology Services, Codes and Regulations including Cathodic Protection and Corrosion Prevention as described in Part III, Section C, Tab 6, Page 385 – 386.
- $0.6 Million related to Human Resources and Operations Governance as detailed in Part III, Section C, Tab 6, Page 397-399, including increases driven by Codes and Regulations such as Business Continuity Planning, Environmental Programming, Security Management Programming, Emergency Preparedness programming, Competency Administration, and Web Based Training, as well as increases driven by Demographics.

113.5 Please explain the 19.3 percent increase in Facilities Costs from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 19.3% increase in Facilities Costs from 2009 to 2010 totalling approximately $2.2 Million consists of the following:

- $0.2 Million related to Distribution Communications and Line Heater Fuel as listed on Part III, Section C, Tab 6, Table C-6-18, Page 364, and as described on Page 367. Communication cost increases applicable to cell phones, pagers, etc are due to increased contract costs as well as increased number of users. Line Heater fuel increases are due to increased unit costs for company use fuel.
- $0.5 Million related to GS&T Transmission Own Use Fuel as described on Part III, Section C, Tab 6, Page 372. Transmission Own Use fuel increases are due to

increased volumes and unit costs, as well as new taxes such as Ice Levy and Carbon Tax.

- $1.0 Million related to Marketing and Business Development Codes and Regulations as described in Part III, Section C, Tab 6, Page 375 – 376. This additional funding would be utilized primarily to increase the frequency of current safety communications focused primarily on gas odour awareness.
- $0.5 Million related to Business and Information Technology Services Facilities Costs as described on Part III, Section C, Tab 6, Page 390. This increase relates primarily to increased building maintenance activities and lease costs, as well as a need to reorganize the Surrey Operations Centre to facilitate the accommodation of additional headcount.

113.6 Please explain the 55.4 percent increase in Recoveries & Revenue from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 55.4% increase in Recoveries & Revenue increase from 2009 to 2010 totalling approximately $7.9 Million consists of the following:

- $0.7 Million relates to recovery from Core Market Administration Expense for related back office costs as described in Part III, Section C, Tab 6, (e) Accounting changes, page 404 (refer to Part III, Section C, Tab 5 for further discussion).
- $2.6 Million relates to increased recoveries of the Shared Services allocation between TGI and TGVI as described in Part III, Section C, Tab 6, (f) Service Enhancements, page 404. The nature of the increase in Shared Services is explained in Part III, Section C, Tab 11, Page 494 – 495.
- $1.1 Million relates to Customer Choice program recoveries where the costs are originally tracked and recorded as part of O&M and later reclassed through Recoveries and deferred.
- $2.1 Million relates to Core Market Administration Expense recoveries that due to different reporting views, were offset against individual accounts in 2009, but reflected separately as Recoveries in 2010.
- $1.4 Million relates to increased recoveries in Core Market Administration Expense due to a realignment of costs between TGI O&M and CMAE as proposed and described in Part III, Section C, Tab 5, Page 339 – 343.

114.0 Reference: Operations and Maintenance Expenditures – Activity View

Part III, Section C, Tab 13, Schedules 29-30

Appendix F-1, pp. 2-3

"The efficiencies achieved during the past six years (the "PBR Period") under the performance-based rate ("PBR") settlement agreement (the "PBR Agreement") have translated into a lower starting point for the Company's … forecasts in 2010" Ref: Part I, p. 1, par. 2

114.1 Please explain the 11.2 percent increase in Distribution from 2009 to 2010, and the further 7.3 percent increase from 2010 to 2011. Include the references to the appropriate material in the Application.

Response:

From a department view, Distribution includes Measurement Maintenance as shown on Line 44 of Schedule 29, Part III, Section C, Tab 13.

From a department view, the increase from 2009 to 2010 is $4.1 Million as described on Table C-6-14 of Part III, Section C, Tab 6, Page 360. From an activity view, this $4.1 Million increase is broken down between Distribution in the amount of $3.7 Million and Measurement Maintenance in the amount of $0.4 Million. The primary drivers of the $3.7 Million or 11.2% increase in Distribution as shown on Table C-6-14 are $2.0 Million of Labour Inflation and Benefits ($2.4 Million less $0.4 Million allocated to Measurement Maintenance) and $1.7 Million due to Codes and Regulations. Explanation and justification thereof can be found on Part III, Section C, Tab 6, Page 360 – 362.

From a department view, the increase from 2010 to 2011 is $3.0 Million as described on Table C-6-15 of Part III, Section C, Tab 6, Page 360. From an activity view, this $3.0 Million increase is broken down between Distribution in the amount of $2.9 Million and Measurement Maintenance in the amount of $0.1 Million. The primary drivers of the $2.9 Million or 7.3% increase in Distribution as shown on Table C-6-15 are $1.7 Million of Labour Inflation and Benefits ($1.8 Million less $0.1 Million allocated to Measurement Maintenance), $0.8 Million due to Codes and Regulations, and $.4 Million due to Service Enhancements. Explanation and justification thereof can be found on Part III, Section C, Tab 6, Page 360 – 368.

114.2 Please explain the 16.7 percent increase in Transmission from 2008 to 2009, and the further 6.1 percent increase from 2010 to 2011. Include the references to the appropriate material in the Application.

Response:

The 16.7% increase in Transmission from 2008 to 2009, which is approximately $2.2 million, is attributed to the following:

- $1.2 million relates to increased activity within the Transmission Pipeline Integrity Project (TPIP) including In Line Inspections, and Hazard programs as well as increased costs resulting from further developments to the Integrity Management Plan brought about primarily as a result of the OCG's adoption of CSA Z662 Annex N and M and discussed in further detail in Part III, Section B, Tab 1, Page 126 - 128.
- $0.6 million relates to staffing challenges as discussed on Part III, Section B, Tab 1, Page 168. Budgeted headcount in 2009 has increased by 2 FTE, and as well additional contractor cost has been budgeted for a Risk Assessment in 2009.
- $0.4 million relates to higher electrical and fuel charges in 2009 due to ICE Levy, Carbon Tax as well as rate increases as discussed on Part III, Section B, Tab 1, Page 168.

The 6.1% increase in from 2010 to 2011, which is approximately $1.0 million, is discussed in Part III, Section C, Tab 6, Table C-6-22, Page 370 and is attributed to the following:

- $0.5 million due to Labour Inflation and Benefits.
- $1.1 million due to Codes and Regulations as discussed on Page 370.
- ($0.6) million recovery due to Accounting Changes which is largely a result of IFRS requiring Major Inspections and Overhaul Costs to be treated as Capital rather than O&M as discussed on Page 371.

114.3 Please explain the 27.2 percent increase in LNG Plant costs from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 27.2% increase in LNG Plant Operations costs in 2010 which approximates $0.3 Million is driven by Labour Inflation and Benefits as well as an increase of 2 headcount, 1 of which is transitional to bridge a pending retirement in 2011 and is part of the Demographics challenge facing the Company. Both of these factors are discussed for the Gas Supply and Transmission department on Part III, Section C, Tab 6, Page 370.

114.4 Please explain the 13.1 percent increase in Measurement costs from 2009 to 2010. Include the references to the appropriate material in the Application.

Response:

The 13.1% increase in Measurement costs from 2009 to 2010 which approximates $0.7 million is attributable to the following:

- $0.5 million due to increased Measurement Maintenance activities for Meter Exchange as discussed on Part III, Section C, Tab 6, Page 364.
- $(0.1) million recovery of Vehicle Lease expenses previously recorded as an operating lease in O&M now being classified as a capital lease in 2010 as discussed on Part III, Section C, Tab 6, Page 363.
- $0.3 million increase in Measurement Operations due to anticipated fewer opportunities to generate new revenue from the repairs of customer owned equipment. $0.2 million of recoveries for repair of TGVI meters will no longer be recognized in Measurement; the recovery in 2010 will be recognized as a part of the Shared Services.

114.5 Please explain the 8.0 percent increase in General Operations from 2008 to 2009, and the further 20.1 percent increase from 2009 to 2010. Specific items will include the increase in Systems Integrity and Environmental Health & Safety. Include the references to the appropriate material in the Application.

Response:

The 8% increase in General Operations from 2008 to 2009 which approximates $1.6 Million is explained by the following main drivers:

- $0.8 million in Operations Engineering as discussed on Part III, Section B, Tab 1, Page 173 is due to changes in the BC Safety Authority – Gas Safety Regulation. Under the new Regulation, TGI now has 2 days (instead of 3 days per the old regulation) to provide gas system information requested by a 3rd party. Additional staff were hired in 2009 to meet this requirement.
- $0.3 million in Environmental Health & Safety includes provision for developing security management and general waste management plans, Cap and Trade analysis and compliance, environmental audit costs, and general labour and benefit inflation.
- $0.3 million in Shops & Stores is attributable to vacancies in 2008 that were filled in 2009, unplanned expenses for a Supply Chain study, increased material costs for tool maintenance, repair of regulator parts, and general labour and benefit inflation.
- $0.2 million in Facilities representing general labour and benefit inflation

The 20.1% increase in General Operations from 2009 to 2010 approximating $4.3 million is explained as follows:

- The $2.0 million increase in Operations Engineering costs which include System Integrity in the department view are comprised of $0.6 million Labour Inflation and Benefits, $1.1 million Codes and Regulations, $0.2 Million Demographics, $0.3 million Accounting Changes and a recovery of $0.2 million in Service Enhancements. These increases are shown on Part III, Section C, Tab 6, Table C-6-28, Page 384 and discussed on Page 384 – 388.
- $0.7 million in Facilities consists of $0.1 million for Demographics as described in Part III, Section C, Tab 6, Page 387 and $0.6 million of increased building maintenance activities and lease costs including a reorganization of Surrey Operations Centre as described in Page 390.
- $0.9 million in EH&S consists of $0.2 million Labour Inflation and Benefits and $0.7 million in Codes and Regulations as described in the first 5 lines of Table C-6-33 Part III, Section C, Tab 6, Page 398.
- $0.2 million in Operations Governance to support the addition of a Competency Administrator and Web Based Training Modules as shown on the last 2 lines of Table C-6-33.
- $.3 million in Shops & Stores to support increased maintenance, general labour and benefit inflation and a reduction in capital charge-out recovery.
- $0.2 million in Property Services to support general labour and benefit inflation as well as increases in easements and ROW fees.

114.6 Please explain the 10.8 percent increase in Marketing from 2008 to 2009, and the 20.9 percent decrease from 2009 to 2010. Specific items will include the elimination of Energy Efficiency O&M, reduction in Marketing Supervision, and increase in Corporate & Marketing Communications. Include the references to the appropriate material in the Application.

Response:

The 10.8% increase in Marketing from 2008 to 2009 which approximates $0.6 Million consists of the following:

- $0.4 million inadvertently misclassified that should have been allocated to Acct 700-20 Customer Management & Sales.
- $0.1million inadvertently misclassified that should have been allocated to Acct 900-20 Forecasting.
- $0.1 million relating to 2008 vacancies that were filled in 2009.

The 20.9% decrease in Marketing from 2009 to 2010 which approximates a recovery of $1.2 million can be explained as follows:

- $(1.6) million recovery is due to change in treatment of Energy Efficiency program costs. In 2009 this amount was included as O&M as per the PBR while in 2010 the program costs are given deferral treatment as shown on Part III, Section C, Tab 3, Table C-3-1, Page 228 and as approved in BCUC Order No. G-36-09.
- $(0.5) Million recovery is due to correction in 2010 of the 2009 misallocations mentioned above.
- $1.0 Million is driven by Codes and Regulations as described on Part III, Section C, Tab 6, Page 375. This is a result of TGI's objective of increasing public awareness of gas safety risks through increased frequency of their current communications media plan (both radio and print) focused on gas odour awareness.
- $0.1 Million is general Communications.

114.7 Please explain the 6.3 percent increase in Customer Care from 2009 to 2010. Specific items will include the increase in Customer Care Supervision and in Customer Management & Sales. Include the references to the appropriate material in the Application.

Response:

The 6.3% increase in Customer Care from 2009 to 2010 which approximates $3.6 Million is explained as follows:

- $1.0 million increase in Customer Care Supervision is a result of
  - $0.4 million inadvertently misclassified that should have been allocated to Acct 700-20 Customer Contract.
  - $0.6 Million due to increase of 4 headcount in the Contract Management Team as described on Part III, Section C, Tab 6, Page 376, plus salaries for 2009 mid year hires, and labour and benefit inflation.
- $1.3 million increase in Customer Contract is a result of
  - $0.8 million in ABSU Customer Care contract costs due to inflation and customer increases as described in Part III, Section C, Tab 6, page 379.
  - $0.9 million due to penalties received from ABSU in 2009 (an offset in 2009) that are expected to be one time in nature and not repeated in 2010.
  - $(0.4) million recovery is offset against Customer Care Supervision as described above.
- $1.5 Million in Customer Management & Sales is a result of
  - $0.4 million offsets the 2009 misclassification in Marketing Supervision as described in IR 114.6 above.

    - $1.1 million increase relates to 4 additional headcount as well as consulting fees, studies and associated expenses with respect to Service Enhancements as described in Part III, Section C, Tab 6, page 377-378.
- $(0.2) million recovery in Bad Debt Management costs is due to a decrease in 2010 in distribution field activities such as meter investigations, unlocks, relights, etc that are tied to Bad Debt management.

114.8 Please explain the 12.6 percent increase in Business & IT from 2008 to 2009, the further 27.2 percent increase from 2009 to 2010, and the further 5.8 percent increase from 2010 to 2011. Specific items will include increases in Application Management and in Infrastructure Management. Include the references to the appropriate material in the Application.

Response:

The increase of 12.6% from 2008 to 2009 which approximates $1.8 million consists of the following:

- $0.4 million in B&ITS Supervision due to general labour inflation and benefits as well as 2008 vacancies that were filled in 2009.
- $1.4 million in Application Management is due to
    - $0.8 million in labour inflation and benefits, increase in headcount to provide support and maintenance of new applications and upgrades that have been implemented by the Company and 2008 vacancies filled in 2009.
    - $0.6 million due to increase cost of SAP licenses, new system licenses, and increases in computer consulting and software costs.

The increase of 27.2% from 2009 to 2010 which approximates $4.5 million consists of the following:

- $0.5 million Labour Inflation and Benefits as shown on Part III, Section C, Tab 6, Table C-6-28. Page 384 (Note that B&IT Services on this table includes Facilities as a department view).
- $1.0 million in Accounting Changes as described on Part III, Section C, Tab 6, Page 387. As part of Canadian GAAP, certain costs that have traditionally been capitalized are now required to be expensed. These would include costs incurred in the development of business cases, training, training material, change management activities and associated general administration costs.
- $2.8 million of Service Enhancements as described on Part III, Section C, Tab 6, Page 388 - 389. This would include $1.7 million for IT contract driven increases, $0.6 million

for 5 additional headcount, and $0.5 million to support the incremental operating expense associated with new IT capital initiatives.

- $0.1 million IT costs associated with change management of Codes and Regulations.

The increase of 5.8% in 2010 to 2011 which approximates $1.2 Million consists of the following:

- $0.2 million Labour Inflation and Benefits as shown on Part III, Section C, Tab 6, Table C-6-29. Page 384 (Note that B&IT Services on this table includes Facilities as a department view).
- $0.5 million of Service Enhancements as described on Part III, Section C, Tab 6, Page 388 – 389.
- $0.6 million to support the incremental operating costs associated with new IT capital initiatives as described on Part III, Section C, Tab 6, Page 389.

115.0 Reference: Operations and Maintenance Expenditures

Outsourcing – Declining performance by AUBPOS/CWLP

Part III, Section C, Tab 6, p. 376, pars. 4-5

115.1 Please explain why these additional resources are being added to the ratepayer costs when it is due to a decline in performance by the outsourced contractor.

Part III, Section C, Tab 6, p. 376, pars. 4-5

Response:

Terasen Gas believes the quality of service currently being provided to ratepayers related to escalated complaints is inadequate. It does however meet the minimal requirements established in the agreements, as discussed in more detail in BCUC IR 1.115.2. In order for the contractor to increase the quality of service, a change order would be required at an additional cost. Terasen Gas does not believe it would be prudent to invest more in the current outsourcing arrangement given the contractor's issues related to attracting and retaining knowledgeable staff in this area.

Terasen Gas does not believe it would be a good investment for ratepayers to initiate a change order with the current service provider to address these service quality issues. It would be more beneficial to invest in Company resources who oversee the outsourcing arrangement. Terasen Gas has existing internal staff that can be recruited into these new roles that would bring a significant base of gas industry and company process knowledge into the area. This will enable a higher level of oversight of the service provider's performance in the billing, collections and call centre functional areas and the ability to identify and initiate actions to improve that performance as required. This will also increase the number of Terasen Gas employees dealing directly with customer complaints and billing issues to ensure we have more timely and effective resolution of customer concerns during the RRA period.

115.2 Please comment on the outsourced contract and why these costs, necessary to maintain the level of service, are not recovered from the outsourced contractor.

Response:

In recent years it is clear that the timing and accurate resolution of escalated complaints and complex inquiries is not meeting customers expectations nor meeting the quality of service

Terasen Gas is expected to provide. As there are no specific service metrics in this area in the agreement, the outsourced contractor believes it is meeting the minimal requirements established. In order for the contractor to increase the quality of service a change order would be required at an additional cost.

In the current agreement the specific level of service related to the handling of escalated complaints and complex inquiries is defined as follows:

"The scope of Services and level of performance documented in this Services Schedule is intended to be consistent with the level of service BC Gas currently provides to its customers."

This was negotiated with the belief that the outsourcer would continue to be able to attract and retain a knowledgeable work force to handle the escalations that we had typically experienced. At that time Terasen Gas did not think it was necessary to develop specific metrics to measure the quality of service in this area, and none was include in the Commission-approved contract with CWLP.

The service metrics that were established in 2002 were at a relatively high level and targeted key operating indicators that Terasen Gas believed were all that would be necessary going forward. Currently there are no specific metrics in the outsourcing agreement in this area that would force the contractor to make changes or improvements within their organization nor are there any specific financial penalties that can be assessed. Our recourse would be to initiate a change under the agreement requesting additional services or enhanced service metrics at an additional cost. Given what we believe to be the root cause of the issue, attracting and retaining staff, we believe it would be more prudent and a better long term approach to invest in additional Terasen Gas resources to address the issues.

116.0 Reference: Operations and Maintenance Expenditures

Outsourcing – IT Services

Part III, Section C, Tab 6, pp. 388-9

116.1 Please provide a table detailing all of the incremental increases for IT Services that are outsourced, separated by service provider, including the reasons for the increases, such as volume or contract escalation clauses. Provide the references in the Application for each item in the table.

Response:

TGI has filed the information as a confidential attachment under a separate cover. The reasons for this are:

- details of contractual obligations are under NDA's with various vendors.
- Some contracts are still in the negotiation phase.
- Some contracts are Time & Materials based and publication of specific budgeted amounts are not in the best interest of Terasen Gas nor its customers.

The following outlines the increases for IT services and the reasons for the various increases. For breakdown by individual vendor, please refer to the confidential attachment.

Application Support

The addition of new applications drives increases in:

- Servers,
- Network capacity (potential – depending on the nature of the application), and
- Application support services

Increases in application support drives increases in:

- Application specific skills which in turn drives additional support personnel,
- Database Support,
- Application integration requirements,
    - In cases where a business process can be streamlined by automating the integration of two or more applications, another software tool known as "middleware" is utilized to facilitate that automated integration.
- Pressure to maintain service levels and meet business support expectations,

Other items that drive increases to support costs are:

- Increases in support hours
  - More and more applications are being put in place to support additional business processes including those in the field. This drives increases in the hours of expected service from the field which in turn drives additional hours of service required from the support organizations which in turn drive higher support costs.

- Maturity of business applications
  - Newer applications will require increased support until they reach a stage of stabilization. This can be anywhere from 3 weeks to 6 months depending on the complexity of the solution.

- Rate changes
  - Most service providers have a periodic increase in their charge out rates. These increases are usually attributed to inflation, increases in experience levels of support teams, and other compensation strategies unique to the service provider but potentially reflected in rates charged. There is no way for a service receiver to accurately determine the cause of the increase; this is usually a matter for negotiation at the time on contract renewal.

Infrastructure Support

Increases in headcount (and the filling of existing vacancies) drive increases in:

- desktop/laptop support,
- incremental peripherals (i.e. printers),
- disc storage,
- e-mail support,
- help desk calls,
- individual technology service requests,
- telecom costs,
- Blackberry costs.[14]

Increases in Servers drive increases in:

[14] Terasen requires all acquisitions that attract additional costs to be prudent and necessary. Management approval is required for the acquisition of blackberry or similar devices.

- Server support,[15]
- Disc storage,
- Backup infrastructure costs,[16]
- Monitoring costs,
- Security costs.

Increases in Network capacity drive increases in:

- Network infrastructure (switches) which have maintenance costs associated with them.

Other items that drive increases in support costs are:

- Business requirement changes on support levels (i.e. upgrades in support services / support levels).
- replacement of obsolete equipment with equipment that has a higher support costs (such as Network switches).
- Inflation (50% of CPI).

[15] There are varying support costs depending on the nature of the servers. Production servers require a higher level of support than a development or sandbox server

[16] Data backup infrastructure consists of tape drive, disc space, 3rd party labour, off-site storage, etc.

117.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations

Table C-6-16, Part III, Section C, Tab 6, and Appendix F.8

117.1 Please identify the activities from Table C-6-16 that Terasen Gas is currently performing in normal business operations.

Response:

Terasen Gas currently performs all of the activities listed in Table C-6-16 (Distribution Codes and Regulations O&M Cost Drivers for 2010 and 2011). Recent changes in existing Codes or the introduction of new Codes have put additional responsibilities on the pipeline operator to examine their programs and meet newer, more stringent requirements (i.e. the recent introduction of CSA Z662 Annexes M and N, CSA Z662 Clause 10.2, the pending introduction of CSA Z246.1). These new and more stringent requirements mean Terasen Gas must continue to examine and evolve its Integrity Management programs; the associated increased costs are reflected in Table C-6-16. This increased diligence will ensure that the needs of the customers, public, and regulators continue to be met.

117.2 Please provide an example or specific description of a type of "preventative maintenance" activity.

Response:

Terasen Gas completes a number of preventive maintenance activities intended to ensure Distribution assets continue to perform within their intended operating parameters. An operational check at a pressure regulating station is an example of a preventive maintenance activity. This activity requires a competent technician to visit the station and complete a number of tasks designed to confirm the station is working within intended parameters or to identify problems that may negatively impact the performance of the station. Those problems identified are then corrected to return the facility to operating within the intended parameters. Regular preventive maintenance ensures the ongoing proper operation of assets, extends the life of the asset and ensures the safety of our customers, the public and our employees.

117.3 Please confirm that the activities of "preventative maintenance" are required to meet Codes and Regulations not a response to changed Codes and Regulations. If so, please explain what incremental activities are required in 2010 and 2011 that Terasen Gas is not already performing through normal business operations.

Response:

Preventative maintenance programs are a key component to ensuring compliance to Codes and Regulations. Many Canadian Code requirements are performance driven and non-prescriptive. This means that the onus is on the operator (in this case Terasen Gas) to develop programs that ensure the system functions properly. Consequently, there may be no specific Code clause that mandates a particular preventive maintenance activity, but that activity is required as part of a larger program to ensure the continued safe and reliable operation of the system. In this context, all Terasen Gas preventive maintenance activities are required to meet existing Codes and Regulations as well as to respond to more stringent Code Requirements.

117.4 Please provide the actual dollars spent in 2006, 2007, 2008 and projection for 2009 for "preventative maintenance" and discuss the reasons for variances from year to year.

Response:

The actual Preventative Maintenance dollars spent in 2006 through 2008 and a projection for 2009 is listed in the table below:

Year	Preventative Maintenance
2009 (projected)	$2,066,000
2008 (actual)	$2,240,000
2007 (actual)	$1,516,000
2006 (actual)	$1,573,000

The main reason for the significant variance from 2007 to 2008 was an increase in industrial meter preventative maintenance activities. Terasen Gas regularly reviews asset performance to adjust maintenance procedures and frequency to ensure the continued safe, reliable operation of the natural gas distribution system. Preventive maintenance frequencies are determined based on the performance of the equipment type or asset; this performance may be influenced by location, throughput, activities in the area, as well as equipment manufacturer and model. As a result of these refinements in maintenance programs, there are irregularities in work load from year to year. For example, some assets may be maintained annually while others may be maintained every two or three years. Efforts will continue to be made to load level the work from year to year to enable accurate budget and work force forecasting, but only where this work load leveling will not result in increased overall costs.

118.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations Appendix F.8

In Appendix F.8, page 1 (second paragraph) Terasen Gas states that: "*To ensure ongoing compliance to existing codes and anticipated new or changed codes, operating and maintenance funding is required*." Terasen then describes 4 main drivers to the increase of $5.297m in2010 and $2.059m in 2011, the first being <u>inflationary costs</u>.

Further on the page (third paragraph) Terasen states: "*The reasons for incremental increases, <u>outside of inflationary needs</u> from the 2009 projection for each of the codes are described (in Table F-8-1),*" which sums up to the same $5.97m increase in 2010 and $2.059m increase in 2011.

118.1 Please clarify the above statements and confirm whether the incremental O&M funding pertaining to changing Codes and Regulations are driven, in part, by inflation. If so, what percentage would this represent?

<u>Response:</u>

Inflation is one of the cost drivers to ensure ongoing compliance and effective risk management related to existing codes, standards, and regulations. Within the Application, inflation related to internal labour and benefits has been identified separately; therefore, the reference above should have been more explicit and stated "outside of labour inflation and benefits".

The incremental increase in costs illustrated in Tables F-8-1 and F-8-2 include inflationary costs related to materials and external contractor costs at a rate of 1.9 percent for 2010 and 2.0 percent for 2011. However, the majority of items listed in Table F-8-3 do not have materials or external contractor components, so the external inflation amount is approximately $5,000 or 0.1%.

119.0 Reference: Operations and Maintenance Expenditures - Government Policy

Part III, Section C, Tab 6, Section 3, page 350

119.1 For Table C-6-4, Codes and Regulations Require Additional Funding in 2010 and 2011, please provide the following:

- Summary of the Code Changes and requirements
- The reason for the cost impact in each of the identified categories (Distribution, Transmission, B&ITS, HR&GOV).
- Outline the method used to estimate the increased cost and reasons why it is necessary to spend this amount at this time rather than deferring the expenditure to future years.

Response:

Please refer to Appendix F.8 of the Application for the details behind Table C-6-4 and the rationale on why this funding is necessary. When determining the 2010-2011 funding requirements, a risk based approach is used to prioritize integrity and reliability issues. Any low risk items that could be adequately handled in the future have been deferred and are not represented in the O&M funding request.

Terasen Gas believes these costs are prudent and necessary to continue safe and reliable natural gas service to its customers.

120.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations

Part III, Section C, Tab 6, page 360- 365

120.1 How are the Code Annexes to CSA Z662, Oil and Gas Pipelines Systems (that encompass Gas Distribution System Integrity Management Guidelines; Guidelines for Pipeline integrity Management Programs; and Safety and Loss Management) different than what is currently being done in each of these cost categories? Can any of these costs be deferred to future years?

Response:

Code Annexes to CSA Z662, Oil and Gas Pipelines Systems have resulted in both new and increased activities within Distribution. Terasen Gas has implemented the Integrity Management Plan required by CSA Z662, Annexes M and N. During the course of that implementation a number of requirements have been identified that were not previously specified by the Code or now have more stringent requirements under the Code. Increased discipline is mandated regarding records management, employee competency confirmation and risk identification. While Terasen Gas has been engaged in all of these activities in the past, this increased requirement has introduced additional costs. Meeting these requirements is mandatory to ensure the Utility continues to meet all legal obligations and deferral is not an option.

120.2 In Table C-6-16, (Distribution Codes and Regulations O&M Cost Drivers for 2010 and 2011 vs. Prior Year) please provide further detail for the following cost drivers:

	2010	2011
Seismic Mitigation	$150	$0
Integrity Management	$215	$185
Single Point Failure Analysis	$0	$200
Preventative Maintenance	-$117	$402
Corrective Maintenance	$402	$139

Response:

Further details regarding Distribution Codes and Regulations O&M Cost Drivers for 2010 and 2011 can be found in Appendix F-8 of the Application. Excerpts from Appendix F-8 for Seismic Mitigation, Integrity Management, Single Point of Failure Analysis, Preventative Maintenance and Corrective Maintenance are listed below:

Seismic Mitigation

Terasen Gas continues to work to ensure Code requirements are met so that natural gas can continue to be delivered to our customers safely, reliably and cost effectively. In 1994 a seismic study was conducted of certain areas of the Terasen Gas system. Since that time new standards have been enacted specific to seismic design. Understanding of seismic vulnerabilities will enable planning and programs to mitigate the risks.

Due to the size and complexity of the natural gas distribution system, the assessment of seismic risk needs to be spread over a number of years. To accomplish these studies, Distribution requires incremental funding of $150 thousand (for labour and consulting fees) starting in 2010. An ongoing program of seismic risk identification and mitigation will ensure continued safe, reliable service to our customers.

Integrity Management

Current staffing levels in Distribution Asset Management are insufficient to implement the requirements of the Integrity Management Plan. The full adoption of CSA Z662, Annex N will increase the workload for this group as follows:

- Additional Maintenance Analyst in Asset Management.
    - Administer programs that monitor for conditions that may lead to failures, to eliminate or mitigate such conditions.
- Two Field Quality Auditors in Asset Management.
    - Will enable the field quality audits that are required by the Terasen Gas Integrity Management Plan and CSA Z662
- Additional Professional Engineer in Asset Management
    - Analysis and decision making specific to capital budget investments. This will include conducting studies or analyzing studies by others to understand issues,

ensure budgets are invested on the higher priority items and applicable standards are maintained.

- Two Additional Operations Support Representatives in Asset Management
    - Support the increased requirement for records to demonstrate compliance by becoming an expert on FileNet (the new records administration technology being introduced in 2009).

Although Integrity Management is not entirely new to Terasen Gas, the full adoption will result in a more comprehensive and formalized demonstration of compliance and enhancements to the program in 2010 and 2011; to ensure that all applicable codes and regulations are met and the distribution system continues to operate safely and reliably. To accomplish this, Distribution funding requirement is increased $215 thousand in 2010 and $185 thousand in 2011.

Single Point of Failure Analysis

Terasen Gas is committed to providing natural gas to its customers safely, reliably and at the lowest cost. Third party damages, natural and man-made hazards impact distribution pipelines regularly. The natural gas distribution system is complex and includes a number of instances where loss of a single pipeline may result in customer outages.

A comprehensive study is required to identify the single points of failure, assess the probability of the failure occurring and identify the consequences of that failure. Distribution requires additional funding of $200 thousand in 2010 to perform analysis of the assets under its accountability. Comprehensive knowledge of the areas of vulnerability will enable Distribution to identify areas of high risk, setting the groundwork for plans and programs to reduce those risks to an acceptable level.

Preventive maintenance

Terasen Gas administers a preventive maintenance program designed to extend the life of assets while ensuring optimal investment of maintenance resources.

Regular preventive maintenance is performed on Terasen Gas assets based on the integrity management program. There are a variety of Code requirements that define the elements of a preventive maintenance program. In some instances Code requirements are prescriptive in what must be included in a preventive maintenance program; in other instances the onus is put on the operator to decide what is in an appropriate program.

Commencing in 2001, Distribution began transitioning to a risk based maintenance program leading to the implementation of SAP Plant Maintenance functionality in 2003. SAP enables gathering of data on asset performance, failure modes and failure frequencies. Anecdotal data, validated by documented observations have enabled adjustments to maintenance frequencies and programs that have resulted in significant savings with no loss of asset reliability while maintaining Code compliance. The numbers of activities for 2010 and 2011 (I.e. visits to an asset) are based on asset growth, observations and maintenance results which are dynamic, based on operating conditions in the system and result in the need for a reduction of funding in 2010 of ($-117 thousand) and an increase in 2011 of $402 thousand.

Preventative maintenance is the first line of attack to ensure safe and reliable service and Terasen Gas requests that the additional funding for these activities be granted.

Corrective maintenance

Regular preventive maintenance is completed on gas system assets to ensure safe and reliable delivery of gas to customers. As many of the failure modes associated with the types of equipment and the operating conditions are random, they cannot always be prevented by preventive maintenance. As a result, assets are designed to ensure they continue to operate even when a piece of equipment fails. Corrective maintenance is initiated when equipment fails and is identified as part of the regular preventive maintenance program.

Technology is limited in its ability to predict failures on piping systems (i.e. there are no internal inspection tools or 'smart pigs' available for distribution or intermediate pressure pipelines). Traditional methods have limited success in predicting failures (i.e. cathodic protection monitoring). Surveys such as 'leak surveys' are designed to identify piping system failures at an early stage where the risk to the public is minimized. Identifying and correcting failures is normal aspect of maintaining gas system assets.

Based on past experience and system age, Distribution requires an incremental funding of $402 thousand starting in 2010 to perform corrective maintenance activities, with an additional increase of $139 thousand in 2011.

As the gas distribution infrastructure grows and ages, failures are monitored closely to determine whether the optimal level of preventive maintenance is being completed (i.e. increases in corrective maintenance are analyzed to determine the root cause and whether an appropriate preventive measure is available). Adequate corrective maintenance resources, coupled with adequate preventive maintenance resources, are a critical aspect of asset management and the programs designed to maximize the service life of the assets.

121.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations

CSA Z662

Part III, Section C, Tab 6, page 385

121.1 TGI states that as a result of the Code (CSA Z662) changes are required for O&M funding of $109 thousand in 2010 and $20 thousand in 2011 for administering the competency and training model to technical staff. What specific training is required and can this training be deferred to later years?

Response:

Technical staff in Operations Engineering are required to hold active membership in APEGBC[17], ASSTBC[18] or NACE[19] International and each of these associations stipulates some degree of continuing professional development for practicing members. "Under the APEGBC *Code of Ethics*, members are responsible for undertaking Continuing Professional Development (CPD) that is relevant to their practice."[20] A detailed list of the types of activities will meet the expectations APEGBC with respect to professional development can be found in the *APEGBC Continuing Professional Development Guideline* with some activity types listed below;

- Courses provided through accredited post-secondary institutions such as universities, technical institutes and colleges.
- Short courses, technical sessions, seminars and workshops provided by technical societies, industry or educational institutions (i.e. IEEE courses, ASHRAE courses).
- Industry or post secondary institution sponsored courses, seminars, facilitated technical field trips, conferences and trade shows.
- Preparation and presentation of courses or seminars.
- Development of published Codes and Standards.

"The ASTT Act and the Code of Ethics imposes on registrants a duty to consistently pursue such self-directed Continuing Professional Development (CPD) as may be required to ensure their continuing competence."[21] As a result, ASTTBC has in place its CPD Program as a guide for members as they consider their continuing education needs. The guide includes the following activities that qualify as continuing professional development:

[17] The Association of Professional Engineers and Geoscientists of British Columbia
[18] Applied Science Technologists & Technicians of British Columbia
[19] The National Association of Corrosion Engineers
[20] APEGBC Continuing Professional Development Guideline
[21] ASTTBC website

- completing technical courses at an accredited institution;
- attending conferences, workshops and seminars;
- participating on technical committees.

NACE International requires its members to complete a specific minimum number of professional development hours in order to be eligible for recertification in their field of expertise. NACE International does not offer information on the specific types of activities that qualify as professional development hours. However, NACE International, NACE local chapters and the Corrosion industry offer a wide range of technical courses, conferences, seminars and committee as opportunities for NACE members to undertake activities that would satisfy the requirements of professional development.

We will continue to require our Technical staff to be members of their respective Professional Associations and to pursue continuing professional development in order to stay current on methodologies, technologies and trends associated with their specific field of expertise.

Continuing professional development cannot be deferred to later years because the Associations define a timeline in which the training is to be completed. For example, APEGBC requires its members to complete an average of 30 Professional Development Hours per year. Note that the $109,000 increase in 2010 is largely due to the addition of 11 Corrosion technical staff and 1 System Integrity Technologist to the competency model. The remainder of the 2010 increase is due to training costs for transitionary headcount and due to the formalization of the model with the remaining technical staff in Operations Engineering.

122.0 Reference: Operations and Maintenance Expenditures - Codes and Regulations

Cathodic Protection

Part III, Section C, Tab 6, page 386

122.1 What are the costs in this category for the period 2003 to 2009?

Response:

The table below summarized the actual and projected costs for the period 2003 to 2009 for the Corrosion group, which is part of the Operations Engineering department and is responsible for cathodic protection. Our 2003 approved base budget for the Corrosion group was $1.564 million in 2003 dollars. Applying the inflation factor of 112.62 to this value converts this approved base budget value to $1.761 million in 2009 dollars ($1.564 * 112.62 / 100 = $1.761). As the table below shows, our inflation adjusted costs have remained relatively flat at an average value of $1.79 million from 2003 to 2009. We believe we have managed our cathodic protection costs prudently within a reasonable range of the 2003 approved based budget amount.

Costs for the Corrosion Group for the Period of 2003 - 2009

Year	Actual Costs ($,000)	Inflation Factor (2009 = 100)	Actual Costs adjusted for inflation (expressed in 2009 dollars) ($,000)
	$1,503	112.62	$1,693
2004	$1,500	110.73	$1,661
2005	$1,607	108.56	$1,745
2006	$1,671	106.22	$1,775
2007	$1,808	104.14	$1,883
2008	$1,950	102.10	$1,991
2009 (Projected)	$1,812	100	$1,812

123.0 Reference: Operations and Maintenance Expenditures - Codes and Regulation Right of Way

Part III, Section C, Tab 6, page 386

123.1 Why is this a basis for an increase in this category of $108 thousand since there is no change in compliance? Please provide costs for the period 2003 to 2009 for this category. Please itemize costs included in ROW fees, vegetation management and public awareness.

Response:

The increased costs of $108,000 associated with ROW fees are required in order to secure necessary rights, pay increasing fees associated with existing ROWs, meet Provincial regulatory compliance and enhance public safety awareness specifically along the ROW. The table below shows that our inflation adjusted expenses for ROW fees, noxious weeds management and public awareness have remained relatively flat between 2003 and 2009. This historical cost profile highlights our prudent management of the costs associated with these items. Please refer to TGI's response to BCUC IR 1.110.1 for details behind the $108,000 increase which we believe is necessary to manage ROW related matters at appropriate levels on a go forward basis.

Summary of Historical ROW Costs Details

Year	ROW fees	Noxious Weeds Mgmt	Public Awareness Along ROW	Total	Inflation (2009 = 100)	Total ROW Costs adjusted for inflation
2003	$91,000	$75,000	$7,000	$173,000	112.62	$195,000
2004	$103,000	$75,000	$7,000	$185,000	110.73	$205,000
2005	$81,000	$75,000	$8,000	$164,000	108.56	$178,000
2006	$94,000	$95,000	$8,000	$197,000	106.22	$209,000
2007	$61,000	$95,000	$10,000	$166,000	104.14	$173,000
2008	$81,000	$95,000	$10,000	$186,000	102.10	$190,000
2009 (Projected)	$88,000	$95,000	$12,000	$195,000	100.00	$195,000

Note: Variations in ROW fees are due to costs associated with the acquisition of additional right of way and the renewal of expiring right of way agreements.

124.0 Reference: Operations and Maintenance Expenditures - Codes and Regulation

Odorant

Part III, Section C, Tab 6, page 387

124.1 What are odorant costs on a $/GJ basis for the period 2003 to 2009. Assuming an inflation increase only in 2009, 2010 and 2011, what would be the odorant costs?

Part III, Section C, Tab 6, page 387

Response:

For clarity, odorant is priced in $US/kg dollars in the North American market – not $/GJ. Historical unit costs for odorant are as shown in the table below;

Historical Unit Costs for Odorant

YEAR	$US/kg (annual avg)	Exchange ($Cdn/$US)	$Cdn/kg (annual avg)
2003	$2.84	1.40	$3.98
2004	$2.84	1.30	$3.69
2005	$2.84	1.21	$3.44
2006	$2.84	1.13	$3.21
2007	$6.15	1.07	$6.58
2008	$7.29	1.07	$7.80
2009*	$6.71	1.22	$8.19

* 2009 values represent projected value.

The historical price information in the above table reflects our efforts to proactively manage the cost of odorant. The price of odorant ($US/kg) is shown as a constant from 2003 to 2006 because we were able to enter into a long term fixed price contract with one of the suppliers at the time. When the fixed price contract expired at the end of 2006, we were faced with paying the then market for odorant for two reasons. First, there were only two odorant vendors in the market place and they both charged the same price. Second, given the economic conditions and boom in commodity prices the time, neither on of the two odorant vendors was willing to enter into any long term pricing arrangement. More recently, we have been able to enter into a formula driven pricing model with our odorant vendor. As a result, our price of odorant is calculated based on two indices - Industrial Chemicals (80%) and #2 Diesel (20%) – and remains fixed for a three month period. We believe that we have been diligent and proactive in managing the cost of odorant in light of recent and current market forces.

Assuming an inflation increase only in 2009, 2010 and 2011, the unit cost of odorant would be as shown in the table below;

YEAR	Average CPI (%)	$US/kg	Exchange ($Cdn/$US)	$Cdn/kg
2008		$7.29	1.07	$7.80
2009*	2.10	$7.44	1.22	$9.08
2010*	1.90	$7.58	1.14	$8.65
2011*	2.00	$7.74	1.11	$8.59

- Odorant unit price in $US/kg are increased based on inflation.

An inflationary increase is not appropriate for the determination of forecast odorant costs. The price for odorant is determined by market conditions of its two components - Industrial Chemicals (80%) and #2 Diesel (20%) – instead of being linked to inflationary forces. Both of these subcomponents are specialised commodities whose prices are driven and determined by the forces of the commodities marketplace. As shown in the above historical price table, the price of odorant more than doubled from 2006 to 2008. This significant increase reflects the short term commodity spike experienced during that timeframe instead of any general and steady inflationary increases. Odorant is treated as a commodity in the marketplace and its price is influenced by commodity market forces rather than inflation.

125.0 Reference: Codes and Regulations

CSA Z662 for Oil and Gas Pipeline Systems

Part III, Section A, pp. 52-53

“Annex N introduces the requirement for a formal IMP for Pipeline Systems, which was formally adopted by the OGC as a requirement on August 26, 2006.” Ref: p. 52, par. 6

“The 2007 version of CSA Z662 also introduced Clause 10.2 Safety and Loss Management Systems as a mandatory requirement of the code … Clause 10.2 also suggests that companies may require a period of two years or more to reach compliance. Terasen Gas is in the process of accessing potential compliance gaps to this new requirement.” Ref: p. 53, par. 2

125.1 Please comment on TGI’s level of compliance with CSA Z662 and why it is only now (mid-2009) in the process of accessing potential compliance gaps.

Response:

TGI has not “only now” begun to address potential compliance gaps, as suggested by the question.

In the period of 2006 to 2007, Terasen Gas first developed its Integrity Management Plan (IMP) for Transmission assets as required by Annex N and then created a second edition incorporating all gas systems assets. During the 2008 period, Terasen Gas worked on the implementation of its IMP, culminating in an internal audit to assess its progress. Work continues in 2009 to address audit findings and to complete activities that required additional work in 2009. Terasen Gas is working within the permitted OCG timeline to implement measures to bring the company into full compliance with the requirements of CSA Z662 Annexes M and N.

Regarding Clause 10.2, although in the 2007 edition, it was not released until 2008. Terasen Gas worked through 2008 and early 2009 to determine the Clause’s requirements, consulting with other Canadian utilities to assess what their response was. We felt that the majority of the clause’s requirements would be met by our IMP, and the current compliance assessment is not anticipated to uncover any major gaps.

In instances where new requirements are introduced the regulatory bodies typically grant a grace period to permit the affected operators to bring their organizations into compliance with the new requirements. Terasen Gas is working within the time permitted by the enforcement agency to assess the requirements of Clause 10.2 and to initiate measures as required to bring the company into compliance with the new regulatory requirements.

Terasen Gas continues to develop, evolve and administer programs as required to meet all regulatory requirements as well as sound operating practices; we are confident that we continue to meet those requirements.

125.2 Please comment on whether TGI took the Clause 10.2 reference to timing as a reason to defer implementation work until after PBR.

Response:

Terasen Gas did not take the timing identified in CSA Z662, Clause 10.2 as a reason to defer the implementation work and has been working to meet all Code requirements during the PBR period.

Please refer to TGI's response to BCUC IR 1.125.1.

126.0 Reference: Codes and Regulations

CSA Z662 for Oil and Gas Pipeline Systems

Part III, Section A, pp. 52-53

"For each of these, Terasen Gas has implemented management systems and/or operating practices to ensure compliance." Ref: Part III, Sec B, Tab 1, p. 126, par. 1

"In order to comply with these requirements we are developing and implemented competency and training requirements, we are evaluating our workers, and providing training where necessary." Ref: Part III, Sec B, Tab 1, p. 127, par. 5

"Terasen Gas believes that its IMP meets all the code requirements of Annex N and is ready for OCG auditing expected towards the end of 2009. In addition the Company believes that its IMP forms a solid base of which to build the requirements of CSA Z662 Clause 10.2 Safety and Loss Management Systems, also referred to as Annex A." Ref: Part III, Sec B, Tab 1, p. 128, par. 1

"Require $150 thousand increased funding in 2010 ... increased O&M funding of $109 thousand in 2010 and $20 thousand in 2011 ..." Ref: Part III, Sec C, Tab 6, pp. 385-6

126.1 Please detail the total amount of funding, by year, spent from 2006 to 2009 to be compliant with CSA Z662.

Response:

CSA Z662, Oil and Gas Pipeline Systems, is one of many Codes that drive programs at Terasen Gas. These Codes, collectively, along with the need to operate the pipeline system safely and effectively are fundamental to all aspects of work plans. As there are many synergies at play in delivering upon operations, maintenance, installation and code compliance requirements, it is not possible to isolate the total funding required to meet the ongoing requirements of CSA Z662. For 2010 and 2011, Terasen Gas has identified *Incremental* funding that is attributable to CSA Z662.

Terasen Gas continues to develop and administer programs and budgets in a holistic fashion to ensure all requirements are met in an efficient manner.

126.2 Please confirm the total amount of funding requested in 2010 and 2011 to be compliant with CSA Z662, and explain the reason for the expenditures in 2010 and 2011.

Response:

The incremental funding required in 2010 and 2011 to ensure continued compliance with CSA Z662 is $4,406,000 and $2,002,000 respectively. A detailed explanation for these expenditures can be found in Appendix F-8 of the Application.

"TGI's Competency and Training project is currently developing a technology solution that will allow it to meet the compliance requirements for Annex N." Ref: Part III, Sec C, Tab 6, p. 395, par. 2

126.3 Please advise if this work will be completed in 2009 or if there are funds for this project included in this Application.

Response:

Implementation of the technology solution is scheduled for completion in 2009. No funds have been included in the Application to carry the project into 2010/2011.

"Terasen Gas has a solid history of code compliance and **has implemented** management systems and/or operating practices to ensure compliance …" [emphasis added] Ref: Part I, p. 6, par. 3

126.4 Please comment on this TGI statement on code compliance and the CSA Z662 situation.

Response:

Terasen Gas developed the Integrity Management and Safety and Loss Management Programs in response to recent changes in CSA Z662. During the course of the program development a number of requirements have been identified that were not previously specified by the Code or now have more stringent requirements under the Code. Increased discipline is mandated regarding safety and loss management, activities records management, employee competency confirmation and risk identification. While Terasen Gas has been engaged in all of these activities in the past, the requirement for increased diligence has introduced additional costs. These costs are prudent and are in the public interest to ensure continued safe and reliable delivery of natural gas.

127.0 Reference: Codes and Regulations

CSA Z662 - Marketing

Part III, Section C, Tab 6, p. 352, Table C-6-4

127.1 Please provide further detail on the $1 million in additional funding under Marketing, including why this is a Marketing responsibility. Details should also include the applicable base costs for this item, by year, from 2006 to 2011.

Response:

The $1 million in funding under marketing is to enhance public information and education communications activities regarding natural gas safety. By increasing knowledge, TGI, as a responsible operator, can help customers avoid potentially harmful situations, which could result in serious injury or damage, both of which would have negative financial impacts for all customers.

All communications activities for TGI, including those for safety, are the responsibility of the Corporate and Marketing Communications group that reports into the Marketing and Business Development group. Previously public safety communications dollars were with the Environment, Health and Safety Department but they were transferred to Corporate and Marketing Communications as that is where the communications expertise resides corporately and is utilized to execute all types of communications activities. The communications planning and strategy will be developed by the Communications group with input from the public safety committee at Terasen Gas which includes representatives from Distribution, Transmission and Environment, Health and Safety. This structure will further enable Terasen Gas to obtain the best net value for customers by leveraging expertise and business relationships.

TGI Actual dollars and projected spending for Public Safety Awareness for the requested years are as follows:

2006 $370,000
2007 $165,000
2008 $342,000
2009 $340,000 (projected)
2010 $1,000,000
2011 $1,000,000

Currently we use a variety of programs to deliver required messages to our stakeholders. As a result of our internal compliance review for CSA Z662-07 Clause 10.2, we have noted that our customers are not as aware of safety issues, such as "gas odour awareness" as they should be. Improving customer awareness will require additional funding.

Public awareness and education is a broad term. The following table outlines key stakeholders and some of the reasons why we would communicate with them.

Stakeholder	Message	Reason
General Public	• Call before you dig • Smell of gas • Emergency response (floods, fires, earthquakes, etc)	Prevent injury, property damage
Users of Gas	• Carbon monoxide risks • Natural Gas/Propane Safety	Prevent injury
Homeowners	• Location of gas infrastructure on/near property • Safe excavation practices	Prevent injury, property damage
Contractors	• Location of gas infrastructure on/near property • Safe excavation practices	Prevent injury, property damage
Contractors (Targeted repeat damagers)	• Safe excavation practices (in-depth)	
Emergency responders	• Working around blowing gas • Keeping safe	Prevent injury, property damage
ROW land owners	• Location of gas infrastructure on/near property • Rules of what activities can be undertaken on a ROW	Prevent injury, property damage

Effectively meeting all of the communication needs identified in the table above would require a budget of much greater than what was requested in the Application. As such, we have implemented a risk based approach to public safety awareness which at present has identified public education through radio communications, similar to BC Hydro's 7 Steps to Electrical Safety, as the most economic and effective method to equally reach the public across our service territory.

On an annual basis, TGI will review past performance metrics, prepare target levels, determine appropriate messaging and communications vehicles and develop a public safety awareness plan for the forthcoming year. During the year, the plan would be reviewed against ongoing performance and funding would be shifted to appropriate areas as required.

127.2 Please provide further explanation of the reasoning for the magnitude of increase in 2010 compared to prior years.

Response:

Through our corporate image and customer satisfaction surveys, customers have indicated that Terasen Gas's safety information is highly-valued by them.

At the same time, additional research has demonstrated that our customers' level of understanding around gas odour and action (what steps to take when they detect a gas odour) is lower than desirable. In 2010 and 2011, TGI is planning to undertake a targeted effort to improve customer recognition of natural gas odour and the steps to take to ensure their safety. This helps protect customers in their homes and businesses, along a right of way or where third party damage may have occurred.

The Company has also measured its third party damage statistics. The underlying factors for damage occurring have remained the same for the past few years. Each year approximately 70 per cent of all damage occurs because those digging did not obtain location information for gas lines in the prescribed dig area.

Per category, the residential homeowner has the highest number of damages resulting from failing to call. Terasen Gas believes that undertaking an increased radio campaign to educate the public on the importance of obtaining gas line locate information prior to digging would achieve a higher level of awareness and then knowledge, contributing to more people obtaining locate information prior to digging, especially for those not directly involved in the digging community.

Terasen Gas's timing to increase awareness is also appropriate as a result of new Oil & Gas Commission regulations which outline public awareness as a way to prevent damage. The regulations are not prescriptive in what activities should be undertaken, but the reference of increased public awareness in the regulations should be seen as significant because it suggests that there are two key aspects to public safety – the integrity of the system and an educated public that through knowledge can avoid.

In order for the anticipated effort in 2010 and 2011 to improve public awareness of natural gas safety, it is important that Terasen Gas selects the appropriate media, prudently balancing reach and cost. Since the last settlement Terasen Gas has undertaken a mass media campaign for Customer Choice and in the first year of the program was able to go from zero awareness to approximately 80 per cent, several months later. The program is now being sustained at a lower level of media (newspapers and online) but is an example of the power of mass media campaigns, especially those involving TV. Incorporating TV would generate results quickly but is the most expensive media choice. We believe as a prudent operator we should explore an incremental step which would be to increase the frequency of our current media plan which relies primarily on radio. For example, one of the programs being considered for 2010 and 2011, is the addition of two to four more weeks of radio buy so that our messaging runs four to eight weeks out of the year in both English and ethnic markets. This would cost approximately $850,000 annually.

For comparison, BC Hydro runs its "Seven Steps to Electrical Safety" at high frequency, helping ensure its customers and the public are provided with information to aide in their safety. Regulatory filings have indicated the BC Hydro spends at least $3.6 million each year on public safety communications.

Terasen Gas will measure on an annual basis, adjusting the media outlets if necessary. At the next revenue requirement Terasen Gas will recommend if the funding level was sufficient or if it needs to be increased to incorporate TV or other channels to achieve a higher level of awareness. Please see also the response to BCUC IR 1.27.1.

128.0 Reference: Codes and Regulations

BCSA Procedures for Excavations

Part III, Section A, page 54

"As a result of this code change, TGI has had to increase staff members handling such requests in order to meet the 2 day requirement." Ref: Part III, Sec A, p. 54, par. 4

"Terasen Gas has been working at meeting this requirement since its introduction and will require additional resources." Ref: Part III, Sec C, p.385, p. 4

128.1 Please confirm TGI is currently meeting the 2 day requirement, and if not, what is the penalty for not meeting the requirement.

Response:

Yes, TGI is currently meeting the 2 day requirement.

128.2 Please detail the previous and current staffing, provide the number of requests, by year, from 2006 to 2009, and the expected volume of requests in 2010 and 2011.

Response:

Staffing Levels to Process BCOneCall Tickets

	2006 Actual	**2007 Actual**	**2008 Actual**	**2009 Projected**	**2010 Forecast**	**2011 Forecast**
Total Number of Requests (see Note)	48,713	57,008	61,566	65,440	68,141	72,446
Number of Requests Processed on Overtime	4,100	3,200	6,300	2,600	N/A	N/A
Number of FTE Staff	15	20	23	28	29	31

NOTES: The total number of requests includes TGI and TGVI requests.

The 2008 jump in the number of requests processed on OT represents our attempt to respond to the 3 to 2 day BCSA regulatory change with staffing levels at the time. We then increased our FTE staffing levels in 2009 to return to a more cost effective operating model where we strive to manage down the number of tickets that are processed on overtime.

128.3 Please comment on how the number and/or type of requests have changed with the change in economic conditions over the past year.

Response:

The change in the economic conditions over the past year has resulted in requests increasing at a slower rate than in previous years. However the type of requests have not been impacted..

129.0 Reference: Codes and Regulations

Safety Communication Media Plan

Part III, Section C, Tab 6, p. 375, par. 6

129.1 Please provide the costs for the safety communication media plan, by year from 2006 to 2011.

Response:

Please see the responses to BCUC IR 1.127.1 and 1.127.2.

129.2 Please explain the events or drivers that focused the Company on this increase in 2010.

Response:

Please see the responses to BCUC IR 1.127.1 and 1.127.2.

130.0 Reference: Codes and Regulations

Expenditures deferred during PBR

Part II, Introduction, p.21

"Expenditures that were pragmatically deferred during the PBR Period cannot be deferred indefinitely and some will need to be made in the 2010/2011 forecast period. … To ensure ongoing compliance to existing codes … additional O&M funding is required." Ref: Part II, p. 21, par. 1

130.1 Please detail the expenditures deferred during PBR related to ongoing compliance to existing codes and regulations.

Response:

Terasen Gas maintained compliance with Codes and Regulations during the PBR. During the PBR period some low-risk maintenance was deferred to the benefit of the customers and shareholders with an acceptable increase in associated risk. Examples of deferred maintenance that has now risen from low-risk and cannot be deferred further include: painting aerial and bridge crossings, stations and other assets; maintenance of non-critical valves; right of way clearing; and, station line heater internal overhauls. Please also refer to Terasen Gas' response to BCUC IR 1.8.2.

We continue to administer a variety of programs to ensure that assets continue to operate safely and reliably, and that Code requirements are met.

131.0 Reference: Operations and Maintenance Expenditures - Service Enhancements

Table C-6-18, Part III, Section C, Tab 6, page 364

131.1 Please provide further detail for the following service enhancements cost escalators:

	2010	2011
Meter to Cash	$331	$135
Operations	$122	$54

131.1.1 What is the history of this cost allocation category from 2003 to 2009?

Response:

Meter to Cash- Meter to cash consists of residential and/or industrial activities related to lock-offs, reconnects, rereads, high bill investigations and meter investigations. Meter to cash activities grow in step with customer growth, changes to credit and collections processes and other associated technology changes have also resulted in activity level changes. This trend is also influenced by cost of gas and a challenging economic environment which particularly impact lock-off and reconnect activity.

Meter to Cash historical 2003 to 2009:

Year	2003	2004	2005	2006	2007	2008	2009P
Meter to Cash ($000s)	$ 145	$ 706	$ 1,001	$ 799	$ 1,141	$ 1,309	$ 1,087

Note: 2003 was an anomaly as it was the year Terasen Gas altered its credit and collection practices with ABSU implementing the changes and the reconnect fee recovery amount was $2.155 million reducing the net spend to $145,000. After 2003 the credits started falling off to $1.5 million level.

Operations- Operations activities consist of a number of surveys and programs conducted by Distribution to monitor the condition of assets and initiate corrective actions as required. Survey results are monitored closely to: determine asset condition; identify areas of concern; develop and implement mitigation programs; adjust operations frequencies and tasks; and to ensure optimal investment of maintenance resources. As the size of the natural gas delivery system increases through regular customer growth and systems age, increased resources are required to conduct the appropriate operations activities.

Operations activities will ensure Distribution can effectively maintain assets to ensure they are fit for purpose and continue to provide gas delivery safely, reliably and cost effectively.

Operations activities consist of a number of surveys and programs, as follows:

- Valve Inspection Survey
- Leak Survey
- Pipeline Inspection Survey
- Odourant
- System Damage Prevention
- Operate General
    - Line Heater Fuel
    - Snow Removal
    - Station Grounds Maintenance
    - Etc

Operations historical 2003 to 2009:

Year	2003	2004	2005	2006	2007	2008	2009P
Operations ($000s)	$ 3,614	$ 3,640	$ 3,738	$ 3,745	$ 4,442	$ 4,891	$ 4,816

131.1.2 Please itemize the surveys to be conducted and the amount allocated to each survey to result in the forecasts for 2010 and 2011.

Response:

The surveys to be conducted and the amount allocated to each survey are listed in the table below:

Survey	2009P	2010F	2011F
Valve Inspections	$ 405,376	$ 396,516	$ 422,203
Leak Survey	$ 1,276,412	$ 1,156,343	$ 1,240,091
Pipeline Inspections (includes additional $150,000 in 2010 and $50,000 in 2011 for Vegetation Management as noted on p. 362 Table C-6-16 of Application	$ 233,260	$ 395,661	$ 421,605
Total Survey	**$ 1,915,048**	**$ 1,948,520**	**$ 2,083,899**

A series of surveys are administered and conducted by the Distribution department to monitor the condition of assets and initiate corrective actions as required. Survey results are monitored closely to: determine asset condition; identify areas of concern; develop and implement mitigation programs; adjust operations frequencies and tasks; and to ensure optimal investment of maintenance resources. As the size of the natural gas delivery system increases through regular customer growth, increased resources are required to conduct the appropriate operations activities. Survey activities in 2010 and 2011 will ensure the Distribution department can effectively maintain assets to ensure they are fit for purpose and continue to provide gas delivery safely, reliably and cost effectively.

132.0 Reference: Operations and Maintenance Expenditures – Service Enhancements

Meter to Cash

Part III, Section C, Tab 6, p.365

"Additional funding is required primarily to support additional meter investigations which are generally initiated by customers."

132.1 Please describe the "additional meter investigations" in the above statement.

Response:

Meter investigations are as a result of customers initiating more meter disputes, high bill complaints and general inquiries. This trend is also influenced by customer growth, cost of gas and a challenging economic environment.

132.2 Please provide the actual spending for 2006, 2007, 2008, and the projected 2009 figure for Meter to Cash activities. Please include the percentage change from year to year.

Response:

"Meter to Cash" in the context of this question consists of Distribution activities related to lock-offs, reconnects, re-reads, high bill investigations and meter investigations. Distribution Meter to Cash activities grow in step with customer growth, although changes to credit and collections processes and other associated technology changes have also resulted in Distribution activity level changes. Actual spending for 2006, 2007, 2008 and the projected 2009 figure are listed in the table below:

Meter to Cash Activities
(lock offs, reconnects, re-reads, high bill and meter investigations, reconnect recoveries.)

($000s)	2006 Actual	2007 Actual	% Change	2008 Actuals	% Change	2009 Projected	% Change
Residential	630	991	57%	1151	16%	920	-20%
Industrial	169	150	-11%	158	5%	167	6%
	$799	**$1,141**	**43%**	**$1,309**	**15%**	**$1,087**	**-17%**

This trend is influenced by cost of gas and a challenging economic environment which particularly impact lock-off and reconnect activities. The 2009 budget was prepared prior to the economic downturn in the 2nd half of 2008 so lockoff and reconnect activity for 2009 is expected to be understated. Although 2009 projected costs in the Application were not revised upwards to reflect this trend, the 2010 and 2011 forecast costs do include the anticipated higher activity levels.

132.3 Please explain how this additional funding requirement relates to the increased meter testing fee described in Part III, Sec C, Tab 12, p. 509, Table C-12-4.

Response:

The additional funding requirement has no relationship to the increased meter testing fee. The increased meter testing fee described in Part III, Sec C, Tab 12, p. 509 relates to an independent process available to customers under the Electricity and Gas Inspection Act of Canada to dispute the accuracy of a meter. If this process is invoked, Terasen Gas must remove the meter, have it quarantined and shipped directly to a Measurement Canada inspector for testing. The new fee more closely represents the true costs of removal.

"Meter to cash activities grow in step with customer growth…" page 365, par.4, line 2.

132.4 According to Appendix F.7, average customer growth is projected at 0.98 percent for 2009, and forecast of 2010 and 2011 at 0.74 percent and 0.68 percent, respectively. Meter to Cash activities, however, are declining from $331,000 to $135,000 between 2010 and 2011. Please discuss the discrepancies with this trend.

Response:

All else being equal, Meter to Cash activities grow in step with customer growth. An additional upward trend can be attributed to cost of gas changes and a challenging economic environment which particularly impact lock-off and reconnect activities.

Meter to Cash activities (not including labour inflation and a change in reconnect fees) is forecast to increase by $331,000 in 2010 and by a further $135,000 in 2011 (see Table C-6-18 on page 364 of the Application).

133.0 Reference: Operations and Maintenance Expenditures - Service Enhancements

Part III, Section C, Tab 6, part (h), p. 380

133.1 Please verify whether any portion of the Service Enhancement costs ($3.6m in 2010 and $1.7m in 2011) relate to the Customer Care Enhancement Project?

Response:

The numbers in the question do not appear on page 380 and are not the amounts for Service Enhancement costs. Additional funding of $2 million in 2010 and $0.9 million in 2011 is discussed in part (h) Service Enhancements on page 380. None of this funding relates to the Customer Care Enhancement Project.

133.2 Would Terasen Gas agree that while Customer Information and Education are important, the tasks relating to Customer Choice programs and other energy options are already being addressed in the unregulated energy markets and gas marketers? Please explain why adding additional staff to this area is adding value to existing **regulated** rate payers.

Response:

The activities of the Customer Information and Education group within the Marketing Department encompass many more tasks and roles than those relating to "Customer Choice Programs and other energy options". The addition of staff to this group is independent of activities related to Customer Choice programs.

Gas marketers focus on marketing initiatives specific to their company's fixed-rate products.

TGI has a much broader range of communications responsibility including public education on all aspects of natural gas delivery and the company's operations. The Company is responsible for customer education and public information regarding key topics of customer interest including safety; information about natural gas; information about rates, energy efficiency; environmental management, billing, payment options and information about system maintenance and upgrades such as the Fraser River Crossing upgrade and public consultation materials for new project development such as the Mt. Hayes Natural Gas Storage Facility and the Whistler Pipeline and Conversion. We also communicate with a full range of stakeholders reflecting the large contribution of Terasen Gas to the environmental, economic and energy framework of British Columbia.

With the ongoing evolution of customer needs and changes in the B.C. energy market, Terasen Gas has a responsibility to communicate with its customers and the public on topics of interest. In addition, new Oil & Gas Commission regulations outline public awareness as a way to prevent damage. The regulations are not prescriptive in what activities should be undertaken, but the reference of increased public awareness in the regulations should be seen as significant because it suggests that there are two key aspects to public safety – the integrity of the system and an educated public that through knowledge can avoid harm.

Given the increased public dialogue on energy in British Columbia combined with the Company's responsibility to help customers use energy safely, efficiently and be equipped with the knowledge to make the energy decisions that are right for them, two additional employees are needed to help manage the increased volume of requirements.

133.3 Please describe the types of customer information and education activities Terasen Gas is currently conducting and how these activities relate to reducing customer complaints.

Response:

The company is responsible for customer education and public information regarding key topics of customer interest including safety, information about natural gas, customer rates, energy efficiency, environmental management, billing, payment options and information about system maintenance and upgrades and public consultation materials for new project development such as the Mt. Hayes Natural Gas Storage Facility, the Whistler Pipeline and the Fraser River Crossing upgrade. We also communicate with a full range of stakeholders reflecting the large contribution of Terasen Gas to the environmental, economic and energy framework of British Columbia.

Communications programs to support key topics of interest can utilize any number of the following communications channels to best reach the target audience for a specific initiative.

Budgeted items:

- Published/printed materials
- Mass media – paper/magazine/directory/radio/online
- E-newsletters
- Public / trade displays
- Website content and design
- Publication distribution costs
- On-hold messaging

Earned media

- Advertorials
- Editorial copy
- News releases
- Media communications

With the ongoing evolution of customer needs and changes in the B.C. energy market, Terasen Gas has a responsibility to communicate with its customers and the public on topics of interest.

Given the increase in focus on energy for British Columbians and a desire to use energy safety, efficiently and at a competitive cost, the Communications Department is looking to add two additional employees to produce attention-getting, informative materials for our customers and provide information for the public.

Informing and educating the public through communication channels in addition to the monthly account statement can assist customers in developing more understanding regarding Terasen Gas and the services we provide to them. Providing more information and education to customers is much more likely to reduce customer complaints from what they otherwise would have been. Communication activities cannot eliminate all customer concerns or complaints; however they can provide customers with additional information and understanding regarding potential issues or concerns. This will lead to a reduction in the number of complaints than those that would have occurred had customers had no information.

134.0 Reference: Metering – Meter Life Extension

Part III, Section B, Tab 1, p. 188

"This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006-2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy … " Ref: Part III, Sec B, Tab 1, p. 188, par. 2

134.1 Please detail the additional O&M required in 2010 and 2011 for the meter recalls deferred from 2006-2008.

Response:

One of the activities conducted within Terasen Gas to ensure the cost effective and reliable operation of the meter fleet is to adjust the meter recall schedule based on the meter fleet age distribution and the results of the performance sampling program. Between 2006 and 2008, the decision to operate residential meters to the full life expectancy of 20 years, coupled with the positive results from sampled meter performance tests, allowed the company to temporarily reduce the total number of scheduled meter recalls. Therefore, no meter recalls were deferred during the time frame referenced within the question. All meter recalls were scheduled at times that were optimal in terms of operational reliability. Finally, by temporarily reducing the number of meter recalls during this period, both customers and shareholders were allowed to benefit from the savings in O&M and capital expenditure.

135.0 Reference: Operations and Maintenance Expenditures

Metering – Meter Quality Recall

Part III, Section C, Tab 6, p. 365, par. 1

"During the late 1990s, certain batches of meters comprised of components constructed with less durable materials were installed within the meter fleet. Although the vendor has since re-designed the meter to address this concern, we believe it is prudent to proactively remove these meters from the fleet to prevent unscheduled failures. As such, the forecasted meter recalls must be increased to 60,000 recalls annually through the period covered by this application."

135.1 Please comment on how this change in timing will affect the future meter recalls, specifically with leveling of workload in 2010 and 2011.

Response:

Through the period of this Application, there are two significant drivers impacting the forecasted meter recall schedule to ensure the cost effective and reliable operation of TGI's meter fleet. One driver influencing the meter recall schedule is our current understanding of optimal fleet management which is defined by a meter life expectancy of approximately 20 years. To achieve this life expectancy, 1/20 of the meter fleet is required to be taken out of service annually. This translates into 42,000 meter recalls within TGI for each year of the Application. The second driver of the meter recall schedule is the need to proactively remove an additional 12,225 meters from service annually from a segment of the meter fleet consisting of meters installed in the late 1990s that are known to have a life expectancy lower than the remainder of the meter fleet. Finally, Terasen Gas budgets annually for an additional 6,000 unscheduled meters recalls for such reasons as gas load changes and inactive services.

As described above, Terasen Gas applies a proactive approach to management of its meter fleet. As such, by scheduling the removal of the meters with a lower life expectancy throughout the period of 2010 through 2018, the workload associated with meter recalls can be levelled in a manner that is cost effective and ensures the meter fleet continues to operate in a reliable manner.

135.2 Please comment on the difference between scheduled and unscheduled failures, and how this is reflected in the meter recall scheduling and O&M costs.

Response:

For clarification, Terasen Gas makes the assumption that the question refers to the difference between scheduled removal of meters from service compared to unscheduled meter failures.

As described within the response to BCUC IR 1.134.1, the meter recall schedule is regularly adjusted based on the meter fleet age distribution and results of the performance sampling program to ensure the cost effective and reliable operation of the meter fleet. As such, meters are scheduled for removal from service in the time period in which they have reached their expected life span. Alternatively, unscheduled meter failures refer to meters that fail the accuracy tests prior to achieving their expected life span and are therefore removed from service prematurely. The program of sampling and testing meters within the fleet at various stages of their expected life span is regulated by Measurement Canada in accordance with the *Gas and Electricity Inspection Act of Canada*.

Management of the meter fleet in this proactive manner provides Terasen Gas the ability to accurately predict the number of meter recalls to be completed annually. The ability to accurately predict the number of meter recalls required in the following year allows the company to order meters from vendors well in advance of the install date to ensure the supply of meters are available when required. In addition, by controlling the date that meters are to be removed from service, Terasen Gas is able to plan for the resources required to complete the meter recalls that occur throughout the following year.

136.0 Reference: Operations and Maintenance Expenditures

Metering – Services for third parties

Part III, Section C, Tab 6, p. 390, par. 5

136.1 Please detail the third parties that are using less meter services, which results in the $110 thousand lower revenues.

<u>Response:</u>

To date, Terasen Gas has experienced a reduction in revenue generated from both pipeline and utility clients within the United States. In Canada, revenue generation has remained flat as current customers have chosen not to expand upon the meter services they currently receive from Terasen Gas and potential customers have continued to receive meter services through their existing service providers.

137.0 Reference: Operations and Maintenance Expenditures - Distribution

Part III, Section C, Tab 6, page 359

137.1 In Table C-6-13, Distribution Forecast O&M Expenditures 2009, 2010-011. Please compare costs by function for the items identified for the period 2003 to 2009.

Response:

Cost by Distribution function for the period 2003 to 2011 is listed in the table below:

Operations and Maintenance Expenditures
Distribution 2003 - 2011
Note: All amounts are in $millions

Function:	2003 Decision	2003A	2004A	2005A	2006A	2007A	2008A	2009P	2010F	2011F
Field Work		$ 14.185	$ 16.791	$ 18.313	$ 16.698	$ 17.802	$ 20.239	$ 20.115	$ 23.170	$ 25.169
Operations Centre		$ 5.655	$ 6.292	$ 5.752	$ 6.450	$ 6.184	$ 6.512	$ 6.375	$ 7.466	$ 8.032
Asset Mgmt, Regional Mgrs, Process Support		$ 6.343	$ 5.400	$ 5.869	$ 5.904	$ 6.453	$ 6.546	$ 7.113	$ 8.288	$ 9.050
Vice President		$ 5.134	$ 3.520	$ 3.531	$ 3.351	$ 3.638	$ 4.304	$ 4.005	$ 4.418	$ 4.504
Total Distribution (including Vehicle Lease and Fort Nelson)		$ 31.317	$ 32.003	$ 33.465	$ 32.403	$ 34.077	$ 37.601	$ 37.608	$ 43.342	$ 46.755
Vehicle Lease									$ (1.612)	$ (1.977)
Fort Nelson		$ (0.521)	$ (0.588)	$ (0.639)	$ (0.690)	$ (0.705)	$ (0.605)	$ (0.656)	$ (0.676)	$ (0.696)
Total Distribution (Excluding Vehicle Lease and Fort Nelson)	**$ 31.700**	**$ 30.796**	**$ 31.415**	**$ 32.826**	**$ 31.713**	**$ 33.372**	**$ 36.996**	**$ 36.952**	**$ 41.054**	**$ 44.082**

Part III: Section C – Tab 6 p. 359-368 of the Application outlines the detailed explanations for cost increases across all of the above noted functions. Details are provided for the following Distribution cost drivers:

- Labour inflation and benefits
- Codes and regulations
- Accounting changes
- Service enhancements
- Internal budget transfers

138.0 Reference: Operations and Maintenance Expenditures - Gas Supply and Transmission

Part III, Section C, Tab 6, page 368-373

138.1 In the Operating and Maintenance category (page 372), why are SCADA operating costs increasing by $130 thousand?

Response:

SCADA costs are increasing by $50 thousand, not $130 thousand as stated on page 372 of the Application, to provide continued maintenance support for the Telvent component. The cost for this support had been offset by opportunities within Gas Control's other annual operating and maintenance expense but can no longer be absorbed. This support is necessary to trouble shoot and repair any problems arising with the SCADA system. Lack of support will result in outages and reduced ability to control the pipeline system on a 24-hour basis.

The additional $80 thousand relates to increased electrical costs for running the compressor stations due to ICE tax (new) and potential rate increases. These two components, though managed by the same group – Gas Control, were erroneously combined during budget summarization.

139.0 Reference: Taxes

Part III, Section C, Tab 7

139.1 What are the comparative and forecast costs required to remain an active participant in the 3 tax associations? Please describe the benefits associated with the participation in these tax associations.

Response:

Forecast annual costs to remain an active member are:

Canadian Property Tax Association	$3,000
Vancouver Board of Trade	$500
CEPA	$0

We believe that membership in the above associations is important because it allows us to remain current on property tax issues and emerging trends in taxation related within a Municipal, Provincial and Canadian context to mitigate the trend of tax increases.

The Canadian Property Tax Association provides easier access to information on property tax practices across Canada for a broad range of Commercial, Industrial and Utility taxpayers. BC Assessment is a member of the Canadian Property Tax Association and often uses this venue to seek comments on proposed changes to policies and practices that may otherwise not be available.

The Vancouver Board of Trade focuses more on tax policy than the Canadian Property Tax Association and benefits from long-standing relationships with the City of Vancouver and the Province of BC. Participation in this organization has provided many insights into the real taxation practices within one of the largest municipalities in BC.

The Canadian Energy Pipeline Association is an association of Pipeline Companies across Canada. This association provides access to property tax issues faced by other similar companies across Canada and to a lesser extent within BC.

140.0 Reference: Taxes

Part III, Section C, Tab 13, Schedule 1

140.1 Please provide reference(s) to the financial schedules in Tab 13 that corresponds to the decrease in "Tax Impacts of Rebase Depreciation" of $4.3M in2010.

Response:

Line No.	Particulars	Rebase Impact	Reference
	(1)	(2)	(3)
1	Projected 2009 Depreciation Expense*	$ 79.7	- Tab C-13, Schedule 72, Column 5, Line 26 /1000
2	Approved 2009 Depreciation Expense*	89.7	- Tab C-13, Schedule 72, Column 2, Line 26/1000
3	After Tax Depreciation Impact	(10.0)	
4			
5	2009 Tax Rate	30.00%	- Tab C-13, Schedule 73, Column 2, Line 11
6			
7	Before Tax Impact of Rebase Depreciation	(14.2)	= Line 3 / (1 - Line 5)
8			
9	Tax Impacts of Rebase Depreciation	(4.3)	= Line 7 - Line 3

*Includes amortization expense. The approved amortization expense is equal to the projected amortization expense; therefore, any variance is attributable to depreciation expense.

140.2 Please provide reference(s) to the financial schedules in Tab 13 that corresponds to the change in Income Tax Expense of $.4M in 2010 and $.1M 2011.

Response:

The amounts shown for change in income tax expense of $.4M in 2010 and $.1M in 2011 represent the change from 2009 approved per the earned return schedules, less the amount of that change that was due to rebasing and therefore included in the Rebasing Section of Schedule 1, less the amount that was due to the depreciation rate change which was included in the Accounting Standard Changes Section of Schedule 1. See the reconciliation below for the calculation.

Line No.	Particulars	2010	2011	Reference
	(1)	(2)	(3)	(4)
1	Forecast Tax Expense	$ 31.6	$ 31.7	- Tab C-13, Schedule 4 & 5, Column 5, Line 31/1000
2	2009 Approved Tax Expense	26.3	26.3	- Tab C-13, Schedule 72, Column 2, Line 31/1000
3		5.3	5.3	
4	Less:			
5	Rebase- Tax Expense			
6	Projected 2009 Tax Expense	23.0	23.0	- Tab C-13, Schedule 72, Column 5, Line 31/1000
7	Approved 2009 Tax Expense	26.3	26.3	- Tab C-13, Schedule 72, Column 2, Line 31/1000
8		(3.3)	(3.3)	
9				
10	Depreciation Change- Tax Expense			
11	After Tax Change in Depreciation Rates	20.8	21.2	- Tab C-13, Schedule 1
12	After Tax Change in Depreciation Timing	1.9	1.9	- Tab C-13, Schedule 1
13		22.7	23.1	
14				
15	Tax Rate	28.50%	26.50%	- Tab C-13, Schedule 6 & 7, Column 5, Line 11
16	Before Tax Depreciation Changes	31.7	32.3	
17		9.0	9.2	= Line 15 - Line 13
18				
19		(0.4)	(0.5)	= Line 3 - Line 8 - Line 17
20				
21	Incremental to 2010		(0.1)	

141.0 Reference: Taxes - Property Tax Forecasts

Part III, Section C, Tab 7, p. 409 & 411

Terasen Gas has stated that two of the components that make up property taxes are the property assessment values and the property tax rates set by the various authorities.

Please fill out the following table.

	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Property Assessed Value						
Property Tax Rates						
OGC Fees						
Total '000				$31,700*	$32,900*	$33,900*
*Totals reconcile to Table C-7-3, p. 411						

__Response:__

	2006 Actual	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Property Assessed Values ($000,000)	1,148.6	1,214.9	1,311.4	1,337.4	1,374.3	1,397.4
Effective Property Tax Rates * ($ per thousand of assessed value)	24.20338	23.7880	22.4188	23.7027	23.9395	24.2593
Total Property Tax Payable ($,000)	27,800	28,900	29,400	31,700	32,900	33,900
OGC Fees ($,000)	87	86	86	82	197	197
Total Property Tax & OGC Fees ($,000)	27,887	28,986	29,486	31,782	33,097	34,097

The table summarizes the actual and projected costs for Property Taxes and OGC fees for the period 2006 to 2011. Because Terasen Gas is taxed across many jurisdictions in BC, each with different tax rates, the Effective Property Tax Rates in the table were calculated by dividing the Total Property Tax Payable by the Property Assessed Value.

OGC Fees are not based on Property Value but rather are a separately assessed fee based on kilometres of pipe.

Also the table does not include 1% of revenues assessed by certain municipalities in lieu of a portion of property taxes paid within those municipalities.

142.0 Reference: Taxes - Carbon Tax

Part III, Section C, Tab 7, section (d), p. 414

Terasen Gas states that: "The estimated cost to the Company in respect of Carbon Tax on own-use fuel is approximately $410 thousand for 2010 and $530 thousand for 2011, and is embedded in O&M and capital in this RRA."

142.1 Please provide a breakdown of the carbon tax amounts charged to O&M and to capital for 2010 and 2011 and discuss the cost drivers for the allocation.

Response:

Carbon tax is embedded in capital as a result of being applicable to gasoline, which is one of the costs applicable to vehicle use. Vehicle usage is charged to O&M or to capital depending on the use of the vehicle. The cost driver for the allocation is the number of hours a vehicle is used on capital projects as opposed to O&M projects.

The estimate of carbon tax amounts charged to capital and to O&M is as follows:

	2010	**2011**
O&M	$354,000	$460,000
Capital	$56,000	$70,000
Total	$410,000	$530,000

142.2 Please discuss the rationale for the portion of carbon tax being charged to capital.

Response:

See the response to BCUC IR 1.142.1.

143.0 Reference: Taxes - PST

Part III, Section C, Tab 7, part (e)

"The estimated PST cost for 2010 and 2011 is approximately $4.2 million and $4.3 million respectively, excluding PST embedded in gasoline and other vehicle fuels. The cost is embedded in capital and O&M depending on the nature of the property or service acquired." Page 415, Par.1

143.1 Please provide the information below using the following table and provide explanations for any increase over prior year greater than 5 percent.

	2007 Actual	2008 Actual	2009 Projected	2010 Forecast	2011 Forecast
Total O&M					
O&M subject to PST					
Estimated PST on O&M subject to PST (@7%)					
% total O&M subject to PST					
% change in over prior year					
Total Rate Base Additions					
Rate Base Additions Subject to PST					
Estimated PST on Rate Base subject to PST (@7%)					
% total Rate Base additions subject to PST					
% increase over prior year					
Total PST				$4.2m*	$33.9m*

Response:

The estimated PST cost for 2010 and 2011 is a high level estimate which was determined by applying the proportion of 2008 actual PST paid over total 2008 O&M and capital expenditures, to 2010 and 2011 O&M and capital expenditures. The estimates do not represent the actual amount of PST included in the Cost of Service; significantly more analysis would be required to determine exact amounts. The TGI information systems are capable of determining the total actual PST paid for any given year, but do not have the capability of determining the amount charged to O&M and to capital separately. We are therefore unable to complete the table as requested.

For 2008, total PST of $3.6 million was paid on O&M and capital expenditures of $275 million. The resulting percentage of 1.3% was applied to 2010 and 2011 O&M and capital expenditures. In 2007, total PST of $3.1 million was paid on O&M and capital expenditures of $252 million, reflecting in part the lower spending in 2007 compared to 2008.

144.0 Reference: Taxes - Goods and Service Tax

Part III, Section C, Tab 7, part (f)

"Terasen as a GST registrant, is entitled to recover virtually all of the GST it pays on its taxable purchases of goods and services. As such, the tax does not represent a net cost to the Company" page 415, par. 2

144.1 In the past three years has Terasen Gas ever experienced a net GST recovery (refund) position?

Response:

Terasen Gas files GST returns monthly and typically experiences a net GST recovery during the summer months, when revenues are less than expenditures.

The Company charges GST to customers on sales, and pays GST on purchases. On the monthly GST return, GST collected from customers on sales is remitted to the Federal Government, and GST paid on purchases is recovered from the Federal Government. In months when sales are higher than purchases, the Company is in a net remittance position, while in months when purchases are higher than sales, the Company is in a net recovery position. None of these GST amounts are embedded in costs or revenues in the Application.

144.2 Does Terasen Gas expect to be in a net GST recovery (refund) position in either 2011 or 2012?

Response:

In 2010, 2011 and 2012, Terasen Gas expects to experience a net GST recovery during the summer months when purchases are typically higher than sales. Please also see the response to BCUC IR 1.142.1, where the impact of GST on TGI's revenue requirements is described.

145.0 Reference: Taxes

Part III, Section C, Tab 7, part (g), p. 415

"Terasen Gas is seeking a deferral account to be recovered through rates in 2012 to capture the impact of changes in tax laws or accepted assessing practices, audit reassessments in respect of any tax year, and impacts on taxes of changes in accounting policies, at Federal, Provincial, Municipal or any other level of jurisdiction. In addition… the income tax deferral account should also capture any changes to the final tax overhead calculation." Page 415, par. 3

145.1 Is it expected that the proposed tax deferral account will capture any of the differences in management estimates of indirect tax (carbon tax, PST, GST)?

Response:

The Company had not envisioned that the tax deferral account would capture differences in management estimates of existing indirect taxes, unless a change in law occurs.

For example, the Company is of the view that the implementation of the Harmonized Sales Tax ("HST") in July 2010, as announced by the BC Government on July 23, is a change in tax law. Once the law is enacted, the Company will determine the impact of the changes and expects to capture the differences in a deferral account. Similarly, changes in indirect tax rates or laws that impact Cost of Service should also be captured in a deferral account.

146.0 Reference: Taxes

Part III, Section C, Tab 7, part (g), p. 415

146.1 Please confirm that taxes are not set by formula during the PBR years but rather are adjusted each year based on the Income Tax continuity scheduled that is calculated on approved tax rates.

Response:

The Company confirms that taxes themselves were not set by formula during the PBR years, although they were calculated based on formula-driven O&M and capital expenditures. Taxes were calculated based on approved pre-tax income (including formula O&M), adjusted for estimated permanent and timing differences (including formula depreciation and CCA), and calculated at income tax rates substantively enacted in Canada Income Tax Act and BC Income Tax legislation.

146.2 Terasen states that the CRA audit of 2002 was completed in 2007 and no audit adjustments were proposed. Please explain why the $8.2 million CCA deduction was not previously adjusted in 2008 or 2009 rates?

Response:

The adjustment for the $8.2 million CCA deduction represents an adjustment to a prior period.

The difference in treatment was noted in the process of preparing for the RRA, too late to be adjusted in the 2007 or 2008 Annual Reports.

147.0 Reference: Taxes - Tax Benefits Relating to Prior Periods

Part III, Section C, Tab 7 Taxes, part (g) (2), p. 415

"As a result of these adjustments, customers have received the **full** benefit on the $2.8 million of costs by way of CCA deduction from 2001 to 2008, and have **shared** in the **remainder** of the tax benefit as a result of the 2009 tax deduction." Page 416, par. 3

147.1 Please confirm that by adjusting the remaining UCC balance of $8.2 million as a deduction in the 2009 Timing Difference schedule (Part III, Section C, Tab 13, Schedule 37, Line 31, Column (2) the benefit of the additional CCA deduction for regulatory purposes is captured in the Earnings Sharing Calculation (Part III, Section C, Tab 13, Schedule 68) resulting in the $2.46 million ($8.2 million X 30 percent 2009 tax rate) benefit being included in the $25 million After Tax Surplus Available for Sharing (Part III, Section C, Tab 13, Schedule 68), when in fact 100 percent of the benefit should go to the ratepayer?

Response:

The Company confirms that the $8.2 million balance is captured in the ESM calculation, but does not confirm that 100 percent of the benefit should go to the ratepayer.

This adjustment does not meet the criteria for deferral as set out in Appendix A to Order No. G-51-03 (page 12), which proposed a deferral account to record variances in income tax rates, LCT rates, and new government tax expenses, charges and levies.

Under the PBR agreement, sharing a variance that relates to a prior period by way of the Earnings Sharing Mechanism is the appropriate way to deal with a difference that does not meet the criteria for deferral.

It should be noted that the adjustment first arose in the 2001 and 2002 periods. ROE variances during the 2001 period were also subject to sharing, while variances during 2002 were borne by the shareholder.

147.2 Please explain why the $8.2 million CCA deduction was not tax effected using the 2002 tax rate of 39.62 percent (25 percent Federal, 1.12 percent Sur Tax, 13.5 Provincial) which was in effect when TGI received the benefit of the tax deduction?

Response:

The Company is of the view that the appropriate tax rate to use is the tax rate in effect at the time the adjustment is determined and the benefits are returned to customers. The Company was uncertain whether the deductions would be accepted as filed, and therefore chose to leave the costs in Undepreciated Capital Cost for regulatory tax purposes. Had the expenses been disallowed as a current deduction, there would have been no change for regulatory tax purposes. The Company, however, would have borne the cash flow cost related to having claimed a deduction and having to repay the increase in taxes payable. Although there was a short delay, the Company is sharing the benefits with customers now that it is known with certainty that the benefits are available. Furthermore, in the intervening period, tax rates could have risen rather than declined.

148.0 Reference: Taxes – Changes to CCA Rates

Part III, Section C, Tab 7, Part (g) (3), p. 416

"As an alternative to reporting the adjustments in the 2008 Annual Report, the Company has adjusted the timing difference on the 2009 Timing Difference schedule by the amount of the increased CCA for 2007 and 2008 of $2.9 million." Page 416, par. 4

148.1 Please confirm that by adjusting the UCC balance by $2.9 million as a deduction in the 2009 Timing Difference schedule (Part III, Section C, Tab 13, Schedule 37, Line 27, Column (2) the benefit of the additional CCA deduction for regulatory purposes is captured in the Earnings Sharing Calculation (Part III, Section C, Tab 13, Schedule 68) resulting in $.87 million ($2.9 million X 30 percent 2009 tax rate) benefit being included in the $25 million After Tax Surplus Available for Sharing (Part III, Section C, Tab 13, Schedule 68), when in fact 100 percent of the benefit should go to the ratepayer?

Response:

The Company confirms that the $2.9 million CCA adjustment is captured in the ESM calculation, but does not confirm that 100% of the benefit should go to the ratepayer.

The CCA rate changes do not meet the criteria for deferral as set out in Appendix A to Order No. G-51-03 (page 12), which proposed a deferral account to record variances in income tax rates, LCT rates, and new government tax expenses, charges and levies.

Under the PBR agreement, sharing a variance that relates to a prior period by way of the Earnings Sharing Mechanism is the appropriate way to deal with a difference that does not meet the criteria for deferral.

148.2 Please provide a breakdown of the $2.9 million CCA deduction between 2007 and 2008.

Response:

The $2.9 million CCA deduction is comprised of increases to the CCA deduction of $0.7 million for 2007 and $2.2 million for 2008.

148.3 Please explain why the $2.9 million CCA deduction was not tax effected using the 2007 and 2008 tax rates that were in effect when TGI received the benefit of the tax deduction?

Response:

The Company is of the view that the appropriate tax rate to use is the tax rate in effect at the time the deduction is known with certainty and the benefits are returned to customers.

149.0 Reference: Taxes - Capitalized Overhead Study and Impact on Taxes

Part III, Section C, Tab 7 Taxes, Part (g) (4), p. 416

"The increase in the amount of the tax deduction for 2008, net of the reduction in 2008 CCA, is reported as a $3.3 million timing adjustment in the 2009 Timing Difference schedule." Page 417, par.2

149.1 Please confirm that by adjusting the UCC balance by $3.3 million as a deduction in the 2009 Timing Difference schedule (Part III, Section C, Tab 13, Schedule 37, Line 26, Column (2) the benefit of the additional CCA deduction for regulatory purposes is captured in the Earnings Sharing Calculation (Part III, Section C, Tab 13, Schedule 68) resulting in $.99 million ($3.3 million X 30 percent 2009 tax rate) benefit being included in the $25 million After Tax Surplus Available for Sharing (Part III, Section C, Tab 13, Schedule 68), when in fact 100 percent of the benefit should go to the ratepayer?

Response:

The Company confirms that the $3.3 million adjustment relating to capitalized overheads is captured in the ESM calculation, but does not confirm that 100 percent of the benefit should go to the ratepayer.

The changes in the capitalized overhead calculation do not meet the criteria for deferral as set out in Appendix A to Order No. G-51-03 (page 12), which proposed a deferral account to record variances in income tax rates, LCT rates, and new government tax expenses, charges and levies.

Under the PBR agreement, sharing a variance that relates to a prior period by way of the Earnings Sharing Mechanism is the appropriate way to deal with a difference that does not meet the criteria for deferral.

149.2 Please explain why the $3.3 million CCA deduction was not tax adjusted using the 2008 tax rate that was in effect when TGI received the benefit of the tax deduction?

Response:

The Company is of the view that the appropriate tax rate to use is the tax rate in effect at the time the adjustment is determined and the benefits are returned to customers.

150.0 Reference: Taxes

Property Tax Rates

Part III, Section C, Tab 7, p. 408, par. 5

"Utility tax rates in 2008 were up to 23 times that of residential rates, depending on the municipality."

150.1 Please provide a table of the municipalities where Terasen Gas pays property taxes. Include the residential and utility tax rates, and amount of taxes paid in 2008 by municipality. Separate the revenue tax from property tax amounts.

Response:

The table below shows the total property taxes collected by municipalities for municipal services and for services provided by other regional or provincial taxing authorities. It is important to note that this table only indicates property tax paid to municipalities by Terasen Gas and does not include property taxes paid in rural districts or property taxes paid to First Nations.

Tax Rates and Taxes Paid Municipal and Other Taxation Authorities

Municipality	Residential Mill Rate ($/$,000)	Utilities Mill Rate ($/$,000)	Property Taxes	S353/S398 Taxes (Revenue Taxes)	Total Property Taxes
100 Mile House	9.67110	61.81719	$51,518	$22,464	$73,982
Abbotsford	6.85511	56.09371	$959,386	$587,432	$1,546,818
Anmore	3.52890	19.66610	$38,059	$7,922	$45,981
Armstrong	5.18470	35.20500	$34,810	$25,143	$59,953
Ashcroft	9.76160	56.60980	$27,237	$10,319	$37,556
Belcarra	4.06580	23.91576	$15,216	$3,183	$18,399
Burnaby	4.56130	48.62550	$1,569,425	$942,930	$2,512,355
Cache Creek	7.42420	31.36880	$11,776	$8,148	$19,924
Castlegar	6.90990	53.30200	$89,400	$47,361	$136,761
Chase	7.86140	61.37150	$23,851	$11,930	$35,781
Chetwynd	11.58900	65.62300	$12,556	$26,874	$39,430
Chilliwack	6.87036	57.78839	$431,965	$311,728	$743,693
Clinton	12.87590	46.93240	$5,697	$4,310	$10,007
Coldstream	6.49724	35.62628	$129,170	$51,541	$180,711
Coquitlam	4.99590	56.57880	$557,460	$524,165	$1,081,624

Municipality	Residential Mill Rate ($/$,000)	Utilities Mill Rate ($/$,000)	Property Taxes	S353/S398 Taxes (Revenue Taxes)	Total Property Taxes
Cranbrook	8.52870	62.42150	$180,211	$127,223	$307,434
Creston	9.78290	66.64070	$49,238	$28,055	$77,293
Delta	5.63210	61.57750	$1,060,664	$600,238	$1,660,902
Elkford	7.93220	47.78546	$79,101	$21,220	$100,321
Enderby	6.33700	36.30810	$32,585	$14,043	$46,628
Fernie	7.50178	71.62927	$34,633	$42,418	$77,051
Fruitvale	9.04774	38.56066	$19,301	$7,283	$26,585
Grand Forks	7.36220	56.63960	$38,245	$26,868	$65,113
Greenwood	9.55970	38.95960	$7,795	$2,830	$10,625
Harrison Hot Springs	6.27373	27.21561	$11,628	$8,859	$20,487
Hope	7.83320	59.16210	$26,840	$28,792	$55,632
Hudson's Hope	7.14810	43.09020	$18,600	$6,720	$25,320
Kamloops	8.02640	57.65920	$763,617	$443,173	$1,206,791
Kelowna	6.50450	36.44480	$775,422	$510,047	$1,285,469
Kent	5.91740	66.89090	$59,319	$22,099	$81,418
Keremeos	8.09640	38.04990	$13,893	$5,998	$19,891
Kimberley	5.81362	57.16674	$42,988	$50,267	$93,255
Lake Country	5.38510	61.10590	$233,114	$40,142	$273,256
Langley	5.85960	57.62390	$61,249	$155,252	$216,500
Langley	5.15950	56.54170	$1,213,126	$488,276	$1,701,402
Logan Lake	7.03530	54.44040	$23,827	$15,207	$39,033
Lumby	8.45083	64.19888	$39,611	$6,308	$45,919
Mackenzie	10.74120	55.81470	$46,072	$40,241	$86,313
Maple Ridge	5.84790	57.62380	$381,548	$303,150	$684,698
Merritt	8.61440	60.59310	$48,209	$47,375	$95,584
Midway	6.81280	38.42340	$184,314	$4,078	$188,392
Mission	6.45710	57.03230	$244,859	$123,596	$368,454
Montrose	7.07462	30.07353	$10,484	$3,470	$13,954
Nelson	8.34565	50.62221	$49,709	$61,152	$110,861
New Westminster	5.88180	47.15270	$174,458	$283,825	$458,283
North Vancouver	4.30790	57.62392	$148,339	$221,775	$370,114

Municipality	Residential Mill Rate ($/$,000)	Utilities Mill Rate ($/$,000)	Property Taxes	S353/S398 Taxes (Revenue Taxes)	Total Property Taxes
North Vancouver	4.37567	57.63059	$330,712	$416,157	$746,869
Oliver	6.04540	34.01610	$16,953	$18,033	$34,986
Osoyoos	5.09350	23.74500	$27,815	$26,552	$54,367
Peachland	5.39770	28.01490	$46,303	$22,895	$69,199
Penticton	6.36360	40.28680	$313,925	$148,446	$462,372
Pitt Meadows	5.59170	57.62480	$102,572	$73,876	$176,448
Port Coquitlam	5.50380	57.61520	$178,788	$231,198	$409,987
Port Moody	5.13550	57.62800	$132,190	$318,742	$450,932
Prince George	10.67185	56.24808	$515,560	$484,138	$999,697
Princeton	6.62141	52.96853	$28,204	$20,602	$48,806
Quesnel	10.71763	62.89198	$114,108	$76,874	$190,982
Revelstoke	5.87190	73.88620	$53,193	$36,312	$89,505
Richmond	4.52504	46.04456	$763,827	$917,592	$1,681,419
Rossland	11.25340	54.27620	$93,058	$17,796	$110,854
Salmo	7.87730	62.28390	$10,540	$4,806	$15,346
Salmon Arm	6.71450	46.20470	$230,756	$95,094	$325,850
Spallumcheen	5.87460	38.77000	$159,364	$28,844	$188,208
Sparwood	6.40390	44.25830	$131,696	$29,974	$161,669
Squamish	5.59398	56.05808	$67,180	$42,760	$109,940
Summerland	5.18700	37.36750	$69,136	$49,138	$118,273
Surrey	4.40401	46.75901	$2,926,788	$1,728,814	$4,655,602
Trail	9.74840	70.20610	$197,665	$59,561	$257,227
Vancouver	4.10778	52.21255	$1,563,802	$3,175,976	$4,739,778
Vernon	7.50155	62.79480	$475,659	$183,936	$659,595
Warfield	8.90678	32.86165	$17,038	$7,641	$24,678
West Vancouver	3.76360	26.67000	$244,501	$304,653	$549,154
Westside	5.46658	26.94804	$255,089	$120,620	$375,709
White Rock	5.53721	39.88658	$35,477	$87,453	$122,930
Williams Lake	10.75836	60.75037	$117,808	$85,492	$203,299

151.0 Reference: Rate Base

Business Risk – Deferral Accounts

Part III, Section C, Tab 8, p. 427, par. 2

"The Commission is concerned that BC Gas has created so many deferral accounts that it may be shielding itself from normal business risks of a Utility."
Ref: BC Gas Utility Ltd. 2003 RRA Decision 2003-02-04, Section 7.3(C)(12), p. 41

151.1 Please confirm all Terasen Gas' deferral accounts impacting the 2010-2011 period are listed in Table C-8-4 on p. 428.

Response:

Table C-8-4 on p. 428 reflects the total mid year balance of all deferral accounts impacting the 2010-2011 periods; however, some of the individual accounts have been summarized together for presentation purposes. A comprehensive list of each deferral account and its individual balance can be found in Section C, Tab 13, Schedule 76 for 2009, Schedule 54 for 2010 and Schedule 55 for 2011.

151.2 Please indicate for the deferral accounts in Table C-8-4 the starting year and the forecast probable ending year.

Response:

The deferral accounts are discussed on pages 428 to 440 of the Application.

With respect to the quoted passage in the preamble, TGI notes that these deferral accounts serve different purposes, and what is most relevant is the reason for which the account was implemented, not the incidental effect that some of the accounts may have in respect of short-term business risk.

The deferral account for the RSAM, a margin-related deferral account, was implemented in part to decouple utility earning from volumes (since without such decoupling there would be a disincentive for the utility to pursue DSM measures) and in part to eliminate a potentially contentious issue from revenue requirement proceedings. The RSAM relates to use per residential and commercial customer; without the account, there would be in every revenue requirement proceeding the possibility of dispute over the forecasts of the use per customer. Appropriate decisions by the Commission on such disputes should, over the longer-term, neither favour the customers or the utility. The RSAM has the same result. So while the RSAM may create a perception that it reduces business risk (TGI does acknowledge it reduces short-term earnings volatility), over the longer-term the utility is in the same position it would be under fair and even-handed Commission decision. The RSAM does not affect the longer-term business risk of the utility but does decouple and eliminate a potential contentious item from revenue requirement proceedings.

The CCRA and the MCRA, and their predecessor the GCRA, are in place to ensure that customers do not pay too much, or too little for the commodity portion of their gas bills.

The Energy Policy Related accounts, for instance, were authorized by the Commission primarily as a means of recording EEC expenditures and conversion grants and recording these costs in the periods to which they benefit, not as a risk mitigation mechanism.

Please also see the response to BCUC IR 1.151.4, which describes how the long term business risk of Terasen Gas is unrelated to deferral accounts.

	Approval Year	Probable Ending Year
Margin Related		
Commodity Cost Reconciliation Account (CCRA)	2004	Ongoing
Midstream Cost Reconciliation Account (MCRA)	2004	Ongoing
Revenue Stabilization Adjustment Mechanism (RSAM)	1994	Ongoing
Interest on CCRA/MCRA/RSAM	2003	Ongoing
Revelstoke Propane Cost Deferral Account	1990	Ongoing
SCP Mitigation Revenues Variance Account	2000	Ongoing
Energy Policy Related		
Energy Efficiency & Conservation (EEC)	2009	Ongoing
NGV Conversion Grants	1999	Ongoing
Non-Controllable Items		
Property Tax Deferral	2003	Ongoing
Insurance Variance	2003	Ongoing
Pension & OPEB Variance	2003	Ongoing
BCUC Levies Variance	2004	Ongoing
Interest Variance	1997	Ongoing
Olympics Security Costs Deferral	2008	2013
IFRS Conversion Costs	2008	2013
Cost of Current Applications		
2009 ROE & Cost of Capital Application	New	2014
2010-2011 Revenue Requirement Application	New	2011
CCE CPCN	New	2014
Other		
IFRS Transitional Deferral	New	TBD
Pension & OPEB Funding	2003	Ongoing
Residual Deferred Charges		
SCP Tax Reassessment	2006	2010
Deferred Service Line Installation Fee	2007	2010
Earnings Sharing Mechanism	2003	2011
Other	Various	2010 [22]

[22] The approval year reflects the most current BCUC Order No. relating to each category of deferral. Some of these accounts, such as the MCRA , CCRA, EEC and Cost of Current Applications have similar predecessor accounts that were in place in advance of the approval date noted.

151.3 For accounts that indicate zero in 2011, please comment on the likelihood that they will actually have zero balances in 2011 or if the 2011 amounts will be adjusted through a process separate from this Application.

Response:

The CCRA, MCRA and Revelstoke Propane Cost Deferral Accounts are not likely to have zero mid-year balances in 2011. These accounts will be adjusted through a process separate from this Application.

The Insurance, Pension & OPEB and BCUC Levies Variance deferral accounts are also not likely to have a zero mid-year balance in 2011. The Application reflects the best available forecast information of the expenses associated with these deferral accounts; therefore, there is no basis for forecast deferral account additions for 2010 and 2011. Furthermore, it is likely that any 2011 mid-year balance that remains in these accounts will be minimal.

It is highly likely that any deferred charges in the Residual Deferred Charges category will have zero mid-year balances in 2011.

151.4 Please comment on the amount of business risk at Terasen Gas which is not shielded by a deferral account.

Response:

Business risk for TGI is the risk to the Company's ability to recover (i) the capital investments it has made to serve customers over the long term and (ii) a fair and appropriate return on those investments.

By their very nature, a gas utility's primary investments have a useful life that extends over a long period of time. Therefore, when evaluating the business risk of a gas distribution utility, it is the longer-term fundamental business risks that must be given primary consideration.

The majority of TGI's deferral accounts have been put in place to ensure forecast variances do not result in costs being inappropriately borne by customers or the company. An incidental effect may be the reduction of some short term risk. TGI's deferral accounts do not have the effect of mitigating long-term business risk. The long-term business risk of Terasen Gas is unrelated to deferral accounts.

As noted in the response to BCUC IR 1.151.2, it is important to consider the reason that each of the deferral accounts was implemented; the effect that a deferral account may have on short-term risk should not be the primary consideration on the appropriateness of the continuation of a deferral account.

152.0 Reference: Rate Base

Deferral Accounts - Regulatory Assets and Liabilities

Part III, Section C, Tab 8, p. 426, par. 4

152.1 Please provide Terasen Gas' policy on standardization with IFRS. Include Terasen Gas' objectives with respect to minimization of separate Regulatory specific accounts.

Response:

Terasen Gas' policy with respect to the standardization with IFRS is to harmonize regulatory accounting with financial reporting to the greatest extent possible while balancing with the need to provide stable delivery rates to customers. To meet these objectives, the Company has proposed to implement deferral accounts where appropriate and to limit all regulatory and IFRS differences to those that can be captured and tracked in deferral accounts.

As noted on page 476 of the Application, Terasen Gas is promoting the minimization of separate Regulatory specific accounts in order to:

a) Reduce the administrative burden of reconciling differences between the financial reporting results under IFRS and the regulatory reporting results;

b) Reduce the costs for additional audit and verification that will be required when amounts recorded for regulatory purposes are not captured in the audited financial statements; and,

c) Improve transparency by presenting harmonized financial results to all stakeholders.

Subsequent to the RRA filing, the IASB has issued its Exposure Draft on Rate-regulated Activities. If the final form of the Standard reflects what is described in the Exposure Draft, then TGI expects that its regulatory deferral accounts will meet the recognition criteria for financial statement purposes under IFRS. Therefore, the objectives that guided the creation and maintenance of deferral accounts under Canadian GAAP continue under IFRS.

152.2 With reference to the material on page 476, please detail the Company's view on the need to avoid volatile impact on the Company.

Response:

The Company has an obligation to adopt and meet the requirements of the new accounting standards. As stated in the Application, the impacts of these standards on rates can be managed through the use of deferral accounts. The existence of regulatory deferral accounts, where also recognized for financial statement purposes, also serves to mitigate the impact on earnings of unforecasted variances from approved costs. The value of regulatory deferral accounts in avoiding volatility in rates and earnings is well demonstrated by the effectiveness of the RSAM, MCRA, and CCRA.

The accounting changes discussed in the Application are not expected to introduce significant volatility (with the exception of certain pension related changes) in that we are not expecting a large increase in costs in one year followed by a large decrease in the next. For example, the increases in depreciation rates are primarily driven by the under-recovery of historical plant balances, so will have no offsetting future decrease until these historical assets are fully recovered.

153.0 Reference: Rate Base

Deferral Account - Energy Efficiency and Conservation

Part III, Section C, Tab 8, p. 432, par. 1

153.1 Please provide the probable impact on future rates, including the percentage increase in 2012 to the prime residential rate, on the deferral of the 2008-2011 costs in Table C-3-2 on p. 229.

Response:

The approximate impact on delivery rates of the deferral of the 2008-2011 costs in Table C-3-2 is an increase of 0.41% in 2010, an increase of 1.17% in 2011 and an increase of 1.77% in 2012. As described on page 228 of the Application, pursuant to the Commission's EEC Application Decision only the actual spend on EEC activities will be charged to the EEC deferral account, with the result that only the actual spend will be reflected in customers' delivery rates for the years 2012 and beyond. As such, the amounts in C-3-2 represent maximum spending levels.

EEC Deferral Account Continuity

	2008	2009	2010	2011	2012
Opening Balance	-	510	5,420	23,222	42,466
Gross Additions	744	7,258	25,845	29,619	-
Less Taxes	(234)	(2,177)	(7,366)	(7,849)	-
Net Additions	510	5,081	18,479	21,770	-
Amortization Expense	-	(170)	(678)	(2,526)	(4,533)
Closing Balance	510	5,420	23,222	42,466	37,933
Mid Year Average	255	2,965	14,321	32,844	40,199

Incremental Cost of Service & Rate Impact of EEC Deferral Account

	2010	2011	2012
Tax Rates	28.50%	26.50%	25.00%
Equity Earned Return	2.97%	2.97%	2.97%
Return on Rate Base	7.31%	7.37%	7.37%
Income Tax Expense Calculation			
Equity Earned Return	425	974	1,192
Add: Amortization Expense	678	2,526	4,533
Taxable Income After Tax	1,103	3,500	5,725
Before Tax Income	1,542	4,762	7,633
Tax Expense	440	1,262	1,908
Cost of Service			
Amortization Expense	678	2,526	4,533
Tax Expense	440	1,262	1,908
Earned Return	1,046	2,421	2,963
Total Cost of Service Impact	2,164	6,208	9,404
Margin @ Existing Rates	528,677	531,158	531,158
Cost of Service Impact as a % of Gross Margin	0.41%	1.17%	1.77%

The approximate impact on delivery rates of the deferral of the 2008-2011 costs in Table C-3-2 is an increase of 0.41% in 2010, an increase of 1.17% in 2011 and an increase of 1.77% in 2012.

154.0 Reference: Rate Base

Deferral Account - New Energy Solutions

Part III, Section C, Tab 8, p. 432, par. 3

154.1 It appears the company is becoming a lender to finance NGV facilities. Why does it make sense for the regulated utility to be in the financing business?

Response:

Note that financing is an option that is already provided for in the TGI Tariff under the General Terms and Conditions Section 15 – Promotions and Incentives whereby the company can "finance natural gas equipment". However this clause notwithstanding, financing will be the last option offered to customers as we believe customers would prefer that TGI own and operate the equipment as part of a comprehensive NGV service. If TGI owns and operates the equipment, it is able to size and resize the equipment to meet the changing needs of the customer. In other words as customers needs and volume requirements change, TGI would could remove existing compression equipment (which would then be used at other customer locations) and install different equipment that would provide the service the customers require (similar to the management of gas meters). The new or existing customers who require capacity or a capacity adjustment must pass the Compression Extension test to ensure that their expected revenues would recover the costs associated with this change in equipment. Further, there would be additional regulatory burden associated with lending options as BCUC approval would be required. For these reasons, TGI believes that while it is important to maintain the option for financing, it would not be the first option TGI would pursue.

However, in the case that the only option a customer wishes to pursue is a financing option, TGI would come to an agreement with the customer on the structure of the financing, which would then be submitted to the Commission for approval. This approach helps to minimize any financing risk. The Company believes that offering grants or financing projects provides an incentive for customers to pursue an NGV option. This helps bridge the gap to convert to natural gas and once converted that new load will increase system utilization reducing delivery costs for all customers.

154.2 What portion of risk is being absorbed by the Company?

Response:

As stated in BCUC IR 1.154.1 financing would be the last option offered to customers; however if offered, TGI will assess each individual case and enter into a contract that will mitigate the risk of default. For customers that are deemed to be higher risk, applicable terms and conditions may include higher interest rates and/or security deposits. Note that this agreement would be submitted to the Commission for approval at that time. We believe that as the NGV service grows and matures, existing customers will benefit from the additional load and revenues. In terms of grants, the approved Rate Schedule 6 is intended to appropriately recover the cost of grants from NGV customers therefore protecting other customers. The same principle would apply to financing natural gas vehicle equipment. Grants are recovered through the compression and refueling charge and the increased load will reduce rates of all customers.

155.0 Reference: Rate Base

Deferral Account - IFRS Transitional

Part III, Section C, Tab 8, p. 435, par. 3

155.1 The items referenced appear to be one-time adjustments required on the adoption of IFRS. Please explain when the items in this deferral account would be cleared.

Response:

TGI has not put forward a proposal to recover the IFRS Transitional Deferral account at this time since the nature of the items that are ultimately recorded in the deferral may impact the proposed recovery period. For example, if the only amount recorded in the deferral is related to employee future benefits, TGI would likely recommend that the amount be recovered over the expected average remaining service life of the employee group, consistent with how these amounts would have been recognized under existing Canadian GAAP. A proposal will be put forward in 2011 relating to the disposition of any amounts in the deferral account.

156.0 Reference: Rate Base

Contribution In Aid of Construction (CIAC)

Part III, Section C, Tab 8, p. 467, par. 1

156.1 Please provide the definition for "SLIF".

Response:

SLIF is the acronym for "Service Line Installation Fee". The SLIF was eliminated on January 1, 2008 by Commission Order No. G-152-07 and the TGI and TGVI "System Extension and Customer Connections Policies Review" Decision (page 19) dated December 6, 2007.

156.2 Please explain why recognition of the elimination of "SLIF" is being deferred until after the end of the PBR period, and why this is in the best interests of the ratepayers. Would recognition of the elimination during the PBR result in a sharing of cost with the Company?

Response:

The statement that "recognition of the SLIF elimination is being deferred until 2010" relates only to the fact that the CIAC itself is being restated to actual in 2010; the elimination of the SLIF has been accurately reflected in customer rates in both 2008 and 2009.

The purpose of the entries related to the elimination of the SLIF was to ensure that customers were neither positively nor negatively affected by the change. Correspondingly, the entries also ensure that the elimination of the SLIF did not impact the Earnings Sharing Mechanism:

- In 2008, the SLIF was eliminated subsequent to when rates were set for that year. Consequently, and consistent with Commission Order G-153-07, TGI made an entry in its rate base to credit the forecast amount of the SLIF to the CIAC account so that the rate base would remain consistent with that used to set rates and customers would be unaffected from an earnings sharing perspective for that year. The offset to that entry was a non-rate base deferral account.
- In 2009, rates were set excluding the SLIF, so the entry noted above was no longer required for that year. As approved by Commission order G-191-08, the existing 2008 non-rate base deferral account was transferred to a rate base deferral account to ensure that the 2009 rate base was unaffected.

- For 2010, TGI is proposing to close the rate base deferral account against the CIAC account. This ensures that that the rate base impact is equal to zero and that the CIAC is effectively "rebased" back to what it would have been had only the actual SLIF of zero for 2008 been recorded.

157.0 Reference: Rate Base

IFRS – Gains and Losses on Asset Disposal

Part III, Section C, Tab 8, p. 425, par. 2

157.1 Please explain why it makes sense for the ratepayers to include asset gains and losses in a deferral account rather than following the required IFRS treatment once Terasen implements IFRS.

Response:

The recommended IFRS treatment for gains and losses on disposal of assets is that they be recognized in income immediately. As indicated in response to BCUC IR 1.180.5, TGI is unable to identify specifically which assets may be retired over the forecast period, and is therefore unable to make an estimate of gains or losses that may result. Therefore, any gains or losses that would occur over the forecast period would be taken into income and the resulting gains and losses would accrue to TGI's shareholder, absent any deferral account mechanism. Since the primary driver behind normal course asset gains and losses for gas distribution and transmission assets is depreciation that has been over or under recovered from ratepayers, and these disposals are a normal and necessary part of operating a utility business, the gains and losses associated with the under and over-recovery of depreciation are also appropriately borne by, or to the credit of, ratepayers.

157.2 What is the impact in 2011 of moving to the IFRS required treatment for gains and losses on Asset disposal.

Response:

There would be no impact on this RRA of moving to the IFRS required treatment for gains and losses on asset disposal, since no gains or losses have been forecast.

158.0 Reference: Rate Base - Gas –in –Storage and Other Working Capital

Part III, Section C, Tab 8, page 442

158.1 In this RRA, TGI is proposing to extend interest treatment to the gas in storage inventory balance. Please provide an example of this proposal and show how it would benefit customers.

Response:

The deferral account for interest on variances in the gas in storage inventory balance benefits customers in ensuring that the rates customers are paying only recover the forecast average cost of gas in storage. Consequently, both the Company and customers benefit from the fact that there is no potential windfall in either direction from variances that are outside of the company's control; any potential savings in financing is captured by the deferral account.

The interest charged or credited to the deferral account covers the financing cost associated with the variance in the gas in storage costs, actual versus forecast. Variances in the Gas-in-Storage costs are subject to significant price movements that the utility has little control over. As an example, from 2001 through 2008 the variance between actual and forecast average cost of gas in storage has varied from a credit (actual less than forecast) of $22.4 million to a debit of $39.5 million.

The deferral account to record the interest on the variance between forecast and actual would work in the same manner as the existing interest deferral account for variances in the CCRA, MCRA and RSAM. The deferred interest amount would be calculated as the actual versus the forecast Gas in Storage costs multiplied by the composite short term interest rate. Only the forecast/approved amount of gas in storage inventory would be included in calculating the Utility Rate Base for regulatory reporting, since the utility and customers are compensated for any variances through the deferred interest mechanism. The following illustrates an example of how the Deferred Interest would be calculated and impact the Rate Base.

Example of Impact on Rate Base From Deferred Interest on Gas in Storage Cost Variance Between Forecast and Actual

	Particulars		Amount $000's
1	2010 Forecast Gas in Storage		$ 100,494
2	Assumed Actual		75,000
3	Variance		$ (25,494)
4			
5	Assumed Composite Short Term Debt Rate		1%
6			
7	Deferred Interest		$ (255)
8	Tax Rate / Tax Offset	28.50%	73
9	After Tax Cost of Deferred Interest		$ (182)
10			
11	Mid-Year Rate Base		$ (91)
12			
13	Cost of Service Impact [1]		
14	Return on Rate Base	7.31%	$ (7)
15	Income Tax Expense		(1)
16	Total Cost of Service		$ (8)
17			
18	Income Tax Expense		
19	Return on Equity [2]	8.47%	$ (3)
20			
21	Taxable Incme After Tax		$ (4)
22	Current Tax Rate	28.50%	
23	Income Tax Expense		$ (1)
24			
25	1) This calculation would be for financial and regulatory statement purposes as the test year forecast assumes no variance.		
26	2) The equity component in the capital structure is 35.01%, hence the calculation is Mid-Year Rate Base x 35.01% x Return on Equity (8.47%)		

In this example the Deferred Interest – Gas in Storage account would be credited $255 thousand with a tax offset of $73 thousand; the deferral account balance would be included in rate base on a mid-year basis.

There are alternatives for the recovery of the deferred interest, starting in 2012. One method would be to amortize the deferred interest – gas in storage account (in this example reducing the cost of service / future revenue requirement). An alternative would be to include the deferred interest on storage costs as part of the Midstream in setting the midstream recovery charge (similar to the method used to recover deferred interest on MCRA).

159.0 Reference: KPMG Cash Working Capital Lead-Lag Study Review

Appendix I, Tab 2, Section 1.0, p. 3

Page 3 of the report states that: "…KPMG found that the Study…does not materially exclude any revenue and expense items as compared to the financial statements."

159.1 What is the materiality level and please discus how this was determined?

Response:

KPMG responds as follows.

The term "material" in this context refers to Terasen Gas' use of revenue and expense data samples from subledgers and/or other financial data systems in order to calculate each component of the lead or lag (i.e. service, billing and payment lags). As such, a specific materiality level was not determined and applied as might typically be done for audit purposes but rather KPMG reviewed the sample data to determine if the information provided a suitable basis for calculation of the lead/lag days.

159.2 Would the materiality level be appropriate for both the TGI and TGVI working capital allowance calculation? Please explain why or why not.

Response:

KPMG replies that "the context of materiality as described in the response to 159.1 applies to both TGI and TGVI."

160.0 Reference: KPMG Cash Working Capital Lead-Lag Study Review

Appendix I, Tab 2, Section 3.0, p. 6

"In arriving at the forecast CWC, it is important for a utility to analyze current business information to provide the confidence that it accurately represents conditions for the forecast years. Generally utilities will use the most recent complete 12 month calendar year as the basis for its lead-lag study and make any significant adjustments that may have arisen since the study period or that are expected to arise in the future."

160.1 Why was a 2007 forecast year used when 2008 data would have been available?

Response:

Terasen Gas used 2007 actual data as it commenced work on the Lead-Lag Study in October 2008 and completed the study in March 2009. As a result, 2007 was the most recent complete 12 month calendar year of actual results on which to base the lead-lag study.

160.2 Were there any significant adjustments that arose since the study period that resulted in adjustments to the 2007 forecast year?

Response:

As noted in the response to 160.1, TGI used 2007 actual year data and not the 2007 forecast year.

The only significant adjustment that has arisen resulting in an adjustment to the 2007 actual data for the Lead-Lag Study was for the BC Carbon tax. This was noted on page 7 of the Lead Lag study, included in Appendix I, Tab 2, Section 3 page 7 of the Application, which states "On July 1, 2008, a Carbon Tax was introduced by the BC Provincial Government. Given the effective date, the study period for the Carbon Tax consists of the last 6 months of the 2008 calendar year."

160.3 Are there any significant adjustments that are expected to arise in the future which required an adjustment to the 2007 forecast year?

Response:

Terasen Gas is not aware of any other significant adjustments that are expected to arise in the future which would require an adjustment to the 2007 actual (not forecast, see TGI's response to BCUC IR 1.160.1) data used for the lead lag study period.

161.0 Reference: KPMG Cash Working Capital Lead-Lag Study Review

Appendix I, Tab 2, Section 1.0, p.3

KPMG states that Terasen "Appropriately uses the 2007 study period to reflect activity expected in the 2010/11 forecast years."

161.1 Please describe the basis for of the above statement?

Response:

Given that Terasen Gas commenced the Lead-Lag Study in October 2008 and completed it in March 2009, the 2007 year represents the most recent complete 12 month calendar year of actual results on which to base the lead-lag study. Terasen Gas expects that business activity in the 2010/11 forecast years will not differ significantly from the business activity carried out in 2007 and in the last 6 months of 2008 for the Carbon Tax. Therefore KPMG is of the view that this is an appropriate basis from which to perform Terasen Gas's Lead-Lag study.

162.0 Reference: KPMG Cash Working Capital Lead-Lag Study Review

Appendix I, Tab 2, p. 3

On page 3 of the report, Terasen Gas states that: "The assumption that the data within the lead-lag calculation models provided by TGI/TGVI accurately represents all major revenue and expense items, and that the study year chosen represents activity expected in the forecast year."

On page 3, KPMG further states that the study includes all major revenue and expense items and does not materially exclude any revenue and expense items as compared to the financial statements."

162.1 Did KPMG verify the balances used in Terasen Gas Inc. Cash Working Capital Lead-Lag Study by tying the balances to the trial balance or the financial statements?

Response:

KPMG verified the balances used in Terasen Gas Inc Cash Working Capital Lead-Lag Study by tying to the 2007 trial balance.

162.2 Can KPMG provide any assurance over the account balances used in the Working Capital Allowance calculation included in Part III, Section C, Tab 13, Schedules 56-60?

Response:

As the process for determination of the Working Capital allowance forms part of the Application and not part of the Lead/Lag study, and with the approach being formulaic and consistent with past methodology, KPMG was not asked to provide any assurance on any other aspects of the Working Capital Allowance for 2010 – 2011 besides the Lead/Lag Days. KPMG was contracted to perform an independent review of the Terasen Gas Inc/Terasen Gas (Vancouver Island) Inc. Cash Working Capital Lead-Lag Study as the Lead/Lag Day calculation forms an important input into the determination of Cash Working Capital.

The Lead/Lag study develops the component Revenue Lag Days and Expense Lead Days for the 2007 forecast year, which are reproduced in Section C, Tab 13, Schedules 59-60. These component Lead/Lag Days are then utilized to develop the Cash Working Capital for 2010 and 2011.

The development of Cash Working Capital for 2010 and 2011 follows a formulaic approach consistent with past methodology. Annual forecasts for the revenue and expense components are multiplied by the component Lead/Lag Days to arrive at component Dollar Days. The Revenue Dollar Days and the Expense Dollar Days are summed and divided by Total Revenues and Total Expenses to produce dollar weighted Lag Days for Total Revenues and Lead Days for Total Expenses. The difference becomes the Net Lead-Lag Days which, when divided by 365 days and applied to Total Expenditures produces Cash Working Capital.

162.3 Please provide a copy of FERC NOPR RM84-9-000, Calculation of Cash Working Capital Allowance for Electric Utilities, April 5, 1994.

Response:

TGI notes that the NOPR is dated April 5, 1984. Please refer to Attachment 162.3.

FERC NOPR RM84-9-000 proposed to add a new rule 35.24 to it's Regulations. The proposed rule would prescribe the expense elements to be considered in calculating Cash Working Capital adjustments to Rate Base. This rule was intended to establish a presumption of cash working capital requirements that most closely reflects utility practises and to that end the objective of the rule is to improve clarity, consistency and accuracy of cost based ratemaking.

KPMG found that the TGI Lead Lag Study was consistent with principles and guidance offered in FERC NOPR RM84-9-000.

162.4 How were transactions between TGI/TGVI treated in the Working Capital Allowance calculation?

Response:

Transactions between TGI and TGVI were treated in the same fashion as other transactions. TGI identified both a Service Lead/Lag as well as a Payment Lead/Lag for such inter-company transactions. The Service Lead/Lag is typically calculated to be 15.2 days as described in the response to BCUC IR 1.163.1. The Payment Lead/Lag is as per payment terms of a contract if one exists. Otherwise, a 30 day payment term is assumed. An example of a contract between TGI and TGVI is the Wheeling Agreement between the two firms. The agreement stipulates that payment is to be made by the 25th of the month following month of service. In this case the Service Lead would be 15.2 days based the mid point of 12 service periods in a year and the Payment Lead would be 25 days for a Total Lead of 40.2 days.

163.0 Reference: Cash Working Capital

Part III, Section C, Tab 13, Schedule 59

On line 25 of Financial Schedule 59 "Gas Sales and Transportation Service Revenue – Residential and Commercial" Lag Days Service to Collect (column 3) in 2009 is 34.8 days and then rises to 38.3 days in 2010 and remains there for 2011.

163.1 The increase in the 'lag days service to collect' has caused the working capital to go from a surplus position in 2009 to a shortfall position in 2010 and 2011. Please provide a full analysis with calculations and explanation for the dramatic increase in this lag time.

Response:

Terasen Gas is of the opinion that the increase in Lag Days Service to Collect over the years is primarily attributable to the increased usage of on-line payment by Terasen Gas customers. On-line payment enables a customer to choose future dates of payment for settling their bills. This simplifies the process of delaying bill payment until payment due date.

Terasen Gas has performed a detailed analysis as set out in its Lead-Lag Study to support the Lag Days Service to Collect of 38.3 days in 2010 and 2011. The Lag Days Service to Collect of 34.8 days currently used for 2009 dates back to a 1991 Lead Lag study and a time when meter reading and collections for Lower Mainland customers was being performed by BC Hydro. As requested, following is a detailed description of the analysis completed.

For 2010 and 2011, Lag Days Service to Collect is the sum of the Service Lag, Billing Lag and Collection Lag.

The Service Lag captures the time from the deemed average receipt date of service to the average meter reading date. Given 12 billing cycles in a 365 day year, each billing cycle spans on average 30.4 days. Under conditions of continuous service, the Service Lag then becomes ½ of the billing cycle span or 15.2 days

The Billing Lag captures the time from meter reading date to billing date. For residential and commercial customers, Terasen Gas attempts to bill customers on the same day as the meter read. However, records show that during the test period 26.84% of the time this customer base was in fact billed the day following meter read. This produces a Billing Lag of 0.3 days

The Collection Lag captures the time between billing date and payment date. In this case, Terasen Gas performed a 100% analysis of the entire database of invoice records for 2007. Invoice dates and payment dates for approximately 10.3 million invoices were captured and weighted to produce a Collection Lag of 22.8 days. This compares to Terasen Gas' payment terms of 22 days following date of invoice.

The Lag Days Service to Collect becomes the sum of 15.2 + .3 + 22.8 for a total of 38.3 days.

Based on its complete analysis and supported by KPMG's review, TGI believes this is the appropriate and reasonable assumption to use in determining working capital requirements.

164.0 Reference: Capital Expenditure

CPCN filing threshold

Part III, Section C, Tab 9, p. 443

164.1 Please clarify that the proposed increase of the CPCN threshold of $5m to $20m is intended to include ALL capital projects (including current core business and new business segments i.e. EEC and Alternative Energy Solutions).

Response:

Yes, it is TGI's intention to have the proposed revised $20 million CPCN threshold limit apply to capital projects in both the current core gas distribution business and the regulated new business segments. TGI believes the proposed $20 million threshold limit, which represents approximately one percent of TGI's rate base, provides for an appropriate balance between ensuring prudent capital spending through proper regulatory oversight and yet avoiding unnecessary administrative burden and costs, both of which are in the interest of ratepayers.

TGI notes, however, that the CPCN threshold (whatever level it is set at) would not apply to EEC expenditures, as suggested in the question. TGI would seek approval for EEC expenditures, as it has here, pursuant to section 44.2 as an expenditure schedule.

164.2 Please describe TGI's Capital Approval policy and discuss whether individual business cases (including an NPV analysis and examination of alternatives) are prepared for each capital project proposed in the test period.

Response:

Please refer to pages 84 and 85 of the Application for a description of TGI's Capital Approval policy.

Proposed capital projects and budgets prepared by departments are presented to the Utility Operating Committee and the Executive Leadership Team annually for review and approval. For administrative efficiency, further approval is not required for specific projects identified, reviewed and approved during the capital budget process.

For projects not specifically budgeted and approved as part of the annual capital budget process, they are subject to an additional review and approval process under TGI's Capital Approval policy. These projects requiring additional approval are brought forth to the Utility Operating Committee and the Executive Leadership with supporting documentation. The supporting documentation required includes a Project Concept document which provides a description of the project, the justification along with the business and financial impacts of not proceeding with the project. A detailed business case summary including NPV analysis and alternative considered may be requested to facilitate a better understanding of the proposal. To ensure effective prioritization of funding for IT capital projects, TGI requires that all IT capital projects regardless of dollar value must be documented and presented to the Utility Operating Committee for review and approval.

TGI's capital review and approval policy provides clearly defined processes for budgeting, approving and authorizing capital expenditures ensuring that capital is put to its best use on behalf of the customer.

164.3 Would Terasen Gas agree that the CPCN process is to ensure prudency of capital spending and is an important regulatory process to ensuring capital spending is necessary and in the best interest of rate payers?

Response:

Terasen Gas agrees that the CPCN process is an important regulatory process to ensuring prudent capital spending in the best interest of rate payers. Terasen Gas believes the CPCN process can work better with the increased threshold limit, as it would exclude projects that are generally not of a complex or significant nature that warrant the cost and administrative burden on all parties of a separate CPCN Application. The proposed $20 million threshold limit for TGI represents less than one percent of its projected rate base for 2010 of $2.5 billion. As the Commission has reiterated in its July 13, 2009 Decision on BCTC's Transmission System Capital Plan Application (at page 17), "As a general guide line, a project would be deemed to be significant if the project cost is in the range of 1 percent of rate base."

Terasen Gas points to its successful track record in managing capital projects that have been subject to the current CPCN process (over $5 m limit) but that would have been excluded under the proposed CPCN threshold of $20 m. In TGI's response to BCOAPO IR No. 1.39.1, listed are four capital projects (under $20 m but more than $5 m) finished during the PBR period, all of which were successfully completed under the funding amounts approved by the Commission.

As indicated in the response to BCUC IR 1.164.1, TGI believes the proposed $20 million threshold limit provides for an appropriate balance between ensuring prudent capital spending through proper regulatory oversight and yet avoiding unnecessary administrative burden and costs, both of which are in the interest of ratepayers.

165.0 Reference: Capital Expenditure - Meter Exchange

Part III, Section C, Tab 9, p.449

165.1 What is the TOTAL estimated number of poor quality meters targeted for recall and retirement?

Response:

Terasen Gas has estimated through its performance sampling program that approximately 105,000 installed meters exhibit a lower life expectancy compared to the remainder of the meter fleet.

165.2 What portion of the 60,000 meters identified in the meter exchange program for 2010 and 2011 relates to the poor quality meters? What portion relates to regular meter exchange activities?

Response:

Please refer to the response to BCUC IR 1.135.1.

165.3 What is the estimated timeframe to replacing all the poor quality meters from the meter fleet?

Response:

The program to remove the meters with lower life expectancy from service is estimated to be completed in 2018. However, the timeline to complete the program will be adjusted according to the results of ongoing performance monitoring of these meters to ensure Terasen's meter fleet continues to operate in a cost effective and reliable manner.

166.0 Reference: Capital Expenditures - Category A – New Meters and Meters Recalled

Part III, Section C, Tab 9, pages 443-467

166.1 Table C-9-1 indicates that New Meters and Meters Recalled will increase from $14 million to $19.7 million and 20.7 million in 2010 and 2011 respectively. What is causing these increases?

<u>Response:</u>

The increase in Meter Capital expenditures from 2009 projections of $14 million to $19.7 and $20.7 million for 2010 and 2011, respectively, is largely due to the increase in the number of meter recalls from approximately 47,000 to 60,000. The increase in quantity from 2009 levels reflects targeting a shift to a 20 year lifespan for meters and a necessity to replace on a shorter cycle certain batches of meters installed in the late 1990's which were comprised of less durable components (refer to page 451 of the Application).

The increase in Meter Capital expenditures is also impacted by a forecasted increase in unit costs from $265/meter in 2009 to $299/meter and $314/meter in 2010 and 2011, respectively. Meter unit costs vary considerably from year to year (refer to page 451 of the Application) and consist of both labour and non-labour costs. The increase in unit costs in 2010 and 2011 from the 2009 level is largely due to increased regulator replacement program expenditures (2009 projection $0.8 million, 2010 forecast $2.1 million, 2011 forecast $2.2 million). In 2003, Terasen Gas began a program of replacing regulators and a large number of these have been identified for replacement due to age and type. Resource limitations have limited Terasen's ability to complete higher levels of this annual program.

The remaining unit cost increases forecast for Meters in 2010 and 2011 are driven by IFRS accounting changes and inflation on materials and labour (wages, pension &benefits changes).

TGI believes these expenditures are prudent and reasonable in providing safe and reliabile meters and regulators to serve new and existing customers.

167.0 Reference: Capital Expenditures - Category A – Mains Activity levels and Unit costs

Part III, Section C, Tab 9, page 446

167.1 What proportion of the costs reflects contractor activity?

Response:

For the 2009 projection and the 2010-11 forecasts, Terasen Gas estimated that 30% of the new mains work would be completed by various install contractors. For 2009-2011, approximately 22% of new mains total forecast expenditures are install contractor costs. The percentage of total forecasted contractor costs (22%) does not equal the percentage of forecasted total contractor work (30%) due to differences in unit costs between Terasen Gas and contractor workforces.

167.2 What is the difference between "Net Customer Additions" and "Gross Net Customer Additions"?

Response:

"Net Customer Additions" is calculated by subtracting the number of customers who have discontinued service in a given year from the number of new customers added during that same year.

The reference to "Gross Net Customer Additions" is a typographical error. It should have read "Gross Customer Additions", which is the total number of new customers added in any given year.

167.3 The ratio of Metres/Net Customer Additions = 18.84 for the period 2009 to forecast 2011. What is this ratio for the period 2003 to 2009 on a yearly basis and overall average? If the average ratio for the 6 year period 2003 to 2008 is 17.20, why would this not be an appropriate ratio to forecast 2010 and 2011?

Response:

The ratio of metres of New Main to Net Customer Additions for the period 2003 to 2011 is provided in the table below together with the six year historical average. The weighted average ratio for the 2003-2008 period is 16.55. The arithmetic average ratio for the 2003-2008 period is 17.19.

Ratio of Metres of New Main to Net Customer Additions

Year	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2003-2008 Average	2009 Projection	2010 Forecast	2011 Forecast
Net Customer Additions	5,546	11,504	12,420	10,181	9,939	9,256	9,808	6,120	5,600	5,850
Gross Customer Additions	12,837	15,549	12,770	13,338	15,533	14,566	14,099	9,600	8,784	9,176
Meters of New Main	121,570	156,604	174,003	164,550	157,004	200,167	162,316	115,305	105,504	110,213
Service Additions	9,955	13,201	12,401	12,525	10,935	10,520	11,590	7,510	6,872	7,178
Ratio of Metres of New Main to Net Customer Additions	21.92	13.61	14.01	16.16	15.80	21.63	16.55	18.84	18.84	18.84
Ratio of Metres of New Main to Net Customer Additions (*2006-2008 Three Year Average*)							17.76			
Ratio of Metres of New Main to Service Additions	12.21	11.86	14.03	13.14	14.36	19.03	14.01	15.35	15.35	15.35
Ratio of Metres of New Main to Service Additions (*2006-2008 Three Year Average*)							15.35			

The Mains activity forecast is not based on the ratio noted above. The forecast is more appropriately based on Service Additions which is derived from Gross Customer Additions. Consistent with previous applications, Terasen Gas has used the 3 year average ratio of Metres of New Main to Service Additions to forecast New Mains.

168.0 Reference: Capital Expenditures - Category A – Services

Part III, Section C, Tab 9, page 447

168.1 What is the ratio of service header mains/Net Customer Additions for the period 2003 to 2008?

Response:

The figure for Net Customer Additions subtracts customers who discontinue service whereas Gross Customer Additions is reflective of new mains and service construction activity. It is not appropriate to use Net Customer Additions to forecast service or mains expenditures and, therefore, the ratio of service header mains/Net Customer Additions is not appropriate for trending. Gross customer additions is the appropriate input for forecasting service and mains expenditures. Please see the response to BCUC IR 1.167.3.

The arithmetical average for the 2003-2008 period was 4.75 metres of Service Header Main for each Net Customer Addition. The weighted average for the 2003-2008 period was 4.66 metres (see table below).

Ratio of Service Header Mains to Net Customer Additions

Year	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2003-2008 Average	2009 Projection	2010 Forecast	2011 Forecast
Service Header Main (Metres)	29,082	49,275	48,480	57,360	41,937	48,041	45,696	34,589	31,821	33,100
Net Customer Additions	5,546	11,504	12,420	10,181	9,939	9,256	9,808	6,120	5,600	5,850
Ratio of Service Header Main to Net Customer Additions	5.24	4.28	3.90	5.63	4.22	5.19	4.66	5.65	5.68	5.66
Arithmetic Average							4.75			

168.2 If the average ratio in this period is 4.75 metres/customer what accounts for the high ratio in 2009 and why is 2009 considered as the base at 5.68 when forecasting 2010 and 2011?

Response:

The Service Header Mains activity forecast is not based on the ratio calculated in the response to BCUC IR 1.168.1. The Service Additions forecast and Service Header Mains forecast are more appropriately based on Gross Customer Additions. The Service Header Mains activities are derived from the Service Additions forecast for 2009-2011 and are projected to decline from the 2008 level of 48,041 metres at the same percentage rates as Services in general.

169.0 Reference: Capital Expenditures - Service Unit Costs

Part III, Section C, Tab 9, page 449

169.1 The unit costs for services over the period 2003 to 2008 had a growth rate of 11.5 percent/year. However the growth rate from 2008 to 2009 is forecast to be 17 percent. What accounts for this increase?

Response:

The 17% growth rate in aggregate services unit cost in 2009 is primarily related to the significant reduction in Interior services activities, which on average are installed at a much lower unit cost than the Lower Mainland and contribute significantly to reducing the overall average unit cost. The number of services installed in the Interior year-to-date (June 30, 2009) is 569 versus 1,742 for the same period in 2008 (a 67% reduction). The slowdown in activities across the province in general is contributing to the overall unit cost increase due to losses in economies of scale. In particular, there is less new subdivision activity (where large numbers of new services can be installed more cost effectively) and proportionately more single in-fill type service work.

For the January to June period in 2008, for example, approximately 33% of services (1,742) installed were in the Interior regions and installed at an average cost of $1298. The remaining 67% of services (3,338) were installed in the Lower Mainland at an average cost of $1792. By comparison, in 2009 for the same time period, approximately 22% of services (569) installed were in the Interior regions and installed at an average cost of $1,778. The remaining 78% of services (1,950) were installed in the Lower Mainland at an average cost of $1,982.

In general, Interior services unit costs tend to be less costly than Lower Mainland services due to favorable contractor pricing, installation conditions (soil type, less pavement, new subdivisions) and less onerous municipal requirements (permits, paving, etc). In 2009, the Interior services installed year-to-date are experiencing higher unit costs ($1,798 versus $1,298) primarily due to the addition of an apprentice to some of the crews, a reduction in new subdivision activity and losses in economies of scale owing to a significant reduction in new services activity.

Since mid-2008, a portion of the Interior crews have included an apprentice as part of the crew compliment to manage the demographic challenge in the Interior IBEW workforce. The apprentices are attached to the crews allowing them to learn alongside the seasoned veterans. Terasen Gas expects this program to continue into 2010 and 2011.

With the economic and housing slowdown, the Interior install contractor workforce has been virtually eliminated. In 2008, approximately one third of services were installed by the install contractor. In 2009, Terasen Gas crews are installing the 97% of new services. New service installations represents work that Terasen Gas emergency response crews can perform while being available to respond to emergencies. It is relatively easy to close up new service construction sites when interrupted by an emergency, respond accordingly and return to the site once the emergency has been resolved. Terasen Gas' internal field workforce level/model is set to core/emergency footprint requirements similar to fire departments, so that adequate levels of resources are able to respond appropriately to emergencies as well as core operations, maintenance and customer service work, with mains and service work as options available to minimize first response standby and idle time.

In addition to the above factors impacting aggregate services unit cost in 2009, there are several other factors contributing to the higher projected services unit costs, including inflationary increases in wages (approximately 3%), vehicles, contracts and materials (gravel, sand, fill, etc). There have been inflationary increases in paving rates, paving requirements by municipalities and material costs. More onerous paving requirements by municipal authorities have increased the amount of replacement paving required during new service installations. Terasen Gas considers these service unit costs to be prudent and necessary to provide safe, reliable and efficient service to new and existing customers while simultaneously maintaining an appropriate emergency footprint and addressing demographic challenges relative to its IBEW field workforce.

170.0 Reference: Capital Expenditures - Meters – Activity Levels

Part III, Section C, Tab 9, page 451

170.1 TGI states that there were batches of meters constructed with less durable components. How many meters fall into this category and has TGI attempted to obtain some form of compensation from the vendor for these meters with a lower life span?

Response:

Please refer to the response provided to BCUC IR 1.165.1 related to the number of meters with a lower life expectancy.

To date, all meter vendors limit their warranty coverage to breakage of certain components within each meter over a specified timeline. Therefore, vendors maintain the warranty coverage does not include a reduction in life expectancy related to worn components that cause the meter to operate outside tolerances legislated by Measurement Canada. As such, Terasen Gas' request for compensation under the warranty has been denied.

Although this issue has presented a challenge to be overcome, Terasen Gas remains proud of its long history managing a reliable meter fleet and looks forward to remaining an industry leader in the area of gas measurement within Canada. Likewise, Terasen Gas continues to provide strong support for its ISO 9001 certified quality management program and remains committed to the program's stated objective of continuous improvement of systems that achieve meter reliability. To this end, in 2008 Terasen Gas incorporated several proactive measures to align meter vendors to this objective which includes conducting annual quality system audits at vendor manufacturing facilities, requiring quarterly information sharing meetings with the vendor's technical employees, investigating costs associated with expanded warranties and increasing the competitive nature of the procurement process in areas of quality assurance, customer service and price.

170.2 When was TGI alerted to the potential design flaw of a number of meters installed in the late 1990's? Please provide information from the vendor that corroborates this position.

Response:

In 2008, Terasen Gas uncovered the concern that meters installed during the late 1990's were showing signs of premature wear through the process of conducting accuracy tests as part of its annual performance sampling program. The concern was raised with the manufacturer;

however, to date the manufacturer has not provided any information that supports the lower life expectancy of the meters in question.

170.3 If TGI knew about a design flaw and the premature failure in a batch of meters in the field that were installed in the late 1990's, why was it prudent to leave them in service?

Response:

Terasen Gas uncovered the concern related to the meters of lower life expectancy in 2008 while conducting its annual performance sampling program. Work was done in earnest to update the meter recall schedule to ensure these meters are removed from service in the time period in which they have reached their restated life expectancy. Furthermore, the meter recall schedule is regularly adjusted according to the results of ongoing performance monitoring of these meters. Therefore, the diligent manner in which these meters is monitored gives Terasen Gas the confidence that a removal program spanning the period of 2010 through 2018 will provide the most cost effective approach to maintaining the meter fleet reliability.

171.0 Reference: Capital Expenditures - Meters Unit Costs

Part III, Section C, Tab 9, page 451

171.1 Please provide a justification for the unit meter cost of $265. Please provide the actual unit meter costs from 2003 to 2008 in groups by type of meter?

Response:

The 2009 projected blended meters capital unit cost of $265 was based on the actual year-to-date (May 31) experience in 2009 and reflects a decline in meters required for new customers (particularly fabrications), an increase in the 2009 meter exchanges and a reduction in the regulator exchange program.

Actual meter unit costs are not currently tracked by customer group (i.e. residential, commercial or industrial) or by meter type and size. Historically, an aggregate or blended unit cost has been used (refer Table B-1-30 page 188 of Application) to track meter capital unit costs. Aggregate or blended meter capital unit cost is influenced by the type, size, design of the meter, the installation, fabrication and exchange conditions, the timing of bulk meter and regulator purchases and the magnitude of the meter and regulator exchange programs and is consistent with past practise in establishing estimated costs. We do not believe a more granular approach would provide for more accurate Meter and Regulator Capital costs.

171.2 Please provide a cost component outline of the unit cost for 2010 ($299) and 2011 ($314) based on the components of type, size, meter design, installation and fabrication etc (as outlined on page 451).

Response:

Consistent with past practice, meter unit costs are not currently forecast or tracked by type, size, meter design, installation and fabrication, etc. Historically, an aggregate or blended unit cost has been used (refer Table B-1-30 page 188 of Application) to track meter and regulator capital unit costs (including purchases, design, fabrication, installation, alterations, upgrades, etc of all customer types). The same approach was taken to determine aggregate or blended meter capital unit cost for 2010-2011 (refer Table C-9-5). We do not believe a more granular approach would provide for more accurate forecasts.

The 2010 and 2011 forecast blended Meter unit costs are based on the 2009 projection of $265/meter adjusted for an increase in the regulator replacement program (refer page 451 – an increase from $0.8 million to $2.1 million). On a per unit basis, the regulator replacement program represents $15 of the $265/meter unit cost in 2009. In 2010 the expanded program represents $32 of the $299 meter unit cost and in 2010, $32 of the $314 meter unit cost. The remaining incremental projection in meter unit costs is for inflation on labour and materials, additional AMR components and a minor IFRS accounting change.

172.0 Reference: Capital Expenditures - Distribution Category B Capital, Part III, Section C, Tab 9, Page 455

172.1 In Table C-9-7, Miscellaneous distribution Plant Expenditures is forecast at $3.1 million in 2010. Please itemize the costs in this category and comment on whether these costs can be shifted to 2012 and beyond?

Response:

An Itemized cost breakdown, with a discussion of deferral potential for each item, is as follows:

Cathodic protection $550,000. Annual amount required to apply corrosion control on new and existing gas infrastructure to ensure safe reliable long term cost effectiveness of gas system. Examples include rectifiers, anode or ground beds. Recent actual cost experience (2007 and 2008) averaged $590,000 per year. Terasen Gas is unable to defer these capital costs as to do so would result in increased pipe degradation through corrosion damage and potentially a higher leak experience and repair costs.

Distribution laterals $2,400,000. Alteration, upgrade and enhancement activity on existing Distribution lateral pipelines to ensure safe reliable long term effectiveness of gas system. Specific projects identified to date:

- Highland Valley Lateral Relocation $2,100,000 – receivable relocation project at Logan Lake to be offset with a third party contribution (refer page 467, paragraph 2).
- Quesnel Valves $50,000 – Due to the removal of a gate station there remains obsolete piping and several valves that are leaking at the upstream end of the Quesnel #2 Lateral. We also lack proper electrical isolation from Spectra and thus we want to replace the piping so a more appropriate configuration exists complete with the proper flange insulating kits. This work will also be coordinated with the replacement of the odorant injection measurement equipment at this site, the existing equipment having become obsolete. – non-deferrable
- Ashcroft Crossing $30,000 – This is to install an engineered solution to the erosion occurring over the Ashcroft Lateral crossing of a creek. Crossing had less than 60cm cover in Aug 2008. Desired cover without any protection is 120cm. Installing protection should allow us to avoid the more costly option of lowering the pipeline. - non-deferrable
- Highmont Vault $10,000 –A leaking valve that needs replacing, however we are trying to time the replacement with the relocation of the Highland Valley Lateral Relocation. The Highmont Lateral is connected to the Highland Valley Lateral through this valve – non-deferrable

- Miscellaneous (Non identified projects) $210,000 – projects on laterals not specifically identified to-date - potentially deferrable

Valve sectionalisation $120,000. Annual amount required to address valve sectionalisation enhancements/upgrades/alterations to ensure safe, reliable long term cost effectiveness of gas system. Recent actual cost experience (2007 and 2008) averaged $123,000 per year. Terasen Gas is unable to defer these capital costs as to do so would result in increased risk of higher numbers of customer outages from third party and natural hazard damage.

Total $3,070,000 or $3.1 million

173.0 Reference: Capital Expenditures - Transmission Category B Capital

Part III, Section C, Tab 9, 457

173.1 In Table C-9-8, Miscellaneous Plant Expenditures are identified as $2.6 million, $3.2 million and $2.7 million for 2009, 2010 and 2011 respectively. What cost components are included in this category in each year and the SCADA system in particular?

Response:

The Miscellaneous category is for expenditures that span across systems for system integrity, cathodic protection, telemetry, security, and unallocated funding. The cost components are shown in the able below.

The expenditure for the SCADA system is listed under Telemetry. The $1,161,000 expenditure in 2009 is for the SCADA system upgrade due to equipment obsolescence. Also within the Telemetry category, the $75,000 and $50,000 expenditures in 2010 and 2011, respectively, are for regular minor enhancement of the SCADA system to accommodate minor changes in technology and operating requirements.

The unallocated amount is based.on historical experience related to unplanned work, most notably those related to hydrotechnical and geotechnical hazards. For example, there have been 6 major pipeline washouts in the past 10 years, ranging between $0.7 million to $1.5 million per replacement. While TGI monitors over 950 sites on its Transmission system through its Natural Hazards program to mitigate this risk, there is always some level of risk to encounter this type of unplanned work.

	2009 Projection	2010 Forecast	2011 Forecast
System Integrity	275,000	1,469,000	901,000
Cathodic Protection	155,000	265,000	265,000
Telemetry	1,161,000	75,000	50,000
Security	30,000	400,000	200,000
Unallocated	1,000,000	1,000,000	1,317,300
Subtotal	2,621,000	3,209,000	2,733,300

174.0 Reference: Capital Expenditures - Transmission Category B Capital

Part III, Section C, Tab 9, 456- 457

174.1 In Table C-9-8, Pipeline Plant Expenditures are identified as $6.9 million and $7.3 million in 2009 and 2010 respectively. What projects and costs are included in these expenditures?

Response:

The Pipeline Plant Expenditures are broken into three sub-groups: Interior Pipeline Systems, Lower Mainland Pipeline Systems, and Right-of-Way (RoW). The table below shows the breakdowns for 2009 and 2010.

The expenditures for both Interior and Lower Mainland pipeline systems involve upgrades to pipelines, valve stations, control stations and creek or river crossings to ensure code compliance, safety and reliability of the transmission systems, as well as to minimize impact to the environment.

The relatively major pipeline projects in 2009 (as outlined in Section B, Clause 2.1, pp. 3-5 of the Annual Review Advance Materials of the Application by Terasen Gas Inc. for Approval of 2009 Revenue Requirements and Delivery Rates) are the upgrades to the Southern Crossing Pipeline for code compliance, the completion of the Columbia River crossing replacement near Brillant, and the initiation of Kootenay River crossing replacement near Shoreacres. The total 2009 expenditure for the three major projects, which are all located in the Interior, is estimated to be $5.0 million.

The relatively major pipeline projects in 2010 (as outlined in this Application, pp. 456-457) are the continuation of Kootenay River crossing replacement near Shoreacres in the Interior, and the initiation of the Huntingdon Alternative Interconnection for security of supply to the Lower Mainland, with 2010 expenditures estimated at $2.0 million and $0.2 million, respectively.

The expenditures for Right-of-Way involve purchasing Right-of-Way and posting of pipeline RoW certificates.

2009 Capital Upgrade Projects	2009 Forecast	2010 Forecast
Pipeline Systems – Interior	6,413,000	5,291,000
Pipeline Systems – Lower Mainland	355,000	1,908,000
Right-of-Way	119,000	121,000
Subtotal	6,887,000	7,320,000

174.2 TGI states that (page 457): "Pipeline relocation and road crossing upgrade costs are estimated at $1.2 million and $1.1 million for 2010 and 2011 respectively. Some portion of the actual expenditures may be recovered depending on third parties involved, and subject to negotiation, legal proceedings and insurance claims." Please explain.

Response:

We take extensive efforts to ensure that any costs associated with pipeline relocation and upgrades are not unfairly borne by our customers. The degree to which we can recover costs for pipeline relocations from other parties, however, depend on the situation. Transmission pipelines are placed within their own registered statutory right-of-ways over private lands, municipal road allowances, or provincial highway allowances, and may cross municipal roads, highways, railways, logging roads, or private driveways. Each of these different tenures is governed by specific agreements and law which dictate how costs are divided between Terasen Gas and the party that needs Terasen Gas to relocate its pipeline.

In unusual cases where a pipeline relocation or road crossing upgrade is required at a location where the nature of tenure of the right-of-way, or the interpretation of an agreement or applicable laws are in dispute, Terasen Gas seeks to recover some or all of the actual expenditures through negotiation, and should negotiation not succeed, legal proceedings. In unusual cases where pipeline relocation or upgrades are undertaken as a result of damage to the pipeline by the actions of a third party, then Terasen Gas may seek recovery of its costs through insurance.

TGI does not know yet all of the agencies which will approach us to relocate our pipelines. However, based on our past experience, we can reasonably estimate that we will be required to relocate or upgrade our pipelines during 2010 and 2011, and we will be responsible for a portion of the costs as a result of agreements that specifically require us to bear the cost or disputes over cost apportionment of such relocations or upgrades. While we believe that our budget for such pipeline relocation or upgrades is well founded in past experience, and for this purpose

TGI has estimated a reasonable portion of the $1.2 and $1.1 million is recoverable, there is some uncertainty related to how much of these relocation costs we will ultimately recover from third parties.

When we plan and negotiate pipeline relocations needed to accommodate third parties, Terasen Gas seeks not only to minimize the cost to customers of the actual relocations, but also to minimize future costs in relation to that pipeline. Therefore we seek the most secure tenure for our relocated pipelines we can. As an example, we seek to negotiate rights that allow us to access our pipeline, that seek to prevent damage by third parties to our works (i.e. ones that require the third party to consult us before doing future work near the pipeline) and that require the third party to bear the costs of further relocations of this pipeline.

174.3 In Table C-9-8, LNG Transmission Plant Expenditures for 20110 are forecast at $2.7 million (page 457). Please break this amount down into the categories of "upgrades to boil off compression", a "new road tanker" and "LNG vaporizer".

Response:

The total LNG Plant expenditures for the Tilbury LNG Facility are anticipated to be $2.6 million for 2010 and 2011. The breakdowns of individual categories are shown in the table below.

The upgrades to boil off compression would include the addition of a second unit to eliminate venting of LNG vapours from the LNG storage tank during maintenance or failure of the primary boil-off compressor unit. It is anticipated that additional $1.0 million expenditures in 2012 would be required to complete the addition of the second boil-off compressor unit.

The new road tanker and the gas fired LNG vaporizer would work together as a temporary natural gas supply system for planned or emergency work while maintaining gas service to customers. Therefore, the two components would be acquired together.

The recurring capital expenditures are to provide minor upgrades to various components of the LNG facility to ensure safe and reliable operations.

LNG Plant Expenditures	2010 Forecast	2011 Forecast
2nd boil-off Compressor	50,000	500,000
LNG road tanker and portable gas fired vaporizer	220,000	1,400,000
LNG Capital Project-recurring	232,000	237,000
Subtotal	502,000	2,137,000

175.0 Reference: Capital Expenditures - Non-IT Category C Capital

Part III, Section C, Tab 9, page 461-463

175.1 TGI states that (page 462): The projected expenditures for Other Non-IT projects for 2010 and 2011 are $9.5 and $9.1 million, respectively. Please compare this forecast to the amounts expended in this category for the period 2003 to 2009. Please provide the 2003 to 2009 information on a yearly basis as well.

Response:

Below is a comparison of the actual and forecast Other Non-IT expenditures.

2003 – 2008 Other Non-IT Capital Expenditures

	2003 Decision	2004 Actuals	2005 Actuals	2006 Actuals	2007 Actuals	2008 Actuals	2009 Projection	2004 - 2009 Average
Other Non-IT	6.9	4.4	3.8	5.6	7.6	7.2	9.9	6.4
Total Nominal	**6.9**	**4.4**	**3.8**	**5.6**	**7.6**	**7.2**	**9.9**	**6.4**
Total Real	**7.8**	**4.9**	**4.2**	**5.9**	**8.0**	**7.4**	**9.9**	**6.7**
Average Customers	770,368	779,498	791,647	803,686	817,480	825,957	833,798	808,678
Total Nominal $/Customer	**9.0**	**5.7**	**4.9**	**7.0**	**9.3**	**8.7**	**11.9**	**7.9**
Total Real $/Customer	**10.2**	**6.3**	**5.3**	**7.4**	**9.7**	**8.9**	**11.9**	**8.2**

Note: Expenditures in $millions; Real totals in 2009 values

2010 – 2011 Forecast Other Non-IT Capital Expenditures

	2009 Projection	2010 Forecast	2011 Forecast
Other Non-IT	9.9	9.5	9.1
Total Nominal	**9.9**	**9.5**	**9.1**
Total Real	**9.9**	**9.3**	**8.7**
Average Customers	833,798	839,949	845,633
Total Nominal $/Customer	**11.9**	**11.3**	**10.7**
Total Real $/Customer	**11.9**	**11.1**	**10.3**

Note: Expenditures in $millions; Real totals in 2009 values

On a per customer basis, reflective of the current approved formulaic approach to determining non-IT capital spending, the forecast capital expenditures on a real $ per customer basis for the 2010 and 2011 years are consistent with that provided for in the 2003 Decision (eg. average of $10.5 per customer for 2010 and 2011 compared to $10.2 per customer for 2003).

While costs on a total basis for this category trends upward as the result of the need to upgrade aging facilities structures and equipment and a focus on hazards mitigation (refer to Part III, Section C – Tab 9: Capital Expenditures, pages 462 – 463), customers continue to only pay in real dollars the equivalent of that allowed in 2003.

In addition, the 2010 and 2011 forecast expenditures on a per customer basis are lower than that projected for 2009, providing further confirmation that costs are being prudently managed on behalf of customers.

175.2 TGI states that: “Maintaining the emergency response capability has required Terasen Gas to outfit more employees with broader tool sets, including … (squeeze-offs).” Please describe this program. How many employees were capable of responding to emergency calls in each year between 2003 and 2009? How many employees would be included in this category in 2010 and 2011?

Response:

As 3rd party construction activity increases and customer base increases, to maintain a favourable emergency response, Terasen Gas has equipped employees with broader skills and tools required to respond to emergencies. The table below lists the number of employees (by year) who are emergency response capable.

TGI DISTRIBUTION IBEW EMPLOYEES - EMERGENCY RESPONSE CAPABLE

2003A	2004A	2005A	2006A	2007A	2008A	2009P	2010F	2011F
334	318	301	275	298	325	335	336	336

An example of broadening skills and tools would be the introduction of Stab-Loc fittings that enable a service repair without the need of a full construction crew with fusion equipment. Implementation of The Distribution Mobile Solution in late 2008 has also improved Terasen Gas’ ability to more efficiently allocate resources to all work including Emergency response.

175.3 Please explain the "hazards mitigation program" and what changes have been made to the program in 2009 to 2011? Please provide a comparison of the costs allocated to the program on a year by year basis between 2003 and 2009.

Response:

Hazard mitigation activities are a significant component of Other Non-IT Category C capital (see page 462 in Part III Section C Tab 9 Capital Expenditures). The centralized identification, tracking and management of hazards are relatively new at Terasen Gas, having been in place for 6 years. Hazards are identified during leak surveys, meter reading or as a result of observations by TGI employees. Hazards include building over the meter set or running line of service, exposed services, stressed piping due to ground settlement, lack of protection posts and regulator vents too close to building air intakes. Hazards that result in an immediate risk to public safety are corrected on an urgent or emergency basis; other lower risk hazards are corrected as resource availability permits.

As a result of the current downturn in the economy, Terasen Gas has the workforce capacity (with Emergency Footprint employees) to increase the number of hazards addressed in 2010 and 2011. Escalation of the hazards mitigation program will result in a reduction of risks to the public as well as Terasen Gas plant and employees.

Capital Hazard Mitigation Expenditures

2011 (forecast)	$	1,960,000
2010 (forecast)	$	1,960,000
2009 (projected)	$	861,000
2008 (actual)	$	1,125,000
2007 (actual)	$	1,023,000
2006 (actual)	$	1,067,000
2005 (actual)	$	815,000
2004 (actual)	$	584,000
2003 (actual)	$	419,000

176.0 Reference: Accounting and Other Policy Changes - IFRS

Appendix H-1

"On transition utilities will be required to perform an impairment test and record any impairment losses that may exist at that date."(Appendix H-1, p.14)

176.1 What is Terasen Gas' definition of "impairment" and please describe your planned process for completion of this impairment test including the timing and methodology employed specific to property, plant and equipment? This should include a description of the cash generating units and the proposed assumptions to be made. If no processes are planned for asset impairment tests, please explain why.

Response:

Terasen Gas' definition of impairment is consistent with the definition used by IAS 36 *Impairment of Assets*. IAS 36 defines impairment loss as the amount by which the carrying amount of an asset or a cash-generating unit exceeds its recoverable amount. IAS 36 defines recoverable amount of an asset or a cash-generating unit as the higher of its fair value less costs to sell and its value in use. IAS 36 defines fair value less costs to sell as the amount obtainable from the sale of an asset or cash-generating unit in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

In accordance with IAS 36 Terasen Gas' property, plant and equipment will be assessed at the end of each reporting period as to whether there are any indications of impairment. If any indications exist then Terasen Gas will estimate the recoverable amount of the asset and determine if an impairment loss exists by comparing it to the carrying amount of the asset or cash-generating unit. Terasen Gas has been identified as a separate cash generating unit.

Terasen Gas' methodology in determining the recoverable amount of property, plant and equipment or a cash-generating unit has not been finalized as of date. However, the methodology will involve a cash flow analysis which will require assumptions to be made, such as an appropriate discount rate to discount the cash flows, estimates of future economic conditions, estimates of future projections of the company's results, estimates for planned capital expenditures, etc.

176.2 Would Terasen Gas agree that obtaining a fair market valuation of all PP&E would have the benefit of meeting both the IFRS requirements of a) establishing an appropriate carrying value of assets and b) conducting impairment tests on assets?

Response:

A fair market valuation of Terasen Gas' property, plant and equipment will not be required upon transition to IFRS. The Rate-regulated Activities exposure draft which was released in July 2009 resulted in a proposed amendment to IFRS 1 allowing an additional exemption related to property, plant and equipment for entities with rate regulated activities that meet the scope of the exposure draft. The proposed IFRS 1 exemption states entities with rate regulated activities may have property, plant and equipment with carrying amounts that include amounts in accordance with a previous GAAP and that under the new exposure draft would be recognized separately as a regulatory asset. If this is the case then the entity may elect to use the carrying amount of such an item at the date of transition to IFRS as deemed cost. If the proposed IFRS 1 exemption is finalized as drafted then Terasen Gas may elect, assuming its activities meet the scope definition, to use its carrying amount under Canadian GAAP at January 1, 2010 as its opening IFRS carrying amount upon transition to IFRS.

Impairment tests are required only if there are any indications of impairment at each reporting period. It can not be determined at this time if upon transition to IFRS an impairment test will be required of Terasen Gas' property, plant and equipment.

177.0 Reference: Accounting and Other Policy Changes - IFRS

Part III, Section C, Tab 11, p. 474

177.1 Given the uncertainty around IFRS standards, please provide an explanation as to why a less reliable projection of results should be utilized in setting 2010 rates. Please clarify why the projected results, which are based on untested accounting principles, provide a solid base for rates in the test period.

Response:

There is some uncertainty around the application of IFRS in a few specific areas. However, there is no uncertainty around the required adoption date for IFRS or the fact that TGI will be required to adopt IFRS. Also, for those standards that are of particular relevance to TGI's regulatory treatment, there is very little change expected prior to adoption. The IFRS principles themselves are well established and have been accepted and put into practice in over 100 countries around the world.

TGI is required to adopt IFRS for 2011 with comparative results provided for 2010, which effectively results in 2010 adoption since all 2010 impacts will be reflected in the Company's accounting records. Therefore, the 2010 impacts will also need to be reflected in TGI's regulatory filings. Ignoring the 2010 impacts and instead basing the 2010 results on Canadian GAAP would result in a significant 2010 impact that would be pushed forward for future recovery, either in 2011 or over longer periods in the future. Even though not all impacts of IFRS can be exactly determined, TGI has done a very thorough review of the standards and believes the results that have been reflected in this RRA are reasonable and appropriate. Providing forecasts and estimates of future events is a normal part of the rate setting process, and mechanisms are established to deal with significant variations from those forecasts. It is prudent for TGI to include an estimate of the impacts of accounting changes in the period to which they relate rather than ignoring the impact of those changes and dealing with them in future years, with costs borne by future ratepayers.

TGI has completed a detailed analysis of the relevant IFRS and believes that the resulting 2010 and 2011 impacts form a solid base for rates in the forecast period. To the extent that there are differences in the application of the standards between that proposed in the RRA and that agreed to with the external auditors, TGI proposes to capture these differences in a deferral account for future disposition.

177.2 Please provide a timeframe for inclusion of TGI's auditor, Ernst and Young LLP, in the evaluation and eventual review of TGI's selected IFRS policies.

Response:

Terasen Gas has engaged the Company's auditors, Ernst and Young, since 2008 in evaluating and reviewing the Company's policy review and selection under IFRS. Ernst and Young will not provide an audit opinion on these policies until 2011 which is when Terasen Gas is required to have financial statements audited under IFRS.

177.3 Please quantify the anticipated total 2009 and 2010 retained earnings adjustments.

Response:

Based on the analysis done to date, the only potential retained earnings adjustment that TGI is aware of today is the employee future benefits amount, estimated at $57.7 million, discussed in the Application and included in the IFRS Transitional Deferral Account. If this amount is approved as part of the deferral account, we anticipate that there will be no retained earnings adjustment.

177.4 Has TGI considered accumulating all adjustments to retained earnings at IFRS adoption on January 1, 2010 (as restated in 2010 and adjusted to retained earnings as at December 31, 2009) for future recovery?

Response:

TGI has reflected all known January 1, 2010 retained earnings adjustments (currently only the transitional employee future benefits amount) in the IFRS Transitional Deferral account.

177.5 If so, what is the planned period of recovery of these IFRS adoption deferrals?

Response:

TGI has not put forward a proposal to recover the IFRS Transitional Deferral account at this time, since the nature of the items that are ultimately recorded in the deferral may impact the proposed recovery period. For example, if the only amount recorded in the deferral is related to employee future benefits, TGI would likely recommend that the amount be recovered over the expected average remaining service life of the employee group, consistent with how these amounts would have been recognized under existing Canadian GAAP.

178.0 Reference: Accounting and Other Policy Changes

International Financial Reporting Standards ("IFRS")

Part III, Sec C, Tab 11, pp. 476-484

"There are several reasons why it is critical that Terasen Gas adopt IFRS for both financial and regulatory reporting purposes. ... Terasen Gas recognizes the need to balance the above goals with the requirement to avoid volatile rate impacts. Where harmonization of regulatory accounting with IFRS has significant impacts to customers, an appropriate mechanism to deal with those impacts would be through the continued use of deferral accounts. Therefore, the Company proposes to implement deferral accounts where appropriate, and also to limit all regulatory and IFRS differences to those that can be captured and tracked in deferral accounts ..." Ref: p. 476, pars. 4-5

178.1 Please confirm that TGI plans to report under Canadian GAAP for the 2010 Fiscal year and plans to adopt IFRS for fiscal 2011 with restatement of fiscal 2010 at that time. Also, please confirm that all of GI's related companies plan to report under Canadian GAAP for the 2010 period.

Response:

TGI plans to report under Canadian GAAP for the 2010 fiscal year in its externally published financial statements for that year. At the same time, TGI will be preparing internal financial statements under IFRS for 2010, so that in 2011 when 2010 must be restated, TGI will have the comparative figures available. These 2010 IFRS changes will then be reflected in the externally published financial statements for TGI in 2011, as 2010 comparatives. All of TGI's related companies will report on the same basis.

Please see TGI's response to BCUC IR 1.177.1 for further discussion about why IFRS should be used in setting 2010 rates.

178.2 If TGI plans to report in Canadian GAAP for 2010, please provide an explanation as to why IFRS should utilized in setting 2010 rates given that IFRS is still subject to significant change?

Response:

Please see the response to BCUC IR 1.177.1.

178.3 Had there been any considerations given to adopt the results of the Depreciation Study in 2011 instead of 2010 given that the requirements for IFRS does not commence until January 1, 2011 and also to mitigate the rate impact to customers in challenging economic times?

Response:

TGI will need to be compliant with IFRS for 2010, even though that compliance will not be demonstrated until the publication of financial statements in 2011. Therefore, TGI is not able to choose to adopt the recommended depreciation starting in 2011 only. Although the adoption of the recommended rates in 2010 does have a significant rate impact, the rate impact of those changes needs to be recognized, whether in 2010 or in some future period. Economic indicators are showing signs of improvement in 2010; additionally the commodity costs for natural gas are forecast to be quite low. These relatively low commodity costs, combined with the rate reduction resulting from rebasing, go a significant way towards mitigating the 2010 rate impacts of the depreciation study.

As stated in the Application, TGI believes it is critical to harmonize regulatory treatment as much as possible with IFRS, to avoid having to maintain two separate ledgers and the associated costs. Where there is a desire to reduce significant rate impacts as a result of IFRS adoption, deferral accounts should be implemented. For example, IFRS compliant depreciation rates could be adopted for recording depreciation expense and net plant in service for both IFRS and regulatory books, and a rate base deferral account could be implemented to manage the customer rate impact of those depreciation rates.

178.4 Assuming Terasen Gas adopts IFRS effective January 1, 2011 as required, please detail any potential IFRS issues relating to the adoption of the revised depreciation rates effective January 1, 2011.

Response:

The adoption of IFRS, although required for 2011 financial statements, is effectively required for 2010, as described in the response to BCUC IR 1.177.1. It is important that the Company adopt the revised depreciation rates effective January 1, 2010 to avoid re-stating the comparative period with different depreciation rates, and then capturing and recovering these 2010 costs. The depreciation rates are required to depreciate assets over their lives and the depreciation study accomplishes this by estimating the life remaining in the various assets classes.

Terasen Gas would anticipate the following issues with adopting revising depreciation rates effective January 1, 2011, along with some more minor items not listed here:

1. Restatement of depreciation for 2010 to comply with IFRS acceptable depreciation rates and methods. The process of restatement can be avoided by adopting rates that are expected to be materially compliant with IFRS in 2010, as further discussed in response to BCUC IR 1.178.3.
2. Acceptance of the use of group depreciation methods, particularly the Average Service Life method, by Terasen Gas' auditors.
3. Obtaining Commission approval to defer gains and losses on retirement of capital assets, and avoid volatile earnings and rate impacts resulting from expensing these unpredictable and potentially volatile amounts.

178.5 Assuming Terasen Gas adopts IFRS effective January 1, 2011 as required, please explain the logic and appropriateness of the proposed IFRS Transitional Deferral Account. Please detail the affect on the ratepayers and on the Company to simply make all the required adjustments in 2011.

Response:

Regardless of the timing of adoption of IFRS for regulatory purposes, TGI will effectively be adopting the standards for financial reporting purposes in 2010. As discussed on pages 435 and 436 of the Application,

"*The Company proposes a deferral account to capture:*

- *Retained earnings adjustments required on transition to IFRS. At present, the only known retained earnings adjustment is to recognize all cumulative actuarial gains and losses on pension plans in the amount of $57.7 million (see further discussion in Part III, Section C, Tab 11).*
- *The 2011 impact of a one-time adjustment of $11.2 million to pension expense under IFRS to recognize a market valuation allowance (see further discussion in Part III, Section C, Tab 11).*
- *The one-time transfer of the existing gain balance of $7.6 million from General Plant as part of the conversion in preparation for IFRS.*
- *The impact of any difference between the depreciation rates or methodology recommended in this Application and the rates eventually required to comply with IFRS.*
- *The impact of any difference between the overhead capitalization rate or methodology recommended in this Application and the rate or methodology required to comply with IFRS.*

- *The rate impact of any other standard where the result of the particular IFRS is varied from what is assumed in the preparation of this Application – see Table C-8-5 below for those standards that are expected to change before adoption."*

Whether TGI reflects the 2010 adjustments in 2010 or in 2011, the same issues exist with accurately predicting the exact impact of IFRS, primarily because the interpretation and application of the standards needs to be approved by the Company's external auditors, and to a lesser extent because of unanticipated changes to the standards. Therefore the effect on ratepayers of making all of the required adjustments in 2011 would be virtually the same as the impact on 2010 (an additional $42.6 million in revenue requirements, as shown in Table C-2-1 of the Application, p.220, would move from 2010 to 2011).

The primary purpose of the IFRS Transitional Deferral account is to capture the impact of unanticipated IFRS requirements on revenue requirements, and avoid any unanticipated gains or losses accruing to either the customers or the Company.

The secondary purpose of the IFRS Transitional Deferral account is to hold the adjustments that result from the transition to IFRS that would otherwise impact retained earnings. It is expected that the recording of this type of adjustment in the IFRS Transitional Deferral account, as demonstrated by the first three items listed in the italicized section above, will not have a material impact on rate setting, since the offset to these entries is to another rate base item. Keeping both sides of the entry in rate base accounts neutralizes the impacts to rates and customers.

179.0 Reference: Operations and Maintenance Expenditures – Accounting Changes

TPIP

Part III, Section C, Tab 6, p.371

179.1 Please provide a schedule of specific TPIP activities and costs planned for 2010 and 2011 and discuss why this type of funding fluctuates widely from year to year.

Response:

A table of TPIP activities follows:

	2010	**2011**	**Reason for Fluctuation**
O&M			
TPIP - General Programs Staffing and administrative costs have been budgeted within this category, as well as programs not attributable to a specific asset at this time (either unknown, or system-wide), such as: - class location surveys (system-wide) - Integrity Management Plan sustainment costs (system-wide) - detailed integrity studies (anticipated expenditures, unknown at this time which specific assets will require studies)	$1,736,831	$2,292,487	Terasen has forecast an increase in 2011 to enable the utilization of emerging analysis methodologies within integrity management programs. As an example, during 2009, Terasen is continuing the application of reliability-based methods (as published in CSA Z662 Annex O) for engineering assessments of selected pipeline segments. By 2011, Terasen is anticipating that broader application of these and possibly other methods would be prudent toward ensuring the continued safety and reliability of the Terasen Gas Inc. pipeline system. While the use of emerging methodologies helps to ensure alignment between Terasen and industry standard and leading practices, cost benefits can also be realized. As an example, an Annex O analysis completed in 2008 demonstrated that replacement of 3.6 kilometres of 273 mm outer diameter pipeline on the Terasen Gas (Vancouver Island) Inc. system was unwarranted due to the pipeline's design and installation, as well as Terasen Gas' current operating practices to manage the ongoing integrity of the segment. The avoided capital expenditure as a result of this study was likely in the millions of dollars. Specialist engineering consultants were required for this work.

	2010	2011	Reason for Fluctuation
TPIP - Natural Hazards Programs to assess and perform required O&M repairs related to: - hydrotechnical hazards (i.e. water crossings) - geotechnical hazards (i.e. areas of slope instability) - seismic hazards (i.e. earthquakes)	$ 820,000	$ 605,000	Specific requirements within the Natural Hazards and all TPIP programs will depend on data obtained and analysis completed in 2009 and beyond. Seismic analysis currently being undertaken is expected to require follow-up work in future years. Based on current information, an increased requirement for site-specific seismic assessments is expected for 2010. It is not known at this time whether the risk of deferring a portion of this work to 2011 would be acceptable.
TPIP - CP Evaluation Program Cathodic protection and coating evaluations (i.e. above-ground surveys) - a primary data source required to assess the risk associated with external corrosion for pipelines not currently scheduled for in-line inspection - a complementary data source for planning and implementing proactive external corrosion mitigation measures for all buried steel pipelines	$ 625,000	$ 425,000	By the end of 2010, Terasen will have completed "baseline" field data collection for Interior pipelines. A lower volume of field work is anticipated to be required in 2011, although this will depend on data obtained and analysis completed in 2009 and beyond.
TPIP - Rehabilitation Program Digs to assess and evaluate coating and/or pipe condition, selected primarily through the CP Evaluation and In-Line Inspection Programs, although digs may be performed for many reasons, including Stress Corrosion Cracking assessments. Any required O&M repairs to pipelines, including re-coating, are also funded within this budget.	$ 688,000	$ 949,000	Similar to other programs, digs required in 2010 and 2011 will depend on data obtained and analysis completed in 2009 and beyond. The forecast activity levels are based on available information and engineering judgment, and are believed to be appropriate to ensure continued safety and reliability of the pipeline system.

Capital	**2010**	**2011**	**Reason for Fluctuation**
TPIP - In-Line Inspection (ILI) Program Terasen and vendor costs associated in-line inspecting pipelines, including required preparation activities (i.e. cleaning the pipeline and ensuring no restrictions exist that would prevent passage of the tool)	$1,194,000	$ 626,000	ILI re-inspection intervals are selected on a risk basis, and are regularly re-evaluated based on information collected through this and other TPIP programs (i.e. annual pipeline digs). This avoids unnecessary expenditures in years when in-line inspections are deemed to be unwarranted. This is also believed to be a more effective strategy for risk management versus the selection of fixed re-inspection timetables to obtain levelized budgets. Appendix 2 of the Terasen Gas Inc. Transmission Pipeline Integrity Program 2008 Activities Report, as submitted to the BC Utilities Commission on May 4, 2009, contains the TGI Internal Inspection Activity Plan for 2008 - 2012. This may be subject to change based on analysis and/or operational considerations.

180.0 Reference: Operations and Maintenance Expenditures - Accounting Changes

Part III, Section C, Tab 6

There appears to be a lack of consistency in the areas of Accounting changes where IFRS has been adopted in 2010 for some accounts while the continuation of Canadian GAAP practices were applied to other accounts.

180.1 Has Terasen Gas considered presenting 2 sets of financial reporting statement for forecast 2010: one set of financial statements prepared under Canadian GAAP and another set of financial statements prepared under IFRS rules.

Response:

Terasen Gas has not considered presenting two sets of financial reporting statements for forecast 2010. Further, TGI does not believe there is a lack of consistency in the way in which IFRS and Canadian GAAP have been applied; TGI has applied a consistent and appropriate principle in each case after a thorough review and consideration of each standard, as described in response to BCUC IR 1.180.7. The Company has proposed to make changes in accounting policies during 2010 which Terasen Gas believes will be compliant with both Canadian GAAP and IFRS. There are a number of areas where Terasen Gas believes it cannot make an accounting policy change until 2011 (i.e. pensions). For these areas, the Company has proposed to keep the existing treatment in 2010 in order to be compliant with Canadian GAAP but to make a policy change in 2011 with a retroactive restatement for 2010 so that Terasen Gas complies with IFRS in 2011. Therefore, there is no need to forecast two separate sets of financial statements.

180.2 Please describe TGI's position regarding dual reporting (using Canadian GAAP and using IFRS) if the change in accounting standards are not available within the required timeframe. Can Terasen Gas provide an estimate of the costs required for the preparation of dual reporting as suggested in the above questions?

Response:

In order to be prepared for the potential requirement for two sets of books, Terasen Gas is preparing for conversion to IFRS as if dual reporting is an alternative. Terasen Gas believes that dual reporting would be a very expensive alternative but has yet to quantify the costs (internal and external). TGI has started the IT portion of this conversion and it is estimated that TGI will spend about $400,000 to implement a flex general ledger in order to allow for the possibility of two ledgers. Any additional incremental costs can be eliminated or reduced by minimizing differences between regulatory treatment and IFRS and confining any differences to rate base deferral accounts to avoid maintaining two asset ledgers.

180.3 As the proposed standards may only contain guidance on regulatory accounts, please describe the expected impact if accounting for taxes and capital gains are not modified by a new accounting standard.

Response:

The Company is currently reviewing the IASB exposure draft on Rate-regulated Activities released in July 2009. From a preliminary review of the exposure draft, it appears that the regulatory future income tax asset is likely to meet the criteria for recognition as an asset under the new standard as long as it can be demonstrated that TGI has a right to recover these future income taxes from ratepayers as they become due in the future. The inclusion of the regulated future income tax asset in rate base will assist in demonstrating the recoverability of the future income taxes, but it is uncertain at this time if the treatment for these amounts will continue in exactly the same manner under IFRS.

Under the current treatment, Terasen Gas continues to utilize flow-through-accounting for income tax expense, which is calculated in accordance with substantively enacted tax legislation. For future income tax purposes, differences between accounting and tax values are captured as part of the future income tax liability, while an offsetting regulatory future income tax asset is also recognized.

TGI is not aware of any IFRS differences related to capital gains.

180.4 Please quantify the value of deferred gains and losses included in the PP&E balances for 2010 and 2011.

Response:

The estimated amount of deferred losses included in the PP&E balance for 2010 and 2011 that have not been reclassified to a deferral account are $135.2 million. Since TGI does not forecast gains or losses on disposal of assets, and if it did any amounts would be recorded in the deferred gain/loss account, the January 1, 2010 opening balance remains unchanged through to the end of 2011. The January 1, 2010 opening balance will be carried forward at historical cost under the proposed IFRS 1 exemption for PP&E.

180.5 Please describe any foreseeable additional gains or losses that TGI expects to realize during the test period that would otherwise be deferred.

Response:

TGI is not aware of any asset disposals that would result in gains or losses being recognized, since TGI is unable to determine which specific assets will be retired over the forecast period. However, due to the use of pre-1998 depreciation rates for most asset classes as discussed in the response to BCUC IR 1.180.4, it is likely that losses would continue to be realized more frequently than gains until such time as updated depreciation rates are implemented. Over time, the implementation of updated depreciation rates will result in the remaining unrecovered cost of the assets at the time of disposal being closer to zero.

180.6 Please clarify if any assessment of the fair value of PP&E has been made. Please compare the anticipated fair value of the assets to the carrying value of the assets.

Response:

Terasen Gas has not undertaken a specific assessment of the fair value of PP&E since TGI expects to use the regulated carrying value of PP&E as its January 1, 2010 opening balance, as outlined under the proposed IFRS 1 exemption. However, in both recent sale transactions involving Terasen Inc. (Kinder Morgan and Fortis) the fair value assigned to the regulated fixed assets has been the regulated carrying value of the assets, so it is likely in any event that the fair value of the PP&E would be equal to its regulated carrying value.

180.7 Given that IFRS requirements are currently speculative, it is unclear what the impact to customer rates will be pending its outcome. Please separately identify all the activities that require accounting changes versus IFRS requirements and identify the dollar impacts in 2009, 2010 and 2011. For items that relate specifically to IFRS requirements, identify the dollar impacts under the following scenarios. Discuss the sensitivity and impact to customer rates under each scenario.

Response:

TGI disagrees with two presumptions made in the preamble and question.

First, TGI would not characterize the impacts of those requirements on this RRA as being speculative in nature. TGI has undertaken a thorough review of IFRS requirements, in conjunction with other Canadian and BC Utilities, and has reflected those requirements in its RRA. As has been the case under Canadian GAAP, IFRS will continue to evolve right up until the time of adoption, and the positions the Company has taken will be subject to audit. TGI has completed assessments of the most likely outcome of IFRS requirements and the impact of those requirements on TGI have been included in this Application after a thorough review, in the same way that utilities prepare future estimates for many forecast period items.

Second, TGI does not agree that there is a "lack of consistency" as suggested in the preamble. The changes in this Application reflect the application of a consistent principle, namely the Company's desire to minimize the accounting and restatement differences upon adoption of IFRS in 2011. TGI believes this is appropriate to minimize incremental costs and increase transparency of the process and consistency of results among various stakeholders.

The changes being proposed do not impact 2009; the 2010 and 2011 effects of the proposed changes are summarized in response to BCUC IR 1.197.0.

180.8 Have TGI's methodologies for adopting certain IFRS requirements in the 2010 year been audited and approved by external auditors? What are Terasen Gas' plans if the adoption of IFRS is delayed or changed?

Response:

While Terasen Gas has not had its auditors audit the methodologies selected, Terasen Gas has done a significant amount of work around its conversion to IFRS and verifying that the recommended policy choices are likely to be compliant with IFRS.

Terasen Gas has been part of working groups across both the Fortis organization, and industry specific working groups like the Canadian Gas Association and the Canadian Electrical Association. Additionally, the Company has consulted with other regulated companies in the Province. In all of these working groups, there has been involvement by the major auditing firms in understanding the choices under IFRS, in what policies have been implemented and accepted by utilities in Europe and elsewhere, and in vetting the soundness of our approach. Although Terasen Gas has engaged its auditors throughout this process, we will not be able to obtain an audit opinion on IFRS compliant policies until late in 2010 at the earliest.

In early 2009, the CICA confirmed its decision to adopt IFRS standards on January 1, 2011 with restatement of comparative periods. There have been no indications of delays or changes to the adoption of IFRS occurring, and it is likely too late in the process for a change in the adoption date to occur. In the extremely unlikely event this does occur then Terasen Gas would propose to still adopt those standards it has proposed for 2010, but not implement those changes it has recommended for 2011. Any differences in the revenue requirement that would result from this change would then be captured in the IFRS Transitional Deferral Account.

181.0 Reference: Accounting and Other Policies

Section 3064 Goodwill and Intangible Assets

Part III, Section C, Tab 11, part (a) (1), p. 475

181.1 It is indicated that $2.0M in training costs and $0.5M in feasibility study costs will be capitalized this year. However, current changes in existing Canadian accounting standards, CICA handbook section 3064, require that these charges be expensed in the current year. This change is not a result of the eventual adoption as TGI has chosen to defer this required change in the 2009 period, expensing the item in the 2010 period.

181.1.1 Please confirm that these amounts will be expensed for financial reporting purposes and will represent a regulatory reporting difference in 2009.

Response:

These amounts will be capitalized for financial reporting purposes in 2009 and therefore will not represent a regulatory reporting difference. The current PBR Agreement for Terasen Gas includes both training costs and feasibility studies as part of capital. Generally, accounting changes during the PBR Period have been treated as exogenous factors and captured in a deferral. Given these two items are already part of capital and reclassification to a deferral has no impact on rates, Terasen Gas has not proposed a change for 2009.

181.1.2 Please confirm that the $2.0M in training costs and $0.5M in feasibility study costs represents the annual expense for the year and not cumulative.

Response:

Confirmed.

181.1.3 Please confirm that TGI expects the value of this expenditure to remain consistent over the 2010 and 2011 fiscal period.

Response:

Per Table C-6-9 of the Application, Training costs are expected to be $2.2 million for 2010 and $2.263 million for 2011. Feasibility study costs are expected to be $521 thousand for 2010 and $578 thousand for 2011. Therefore, these values are relatively consistent over the two years.

181.1.4 Please quantify any unamortized amounts for training costs and feasibility study costs that will be included within property, plant and equipment of TGI at the beginning of 2010 and please confirm that these amounts will be removed from the asset account upon adoption of IFRS.

Response:

The proposed IFRS 1 exemption for Rate-regulated Enterprises allows the regulated carrying cost of PP&E to become the deemed cost as at January 1, 2010. This exemption was developed due to the impracticability of separating the various components of the PP&E balances on conversion. Similarly to all items included in the January 1, 2010 plant balances, it is impracticable to separate the training costs and feasibility costs from the other plant balances. Therefore, TGI is unable to quantify these amounts.

Under this IFRS 1 exemption, TGI will not be removing these amounts from the asset accounts upon IFRS adoption.

182.0 Reference: Accounting and Other Policy Changes – Property Plant and Equipment - Valuation

Part III, Section C, Tab 11, Section (3), p. 478

182.1 Please advise whether Terasen Gas has deemed it "impracticable" to determine fair value of its assets? Please also advise whether Terasen Gas has also deemed it "impracticable" to restate all historical costs for asset valuation?

Response:

The impracticable criteria has been removed from the IFRS 1 standard as it relates to rate regulated enterprises. Therefore, Terasen Gas has not gone through a determination of whether it is "impracticable" to determine the fair value of its assets.

183.0 Reference: Accounting and Other Policies - Property, Plant and Equipment - Valuation

Part III, Application, Section C- Tab 11, section (b) (3) 3.1, page 479

"Although we do not anticipate any retained earnings adjustments to result from the initial adoption of IFRS as it relates to PP&E, any unanticipated adjustments would be captured in the IFRS Transitional Deferral Account." Page 479, par. 1

183.1 Please confirm what process TGI has undertaken to evaluate if all assets included within the property, plant and equipment subledger are allowable assets under IFRS.

Response:

Terasen Gas is in the process of reviewing each asset class in detail with material items investigated further through interviews with field, operations and plant managers and accounting staff, in addition to review of backup ledger details where required. This process is not fully complete to date and has not yet been reviewed with Terasen Gas' auditors.

183.2 Please confirm if the process to evaluate and transition your property, plant and equipment subledger to IFRS has been discussed or evaluated by any external consultants.

Response:

Terasen Gas has not directly engaged an external consultant to evaluate PP&E on transition to IFRS, but it has participated in discussions and reviews with Gannett Fleming and with other utilities in Canada. Terasen Gas' auditors have not yet reviewed PP&E on transition to IFRS; this process will be completed as part of the audits for 2010 and 2011. On the IT side, Terasen Gas has engaged SAP consultants to assist with the IT conversion.

183.3 Please confirm if the process to evaluate and transition your property, plant and equipment subledgers to IFRS have been discussed and/or approved by TGI's independent auditor.

Response:

The process for how we are reviewing PP&E on transition has been discussed with Terasen Gas' external auditor; however the results themselves have not been reviewed or approved at this time.

183.4 Please explain if TGI has concluded that the adjustment to remove non-allowable assets such as training, feasibility costs will not result in a significant opening retained earnings adjustment in order to adopt IFRS?

Response:

Upon IFRS transition, Terasen Gas will be utilizing the PP&E IFRS 1 exemption available for rate regulated enterprises, with the result that the carry value of PP&E will become our deemed cost as at January 1, 2010 for IFRS. This exemption effectively means that we do not have to go back and re-state PP&E for amounts that are excluded under IFRS and therefore there will be no retained earnings adjustment related to this item.

183.5 Please clarify if the property, plant and equipment subledgers include any non-standard amounts which have been capitalized in past periods. Specifically, please describe if the subledger includes any credit accounts, unmatched depreciation amounts, unrealized gains/losses or any other amount that is not specifically attributable to an asset that exists and is in use by TGI.

Response:

Yes, the PP&E subledger does contain non-standard amounts including credits for contributions in aid of construction and negative net salvage; unrealized gains and losses are described elsewhere in the Application. Terasen Gas continues to investigate similar types of items in PP&E, but nothing has come to our attention at this point that indicates a departure from the treatment proposed in the Application.

184.0 Reference: Accounting and Other Policies - Asset Retirement Obligation

Part III, Section C- Tab 11, section (b) (5) 5.3, p. 480

"Terasen Gas does not believe it has any material asset retirement obligations that will be required to be recognized under IFRS. The Company is of the view that a constructive obligation may exist with respect to decommissioning costs that will be incurred when a major portion of our network may reach the end of its useful life. We may therefore be required to recognize that obligation as a provision on our balance sheet in accordance with International Accounting Standard 37 when we have an estimate of when a major portion of our network may reach the end of its useful life. However, because our network is essentially operated in perpetuity, the date upon which it will be taken out of service is generally not determinable. Therefore the present value of that obligation will be immaterial." Page 480, par.3

184.1 Please quantify, on an undiscounted basis, the asset retirement obligation / decommissioning liability that you have identified.

Response:

Terasen Gas is unable to quantify, on an undiscounted basis, any asset retirement obligations as we have not had a major portion of our network reach the end of its useful life. An estimate of any possible asset retirement obligation/decommissioning liability will likely not be possible until closer to the time when the network reaches the end of its useful life which is not determinable at this time.

184.2 Please confirm if your proposed conclusion under IFRS has been discussed or recommended by an external consultant.

Response:

While Terasen Gas' proposed conclusion has not been recommended by an external consultant, the Company is an active participant in both the Fortis working group (which is led by Deloittes, who consults with their counterparts in Europe to determine European practice) and industry specific working groups like the Canadian Gas Association and the Canadian Electrical Association. Additionally, the Company has consulted with other regulated companies in the Province. In these consultations with other regulated companies, many of TGI's peers are reaching similar conclusions around asset retirement obligations.

184.3 Please confirm if your proposed conclusion under IFRS has been discussed and approved by your Independent auditor.

Response:

Please see the response to BCUC IR 1.184.2.

185.0 Reference: Accounting and Other Policies - Asset Retirement Obligation

Part III, Section C, Tab 11, section (b) (5) 5.3, p. 481

"The Company collects non-ARO costs related to removal and decommissioning from current customers for future removal of today's assets, as these amounts represent costs of operating the system today. These estimates are currently being recovered as a component of depreciation rates. Terasen Gas proposes to continue this recovery methodology as well as the current regulatory classification as a component of accumulated depreciation. For financial statements purposes, the Company will classify these amounts as a regulatory liability against which future removal costs will be charged." Page 481, par. 1

185.1 Please quantify how much decommission costs have been collected from customers and included in accumulated depreciation to date and by year for each of 2006-2008.

Response:

	2006	2007	2008
Meters - positive salvage at 5% of rate			
Opening Balance	41,227	(165,098)	(429,202)
Collected from Customers	(366,325)	(394,105)	(406,780)
Costs Incurred	(160,000)	(130,000)	(216,000)
Closing Balance	(165,098)	(429,202)	(619,983)

Meter Install & Reg - negative salvage at 25% of rate			
Opening Balance	2,146,804	2,744,048	3,272,725
Collected from Customers	1,323,243	1,407,677	1,497,229
Costs Incurred	726,000	879,000	901,000
Closing Balance	2,744,048	3,272,725	3,868,954

Decommissioning costs have only been collected from customers for Meters and Meter Installations/ Regulators, and this only occurred since 2004. The reasons for this are set out below.

For TGI, the recommendations from the last filed depreciation study which included a provision for removal costs were not implemented due to concerns over the large rate increase at that time, with the exception of the two asset classes, Meters and Meter Installations/Regulators which had rates updated in 2004. To TGI's knowledge, the inclusion of a net salvage component in the calculation of depreciation rates was first formally discussed and acknowledged by the Commission as part of the 2004 – 2007 PBR proceedings, where the

Commission approved Terasen Gas' recommended depreciation rate increase for the asset classes Meter Installation / Regulators, Meters and Computer Software. Prior to this, the removal costs component of the pre-1998 current depreciation rates is not known.

For the two asset classes Meters and Meter Installations/Regulators, the amounts collected from customers and included in accumulated depreciation are known for each of the years since 2004. The 2006 to 2008 amounts are displayed in the following tables (note that for Meters, positive salvage was expected, whereas Meter Installations/Regulators display a negative salvage value):

	2006	2007	2008
Meters - positive salvage at 5% of rate			
Opening Balance	41,227	(165,098)	(429,202)
Collected from Customers	(366,325)	(394,105)	(406,780)
Costs Incurred	(160,000)	(130,000)	(216,000)
Closing Balance	(165,098)	(429,202)	(619,983)

Meter Install & Reg - negative salvage at 25% of rate			
Opening Balance	2,146,804	2,744,048	3,272,725
Collected from Customers	1,323,243	1,407,677	1,497,229
Costs Incurred	726,000	879,000	901,000
Closing Balance	2,744,048	3,272,725	3,868,954

As the Commission only approved the above depreciation rate adjustments as part of the 2004 – 2007 proceedings, it is only the above two accounts that TGI has been explicitly recovering a net salvage component for depreciation.

The collection of removal costs as a component of utility depreciation rates is an accepted part of the calculation of those rates under a depreciation study, and TGI believes that depreciation rates should be approved as sought.

	2006	2007	2008
Meters - positive salvage at 5% of rate			
Opening Balance	41,227	(165,098)	(429,202)
Collected from Customers	(366,325)	(394,105)	(406,780)
Costs Incurred	(160,000)	(130,000)	(216,000)
Closing Balance	(165,098)	(429,202)	(619,983)

Meter Install & Reg - negative salvage at 25% of rate			
Opening Balance	2,146,804	2,744,048	3,272,725
Collected from Customers	1,323,243	1,407,677	1,497,229
Costs Incurred	726,000	879,000	901,000
Closing Balance	2,744,048	3,272,725	3,868,954

185.2 Please explain how decommissioning funds collected from customers are managed and if these funds are maintained in segregated holding accounts for future usage.

Response:

As discussed in the response to BCUC IR 1.185.1, the majority of the depreciation rates currently being applied and included in customers' rates have not separately identified the removal cost component. Therefore, these amounts have not historically been segregated in separate accounts. With the most recent depreciation study, Gannett Fleming has provided TGI with an estimate of the opening balance for accumulated decommissioning costs, as well as the estimated depreciation rate applicable to these costs. To comply with GAAP requirements, TGI is implementing changes to its systems to enable it to track and manage these costs separately, but still within the asset management system of SAP. This change is expected to be implemented for 2010.

185.3 Please confirm how decommissioning costs charged to customers are managed to ensure funds are available for usage as needed and to ensure that customers are not further charged when assets are taken out of use.

Response:

As described in the response to BCUC IR 1.185.2, decommissioning costs are not currently segregated in TGI's SAP system. However, segregation is not a requirement to ensure that customers are properly charged for these costs through the life of the asset. To the extent that depreciation rates include a separate component for decommissioning, costs are recovered from customers at that time and included as a credit to accumulated depreciation. When decommissioning costs are incurred, accumulated depreciation is reduced. With this method, the outstanding liability for these costs is a component of the accumulated depreciation. This has the same impact on rate base and cost of service as if the outstanding liability was held in a separate account.

185.4 Please explain how these decommissioning costs charged to customers are determined, and how frequently the methods and assumptions of the calculation are reevaluated.

Response:

The methods and assumptions in calculating the decommissioning estimates are reevaluated whenever a depreciation study is undertaken. As part of the completion of the most recent depreciation study, Gannett Fleming developed the appropriate net salvage components for TGI's different asset classes. In order to come up with the recommended net salvage values, Gannett Fleming considered a number of factors on which they based their determination. The primary factors were knowledge of the company's plans and operating practices as determined during the field visit and discussion with operating, engineering and budget staff; a general knowledge of the natural gas industry; and a review of the net salvage estimates of other comparable gas companies.

Please refer to pages II-27 and II-28 of the depreciation study in Appendix H-2 of the Application for further discussion of Net Salvage included in depreciation rates.

185.5 Please describe what circumstances allow for the usage of the decommissioning costs amounts collected through depreciation for the purposes of decommissioning? Has this fund been utilized in the past three years and if so, how much was used each year?

Response:

In the normal course, all decommissioning (removal) costs incurred are charged against the accumulated depreciation reserve related to decommissioning. Where that reserve has not been adequately built up by collections through depreciation rates, the removal costs would remain to be recovered through future depreciation rates. As illustrated by the rate increases resulting from the most recent depreciation study, rates in the future will need to increase as a result of under recovery of removal costs from past customers.

A good example of this is asset class 473 Services, where we are incurring substantial removal costs each year ($5.4 million in 2008). These costs primarily result from customer driven requests to remove or deactivate existing service from plant due to redundancy, leaking beyond economical repair, insufficient capacity, etc. In TGI, we perform approximately 4,000 of these activities per year.

Please see the response to BCUC IR 1.185.1 for the removal costs incurred for the years 2006 to 2008 related to the two asset classes where decommissioning costs were specifically identified. Total removal costs for all asset classes incurred for each of those years were $6,780,000 in 2006, $6,710,000 in 2007 and $6,833,000 in 2008.

185.6 Please discuss if any future decommissioning costs represent a provision, legal or constructive obligation under IAS 37?

Response:

As described in the Application, these costs represent non-ARO costs which Terasen Gas considers to be a regulatory liability, when the recovery of these amounts as a component of depreciation rates has been approved by the Commission. The costs incurred relate to the future removal and decommissioning of gas utility assets.

185.7 Please confirm if the proposed conclusion under IFRS has been discussed or recommended by an external consultant.

Response:

At a conceptual level, Terasen Gas has reviewed this conclusion with the Company's external auditors. Terasen Gas' external auditors have yet to audit the Company under IFRS and as such, this has not yet been audited.

185.8 Please confirm if the proposed conclusion under IFRS has been discussed and approved by an Independent auditor.

Response:

At a conceptual level, Terasen Gas has reviewed this conclusion with the Company's external auditors. Terasen Gas' external auditors have yet to audit the Company under IFRS and as such, this has not yet been audited.

186.0 Reference: Accounting and Other Policies – Depreciation

Part III, Section C- Tab 11, section (b) (7), page 482

"• Continuing the use of the Average Service Life for those asset classes where group depreciation methods are deemed appropriate;

• Using the amortization accounting method for those general plant categories where this method is acceptable; and

• Recognizing the accounting impacts of the disposal of individual assets where reasonable and appropriate." Page 482, par.1

186.1 Please describe what "groups" you identified for the purpose of group depreciation rates under IFRS.

Response:

The term group refers to asset class. Under IFRS, most of TGI's asset classes will continue using group depreciation methods except for some specific categories of general plant. These categories of general plant as listed on page 489 of the RRA include:

- Frame structures
- Masonry structures
- Leased structures (depreciated over lease term)
- Computer software over $1 million
- Vehicles
- Heavy work equipment
- Heavy mobile equipment

186.2 Please confirm if the proposed treatment under IFRS has been discussed or recommended by an external consultant.

Response:

Yes, the proposed treatment under IFRS has been discussed and recommended by Gannett Fleming

We have confirmed with Gannett Fleming that the amortization accounting method for most of TGI's general plant categories and specific asset accounting for some general plant categories are consistent with IFRS, acknowledging that specific asset accounting for some general plant categories is better at minimizing the amount of gains and losses recognized.

Based on its work with groups across the Fortis organization, industry specific working groups like the Canadian Gas Association and the Canadian Electrical Association and other regulated companies in the province, Terasen Gas believes the recommended depreciation rates will be IFRS compliant.

186.3 Please confirm if the proposed treatment under IFRS has been discussed and approved by an Independent auditor as IFRS has strict guidelines regarding asset amortization.

Response:

At this time, Terasen Gas' independent auditors have not audited the proposed amortization methods.

While Terasen Gas has not had its auditors audit or approve the methodologies selected, Terasen Gas has done a significant amount of work around its conversion to IFRS including close involvement with working groups across the Fortis organization, industry specific working groups like the Canadian Gas Association and the Canadian Electrical Association and other regulated companies in the Province. As a result, Terasen Gas believes the recommended depreciation rates will be IFRS compliant.

186.4 The last built point of the quote above indicates that certain accounting impacts resulting from the disposal of assets may only be recognized if reasonable or appropriate. Please clarify the meaning of this point and specifically address where such gains or losses on disposal may not be reasonable or appropriate.

Response:

To clarify, the last bullet point reference was to the General Plant categories where we have adopted the whole life accounting method. Since these assets are individually tracked, any gains and losses on disposal of individual assets would be required to be recognized in income under IFRS. TGI has proposed that these gains and losses be recorded in a deferral account, along with gains and losses on other group assets, for disposition starting in 2012.

The words "reasonable and appropriate" were intended to refer to the timing of when those deferred amounts would be recognized, which would be dependent on both their amount and the particular asset classes involved.

187.0 Reference: Accounting and Other Policies - Past Service Costs

Part III, Section C- Tab 11, section (b) (9) 9.3, p. 483

"Terasen Gas proposes to recognize past service costs in accordance with IFRS, which will generally result in immediate recognition since past service costs would already have vested." Page 483, par. 2

187.1 Please quantify the amount of the adjustment, if any, upon transition to IFRS to convert to a method of immediate recognition of past service costs.

Response:

Terasen Gas will be unable to quantify this amount until January 1, 2010 at the earliest. To assess the impact, Terasen Gas will need to know the unamortized past service costs on conversion to IFRS.

188.0 Reference: Accounting and Other Policies - Return on Plan Assets

Part III, Section C- Tab 11 (b) (9) 9.4, p. 483

“For pension accounting, Terasen currently utilizes market related fair values which result in a smoothing of assets over a three year period. The smoothing of the fair value of pension assets also results in a smoothing of the pension expense especially during time of significant volatility in market returns. As a result of the adoption of IFRS, the Company can no longer utilize market related fair values and is required to recognized a one time charge as a result of the change from market related value of assets to fair values. Terasen Gas proposes to defer this adjustment and recover it from customers along with the amount resulting from initial adoption of IFRS in the IFRS Transitional Deferral Account.” Page 483, par. 3

188.1 Please quantify the one time adjustment for the change of the relative value of assets to the fair value method.

Response:

Terasen Gas is unable to quantify the one-time adjustment for the change in the relative fair values until January 1, 2010. The smoothed asset value of the pension assets at January 1, 2010 needs to be compared to the non-smoothed asset value at this same date to determine the one time adjustment.

189.0 Reference: Accounting and Other Policies

Summary of Pension and Employee Future Benefit Changes

Part III, Section C, Tab 11 b.9.4, page 483

"Terasen Gas proposes to continue to estimate pension and employee future benefit costs as per actuarial assumptions, and include those costs in revenue requirements. Where significant fluctuations in expenses occur from those that have been anticipated, the Company proposes to defer those amounts." Page 483, par.4

189.1 Please quantify if any such significant fluctuations in expenses over the estimated amount has occurred and/or been deferred in the past 3 years.

Response:

The variations between the estimated and actual pension expenses over the past three years that have been deferred are as follows:

	($ thousands)		
	2006	2007	2008
Estimate	6,299	3,862	1,103
Actual	3,611	2,355	1,520
Variance	(2,688)	(1,507)	417

As noted in the Application, the IFRS changes are likely to result in more volatility in the pension expense amounts than has been previously experienced, which increases the desirability of continuing the pension variance deferral account for rate stability purposes.

190.0 Reference: Accounting and Other Policies - Highlights

Part III, Section C- Tab 11 c.2, page 486

"The recommended depreciation rate including the Service Life and Net Salvage components for Distribution Services plant is 3.3 percent compared to the current depreciation rate of 2.00 percent as indicated on line 25 in Table C-11-2 below." Page 486, par .1

190.1 Please describe how applicable net salvage component was determined.

Response:

Please refer to the response to BCUC IR 1.185.4.

190.2 Please provide the average net salvage component, as a percentage, under the prior depreciation rates.

Response:

Please refer to TGI's response to BCUC IR 1.185.1.

191.0 Reference: Accounting and Other Policies - Highlights

Part III, Section C- Tab 11 c.2, page 488

"Of the 3.4 per cent composite depreciation rate, 3.0 per cent is related to the life of the assets whereas 0.4 per cent is for depreciation related to negative net salvage value." Page 488, par.1

191.1 Please provide Table C-11-2 (page 487) to include a breakout of Depreciation Life Assets and Depreciation Net Salvage by asset account.

Response:

Table C-11-2 (page 487) has been updated to include a breakout of the depreciation by Life Assets and Net Salvage by asset account. The total depreciation for 2010 has been adjusted slightly higher by $47,340 from $109,651,261 to $109,698,601 to reflect a correction in the recommended rate for GP (Leased) Structures from 0 percent to that based on the Lease Term of the asset.

Line #	Class	Description	Current Rate	Recommended Depreciation % Related to Life (A)	Recommended Depreciation % Related to Net Salvage (B)	Recommended Depreciation Rate (A + B)	Depreciation $ Based on Current Rate	Depreciation $ Related to Life Based on Recommended Rate C)	Depreciation $ Related to Net Salvage Based on Recommended Rate (D)	Depreciation $Based on Recommended Rate (C+D)	Total Depreciation $ Increase + / Decrease
		NATURAL GAS & PETROLEUM PIPELINE SYSTEMS									
1	40100	Franchises and Consents	1.00%	19.76%	0.00%	19.76%	992	19,609	-	19,609	18,617
2	40200	Intangible Plant	1.00%	2.14%	0.00%	2.14%	6,876	14,714	-	14,714	7,838
3	40210	Plant Acquisitions and Adjustments	1.00%	23.66%	0.00%	23.66%	625	14,777	-	14,777	14,152
4	43200	Mfg. Gas Structures	1.50%	3.28%	0.00%	3.28%	7,117	15,561	-	15,561	8,444
5	43300	Mfg. Gas Equipment	3.00%	6.30%	0.00%	6.30%	12,658	26,582	-	26,582	13,924
6	43400	Mfg. Gas Holders	2.00%	3.90%	0.00%	3.90%	13,195	25,730	-	25,730	12,535
7	43600	Mfg. Gas Compressor Equipement	3.00%	4.96%	0.00%	4.96%	1,599	2,644	-	2,644	1,045
8	43700	Mfg. Gas Meas/Reg Equipment	3.00%	19.50%	0.00%	19.50%	9,283	60,342	-	60,342	51,059
9	44200	LNG Gas Structures	4.00%	3.65%	0.37%	4.02%	195,383	178,287	18,073	196,360	977
10	44300	LNG Gas Equipment	4.00%	2.18%	0.43%	2.61%	666,133	363,043	71,609	434,652	-231,481
11	44900	LNG Gas Other Equipment	4.00%	3.36%	0.34%	3.70%	935,696	785,985	79,534	865,519	-70,177
12	46200	TP Compressor Structures	3.00%	3.84%	0.19%	4.03%	440,702	564,098	27,911	592,009	151,307
13	46300	TP Meas/Reg Structures	3.00%	4.27%	0.21%	4.48%	148,441	211,281	10,391	221,672	73,231
14	46400	TP Other Structures	3.00%	2.88%	0.14%	3.02%	178,759	171,608	8,342	179,950	1,191
15	46500	TP Transmission Pipeline	2.00%	1.63%	0.16%	1.79%	15,270,551	12,445,499	1,221,644	13,667,143	-1,603,408
16	46510	TP Transmission Pipeline - Byron Creek	5.00%	5.00%	0.00%	5.00%	46,579	46,579	-	46,579	-
17	46600	TP Compressor Equipment	3.00%	3.18%	0.32%	3.50%	3,329,658	3,529,438	355,164	3,884,601	554,943
18	46710	TP Meas/Reg Equipment	3.00%	7.19%	0.36%	7.55%	882,192	2,114,319	105,863	2,220,182	1,337,990
19	46720	TP Telemetry Equipment	10.00%	1.33%	0.00%	1.33%	846,904	112,638	-	112,638	-734,266
20	46730	TP Measurement/Regulator Equipment	3.00%	4.01%	0.20%	4.21%	1,161	1,553	77	1,630	469
21	46800	TP Communications Equipment	10.00%	5.32%	0.00%	5.32%	34,589	18,401	-	18,401	-16,188
22	47200	DS Structures	3.00%	3.60%	0.18%	3.78%	440,886	529,063	26,453	555,517	114,631
23	47210	DS Structures - Byron Creek	5.00%	5.00%	0.00%	5.00%	5,362	5,362	-	5,362	-
24	47300	DS Services	2.00%	2.25%	1.13%	3.38%	12,838,744	14,443,587	7,253,890	21,697,478	8,858,734
25	47301	LILO DS Services	2.00%	2.20%	1.10%	3.30%	864,582	951,041	475,520	1,426,561	561,979
26	47400	DS Meters/Regulators Installations	3.57%	5.21%	0.00%	5.21%	4,797,021	7,000,695	-	7,000,695	2,203,674
27	47401	LILO DS Meters/Regulators Installation	3.57%	2.19%	0.00%	2.19%	573,704	351,936	-	351,936	-221,768
28	47500	DS Mains	2.00%	1.89%	0.37%	2.26%	16,901,151	15,971,588	3,126,713	19,098,300	2,197,149
29	47501	LILO DS Mains	2.00%	2.00%	0.40%	2.40%	794,087	794,087	158,817	952,905	158,818
30	47600	DS NGV Fuel Equipment	6.67%	25.04%	0.00%	25.04%	38,076	142,943	-	142,943	104,867
31	47710	DS Meas/Reg Additions	3.00%	5.72%	0.00%	5.72%	2,474,212	4,717,497	-	4,717,497	2,243,285
32	47720	DS Telemetry	10.00%	0.25%	0.00%	0.25%	591,343	14,784	-	14,784	-576,559
33	47730	DS Meas/Reg Equipment	5.00%	0.00%	0.00%	0.00%	8,158	-	-	-	-8,158
34	47810	DS Meters	3.57%	5.31%	0.00%	5.31%	6,598,042	9,813,895	-	9,813,895	3,215,853
35	47811	LILO DS Meters	3.57%	3.29%	0.00%	3.29%	357,954	329,879	-	329,879	-28,075
36	47820	DS Instruments	3.57%	4.03%	0.00%	4.03%	401,674	453,430	-	453,430	51,756
37	17500	Unamortized Conversion/Expense	1.00%	1.00%	0.00%	1.00%	78,790	78,790	-	78,790	-
38	17800	Organizational Costs	1.00%	1.00%	0.00%	1.00%	7,281	7,281	-	7,281	-
39							70,800,160	76,328,546	12,940,001	89,268,548	18,468,388
40											
41		**PLANT, BUILDING AND EQUIPMENT**									
42	48210	GP (Frame) Structures	3.00%	3.67%	0.00%	3.67%	158,584	194,001	-	194,001	35,417
43	48220	GP (Masonry) Structures	1.50%	4.37%	0.00%	4.37%	1,252,911	3,650,147	-	3,650,147	2,397,236
44	48230	GP (Leased) Structures	Lease Term	Lease Term	Lease Term	Lease Term	47,340	47,340	-	47,340	-
45	48310	GP Computer Hardware	20.00%	20.00%	0.00%	20.00%	3,643,752	3,643,752	-	3,643,752	-
46	40201	Application Software - 8 yr life	12.50%	12.50%	0.00%	12.50%	6,953,519	6,953,519	-	6,953,519	-
47	40202	Application Software - 5 yr life	20.00%	20.00%	0.00%	20.00%	1,610,241	1,610,241	-	1,610,241	-
48	48320	GP Computer Software	20.00%	20.00%	0.00%	20.00%	170,765	170,765	-	170,765	-
49	48330	GP Office Equipment	5.00%	6.67%	0.00%	6.67%	224,040	298,869	-	298,869	74,829
50	48340	GP Furniture	5.00%	5.00%	0.00%	5.00%	986,465	986,465	-	986,465	-
51	48400	GP Vehicles	15.00%	7.70%	-1.54%	6.16%	341,847	175,481	-35,096	140,385	-201,462
52	48510	GP Heavy Work Equipment	5.00%	6.64%	-0.99%	5.65%	10,438	13,861	-2,067	11,795	1,357
53	48520	GP Heavy Mobile Equipment	5.00%	8.48%	-2.05%	6.43%	28,052	47,576	-11,501	36,075	8,023
54	48600	GP Small Tools/Equipment	5.00%	5.00%	0.00%	5.00%	1,608,902	1,608,902	-	1,608,902	-
55	48720	GP NGV Cylinders	10.00%	6.67%	0.00%	6.67%	2,417	1,612	-	1,612	-805
56	48810	GP Telephone Equipment	5.00%	6.67%	0.00%	6.67%	561,978	749,679	-	749,679	187,701
57	48820	GP Radio Equipment	10.00%	6.67%	0.00%	6.67%	489,515	326,506	-	326,506	-163,009
58							18,090,766	20,478,716	-48,664	20,430,053	2,339,287
59											
60			Total Annual Depreciation				88,890,926	96,807,262	12,891,337	109,698,601	20,807,675
61											
62			Annual Composite Rate				2.7%			3.4%	
63											
64		* Numbers above are in actual dollars with depreciation calculated using the January 1, 2010 gross asset values.									

191.2 Please provide a continuity schedule for the "Net Salvage" depreciation component, similar to Financial Schedule 48 (Depreciation and Amortization Continuity Schedule).

Response:

Following is a continuity schedule for "Net Salvage" depreciation component for 2010 and 2011.

TERASEN GAS INC.

NET SALVAGE DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	0.00%						-
3	175-00 Unamortized Conversion Expense	109	0.00%						-
4	175-00 Unamortized Conversion Expense - Squamish	777	0.00%						-
5	178-00 Organization Expense	728	0.00%						-
6	179-01 Other Deferred Charges	-	0.00%						-
7	401-00 Franchise and Consents	99	0.00%						-
8	402-00 Utility Plant Acquisition Adjustment	63	0.00%						-
9	402-00 Other Intangible Plant	688	0.00%						-
10	461-00 Land Rights - Transmission	43,843	0.00%						-
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%						-
12	471-00 Land Rights - Distribution	1,065	0.00%						-
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%						-
14	402-01 Application Software - 12.5%	57,991	0.00%						-
15	402-02 Application Software - 20%	7,128	0.00%						-
16	TOTAL INTANGIBLE PLANT	112,506		-	-	-	-	-	-
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%						-
20	432 Manufact'd Gas - Struct. & Improvements	475	0.00%						-
21	433 Manufact'd Gas - Equipment	608	0.00%						-
22	434 Manufact'd Gas - Gas Holders	660	0.00%						-
23	436 Manufact'd Gas - Compressor Equipment	53	0.00%						-
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	0.00%						-
25	440/441 Land in Fee Simple and Land Rights	928	0.00%						-
26	442 Structures & Improvements	4,885	0.37%	18			-		18
27	443 Gas Holders - Storage	16,883	0.43%	73			-		73
28	446 Compressor Equipment	-	0.00%						-
29	447 Measuring & Regulating Equipment	-	0.00%						-
30	448 Purification Equipment	-	0.00%						-
31	449 Local Storage Equipment	23,393	0.34%	80			-		80
32	TOTAL MANUFACTURED GAS / LOCAL STORAC	48,225		171	-	-	-	-	171
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%						-
36	462-00 Compressor Structures	14,690	0.19%	28			-		28
37	463-00 Measuring Structures	4,948	0.21%	10			-		10
38	464-00 Other Structures & Improvements	5,959	0.14%	8			-		8
39	465-00 Mains	772,016 *	0.16%	1,235			-		1,235
40	465-00 Mains - INSPECTION	1,653	Term						-
41	465-10 Mains - Byron Creek	932	0.00%						-
42	466-00 Compressor Equipment	111,765	0.32%	358			-		358
43	466-00 Compressor Equipment - OVERHAUL	-	Term						-
44	467-00 Measuring & Regulating Equipment	29,406	0.36%	106			-		106
45	467-10 Telemetering	8,516	0.00%						-
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	0.20%	-			-		-
47	468-00 Communication Structures & Equipment	346	0.00%						-
48	469-00 Other Transmission Equipment	-							-
49	TOTAL TRANSMISSION PLANT	957,677		1,745	-	-	-	-	1,745
50									
51	* Adjusted for full year impact of 2009 Fraser River SBSA CPCN.								

TERASEN GAS INC.

NET SALVAGE DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2010
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2010 (Cr.)	Adjust- ments	Retirements	Retirement Costs	Accumulated 12/31/2009	Accumulated 12/31/2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%						-
3	472-00 Structures & Improvements	14,696	0.18%	26			-		26
4	472-10 Structures & Improvements - Byron Creek	107	0.00%						-
5	473-00 Services	651,802 **	1.13%	7,364			(9,685)		(2,321)
6	473-00 Services - LILO	43,229	1.10%	476			-		476
7	474-00 House Regulators & Meter Installations	135,572	0.00%				(500)	4,952	4,452
8	474-00 House Regulators & Meter Installations - LILO	16,070	0.00%						-
9	475-00 Mains	853,964	0.37%	3,160			(500)		2,660
10	475-00 Mains - LILO	39,704	0.40%	159			-		159
11	476-00 Compressor Equipment	571	0.00%						-
12	477-00 Measuring & Regulating Equipment	84,497	0.00%				(105)		(105)
13	477-00 Telemetering	6,021	0.00%						-
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%						-
15	478-10 Meters	185,804	0.00%				(500)	(1,546)	(2,046)
16	478-11 Meters - LILO	10,027	0.00%						-
17	478-20 Instruments	11,251	0.00%						-
18	479-00 Other Distribution Equipment	-	0.00%						-
19		2,056,894		11,185	-	-	(11,290)	3,406	3,301
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	21,968	0.00%						-
23	481-00 Land Rights	-	0.00%						-
24	482-00 Structures & Improvements	-	0.00%						-
25	- Frame Buildings	5,286	0.00%						-
26	- Masonry Buildings	84,641	0.00%						-
27	- Leasehold Improvement	557	Lease Term						-
28	Office Equipment & Furniture	-	0.00%						-
29	483-30 GP Office Equipment	4,479	0.00%						-
30	483-40 GP Furniture	19,983	0.00%						-
31	483-10 GP Computer Hardware	17,347	0.00%						-
32	483-20 GP Computer Software	843	0.00%						-
33	483-21 GP Computer Software	-	0.00%						-
34	484-00 Transportation Equipment	3,094	-1.54%	(48)			-		(48)
35	484-00 Vehicles - Leased	26,877	Lease Term						-
36	485-10 Heavy Work Equipment	209	-0.99%	(2)			-		(2)
37	485-20 Heavy Mobile Equipment	576	-2.05%	(12)			-		(12)
38	486-00 Small Tools & Equipment	32,746	0.00%						-
39	487-00 Equipment on Customer's Premises	24	0.00%						-
40	- VRA Compressor Installation Costs	-	0.00%						-
41	488-00 Communications Equipment	-	0.00%						-
42	- Telephone	11,390	0.00%						-
43	- Radio	4,998	0.00%						-
44	489-00 Other General Equipment	-	0.00%						-
45	TOTAL GENERAL PLANT	235,016		(62)	-	-	-	-	(62)
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%	-					-
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-
50									
51	TOTALS	$3,410,317		$13,039	$0	$0	($11,290)	$3,406	$5,155
52									
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects								
54									
55	**Net Depreciation Expense**			$13,039					

TERASEN GAS INC.

NET SALVAGE DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$0	0.00%					-	-
3	175-00 Unamortized Conversion Expense	109	0.00%					-	-
4	175-00 Unamortized Conversion Expense - Squamish	777	0.00%					-	-
5	178-00 Organization Expense	728	0.00%					-	-
6	179-01 Other Deferred Charges	-	0.00%					-	-
7	401-00 Franchise and Consents	99	0.00%					-	-
8	402-00 Utility Plant Acquisition Adjustment	63	0.00%					-	-
9	402-00 Other Intangible Plant	688	0.00%					-	-
10	461-00 Land Rights - Transmission	43,965	0.00%					-	-
11	461-10 Land Rights - Transmission - Byron Creek	16	0.00%					-	-
12	471-00 Land Rights - Distribution	1,065	0.00%					-	-
13	471-10 Land Rights - Distribution - Byron Creek	-	0.00%					-	-
14	402-01 Application Software - 12.5%	61,472	0.00%					-	-
15	402-02 Application Software - 20%	5,631	0.00%					-	-
16	TOTAL INTANGIBLE PLANT	114,613		-	-	-	-	-	-
17									
18	**MANUFACTURED GAS / LOCAL STORAGE**								
19	430 Manufact'd Gas - Land	31	0.00%					-	-
20	432 Manufact'd Gas - Struct. & Improvements	475	0.00%					-	-
21	433 Manufact'd Gas - Equipment	794	0.00%					-	-
22	434 Manufact'd Gas - Gas Holders	660	0.00%					-	-
23	436 Manufact'd Gas - Compressor Equipment	53	0.00%					-	-
24	437 Manufact'd Gas - Measuring & Regulating Equipm	309	0.00%					-	-
25	440/441 Land in Fee Simple and Land Rights	928	0.00%					-	-
26	442 Structures & Improvements	4,885	0.37%	18			-	18	36
27	443 Gas Holders - Storage	17,928	0.43%	77			-	73	150
28	446 Compressor Equipment	-	0.00%					-	-
29	447 Measuring & Regulating Equipment	-	0.00%					-	-
30	448 Purification Equipment	-	0.00%					-	-
31	449 Local Storage Equipment	23,393	0.34%	80			-	80	160
32	TOTAL MANUFACTURED GAS / LOCAL STORAC	49,456		175	-	-	-	171	346
33									
34	**TRANSMISSION PLANT**								
35	460-00 Land in Fee Simple	7,408	0.00%					-	-
36	462-00 Compressor Structures	14,690	0.19%	28			-	28	56
37	463-00 Measuring Structures	4,948	0.21%	10			-	10	20
38	464-00 Other Structures & Improvements	5,959	0.14%	8			-	8	16
39	465-00 Mains	793,490	0.16%	1,270			-	1,235	2,505
40	465-00 Mains - INSPECTION	3,497	Term					-	-
41	465-10 Mains - Byron Creek	932	0.00%					-	-
42	466-00 Compressor Equipment	113,336	0.32%	363			-	358	721
43	466-00 Compressor Equipment - OVERHAUL	-	Term					-	-
44	467-00 Measuring & Regulating Equipment	29,406	0.36%	106			-	106	212
45	467-10 Telemetering	8,593	0.00%					-	-
46	467-20 Measuring & Regulating Equipment - Byron Cr	39	0.20%	-			-	-	-
47	468-00 Communication Structures & Equipment	346	0.00%					-	-
48	469-00 Other Transmission Equipment	-	0.00%					-	-
49	TOTAL TRANSMISSION PLANT	982,643		1,785	-	-	-	1,745	3,530

TERASEN GAS INC.

NET SALVAGE DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2011
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	Provision 2011 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Accumulated 12/31/2010	Accumulated 12/31/2011
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**DISTRIBUTION PLANT**								
2	470-00 Land in Fee Simple	$3,418	0.00%					$0	$0
3	472-00 Structures & Improvements	14,696	0.18%	26			-	26	52
4	472-10 Structures & Improvements - Byron Creek	107	0.00%					-	-
5	473-00 Services	672,119	1.13%	7,595			(8,525)	(2,321)	(3,251)
6	473-00 Services - LILO	43,229	1.10%	476			-	476	952
7	474-00 House Regulators & Meter Installations	138,035	0.00%				(500)	4,452	3,952
8	474-00 House Regulators & Meter Installations - LILO	16,070	0.00%					-	-
9	475-00 Mains	871,791	0.37%	3,226			(500)	2,660	5,386
10	475-00 Mains - LILO	39,704	0.40%	159			-	159	318
11	476-00 Compressor Equipment	571	0.00%					-	-
12	477-00 Measuring & Regulating Equipment	88,550	0.00%				(107)	(105)	(212)
13	477-00 Telemetering	6,232	0.00%					-	-
14	477-10 Measuring & Regulating Equipment - Byron Cree	163	0.00%					-	-
15	478-10 Meters	187,822	0.00%				(500)	(2,046)	(2,546)
16	478-11 Meters - LILO	10,027	0.00%					-	-
17	478-20 Instruments	11,251	0.00%					-	-
18	479-00 Other Distribution Equipment	-	0.00%					-	-
19		2,103,784		11,482	-	-	(10,132)	3,301	4,651
20									
21	**GENERAL PLANT & EQUIPMENT**								
22	480-00 Land in Fee Simple	22,096	0.00%					-	-
23	481-00 Land Rights	-	0.00%					-	-
24	482-00 Structures & Improvements	-	0.00%					-	-
25	- Frame Buildings	5,286	0.00%					-	-
26	- Masonry Buildings	87,190	0.00%					-	-
27	- Leasehold Improvement	667	Lease Term					-	-
28	Office Equipment & Furniture	-	0.00%					-	-
29	483-30 GP Office Equipment	4,012	0.00%					-	-
30	483-40 GP Furniture	19,830	0.00%					-	-
31	483-10 GP Computer Hardware	18,979	0.00%					-	-
32	483-20 GP Computer Software	734	0.00%					-	-
33	483-21 GP Computer Software	-	0.00%					-	-
34	484-00 Transportation Equipment	4,712	-1.54%	(73)			-	(48)	(121)
35	484-00 Vehicles - Leased	28,198	Lease Term					-	-
36	485-10 Heavy Work Equipment	209	-0.99%	(2)			-	(2)	(4)
37	485-20 Heavy Mobile Equipment	606	-2.05%	(12)			-	(12)	(24)
38	486-00 Small Tools & Equipment	33,867	0.00%					-	-
39	487-00 Equipment on Customer's Premises	24	0.00%					-	-
40	- VRA Compressor Installation Costs	-	0.00%					-	-
41	488-00 Communications Equipment	-	0.00%					-	-
42	- Telephone	10,975	0.00%					-	-
43	- Radio	4,706	0.00%					-	-
44	489-00 Other General Equipment	-	0.00%					-	-
45	TOTAL GENERAL PLANT	242,088		(87)	-	-	-	(62)	(149)
46									
47	**UNCLASSIFIED PLANT**								
48	499 Plant Suspense	-	0.00%					-	-
49	TOTAL UNCLASSIFIED PLANT	-		-	-	-	-	-	-
50									
51	TOTALS	$3,492,582		$13,355	$0	$0	($10,132)	$5,155	$8,378
52									
53	Less: Capital Lease Vehicle Depreciation allocated to Capital Projects								
54									
55	**Net Depreciation Expense**			$13,355					
56									

192.0 Reference: Accounting and Other Policies - Implementation of Recommendations

Part III, Section C- Tab 11 c.3, page 488

The depreciation study conducted provided methods of depreciation under both Average Service Life ("ASL") and Equal Life Group ("ELG"). ASL allows for averaging of service lives of group of assets. ELG is more specific by sorting assets into group based on service lives and amortizing the group together. IFRS requires the use of asset components to break larger assets into smaller pierces based on the useful lives of those assets. Various methods of amortization currently acceptable in Canada will be closely scrutinized under IFRS and judgment will ultimately determine if such methods are acceptable.

192.1 Please explain how TGI has concluded that the ASL is appropriate under IFRS as IFRS requires that assets are amortized over their service life at a component level.

Response:

Per lines 19 to 23 on Page 25 of Appendix H-1 "International Financial Reporting Standards (IFRS): A Summary of Anticipated Impacts of Transition to IFRS on Rate Regulated Utilities in British Columbia":

"*To the extent asset classes include components with different lives that would materially impact depreciation, these components must be separately depreciated (IAS 16.43)."*

And lines 10 to 15 also on Page 25:

"IFRS does indicate that where a significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item, such parts may be grouped in determining the depreciation charge (IAS 16.45)."

Therefore, TGI concludes that the use of group depreciation accounting methods, whether ASL or not, continues to be acceptable under IFRS. Both the ASL and the ELG group depreciation methods are designed to amortize the consumption of assets over their service lives. However, ELG is better at minimizing the amount of gains and losses to be recognized.

TGI has done an initial analysis to confirm that there are no asset classes where a more granular level of componentization would materially impact the depreciation expense. This initial analysis suggests that none exist, with the exception of the segregation of inspection and overhaul costs. TGI is close to completing a more detailed review of the historical asset records by the end of September 2009. After we conclude our work in this area, our external auditors will review our findings during the last quarter of this year but will not issue an opinion specifically on the method of depreciation selected nor the componentization of the capital assets.

192.2 Please confirm that Gannet Fleming does not conclude within the depreciation study, included as Appendix H-2 to Exhibit B-1, that either ASL or ELG is or is not compliant with IFRS.

Response:

TGI confirms that Gannett Fleming does not conclude in the depreciation study that either ASL or ELG is compliant with IFRS. Gannett Fleming's primary conclusion is that TGI's current depreciation rates are too low, and need to be increased in order to recover the existing book value of the assets over the period of time that those assets are providing service to utility customers.

We have confirmed with Gannett Fleming that both ASL and ELG are consistent with IFRS, although ELG is better at minimizing the amount of gains and losses to be recognized. The proposed deferral account to capture gains and losses will serve to eliminate this potential advantage, and since it is expected that the annual amounts recorded in the deferral account would be less than the additional incremental annual depreciation expense required under the ELG method, the rate impact to customers is minimized.

192.3 Please confirm if your independent auditors have concurred with the conclusion that the use of ASL will be appropriate upon conversion to IFRS.

Response:

At this time, TGI's independent auditors have not concurred with the conclusion that the use of ASL will be appropriate upon conversion to IFRS. Terasen Gas has discussed the use of ASL versus ELG with Terasen Gas' auditors but the Company has not yet had the 2010 financial statements audited. Please also see Terasen Gas' response to BCUC IR 1.192.2 for the views of Gannett Fleming.

193.0 Reference: Accounting and Other Policies - Implementation of Recommendations

Part III, Section C- Tab 11 c.3, page 489

"For some specific categories of general plant which do not lend themselves well to mass asset accounting practices under IFRS, Terasen Gas proposes a change in methodology from mass accounting to where the assets will be individually tracked, with gains and losses recorded on disposal and depreciation according to whole life rates developed by Gannett Fleming. The categories of general plant include:

• Frame structures

• Masonry structures

• Leased structures (depreciated over lease term)

• Computer software over $1M

• Vehicles

• Heavy work equipment

• Heavy mobile equipment

Instead these assets should be individually tracked and disposed of, there should be no negative salvage estimates involved, and any gains or losses on disposal should be recognized. We believe this change in methodology is required to be compliant with IFRS for general plant." Page 489, par 1

193.1 Please describe what situations negative salvage values will be applied to assets not included in the list above, and explain how it was determined that those values will be acceptable under IFRS.

Response:

Negative salvage values will applied to those assets listed on Table 2 page III-8 of the Gannett Fleming depreciation study in which a negative salvage estimate is provided. The assets identified as having negative salvage include LNG Plant, Transmission Plant and Distribution Plant.

As described in the Gannett Fleming depreciation study pages 27 and 28, appropriate depreciation policies should provide for the recovery of the service value of assets in regulatory service. The concept of service value includes both the original cost of the asset and the net salvage cost incurred at the time of retirement. Accordingly, the proposed depreciation rates include a provision for recovery of the estimated retirement costs with the estimate of negative salvage based primarily on judgement, giving consideration for a number of factors including TGI's practices and comparison to the negative salvage estimates of other gas companies.

Under IFRS, Terasen Gas will be required to breakout both the negative salvage collected in rates on an annual basis and the cumulative balance of the negative net salvage liability balance at the end of each reporting period.

193.2 Please explain if any assets or types of assets of TGI excluded from the list of general plant assets above have an individual carrying value of more than $1M?

Response:

General plant assets not included in the above list will not have an individual carrying value of more than $1M. However, there are assets in other categories including Transmission, Distribution and Manufactured Gas plant that have an individual carrying value of more than $1M for which mass asset accounting is being appropriately used.

TGI clarifies that the $1M threshold indicated for computer software is used to distinguish larger, enterprise software applications from general desktop software for the purposes of calculating depreciation. Otherwise, no dollar threshold is used in determining whether mass asset or specific asset accounting is applied to an asset type.

194.0 Reference: Accounting and Other Policies - Overheads Capitalized

Part III, Section C- Tab 11, section (d), page 490

"Terasen Gas considers the results of the recent study as being reasonable and representative of the activities and related overhead costs that should be capitalized and will enable the Company to also comply with new IFRS requirements. Included in Appendix H-3, the current study and results are consistent with the prior study results, highlighting the ongoing difference between the Company's current overhead capitalization rate and that being recommended in the study. For validation, the recommended capitalization approach has been reviewed independently by KPMG to evaluate the suitability of the Company's approach. KPMG states in the study that it considers the overhead capitalization results to be fair and reasonable. KPMG is a major audit, tax and advisory services firm with significant experience in conducting overhead capitalization studies for utility clients." Page 490, par.2

194.1 Please explain if TGI plans to use actual costs for large capital projects or if the proposed rate will be applied without exception.

Response:

TGI plans to use actual project costs to allocate the pool of overheads capitalized. Overhead costs will be allocated to all transmission and distribution additions, with the exception of land, land rights, general plant assets and meters.

Large projects, defined as CPCN status, will be dealt with on an individual basis. For CPCN projects, if support staff are incremental to the project and thereby charging directly to the project, then the project will not be subject to the overheads capitalized allocation.

This process ensures that new assets TGI acquires and constructs will receive an appropriate allocation of overhead costs.

194.2 Please explain the proposed process to test and ensure that the capitalized overhead rate continues to remain appropriate during the two year test period.

Response:

TGI does not believe it is necessary to complete another review over the next two years to ensure that the capitalized overhead rate continues to remain appropriate. The most recent study concluded eight per cent as an appropriate overhead capitalization rate and is not materially different from the previous study's recommended rate of ten percent. In addition, TGI does not anticipate any change in capital activity that would cause a significant change in the overhead capitalization rate.

TGI believes the proposed eight percent is appropriate for the two year test period.

194.3 Please clarify how TGI will differentiate between time spent on capital projects that are seen through to completion vs. time spent on development of potential capital projects that are not seen through to completion and which would otherwise not be subject to capitalization. Please indicate the rate of project successfully completed as a percentage to all potential projects initiated.

Response:

Currently, time spent directly on development of capital projects are charged to the capital project. Until it is known that a capital project is not proceeding, there is no differentiation between the treatment of time charged for projects completed versus projects that are not seen through to completion. When a project has not resulted in an asset being constructed and eligible for capitalization, the costs associated with the project are written off.

To minimize projects and development costs not seen through to completion, TGI has a comprehensive capital project review process. Capital budgets are reviewed, evaluated and approved annually by the Utility Operating Committee and the Executive Leadership Team. In addition, capital project funding requests that arise throughout the year are evaluated on a case by case basis and approved by the Utility Operating Committee before commencement. Project requests are screened at the conceptual stage to ensure successful completion. Once approved, capital projects are monitored on a regular basis to ensure that they remain on track and on budget.

Given TGI's approach to project development outlined above, all projects that pass the review and approval stage of the capital budget process are completed. Any projects initiated thereafter are successfully completed.

Under the new accounting standards (IFRS), time spent on the development of a potential capital projects (feasibility studies) will be considered an operating expense. Therefore, TGI has included funding in the Application for feasibility studies in its 2010 and 2011 O&M budgets (i.e. refer to page 355 of the Application).

194.4 Various estimates used in the capitalization study, included as Appendix H-3 to Exhibit B-2, to determine the capitalization rate included the usage of management's estimate of time. Please explain how department managers were able to make such estimates of time including the time frame considered, the methods used to collect data, the review process to ensure estimates were reasonable. Please include a description of customer service staff whose time is not based on customers.

Response:

Department managers are considered the best source of accurately assessing the level of capital support activities occurring within their department. Their assessments are based upon knowledge of the business and key processes, the nature and extent of capital support being offered, and the allocation of resources within their department. Managers frequently collaborated with their staff as a means of augmenting their decision process.

The managers reviewed and documented their respective department's capital activities for the period 2009 to 2011. This data was collected using standardized templates. Finance staff met with department managers and reviewed the data assembled in the templates. They checked that the information provided was consistent with the definition of overheads capital.

Any assignment of overhead costs to capital project is based on some reasonable causal link or association with the capital activity. For most cost centers, the key driver of the extent of capital support being provided was determined to be labour. As a result, estimates of labour time were deemed as the most reasonable basis for forming an overhead allocation.

KPMG completed an independent review of TGI's approach and methodology. Their findings are documented in the report filed as Appendix H-3. In their assessment (please refer to pages 20 -21). KPMG concluded TGI's criteria for freedom from bias, stability and accuracy of the underlying data was satisfied. In addition, page 31 of KPMG's report states, "KPMG finds the methodology to be reasonable and in accordance with internal policy, external guidance from the regulators and industry standards practices related to overhead capitalization."

TGI's customer service staff that form a part of TGI's outsourced customer care agreement, predominantly spend their time providing service to customers. These expenses are considered to have no direct relationship to capital activities. For this reason, they have been excluded from the capitalized overhead allocation.

194.5 Is a breakdown, by percentage, of capitalized overhead by department available. Also, is such a breakdown available for the past period?

Response:

The most recent review of the overheads capitalized produced the following percentage of overheads capitalized by department resulting in a total proposed rate of eight percent.

Department	% Overheads Capitalized
Distribution	20%
Gas Supply and Transmission	3%
Marketing and Development	1%
Business and Information Technology Services	16%
Human Resources and Operations Governance	3%
Finance and Regulatory Affairs	9%
President	3%
Total - % Capitalized to Total O&M	8%

The previous studies were filed as part of the 1998-2002 PBR Application and 2003 Revenue Requirement Application. The table below represents the department view as shown in the 2003 Revenue Requirement Application. Due to organizational changes over time, the two tables are not comparable on a department by department basis.

Department	% Overheads Capitalized
Distribution Operations	25%
Network Development & Operations Support	49%
Gas Supply and Transmission	N/A
Customer Care & Marketing	N/A
Finance	5%
CEO & President	N/A
Human Resources	N/A
RESSCL and Legal / Risk Management*	10%
Information Technology	N/A
Total - % Capitalized to Total O&M	10%

*RESSCL - Regulatory, Environmental, Health & Safety, Supply Chain & Logistics and Legal & Risk Management

From a total overhead percent capitalized basis, the recent study's results of eight percent is consistent with that of the previous study's proposed rate of ten percent. And as noted in the RRA, TGI had proposed the implementation of a ten percent overhead capitalized rate in its 2003 Revenue Requirement Application. The Commission instead approved a 16% rate which is the rate that is being applied today.

Department	% Overheads Capitalized
Distribution	20%
Gas Supply and Transmission	3%
Marketing and Development	1%
Business and Information Technology Services	16%
Human Resources and Operations Governance	3%
Finance and Regulatory Affairs	9%
President	3%
Total - % Capitalized to Total O&M	8%

Department	% Overheads Capitalized
Distribution Operations	25%
Network Development & Operations Support	49%
Gas Supply and Transmission	N/A
Customer Care & Marketing	N/A
Finance	5%
CEO & President	N/A
Human Resources	N/A
RESSCL and Legal / Risk Management*	10%
Information Technology	N/A
Total - % Capitalized to Total O&M	10%

194.6 On occasion, TGI will expend resources towards projects that never reach final completion. Please explain how such time towards projects not otherwise put into service will be extracted from costs otherwise capitalized.

Response:

Please refer to the response to BCUC IR 1.194.3.

194.7 Please confirm that KPMG does not conclude that the use of a rate for the purposes of capitalization is appropriate under IFRS.

Response:

Confirmed. On pages 21-22 of Appendix H-3, KPMG does not conclude that the rate is appropriate to comply with IFRS, and TGI had not expected KPMG to reach a definitive conclusion on this point one way or the other given IFRS was still evolving. IFRS standards are principles based standards and do not provide specific rules or guidance on how to apply the various standards.

In July 2009, the International Accounting Standards Board (IASB) issued an Exposure Draft on Rate Regulated Activities. In the current version of this Exposure Draft, the IASB describes how an overheads capitalized rate allowed by the regulator would also be accepted for financial reporting purposes. Thereby, the decision borne by the regulator for overheads capitalized will be appropriate for the rate setting purposes. The exposure draft is not the final standard, and as such, the guidance may change between the current Exposure Draft and the final guidance issued by the IASB.

TGI's RRA Application was submitted before the current version of the Exposure Draft was released. On page 490, Part III, Section C, Tab 11, TGI has proposed that an IFRS Transitional Deferral account be permitted to record any differences between the rate recommended in the study and the rate ultimately required for TGI to comply with IFRS.

194.8 Please confirm if TGI's independent auditors have concurred with the conclusion that the use of this overhead capitalization rate will be appropriate upon conversion to IFRS.

Response:

TGI's independent auditors, Ernst and Young, have not yet completed their review of the overhead capitalization study. In completing their work, Ernst and Young will also incorporate recently issued guidance on rate-regulated enterprises.

195.0 Reference: Capitalized Overhead

Appendix H-3

195.1 Please confirm that Gross O&M costs are net of direct labour charges to capital projects.

Response:

That is correct, gross O&M costs are net of direct labour charges to capital projects.

195.2 Please provide a numeric calculation to the Overhead Cost Allocation formula for 2010 and 2011, as presented in Figure 2 of Appendix H-3.

Response:

At the time of the initiation of the overhead capitalization study, the 2010 and 2011 budgets had not been finalized. As such, the 2009 budget was used as the basis for the capitalized overhead review, with the objective the total composite overhead rate (i.e. 8%) would be appropriate to apply to the 2010 and 2011 budgets, once completed.

TGI believes the overall composite overhead capitalization of 8% is appropriate for 2010 and 2011, since no material differences are expected in this period. TGI's previously recommended overhead capitalization rate has not materially changed over the years (i.e. 10% recommended in the previous studies to the current proposal of 8%) and is not likely to materially change in the next two years. As such, TGI believes the 8% proposed rate is appropriate.

To produce similar results to that requested, TGI would have to undergo a fairly exhaustive and lengthy process to provide the calculation. TGI respectfully suggests that the work required to perform the calculation is disproportionate to the value that might be obtained from the response.

195.3 Please identify the customer rate impact due to the reduction of the Capitalized Overhead from 16 percent to 8 percent. What portion of this reduction is a result of IFRS standards pertaining to Capitalized Overhead?

Response:

As identified on Schedule 1 in Section C, Tab 13, the revenue requirement impact of the change in the capitalized overhead rate is approximately $11.2 million. This revenue requirement impact translates to an increase as a percentage of gross margin equal to approximately 2.1%.

Although the reduction of the Capitalized Overhead is required for compliance with IFRS, Terasen Gas had already identified the need for a change to its existing overhead rate in previous years' applications and considers the results of the recent study as being reasonable and representative of the activities and related overhead costs that should be capitalized. Please see the Application, p.489-490.

Subsequent to the filing of this Application, in July of 2009, the IASB issued its Exposure Draft on Rate-regulated Activities which if accepted as a final standard as written, would allow the inclusion in self-constructed assets of the amount of overheads allowed by the Commission, regardless if that amount is otherwise compliant with IFRS.

196.0 Reference: Capitalized Overhead

Part III, Section C, Tab 11, p. 493

"With the proposed change to the capitalization rate from 16 per cent to 8 percent, overhead capitalized is expected to decrease by $11.3 million from 2009 to 2010, composed of an $11.2 million decrease related to the rate change and a $1.3 million decrease related to rebasing of O&M, offset by a $1.2 million increase related to higher 2010 O&M forecast compared to 2009 projection." Page 493, par. 1

196.1 Please elaborate on the description of the"$1.3 million decrease related to the rebasing of O&M" from the above statement.

Response:

The $1.3 million overhead capitalized impact related to rebasing of O&M reflects the decrease in overhead capitalized that occurs when the O&M is rebased. This decrease would have occurred even without the adoption of the reduced overheads capitalized rate.

The impact is calculated by taking the rebasing of O&M expenses of $8 million multiplied by the existing approved overhead capitalized rate.

	($ Millions)	
2009 Approved O&M	$ 173.1	- Tab C-13, Schedule 72, Column 2, Line 23/1000
2009 Projected O&M	165.2	- Tab C-13, Schedule 72, Column 5, Line 23/1000
	8.0	
x Existing Overhead Capitalized Rate	16%	
Overhead Capitalized- Rebasing	1.3	

197.0 Reference: Accounting and Other Policies

Part III, Section C- Tab 11, page 474

Please see the attached Appendix A that attempts to summarize accounting and other policy impacts by year of applicability. Please review and complete the Appendix table including all amounts that are anticipated to change in each corresponding year. Where the table has been pre-populated, please review the attached detail and ensure that it is accurately recorded in the appropriate year. Where it is not accurately reported, please update the table and explain the nature of the changes required.

Also, the table indicates a section for items for which proposed TGI accounting policies selected are not yet approved under existing IFRS. Please indicate, at a high level, an estimate of the value of the adjustments that would be necessary to comply with exiting GAAP, should changes in IFRS not become available. Please include a brief description to explain accounting policies that would be applied in this situation.

See: Appendix A

Response:

Please refer to Attachment 197.0.

198.0 Reference: Accounting and Other Policies

Part III, Section C- Tab 11, page 474

Various IFRS accounting policy selections made by TGI are dependant on changes to existing IFRS. Specifically, IFRS 1 changes and an exposure draft for rate regulated activity are frequently noted in TGI proposed policy selections.

198.1 Please provide a status update on the progress related to the potential exposure draft for rate regulated entities. Please include a description of recent meetings held by international standard setters and any updates on proposed timelines. If available, please include a copy of any documents issued by international standard setters related to this matter.

Response:

Please see the response and attachment to BCUC IR 1.198.3, which address this question.

198.2 Please provide a status update on the progress related to changes to IFRS 1 which may allow for the conversion of property, plant and equipment at existing carrying value. Please include a description of recent meetings held by international standard setters and proposed timelines.

Response:

Please see the response to BCUC IR 1.198.3 which includes the exposure draft and proposed IFRS 1 exceptions related to regulated enterprises.

198.3 Please explain if TGI plans to use actual costs for large capital projects or if the proposed rate will be applied without exception. If available, please include a copy of any documents issued by international standard setters related to this matter.

Response:

For all January 1, 2010 Regulated PP&E balances, including any amounts in work-in-progress including CPCNs and other large capital projects, TGI will elect to use the IFRS 1 exemption, so that the opening IFRS balance for 2010 will equal the actual historical cost as recorded in the

Company's financial statements. The IFRS 1 exposure draft proposes an exemption for an entity with operations subject to rate regulation. Such an entity could elect to use the carrying amount of items of property, plant and equipment held, or previously held, for use in such operations as their deemed cost at the date of transition to IFRS. TGI is proposing that from that point forward, costs will be recorded under IFRS guidelines. On July 24th, 2009, the IASB released the exposure draft on rate-regulated activities as well as additional guidance on additional exemptions for First-time Adopters. A copy of these documents is included in Attachment 198.3.

199.0 Reference: Accounting and Other Policies - Provisions, Legal and Constructive Obligations

Part III, Section C, Tab 11, section b.6, page 481

"Terasen Gas includes a working capital allowance in rate base, calculated according to accepted regulatory practices. The Company does not anticipate that the IFRS standard on provisions, legal and constructive obligations will have an impact on its working capital or rate base calculations." Page 481, par. 2

199.1 Please explain the process that TGI has conducted to identify any such costs and it was determined that there were no such amounts to record under IAS 37.

Response:

An exposure draft leading to a new standard on liabilities is expected to be issued in the fourth quarter of 2009. The current standard has three main areas where it differs from Canadian GAAP:

1. Greater emphasis in IFRS on the recognition of constructive obligations;
2. A lower threshold for the recognition of provisions ("probable" under IFRS instead of "likely" under Canadian GAAP);
3. The amount of a contingent liability to be recognized in the financial statements may be higher under IFRS than under Canadian GAAP.

As part of the IFRS project, Terasen Gas has reviewed its existing liabilities to ensure they still meet the definition of a liability under the IFRS framework, by evaluating each liability against the IFRS criteria for recognition. Additionally, during this process, Terasen Gas attempted to quantify any unbooked liabilities which may meet the definition of an existing liability under the IFRS framework. However, it is not possible to conduct a review of future potential liabilities to determine if at that time there will be a greater amount of liabilities recognized under IFRS. With no evidence to support an increased level of liabilities and resulting O&M to be recognized, TGI has forecast the annual O&M expense using methodologies consistent with past practice.

200.0 Reference: Accounting and Other Policies - Leases

Part III, Section C, Tab 11, section b.10, page 484

"The vehicle lease will continue to be treated as an operating lease for regulatory income tax calculation purposes. The result of this change is that the vehicle lease is removed from operating expenses. The net book value of the leased assets is added to PPE with depreciation being calculated annually, and the capital lease liability is included in long-term debt with associated interest expense. The impact of the accounting change to rates is immaterial at less 0.1 per cent in 2010." Page 484, par. 1

200.1 Please quantify in dollars, the impact of this accounting change in 2010 and 2011.

Response:

The accounting change increases the cost of service by $741 and $730 thousand in 2010 and 2011, respectively; increases the mid-year Rate Base by $12.6 and $12.9 million in 2010 and 2011, respectively; and the return on common equity is increased by $373 and $382 thousand in 2010 and 2011, respectively. This results in an impact to rates of 0.14 per cent in 2010, which is slightly higher than the "less than 0.1 per cent" calculated at a high level and included on page 484 of the Application.

200.2 Please explain the rationale for treating leases as operating for regulatory tax purposes.

Response:

For financial statement purposes under Canadian GAAP, the TGI vehicle lease is treated as a capital lease; this treatment is anticipated to continue under IFRS. However, under the Income Tax Act, given the terms of the vehicle lease contract, it is treated as an operating lease for income tax purposes. Since TGI follows the taxes payable (flow through) method of recording income taxes for regulatory purposes, income taxes are recorded at the amount of income tax payable under the Income Tax Act. The regulatory tax treatment therefore follows the income tax treatment. This same difference exists for financial statement purposes – the lease is capital for financial reporting purposes, but are operating for tax purposes.

200.3 Please quantify the expected tax impact if the leases were treated as capital for regulatory tax purposes.

Response:

Under the provisions of the Income Tax Act the vehicle lease is an operating lease for income tax purposes, regardless of its treatment for financial statement or regulatory purposes. As discussed in the response to BCUC IR 1.200.2, following the taxes payable method for regulatory tax purposes requires that the regulatory tax treatment be aligned with the income tax treatment. It would not be reasonable to depart from this methodology for the vehicle lease.

201.0 Reference: Depreciation Study

Appendix H-2

Terasen Gas states that: "Terasen Gas has entered into a program to replace the older electro-mechanical meters with newer technology digital metering equipment. Furthermore, Terasen is testing AMR technology through a residential test program. The impact of the new metering technology and potential for the implementation of AMR is unknown, but may cause a future retirement program to replace a significant portion of the investment in this account."

201.1 Please explain whether this meter replacement program is treated as a capital project or maintenance project? What are the costs that have been incurred with this project to date and please confirm whether these costs are included in this Application.

Response:

For accounting purposes, the referred meter replacement program expenditures or alternatively referred to at TGI as "Offsite Meter Reading" have been treated as a capital project similar to how other similar meter exchange programs are accounted for.

From 1998 to 2009, Offsite Meter Reading ("OMR") technology has been deployed at TGI on a limited basis to meet the operational needs of having to read hard-to-read meter locations, meters that are located in challenging locations and difficult to read using the normal walk-by meter read process. The OMR meter employs a small battery powered radio which has the capability to broadcast meter reads on demand. In addition to meeting operational requirements, the deployment of OMR technology, an early stage version of evolving Automatic Meter Reading (AMR) technology, allows TGI also to gain insight and experience working with AMR technology.

Over the timeframe noted, to meet operational requirements, TGI has deployed approximately 2100 OMR meters at an approximate cost of $410,000

The above costs are currently in the existing rate base number included as part of TGI's Application.

201.2 Has Terasen Gas studied the average service lives of the digital meters installed with other comparable utilities that have already installed AMR technology?

Response:

The OMR technology TGI currently utilizes has been widely deployed across North America for a number of years and represents proven metering technology. Based on industry and TGI experience, the life expectancy of the OMR technology deployed at TGI is approximately 10 to 12 years in the field, driven primarily by the life of the battery.

For clarity, the OMR technology TGI has implemented is different than some other more advanced forms of AMR technology at other utilities which involve large scale deployment of meters that can be read by drive-by vehicles or remotely through a radio tower network.

201.3 What is the data collection and approval process for fixed asset additions and retirements? Specifically, what is TGI's current process involved in the collection of fixed assets data to ensure that it is accurate, robust, and free from material errors?

Response:

Terasen Gas has established fixed asset controls in place to ensure that our fixed assets are accurate, robust and free from material errors. Some of the key internal controls over PP&E additions include proper authorization and accurate recording of assets acquired by the organization. Internal controls over PP&E retirements and sales exist to ensure that all PP&E retirements and sales are properly approved, accurately calculated, recorded and represent actual disposals. Segregation of duties exist to ensure proper accounting and PP&E account reconciliations are performed on a monthly basis to ensure the records are complete and accurate.

On a quarterly basis, to validate the controls are working and to assist in certifying the effectiveness of Terasen Gas' internal control environment, the assigned process/control activity owners must provide an attestation to the best of their knowledge that the assigned internal controls documented are effective, ineffective or unable to determine. The fixed assets controls have been certified to be effective.

In addition, as part of the annual financial statement audit, the external auditors also look at the internal controls and test those controls in addition to substantive procedures to verify assets and inventory on a test basis as is standard audit practice. The Company believes that this provides substantial assurance that the assets are being recorded properly and accurately, adequately safeguarded and free from material errors.

In March 2008, at the request of the Commission, Terasen Gas' Internal Audit Services conducted a detailed review of Terasen Gas' fixed assets. Overall, the financial and operational controls over Inventory and Property, Plant and Equipment of Terasen Gas were found to be effective.

201.4 What is the customer rate impact if there were no changes to the depreciation rates?

Response:

If the entire impact of the change in depreciation rates resulting from the depreciation study is excluded from the calculation of the revenue deficiencies for 2010 & 2011, the resulting customer rates would show an approximate decrease to existing rates of 0.2% in 2010 and an additional approximate increase of 4.1% in 2011 (cumulative increase of 3.9%).

Since one of the primary drivers of the increased depreciation rates is underrecovery of past depreciation amounts, removing these impacts from the 2010 and 2011 revenue deficiency and deferring these costs to future periods will result in a continued build of the unrecovered depreciation amounts to be borne by future customers.

Section 56(2) of the *Utilities Commission Act* provides that "The commission must determine and, by order after a hearing, set proper and adequate rates of depreciation." TGI believes that "proper and adequate" rates of depreciation are those set out in the depreciation study included with the Application. The adoption of the recommended depreciation rates in the Application are necessary to appropriately allocate the consumption of Terasen Gas' assets useful lives over time and address the requirements of IFRS.

201.5 Would Terasen Gas agree that the substantial increase in depreciation expense, resulting from the Depreciation Study, is an indication that plant assets were possibly overstated and hence Ratebase in previous years was possibly overstated?

Response:

Terasen Gas disagrees with the characterization that plant assets and rate base in previous years were "possibly overstated". Rate base is the valuation of a utility's assets made by a regulator – in this case, the Commission - for the purpose of determining the rates the utility is permitted to charge it customers. It reflects the original cost and the depreciation that the

Commission allows for the recovery of the investment over time. The Commission has regularly reviewed TGI's rate base during the PBR period which was set by formula and approved CPCNs, and this value has been used to calculate rates. It is correct, however, to say that based on the current depreciation study results, the plant assets have been under-depreciated, thus preventing the Company from recovering its Commission-approved investment in assets for customer benefit. TGI believes this should be rectified at the present time.

The issue of under-depreciating plant assets was recognized by TGI in 2000 when a similar depreciation study prepared by Gannett Fleming was reviewed with Commission staff with a summary of the study circulated to interested parties. A proposal for increases in depreciation rates was included in the Annual Review of November 2000 but because of concerns expressed by parties about the rate impact to the customer, the proposal was not implemented. Except for a few adjustments to asset depreciation rates approved in 2004, for the purposes of setting rates for customers. TGI has been using the same depreciation rates which date back many years.

Rate base should be based on the best available evidence. A new depreciation study has now been prepared which results in the revision of deprecation rates, and demonstrates that the current rates are no longer appropriate. TGI believes that it is appropriate for rate base and customer rates to reflect the depreciation rates identified by Gannett Fleming, thus rectifying the disconnect that has existed between the depreciation rates determined through the previous depreciation study and the rate base determined for the purpose of rate setting during the PBR period.

201.6 What is the effect on Ratebase over the next five years as a result of the adjustment to depreciation expense, ignoring any changes to the existing PP&E balances?

<u>Response:</u>

The adjustment to the depreciation expense, all else equal and excluding any changes to the existing PP&E balances, results in an annual rate base decrease of approximately $20.8 million per year. This equates to a total cumulative rate base decrease of approximately $104 million for the 5 year period ending 2014.

202.0 Reference: Shared Services Agreement

Appendix H.4

202.1 Please provide the comparative amounts of Total Shared Services Costs for TGI, TGVI, and TGW by using the Table below:

	2006A	2007A	2008A	2009P	2010F	2011F
Shared Services:	$'000	$'000	$'000	$'000	$'000	$'000
TGI						
TGVI						
TGW						
Direct Costs retained by TGI						
Total						

Response:

('000's)	Actual			Projection	Forecast	
	2006	2007	2008	2009	2010	2011
Shared Services						
TGI	42,119	45,470	47,754	55,109	66,533	70,054
TGVI	4,840	5,104	5,477	6,283	7,578	8,032
TGW	-	-	-	169	202	212
Total Cost of Services Shared	**46,959**	**50,573**	**53,231**	**61,561**	**74,313**	**78,298**
Direct Costs Retained by TGI	141,927	138,607	143,463	145,549	150,837	157,339

Over the years, under the centralized management and process support model, the shared services provided by TGI have been increasing, recognizing the higher level and scope of activities performed. These shared service arrangements enable the companies to harvest the benefits of economies of scale and avoid duplication of effort with the efficiencies realized for the benefit of customers.

202.2 In Appendix H.4 (page 11) Terasen Gas states that:

"*The total cost pool for allocation is $61,561,380, of which $55,109,372, $6,283,451 and $168,557 are allocated to TGI, TGVI, and TGW respectively*."

202.2.1 Please calculate the percentage allocations to TGI, TGVI, and TGW from the above figures and explain why these percentages are different than the data presented in the pie chart in Figure 3.4.1a in Appendix H.4.

Response:

Some of TGI's operating costs relate exclusively to TGI, and are not allocated to TGVI or TGW. The $61,561,380 figure mentioned in the report refers to the portion of TGI's O&M costs that are pooled and allocated to TGVI and TGW using appropriate cost drivers. This pool of costs makes up the services shared by TGI, TGVI and TGW.

202.2.2 Please identify what year the data from appendix H.4, the KPMG study is referring to.

Response:

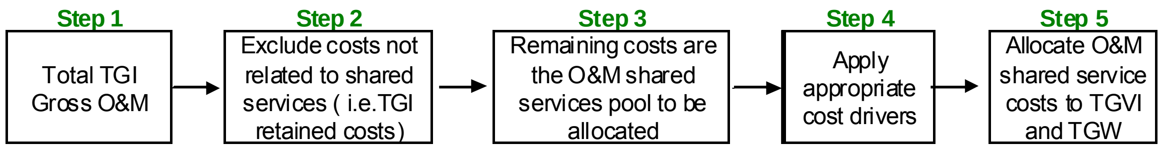
The data refers to a more recent 2009 forecast.

202.3 Please discuss the difference between "Direct costs retained by TGI" and "Shared Services costs allocated to TGI." Please provide a list of O&M items that are considered *Direct costs retained by TGI*.

Response:

"Direct costs retained by TGI" are those that are excluded from the pool of costs allocated to TGVI and TGW as these costs are exclusive to TGI activities. In contrast, "shared service costs allocated" are those costs that are pooled and allocated to TGVI and TGW using appropriate cost drivers. This pool of costs makes up the services shared by TGI, TGVI and TGW.

The following diagram depicts the Shared Services cost allocation methodology, and thereby the distinction between retained costs by TGI and allocated shared service costs.



The following expenses are considered direct costs retained by TGI as they are exclusive to TGI activities. The list below accounts for the majority of the retained costs:

- TGI Customer Care Contract fees
- TGI Field operations cost centers
- TGI Dedicated Transmission field operations
- TGI Dedicated Management and Operations back-office support
- TGI Bad Debt expense
- TGI Insurance
- TGI Dedicated Telecom & IT infrastructure & application support
- TGI External fees related to BCUC assessments, bank charges, bond ratings and auditors

203.0 Reference: Shared Services Agreement

Appendix H.4

"The results of the review indicate that the amount of annual Shared Services to be allocated from Terasen Gas to TGVI is estimated to be $7.6 million in 2010 and $8.0 million in 2011, subject to true-up of actual costs in 2012 on expiration of this RRA period." Page 494, par. 3, line 2

203.1.1 Please reconcile the numbers presented in the above statement to Line 32 in Financial Schedule 30.

Response:

Line 32 of Financial Schedule 30 shows Shared Service amounts of $1,242K for 2010 and $868K for 2011. These amounts are calculated as follows:

(000's)	2010	2011
Corporate Services provided by Terasen	9,022	9,112
TGVI Shared Service Recovery	(7,578)	(8,032)
TGW Shared Service Recovery	(202)	(212)
Total Shared Services	**1,242**	**868**

The Corporate Services refer to the corporate functions provided to TGI by Terasen Inc. The TGVI and TGW Shared Services recoveries represent the services TGI provides these utilities under a single management team and common work processes and IT platforms. The effect of these services financially nets out to a total impact of $1.2 m on TGI's O&M in 2010.

203.1.2 Please provide a reconciliation of the above figures to the data presented in the Shared Services Cost Allocation Review and discuss why there are differences.

Response:

The KPMG Shared Services Cost Allocation Review, an independent review of the shared services allocation methodology and the reasonableness of the costs allocated, was completed using 2009 forecast information, as the 2010 and 2011 O&M budget data for determination of shared services was not available at the initiation of the KPMG review.

The above figures for 2010 and 2011TGVI Shared Services were determined recently as part of the O&M budget process using the same allocation methodology that KPMG concluded to be reasonable.

203.1.3 Please advise whether the amount on Line 32 in Financial Schedule 30 represents a "net" amount.

Response:

Yes, as described in the response to BCUC IR 203.1.1, the amount on Line 32 refers to a net amount and includes Terasen Inc. Corporate Shared Services allocation, TGVI and TGW Shared Services recoveries.

204.0 Reference: Operating & Maintenance

Operation Support Recoveries

Part III, Section B, Tab 1, pp. 173-4

204.1 Please explain why the shared service recoveries for services provided by Operations Engineering and Operations Support are credited to the President's office instead of the group incurring the extra expense.

Response:

Shared Service costs are consolidated at the President and CEO's Office in order to ensure year to year consistency, ease tracking of the aggregate costs and facilitate efficiencies in the administration of the shared service agreements. All shared service costs are calculated at the individual cost center level and then consolidated into one charge processed at the President and CEO's Office level. Aggregating the individual department shared service costs and crediting the President and CEO's Office enables the departments to report and manage their true department costs.

204.2 Does crediting the shared services recoveries to the President's office mask the true costs of the President's office compared to "Corporate Costs"?

Response:

Please see TGI's response to BCUC IR 1.204.1

TGI does not believe crediting the shared services recoveries to the President and CEO's Office masks its true costs. The costs are transparent in the regulatory process. TGI discloses on page 403 of the RRA the different components of the President and CEO's 2010 and 2011 O&M budget including the shared services recoveries.

205.0 Reference: Transfer Pricing Policy and Code of Conduct

Appendix H.6

205.1 What is TGI`s process in ensuring that the full recovery costs are comparable with current market prices?

Response:

TGI's current process is to review its Transfer Pricing Policy on an as required basis to ensure comparability of transfer prices to current market prices. Due to the nature of the services being provided (i.e. back office support including accounting and administration, marketing and field support) and their dependency on integration and understanding of TGI's operations and systems, it is difficult to obtain competitive market prices for comparable services being contracted from TGI.

As indicated in the response to question BCUC IR 1.205.5, the amounts of TGI services currently charged to NRBs (i.e. approximately 0.3% of total TGI O&M budget) are relatively immaterial. As a consequence, TGI believes the time and effort to ensure comparability to current market prices is not warranted at this time given that the costs incurred by TGI to provide such services are fully recovered from the NRBs.

205.2 Will the Transfer Pricing Policy apply to Alternative Energy Solutions as proposed in the Application?

Response:

No. TGI does not believe it would be appropriate to have the existing Transfer Pricing Policy apply to TGI's Alternative Energy Solutions as the existing Transfer Pricing Policy is intended to govern financial transactions between TGI and non-regulated affiliates of TGI. The Alternative Energy Solutions that TGI is proposing are a regulated service provided by the Company itself.

Instead, TGI believes it would be more appropriate to utilize a fully allocated cost of service approach for allocation of overhead/support costs between the natural gas and the alternative energy businesses as they will both be under the same single regulated entity. For the majority of costs as outlined in the Application, TGI proposes to utilize an economic test using a cost of service analysis as an efficient means of ensuring appropriate cost allocations and just and reasonable rates for natural gas and alternative energy customers.

205.3 What process is in place to ensure that the periodic audits (no less than once per calendar year as per point IV in the Code of Conduct Principles and Part 7 in the Transfer Pricing Policy) are conducted with all company employees (including contractors, seasonal employees)?

Response:

To monitor employee compliance with TGI's Code of Conduct and Transfer Pricing Policies, an annual review is conducted by TGI's Internal Audit Services, and the results are filed with the Commission. In addition, TGI's independent external auditor is required to review and report to the Commission on the work performed by TGI's Internal Audit Services. This is one of the conditions for compliance with the negotiated settlement for the 2004 – 2007 Performance-Based Rate Plan and which was extended for 2008 and 2009 as approved by the Commission.

The objective of Internal Audit Services' review is to determine whether the existing processes and controls that support compliance are adequately designed and operating effectively during the period under review. In this regard, TGI's Internal Audit Services performs the following activities in accordance with Canadian generally accepted standards for review engagements as set out in the CICA handbook.

- Review the Code of Conduct and Transfer Pricing Policy.
- Make enquires to understand the provision of Utility resources to Non-Regulated Businesses.
- Make enquiries to understand the processes and controls maintained by Terasen Gas to comply with the policies.
- Review evidence of such processes and controls and compliance with the policies.

This process has worked well over the years. Any issues identified are promptly addressed by TGI management. As indicated in the TGI RRA Application, while the practice of an additional independent review to TGI's Internal Audit Services' work has been required over the years, TGI believes there is an opportunity to avoid duplication of efforts by eliminating the external audit review requirement and yet not compromise the compliance process.

In addition to the review requirements, there are other avenues used as a reminder to all employees:

- On their weekly timesheets, requiring that employees confirm that their recorded time complies with the Code of Conduct and Transfer Pricing Policies.
- On sign in to the network, a pop-up screen with the Code of Conduct and Transfer Pricing Policy appears on a regular basis requiring acknowledgement.
- One of the Annual performance review steps is to discuss the policy with the employee.
- New employee starts are provided the policy for review and adherence.

205.4 Prior to the current KPMG study supplied in the Application, when was the last audit conducted? Please file the results of that audit and note any process and or policy changes that were a result of that audit.

Response:

As indicated in the answer to BCUC IR 1.205.3, TGI's Internal Audit Services completes an annual review to monitor for compliance with the Code of Conduct and Transfer Pricing policies. The last report was filed with the Commission on October 8, 2008.

To clarify, the KMPG study titled "Terasen Gas Inc. Transfer Pricing Methodology Review" was initiated not for the purpose of auditing compliance with the existing Transfer Pricing policy, but instead to perform an independent review of the Transfer Pricing Methodology for completeness and reasonableness.

205.5 Are there currently any plans in place to adhere to the recommendations as set out in the KPMG audit? If not, when is the expected time frame that TGI will embark on making these improvements? If yes, please submit a preliminary plan along with estimated timelines for the compliance activities.

KPMG's recommendations as outlined pages 16 and 17 of their report are replicated below with TGI's responses provided.

- Consider a periodic test against market to ensure TGI is compliant with the requirement to set the Transfer Price of services appropriately. Under the Pricing Rules of TGI's Transfer Pricing Policy, (ii), where no tariff rate exists, the Transfer Price will be set at either the full cost or, where feasible and practical, the Competitive Market Price, whichever is greater.

  TGI response: Given the relatively immaterial amounts of TGI services currently charged to NRBs (i.e. approximately 0.3% of total TGI O&M budget), TGI believes the time and effort required to periodically test market rates is not warranted at this stage. TGI's opinion is consistent with KPMG's view as indicated on page 3 of KPMG's report. However, should the amount of services increase materially (i.e. to over $1 million per year), TGI would consider engaging in a test of Transfer Price against the competitive market price, recognizing though it may be difficult to obtain competitive market prices for the services being contracted from TGI by the NRBs.

- Document how the charges for the use of equipment included in the Transfer Pricing Policy are determined.

  TGI response: KPMG's comment is noting the point that currently the Transfer Pricing Policy does not describe what equipment charges are flowed through to NRBs. TGI considers KPMG's point an administrative matter and a request to provide more clarity for the purpose of applying the Transfer Pricing Policy.

  For NRB work, the most commonly used equipment used by TGI personnel are vehicle charges which are tied to the time costing system used by TGI staff to record time. Vehicle expenses charged include insurance, fuel, lease, repair costs and vehicle administration. This type of description for vehicle charges can be readily included in the next publication of an updated Transfer Pricing Policy document.

- Develop a 'Change Log' worksheet to track changes and updates to the electronic version of the model.

  TGI response: TGI considers this an administrative matter not affecting the integrity of the model and its output. TGI will be updating its records and documentation.

- Review facilities costs annually and update as needed with actual cost data to ensure transfer pricing rates are current for facilities costs.
-

  TGI response: As part of the review with KPMG, TGI updated the current $100 per day facilities charge with current costs and was able to confirm the existing $100 per day charge was still representative of current facilities costs. In addition, TGI does not believe facilities costs change materially from year to year with material changes likely occurring with significant facility upgrade or relocation. Instead of updating annually, TGI believes it would be more appropriate to review the $100 facility charge upon a significant facility upgrade or relocation event.

205.6 Please provide an example of a Designated Sub / Affiliate Service.

Response:

Under the existing TGI Transfer Pricing Policy, a Designated Subsidiary / Affiliate is a related company that is designated by TGI and approved by the Commission to receive reduced loadings in the transfer price.

Currently, TGI does not provide services to a Designated Subsidiary / Affiliated Service. Previously, TGI did provide services to an affiliate BC Gas International under the Designated Subsidiary / Affiliated Service status. This arrangement ended in the 2004/2005 timeframe and since then no similar Designated Subsidiary / Affiliated Service has been approved by the Commission.

206.0 Reference: Transfer Pricing Policy and Code of Conduct

Appendix H.6

206.1 Has there been any consideration given to establish a clear separation of business entities for the 4 NRB's currently being serviced by TGI?

Response:

For clarity, the four NRBs referred to and listed in the KPMG report include Terasen Inc., Terasen Huntingdon Inc., Inland Energy Corporation and Terasen Energy Services.

In the context of this response, clear separation from TGI's perspective means a situation where TGI does not provide any form of support or services (i.e. employee time) to the NRBs. Given that and reasons described below, there has been no consideration given to ceasing to provide any form of support or services to the four business entities for two principle reasons.

First, as noted in the earlier response to BCUC IR 1.205.1, relatively immaterial amounts of TGI services are currently charged to NRBs (i.e. approximately 0.3% of total TGI O&M budget).

Second, TGI believes the current arrangement with the four NRBs appropriately protects TGI ratepayers from subsidizing unregulated activities and provides for recovery of overhead costs (i.e. general overhead, facilities charge) for the benefit of TGI's ratepayers.

TGI believes that the current approach is appropriate and continues to serve customers of TGI.

207.0 Reference: Operations and Maintenance Expenditures – Regulatory Hearing Costs

Part III, Section C, Tab 6, p.347

207.1 Please provide a breakdown of the expected Regulatory / Hearing costs associated with the current Application. Please also provide a reconciliation to Line 31 in Financial Schedule 30 (ref: Part III, Section C, Tab 13, Schedule 30: Operations and Maintenance Expenses – Activity View).

Response:

The costs associated with the current Application are estimated at $1,057,500 pre-tax as shown on Tab 13 Schedule 76 Line 29 Column (3). This amount is composed of:

External Legal Costs	$ 414,000
Studies	390,000
Intervenor/Participant Funding	120,000
Commission Costs	120,000
Expenses & Training	110,000
Public Communications	21,000
Total	1,175,000
Less 10% allocation to TGVI	(117,500)
Total Costs for TGI	$ 1,057,500

Since these costs are forecast as part of the deferral balance, they are not included in the O&M forecast and therefore not included in Schedule 30: Operations and Maintenance Expenses – Activity View.

208.0 Reference: Tariff Changes

Meter Testing Fee

Part III, Section C, Tab 12, p. 509, Table C-12-4

"0.75 hours includes travel time, exchange, relight."

208.1 Please explain where the cost of the actual meter testing is calculated, reflected in O&M, and charged to customers (in cases where the meter is found to be

Response:

For a Disputed Meter Test, specifically a residential meter (meters rated less than or equal to 14.3 m3/hr), Measurement Canada performs the actual meter test and does not charge a fee for meter testing (please refer to page 509 of Application). Therefore, there is no cost recorded in O&M and no charge is passed onto customers.

Attachment 1.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 1.2

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 1.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 1.4

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 2.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 2.3

Price Responsiveness in the *AEO2003* NEMS Residential and Commercial Buildings Sector Models

by
Steven H. Wade

This paper describes the responses of the Annual Energy Outlook 2003 (AEO2003) *versions of the Energy Information Administration's (EIA's) National Energy Modeling System (NEMS) Residential and Commercial Demand Models to changes in energy prices, updating the results reported previously for the* Annual Energy Outlook 1999 (AEO99) *versions of the models.*[1] *Since that report, several changes have been made to the buildings models and their technology data. Own-price and cross-price elasticities, both short-run and long-run are described. Results for permanent price increases and temporary shocks are also discussed. Own-price elasticities range from -0.10 for initial year, short-run responses (commercial electricity) to -0.60 for long-run responses (residential distillate oil). Cross-price elasticities range from 0.0 to 0.86 (commercial natural gas consumption in response to changes in electricity price).*

Overview

The Residential and Commercial Demand Models are separate modules within NEMS. The two models are similar in their overall behavior, but there are differences in their internal accounting and equipment choice algorithms. In some cases, one model may include effects or exhibit behavior slightly different from the other. The discussion of model features and algorithms is intentionally brief, and only significant differences are noted here. Detailed information on both models is provided elsewhere.[2] A series of simulations using different assumptions for energy price paths is employed to develop measures for the sensitivity of energy consumption projections from the two models to changes in energy prices.

The NEMS residential and commercial models exhibit both short-run and long-run consumption responses to changes in real energy prices.[3] Responses categorized as short-run are the near-term behavioral responses of end uses that affect the utilization intensity of energy-consuming equipment when energy prices change. Examples include adjusting the thermostats of heating and cooling equipment, being more or less careful about leaving lights on or equipment running when not needed, and altering habits related to the consumption of hot water. The short-run effects in the buildings models are phased in over a 3-year period, reflecting the potential for ongoing adaptive behavior in response to persistent price changes.

Long-run price responses occur through changes in the capital stock of energy-consuming equipment installed in buildings. Energy-consuming capital goods convert energy from its raw potential into end-use services. The NEMS building models employ "stock turnover" accounting; that is, they track capital stocks by estimating what is retained from the last model year and then adding simulated equipment purchases for new construction, for the replacement of worn-out equipment,

[1]See S.H. Wade, "Price Responsiveness in the NEMS Building Sector Models," in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1999*, DOE/EIA-0607(99) (Washington, DC, August 1999).

[2]For reference case projections see Energy Information Administration (EIA), *Annual Energy Outlook 2003*, DOE/EIA-0383(2003) (Washington, DC, January 2003). For modeling assumptions and general techniques see EIA, *Assumptions to the Annual Energy Outlook 2003*, DOE/EIA-0554(2003) (Washington, DC, January 2003). For greater modeling detail see EIA, *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067(03) (Washington, DC, January 2003); and *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(03) (Washington, DC, March 2003).

[3]When prices are referenced in this paper, the reference is always to "real" energy prices, adjusted to remove any effects from general inflation in the economy. The internal calculations of the residential and commercial models operate on real prices.

and for any "retrofitting" of equipment that is still functioning but is economically obsolete.[4]

For buildings, the life of major capital equipment generally ranges from 12 years (e.g., air conditioners and heat pumps) to 30 years (e.g., boilers). As a result, full responses to energy price changes occur incrementally over an extended interval. Long-run price responses are seen in the models through projections of altered equipment purchases under different energy price regimes.[5] During periods of higher energy prices, examples of long-run responses include the purchase of more efficient lighting fixtures and bulbs, adding lighting controls like timers and motion sensors, purchasing higher efficiency space heating equipment, installing extra attic and/or wall insulation (residential model only), and switching heating fuels when price increases vary by fuel (cross-price elasticity). During periods of lower energy prices, most of the above tendencies simply reverse.[6]

Own-Price Responses

The concept of own-price elasticity is a metric that describes numerically the responsiveness of a quantity to changes in its price. It is measured simply as the percentage change in quantity divided by percentage change in price. Because price increases normally induce reduced purchases, own-price elasticities are negative quantities.[7] A sensitive or "elastic" response refers to percentage quantity changes larger in absolute value than the percentage price change (e.g., an elasticity of -2.0 indicates that the percentage reduction in quantity is twice the percentage increase in price). Empirical studies of energy demand have generally found insensitive or "inelastic" responses to energy prices, especially in the short run. That is, for a given percentage change in energy prices, there is a less than proportional percentage adjustment in energy consumption.[8] The short-run elasticity parameters in the buildings models are for each individual end use (heating, lighting, etc.). For both models, all end uses except refrigeration include a short-run price response. For all end uses with simulated equipment choices (including refrigeration), there are potential long-run adjustments in the efficiency of the equipment stock as a result of energy price changes.

Long-run responses to energy prices in the buildings models are determined endogenously. These responses occur through the interaction of installed equipment costs, equipment efficiencies, energy prices (either the "own" prices of the energy fuel used by the equipment or, where end-use services can be provided by more than one energy source, the "cross" prices of other energy sources), discount rates, maintenance costs, and annual equipment utilization rates.[9] Both models weigh all these elements, although the specific details of equipment choice differ.[10]

As described above, the long-run effects of equipment choice occur incrementally over an extended interval; and, because of the multi-year equipment lives, the effects persist once purchases are made. Thus, the effects of a temporary price increase will wear off over an extended simulation interval. For the residential model, price-induced increases in building shell efficiency (e.g., insulation, caulking, thermally-efficient windows) persist longer than other equipment purchase decisions,

[4]Equipment that is still capable of providing energy services but has operating costs (fuel and maintenance) that exceed the annualized capital and operating costs of newer equipment is "economically obsolete." The retirement and retrofitting of economically-obsolete equipment is simulated in the commercial model, adding another dimension to its potential price responsiveness.

[5]Both the residential and commercial models employ "myopic" expectations of future energy prices—that is, the current energy price is used in formulating equipment purchase decisions.

[6]The residential model insulation upgrades are an example of an effect that does not reverse in response to lower energy prices. Once installed, the insulation is assumed to last for the life of the structure.

[7]An exception is the unusual case of what are referred to as "Giffin goods." By definition, for these goods, price reductions lead to reductions in demand. Real-world examples are hard to come by, but a good purchased primarily for its "conspicuous consumption" attributes might exhibit this type of price response.

[8]C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract No. DE-AP01-93EI23499 (Washington, DC, October 1993). The Dahl survey incorporated results from other survey articles and from newer studies, not reviewed previously. From prior surveys, the residential/commercial own-price elasticities for total energy ranged from -0.012 in the short run to -0.44 in the long run. Focusing on studies of aggregate time series data, demand elasticities for electricity from more recent studies averaged from -0.22 in the short run to -0.91 in the long run for residential buildings and from -0.22 in the short run to -0.82 in the long run for commercial buildings. For natural gas the averages from more recent studies were -0.13 (short run) to -0.68 (long run) for residential buildings and -0.26 (short run) to -0.99 (long run) for commercial buildings.

[9]Equipment that is used only for short periods during the year (e.g., air conditioning in northern climates) will have relatively low energy consumption and thus low energy costs. In such cases, equipment choice will be less influenced by energy prices than in areas where equipment is more heavily used.

[10]The residential model projects equipment choices using a "continuous function" approach to model the tradeoff between equipment cost and equipment efficiency, whereas the commercial model employs a "discrete algorithmic" approach. As will be seen from the simulation results, the overall behaviors of the two models are similar. For further details on equipment choice formulations, see the model documentation reports and the *AEO2003* key assumptions (cited above).

because adjustments to the shell are assumed to retire only when the housing unit decays from the stock.[11] Thus, if in subsequent years prices decline after a temporary shock, the effects of the installed shell measures will act as an additional damper on the return to pre-price shock consumption levels. This point is illustrated below, using a simulation that includes a temporary price increase. Equipment purchases other than shell adjustments have a persistence that is less than the life of the structure, and, therefore, their effects can wear off faster than the effects of shell measures after a price shock. For the equipment-related component of long-run price response there is an interval of 10 to 20 years or more before full adjustment occurs, depending on end use and equipment type (e.g., furnaces last longer than water heaters).

Another aspect of long-run price response simulated in the buildings models is what has been referred to as the "efficiency rebound" effect, which occurs when higher efficiency equipment is purchased.[12] Higher efficiency equipment lowers the marginal cost of the end-use service relative to lower efficiency equipment. Because the marginal cost of the service is reduced, a service demand response occurs, parallel to a direct price response for a good or service that is purchased directly (i.e., does not involve a consumer-purchased capital good to provide the service). Rebound effects influence consumption in the long run because of their link to equipment efficiency, which changes over an extended interval.[13]

Cross-Price Effects

Another type of price effect occurs when one fuel's consumption is affected by changes in another fuel's price. These are referred to as cross-price effects, which can be either short-run or long-run. Cross-price responses are quantified by cross-price elasticities, defined as the percentage change in the quantity of a commodity purchased, divided by the percentage change in the price of a different commodity. While own-price elasticities are expected to be negative, cross-price elasticities can be negative or positive, depending on the relationship between two goods or services.

When cross-price elasticities are positive, consumption of one good increases in response to an increase in the price of another good. This indicates that the two goods may substitute for one another. This is also what would normally be expected for energy sources, which can often "compete" (through energy stock equipment purchases) to supply end-use energy services. When cross-price elasticities are negative, the consumption of one good decreases in response to an increase in the price of another good. This type of relationship indicates that the goods are "complementary" or used together. As an example of a complementary relationship, if the price of computer equipment falls (and the quantity of computer equipment purchased increases), the quantity for electricity purchased (which provides energy for computers) increases.

An example of a short-run cross-price effect would be altering the relative amount of food prepared using electricity relative to that prepared using gas in response to a change in electricity prices (all other prices held constant). Although many homes have options to use both fuels (e.g., a home with both a gas oven and an electric microwave oven), short-run opportunities for fuel switching are rare and insignificant in residential and commercial buildings. Thus, the NEMS buildings models do not include short-run cross-price effects.

Over the long run, the buildings models do exhibit some cross-price responsiveness, because certain equipment choice decisions include the consideration of the costs of competing equipment types using different fuels (e.g., electric versus natural gas or distillate water heaters). When other fuel alternatives exist for a particular end-use service, equipment choices will be based on more than just the price of a single fuel, because the projected choices can result in measurable long-run cross-price elasticities.

Significant Model Changes Since *AEO99*

Since *AEO99*, there have been a number of modeling changes and data updates that could affect the price responsiveness of the buildings models. For *AEO99*, the

[11] A 5-percent increase in energy prices is assumed to result in a 1-percent increase in the shell efficiency index for residential buildings. No adjustment to shell efficiency is made for price declines.

[12] For the commercial model, the same end uses subject to the long-run price elasticity response are also covered by the efficiency rebound effect. For the residential model, space conditioning is covered by the rebound effect. For a discussion of the rebound effect, see J.D. Khazzoom, "Economic Implication of Mandated Efficiency Standards for Household Appliances," *Energy Journal*, Vol. 1, No. 4 (1980), pp. 21-40.

[13] Efficiency rebound effects for both the residential and commercial models are based on a parameter that results in a 0.15-percent increase in consumption for a 1-percent increase in efficiency.

residential model was based on EIA's 1997 Residential Energy Consumption Survey (RECS 1997), and the commercial model was based on EIA's 1995 Commercial Buildings Energy Consumption Survey (CBECS 1995).[14] Both surveys have since been updated: the residential model is now based on RECS 2001 and the commercial model on CBECS 1999.[15] These surveys provide the models' "base year" estimates of energy consumption by Census Division, building type, fuel, end use, and technology category. Starting from the base-year estimates, energy consumption evolves over the forecast horizon, based on growth in households or commercial floorspace, energy prices (both absolute and relative), penetration of new end uses, changes in weather from the base year, and changes in end-use equipment combinations and efficiency. Changes introduced by updating the base-year estimates could affect the price elasticities exhibited by the models through altered opportunities either for direct short-run responses or for long-run equipment-related responses.

In addition to new end-use survey data, both models also incorporate updated equipment cost and performance data on energy-consuming equipment.[16] The performance data include energy efficiency ratings and maintenance costs for current and projected equipment. As was described in the preceding sections, technology choices for new and retiring equipment in both models are dependent on capital costs, operating costs (which are directly affected by energy prices), and maintenance costs of competing end-use technologies. Because long-run responses to energy prices depend on technology choices made over the modeling horizon, changes to the technology data can affect the long-run own-price and cross-price elasticities exhibited by the models.

For both models, the short-run price elasticity response is distributed over a 3-year interval in *AEO2003*. This distribution phases in modeled behavioral changes that result from a price change, recognizing that not all behavioral adjustments occur in the same year as a price change. Because of this change, a series of short-run effects for 1, 2, and 3 years are presented, whereas for *AEO99* all the short-run effects were assumed to occur in the same year as the price increase, and a single short-run elasticity was reported.

For both models, distributed generation modules that explicitly characterize different generating technologies have been added.[17] Both the residential and commercial distributed-generation modules include photovoltaics as well as fuel-based technologies. For the commercial sector there are several natural gas-based technologies that have the potential for additional market penetration in response to changing energy prices—engines, turbines, fuel cells, and microturbines. For the residential sector, the only fuel-based technology in *AEO2003* is residential-sized fuel cells, which, although they were modeled, are in such early stages of development that they have only a negligible impact in *AEO2003*. Distributed generation now plays a minor role in the commercial sector and an even smaller role in the residential sector; however, *AEO2003* projects more than a doubling in electricity for buildings derived from such technologies by 2025, mainly as a result of programs targeting photovoltaics and projected improvements (cost reductions and efficiency gains) in distributed generation technologies.[18] Significant departures from reference case energy price paths (e.g., doubling the purchased electricity price) can stimulate adjustments to projected distributed generation and potentially result in measurable effects on both the own-price elasticity for electricity and the cross-price elasticities between electricity and natural gas.

Finally, for the residential model, a discrete building shell module has been added in order to better characterize some of the efficiency programs sponsored by the U.S. Department of Energy and the U.S. Environmental Protection Agency—specifically, Energy Star and PATH homes.[19] The choice of such homes is modeled on the basis of tradeoffs between increased construction costs and reduced energy costs. Because the development of this modeling capability also involved a review and update of the costs of achieving the shell measures, long-run elasticities can be affected in a manner parallel to effects stemming from updated end-use equipment data.

[14]See Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0632(97) (Washington, DC, November 1999); and *A Look at Commercial Buildings in 1995*, DOE/EIA-0625(95) (Washington, DC, October 1998), for more information on these surveys and results.

[15]RECS 2001 and CBECS 1999 are not yet available in printed reports. Links to the currently available information are as follows: for RECS, see http://www.eia.doe.gov/emeu/recs/recs2001/detail_tables.html; for CBECS, see http://www.eia.doe.gov/emeu/cbecs/contents.html.

[16]Arthur D. Little, Inc., "EIA Technology Forecast Updates: Residential and Commercial Building Technologies—Reference Case," Reference No. 8675309 (October 2001).

[17]See the model documentation reports (cited above) for a description of the distributed generation modules. *AEO99* modeled commercial cogeneration, but with a relatively simple single-equation representation that did not include explicit technologies.

[18]Distributed generation natural gas-based technology characterizations are from ONSITE SYCOM Energy Corporation, *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector* (Washington, DC, January 2000). Photovoltaic technology characterizations are from U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997).

[19]For information on Energy Star homes, see web site www.energystar.gov. For information on PATH homes, see Partnership for Advancing Technology in Housing, web site www.pathnet.org.

Elasticity Estimates and Simulations

To estimate responses to energy price changes, a series of alternative simulations were made, based on adjustments to the energy price paths from the *AEO2003* reference case.[20] The adjustments model price doublings, beginning in 2005 and continuing through the end of the model run, 2025.[21] Short-run price responses are defined here to be those that occur in the year of the price change and in the first and second years after the price change.[22] Long-run price responses are based on consumption changes in 2025. This choice in measuring long-run responses is somewhat arbitrary, and for very long-lived equipment (such as space heating), some additional responsiveness could potentially occur.[23] Table 1 reports the elasticity calculations based on simulations doubling individual energy prices over the *AEO2003* levels for all years, beginning in 2005, one fuel at a time, and then examining the results on own-fuel and cross-fuel consumption. For ease of comparison, Table 1 also presents the results previously reported for *AEO99*. A brief comparison discussion follows the discussion of the *AEO2003* results below.

Table 1. Summary of Price Responses in the NEMS *AEO2003* and *AEO99* Residential and Commercial Buildings Models

Sector and Fuel	NEMS Model Year	Short-Run Own-Price Elasticity			Long-Run Own-Price and Cross-Price Elasticity		
		1-Year	2-Year	3-Year	Electricity	Natural Gas	Distillate Fuel
Residential							
Electricity	*AEO2003*	-0.20	-0.29	**-0.34**	**-0.49**	0.01	0.00
	AEO99	-0.23			-0.31	0.03	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	**-0.30**	0.13	**-0.41**	0.02
	AEO99	-0.26			0.08	-0.43	0.02
Distillate Fuel	*AEO2003*	-0.15	-0.27	**-0.34**	0.01	0.05	**-0.60**
	AEO99	-0.28			0.05	0.15	-0.53
Commercial							
Electricity	*AEO2003*	-0.10	-0.17	**-0.20**	**-0.45**	0.01	0.00
	AEO99	-0.23			-0.24	0.00	0.00
Natural Gas	*AEO2003*	-0.14	-0.24	**-0.29**	0.86	**-0.40**	0.01
	AEO99	-0.28			0.00	-0.34	0.03
Distillate Fuel	*AEO2003*	-0.13	-0.23	**-0.28**	0.08	0.75	**-0.39**
	AEO99	-0.47			0.00	0.49	-0.87
Commercial Electricity by End Use							
Core End Uses	*AEO2003*	-0.17	-0.29	**-0.36**	**-0.88**	—	—
	AEO99	-0.24			-0.31	—	—
Other End Uses	*AEO2003*	-0.03	-0.05	**-0.06**	**-0.24**	**—**	—
	AEO99	-0.24			-0.20	—	—

Sources: ***AEO2003:*** Energy Information Administration, calculated from the following price path scenarios using NEMS *AEO2003*: regeneration of the reference case price path, ELAST03.D121203B; electricity price increase case, ELAST03.D121203G; natural gas price increase case, ELAST03.D121203H; distillate fuel price increase case, ELAST03.D121203I. ***AEO99:*** S.H. Wade, "Price Responsiveness in the NEMS Building Sector Models," in Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1999*, DOE/EIA-0607(99) (Washington, DC, August 1999).

[20]The simulations are based on "stand-alone" runs of the commercial and residential models. This is appropriate, since the purpose of this paper is to describe the responses of these models. In an "integrated" NEMS model run, macroeconomic effects due to large swings in energy prices could affect the calculated elasticities, possibly increasing the own-price sensitivity of the integrated model results (i.e., higher energy prices reduce economic activity, leading to further consumption decreases). Elasticities are measured using the logarithmic percentage change formula given by: $elasticity = ln(q1/q0)/ln(p1/p0)$, where $p0$ and $q0$ are base prices and quantities, and $p1$ and $q1$ represent an alternate price-quantity combination.

[21]The earlier paper, reporting *AEO99* results, was based on simulations using a 10-percent price increase instead of a price doubling. A price doubling was chosen for this report on elasticities, because price paths with such large changes are relevant to current policy analysis. Higher energy prices increase the monetary value of energy savings that accrue to higher efficiency purchases and can thus lead to greater long-run consumption responses.

[22]As mentioned above, the short-run behavioral adaptations are spread over a 3-year interval in *AEO2003*, whereas the entire effects were assumed to occur in the first year in *AEO99*. Fuel price changes also affect capital purchases for retiring equipment in the first 3 years of a simulated price change; however, no attempt has been made to isolate the capital purchase-induced component during the initial phase-in period. Capital purchases will build gradually over the forecast horizon as more equipment becomes available for replacement.

[23]The 20-year horizon was chosen because NEMS currently runs through 2025, and the initial price increase is imposed in 2005. For equipment such as commercial boilers and residential furnaces, additional long-run effects could occur beyond 2025.

Across both models, the short-run own-price elasticities for the various fuels range from -0.10 to -0.20 in the first year to -0.20 to -0.34 in the third year. Included in the estimated effects are the direct short-run effects plus the effect of altered equipment purchases and fuel choices. Long-run own-price effects indicate greater price sensitivity than short-run own-price effects in both models, reflecting the cumulative impact of altered equipment choices. Overall, long-run own-price effects for the two models are similar, with the residential model being slightly more sensitive to the distillate fuel own-price.

The difference between the short-run and long-run price sensitivity for commercial electricity can be further classified as for either "major" or "minor" end uses. Major end uses (space heating and cooling, water heating, ventilation, cooking, refrigeration, and lighting) are defined as having endogenous, price-sensitive equipment efficiency choices in addition to short-run price-sensitive usage intensity. Minor end uses (office equipment and other miscellaneous uses) do not include endogenous equipment choice. Minor end-use consumption is a function of non-price-responsive factors (e.g., floorspace growth, which is not price-responsive in these "non-integrated" NEMS simulations focusing on the buildings models) or projected additional penetration over the modeling horizon (e.g., office equipment). With no endogenous technology choice, the minor end use price responses are expected to be less sensitive than those for major end uses.[24] The calculated short-run and long-run elasticities for the major end uses range from -0.17 to -0.88. For the minor end uses, the elasticities range from -0.03 and -0.24.

Own-price responsiveness for natural gas, both short-run and long-run, is similar in the two models. For distillate, the residential model is slightly more responsive than the commercial model in both the short run and the long run.

For *AEO2003*, long-run cross-price effects exhibited by both models are always either positive or zero.[25] The positive cross-price effects indicate that different energy sources are competing for service demands. Using an arbitrary cutoff of 0.05 for noteworthy effects, significant effects for both models are found for natural gas consumption in response to a change in electricity prices and for distillate consumption in response to a change in natural gas prices. The commercial model also indicates sensitivity of distillate consumption to electricity prices.

Using distillate fuel consumption as an example, as natural gas prices increase, there are some small shifts from natural gas to distillate. Because distillate consumption is only about 13 percent of commercial natural gas consumption and 18 percent of residential natural gas consumption, any shift from natural gas to distillate will be magnified by a factor of nearly 6 for the residential sector and just under 8 for the commercial sector. For example, if 10 trillion British thermal units (Btu) of energy use shifts from commercial natural gas to distillate fuel, commercial natural gas consumption will decline by 0.3 percent and distillate consumption will increase by 2.2 percent (the percentages are 0.2 and 1.1 percent, respectively, for the residential sector). This leveraging of any movement away from natural gas causes the relatively large cross-price elasticity for distillate in response to natural gas price changes. For an increase in distillate prices, distillate's small share causes a much smaller percentage effect on gas, resulting in the nearly negligible cross-price effects for natural gas in response to changes in distillate prices.

Comparison With *AEO99* Results

The changes in simulated elasticities since *AEO99* are in many cases not very significant. Short-run behavioral effects were previously modeled as single-year responses but are now spread over 3 years. Thus, the 1-year elasticities for *AEO2003* are all smaller in magnitude than the short-run elasticities reported for *AEO99* (Table 1). The 3-year elasticities for the residential model are all slightly greater than previously reported.[26] The same holds for the commercial model, with the exception that the own-price elasticity for distillate fuel is smaller.[27]

Long-run own-price elasticities for the residential model are similar to the *AEO99* results for natural gas and distillate oil and notably larger for electricity.[28] For the commercial model, the natural gas elasticity is fairly similar to the previous results, and electricity also exhibits increased responsiveness, similar to the increase found in the residential model. The long-run distillate elasticity is of a much smaller magnitude, paralleling the change in its short-run elasticity.

[24]Examples of other miscellaneous uses include service station equipment, automated teller machines, telecommunications equipment, medical equipment, and elevators and escalators.

[25]Some negligible negative cross-price elasticities were found for *AEO99*, but in all cases they rounded to 0.00.

[26]There are also some effects of altered equipment purchases during the first 3 years beyond what would have occurred in the first-year *AEO99* short-run results. The equipment-related components during this period are not separately identified.

[27]Under the more recent technology characterizations used for *AEO2003*, distillate equipment is generally more costly relative to natural gas-based equipment than was the case for *AEO99*. This change probably is responsible for most of the reduction in long-run sensitivity.

[28]Based on results prepared for the earlier paper reporting *AEO99* results, it is estimated that roughly one-half of the reported differences in the long-run own-price elasticities of electricity for both sectors are due to the use of price doublings for analyzing the *AEO2003* models.

Cross-price elasticities for the residential model are not much different than before. There is a slight decrease in the response of distillate to the natural gas price and a slight increase in the response of natural gas consumption to the electricity price. All of the cross-price magnitudes are fairly small or negligible compared to own-price responses, and the same holds true for *AEO2003*. For the commercial model cross-price elasticities are more significant. There are two notable cases. First, the elasticity of natural gas consumption relative to the electricity price is now 0.86, where before it was negligible. This change is in part due to the addition of the distributed generation module, with opportunities for natural gas generating technologies to compete against the electricity price. The second change is an increase in magnitude of the cross-elasticity of distillate consumption relative to the natural gas price.

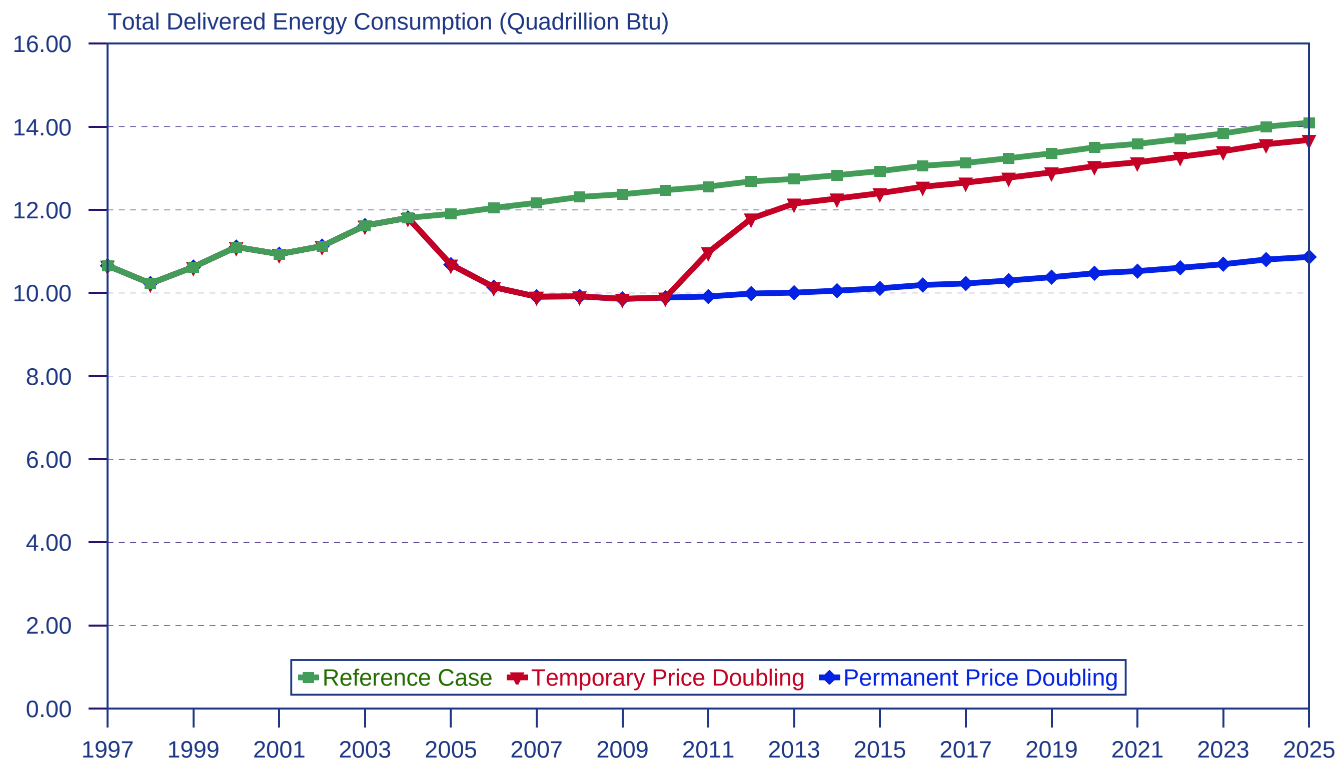
Price Shock Cases

To illustrate the responses of the NEMS buildings models under conditions other than a permanent price change, figures are provided for the residential and commercial models comparing the reference case, the permanent price doubling case (used to generate the Table 1 results) and a temporary price doubling case in which prices return to the reference case path after a 5-year period.

Reviewing the results for the residential model (Figure 1), there are two things to note. First, under persistent doubled prices, the initial reduction in energy consumption rapidly widens to a gap of approximately 2.3 quadrillion Btu by the third year, then continues gradually to widen to 3.2 quadrillion Btu by 2025. This widening of the gap is attributable to continued choices of higher efficiency equipment under the higher price regime. The gradual nature of the widening is due to different simulated equipment choices that occur as equipment is retired and then replaced. The second observation is that, for the case where prices return to the reference path, there is still a slight gap that narrows over time but does not completely disappear. The gradual narrowing reflects the return to baseline equipment choices after the shock has ended (in the NEMS buildings sector models consumers are assumed to operate under "myopic" expectations, so that past prices or shocks do not affect purchase decisions once prices return to the original path).

The gradual return of consumption occurs for the same reason that the widening in the permanently price-

Figure 1. Response of Residential Delivered Energy Demand to a Doubling of Residential Sector Energy Prices



Source: Energy Information Administration, calculated from the following price path scenarios using NEMS *AEO2003*: regeneration of the reference case price path, ELAST03.D121203B; permanent price doubling case, ELAST03.D121202J; temporary price doubling case, ELAST03.D121203K.

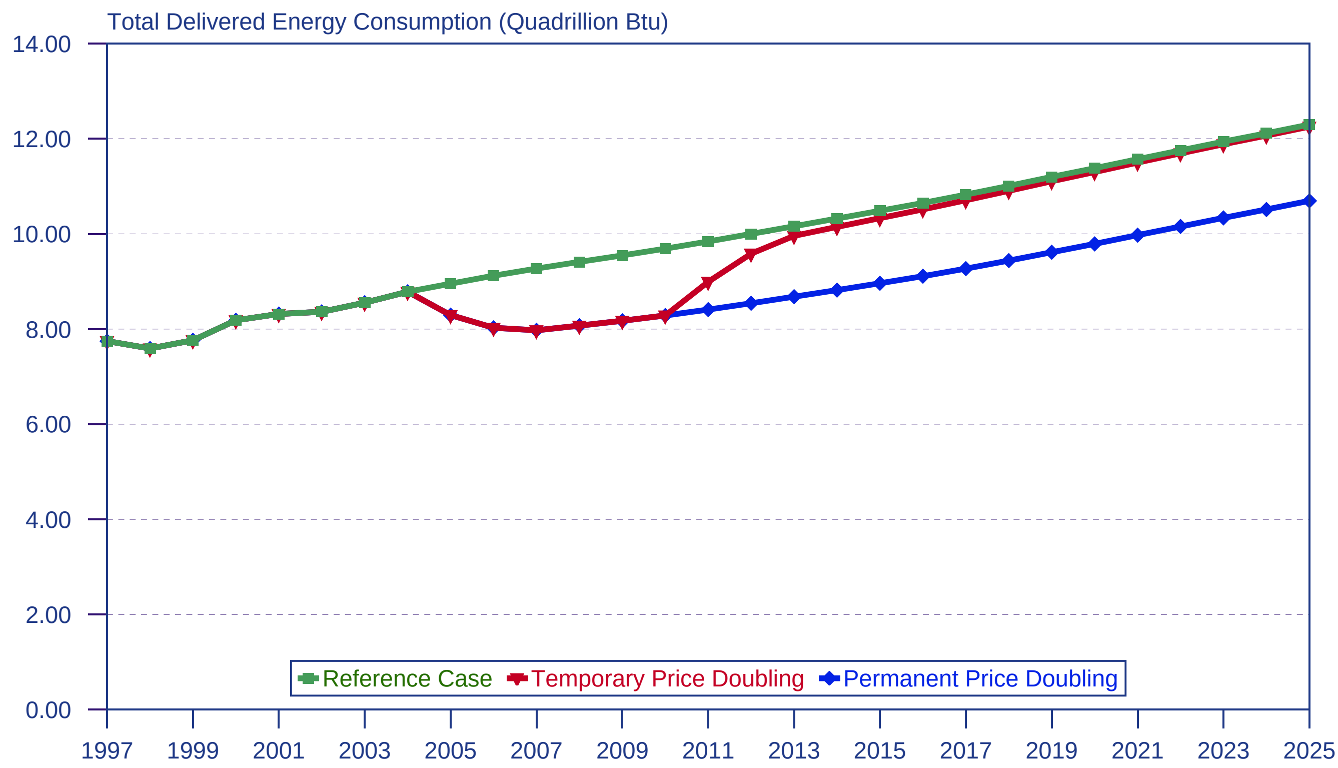
doubled case was gradual—it occurs as equipment is retired and replaced. Over the 20-year course of the simulation, the gap between the reference case and the price shock still remains, because building shells upgraded in response to higher prices during the shock period remain more energy efficient. Any installed shell efficiency measures remain in place until the buildings themselves are retired from the stock. Similar results are shown for the commercial model in Figure 2; however, the effects are not as persistent, in large part because there is no price-responsive retrofitting of building shells in the commercial model.

Illustrating Cross-Price Effects

The second set of comparison cases illustrates cross-price effects, using distillate consumption as the example for both sectors. As discussed above, the residential and commercial models respond to relative energy prices not through instantaneous fuel switching but rather through long-run changes in equipment purchases. If one fuel becomes relatively expensive, then end uses served by that fuel might switch to or favor another fuel when end-use equipment is purchased. The comparisons include the reference case and three alternative cases—one with all prices doubled, another with only the natural gas price doubled, and a third with only the distillate price doubled. As in the previous cases, all price changes begin in 2005.

Comparing these three cases against the reference case illustrates the effects of relative prices on fuel choices in the two models. Figure 3 illustrates the residential model results, focusing on the sensitivity of distillate consumption to relative price changes that lead to cross-price effects. When only the natural gas price doubles, the distillate fuel price relative to the natural gas price is halved, and equipment using distillate becomes more attractive relative to natural gas equipment for end uses that potentially can be served by either fuel. The modest increase in demand for the distillate fuel when the natural gas price doubles is the result of adjustments of modeled equipment purchases in the residential model. From Table 1, the cross-price elasticity of distillate consumption in response to the natural gas price is small in comparison with distillate's own-price elasticity (0.05 versus -0.60), indicating that own-price effects are significantly larger. Indeed, as shown in Figure 3, when the distillate price doubles, the effects on distillate consumption are much greater than when the natural gas price doubles.

Figure 2. Response of Commercial Delivered Energy Demand to a Doubling of Commercial Sector Energy Prices



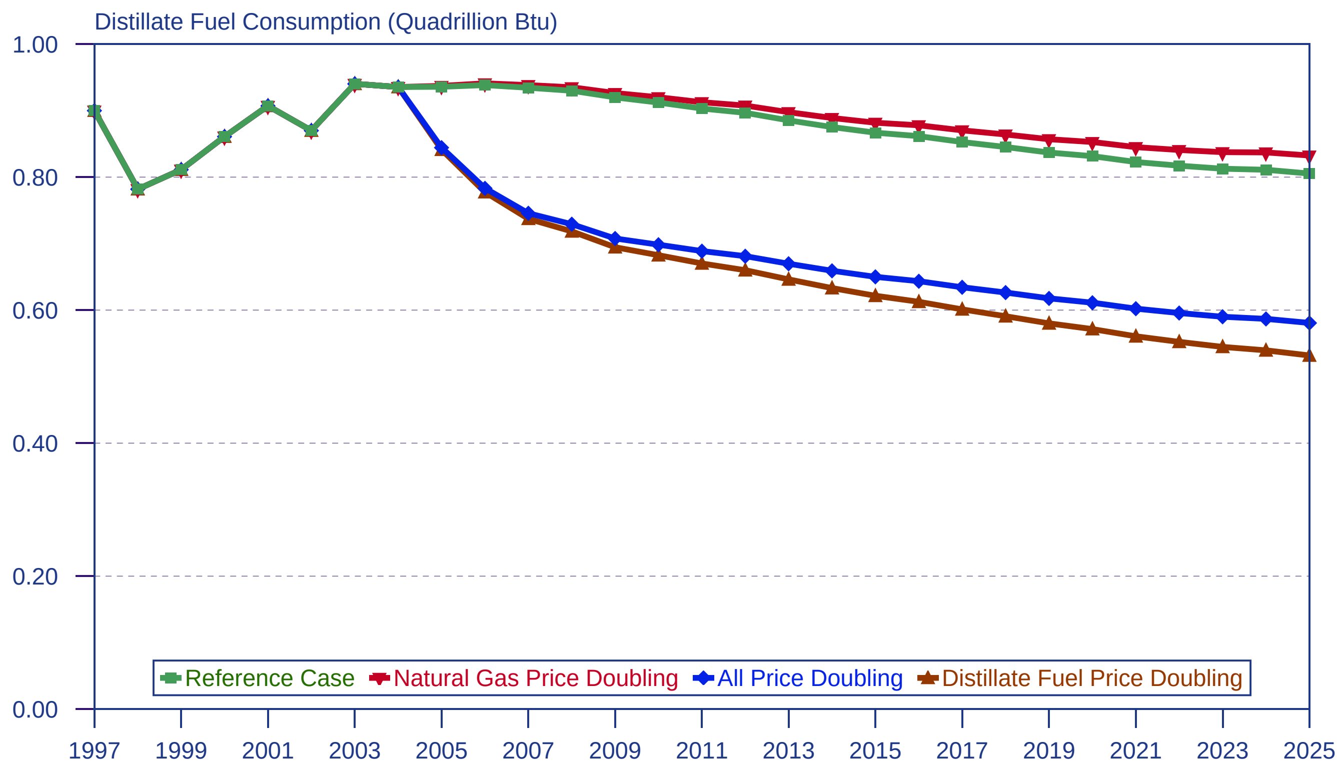
Source: Energy Information Administration, calculated from the following price path scenarios using NEMS *AEO2003*: regeneration of the reference case price path, ELAST03.D121203B; permanent price doubling case, ELAST03.D121202J; temporary price doubling case, ELAST03.D121203K.

When all energy prices double, the relationships among the prices remain the same as they are in the reference case. Thus, no additional fuel switching (beyond that already embodied in the reference) is stimulated when the price of one fuel becomes more attractive than the price of another fuel. This alternative price path (all prices doubled) produces the second-largest drop in distillate consumption compared with the reference case consumption path. Only when the distillate price alone doubles, does a greater suppression of distillate consumption occur. When only the distillate price doubles, not only the absolute price but also the relative price of distillate (compared with the prices of natural gas and other heating fuels) is doubled, further suppressing demand for distillate fuel by making natural gas and other energy sources more attractive.

Figure 4 illustrates the commercial model results for the same alternative cases shown for the residential model in Figure 3. Again, the focus is on the sensitivity of distillate consumption to price changes designed to show the impacts of relative price changes leading to cross-price effects. The results for the residential sector are generically similar to those for the commercial sector: when only the natural gas price increases, distillate fuel use is projected to grow at a substantially higher rate than in the reference case—from just under 0.5 quadrillion Btu in 2025 to more than 0.8 quadrillion Btu. This represents the switching of commercial natural-gas-fueled services to distillate-fueled services. An inspection of equipment choices indicates that distillate furnaces (meeting the 2003 standard) and high-efficiency distillate water heaters account for most of the shifting service demands. The commercial model is more sensitive than the residential model in this aspect, as could be anticipated from the larger cross-price elasticity reported for distillate fuel consumption in the commercial sector (0.75) than in the residential sector (0.05), as shown in Table 1.

When all energy prices are doubled, commercial demand for distillate fuel is also suppressed, but not by as much as in the residential model. When only distillate prices increase, the resulting suppression of distillate consumption is greater than that seen when all prices increase (by approximately 0.1 quadrillion Btu, as shown by the difference between the two bottom lines in Figure 4). This result is similar to, but slightly more sensitive than, the response of the residential model.

Figure 3. Residential Distillate Price Sensitivity: Own- and Cross-Price Effects



Source: Energy Information Administration, calculated from the following price path scenarios using NEMS *AEO2003*: regeneration of the reference case price path, ELAST03.D121203B; gas price doubling case, ELAST03.D121203H; distillate price doubling case, ELAST03.D121203I; all price doubling case, ELAST03.D121203J.

Comparisons With Other Studies

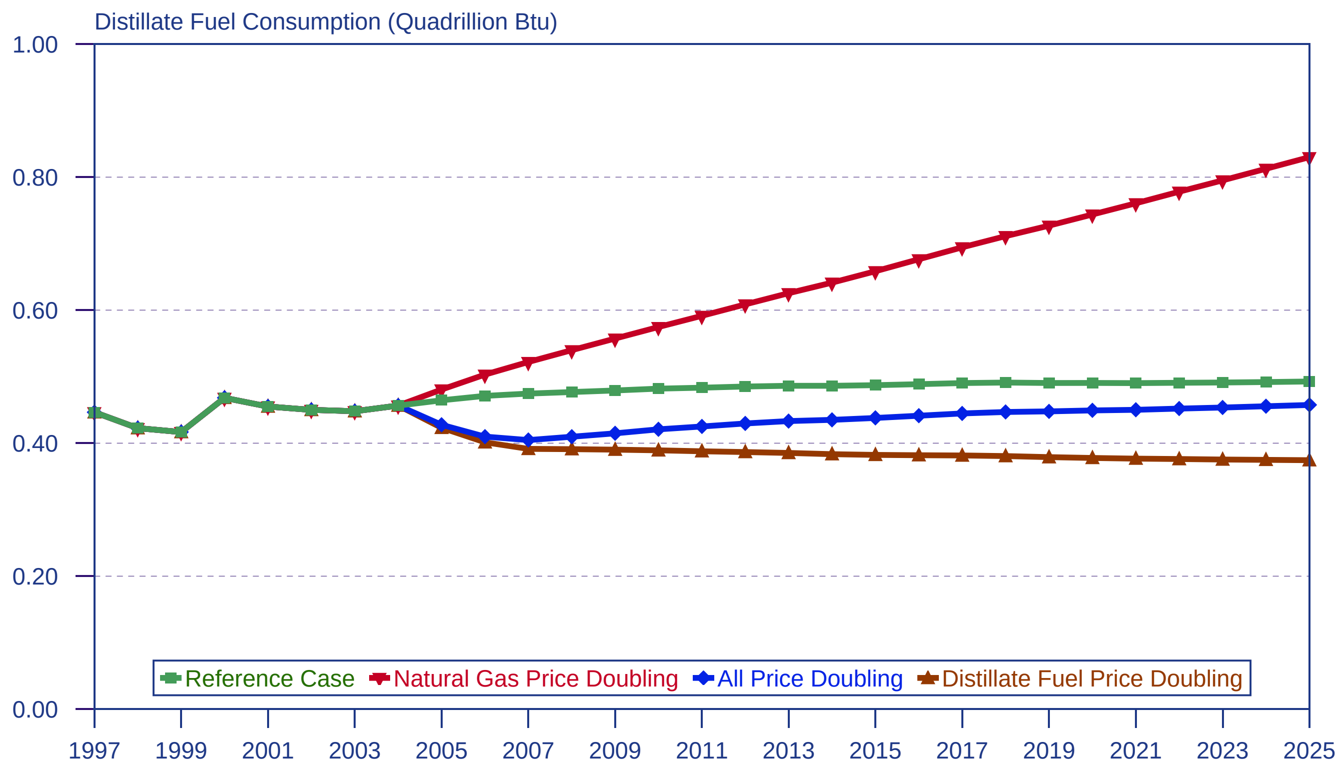
In 1993, EIA commissioned a survey of energy demand elasticities by Professor Carol Dahl,[29] as background for the development of NEMS. The survey incorporated results from previous survey articles as well as from more recent studies (referred to as "new studies" below) that had been performed after the last major surveys. The previous survey articles included data primarily from the 1970s or earlier. A limited number of the new studies included data as recent as 1990, but many of the time-series-based new studies also included pre-energy-crisis intervals, and one used data from 1937 through 1977. Thus, the "new" studies do not necessarily represent studies of more recent consumer responses to prices, which would be more relevant for comparisons with the *AEO2003* NEMS results.

In addition to short-run and long-run elasticities, Dahl also categorized the results of some models as "intermediate run" price elasticities—generally, from studies based on models that did not explicitly recognize a time path of adjustment to prices. Such models usually mix both short-run and long-run effects into a single estimate—hence the "intermediate run" nomenclature. A few of the studies reported results for the combined residential and commercial sectors, but they are not summarized here because the comparisons to the individual model results are less appropriate. Finally, because the Dahl study focused on own-price elasticities, comparisons here are limited to own-price elasticities.

Table 2 summarizes the information from the Dahl survey for the residential and commercial sectors. The table reports ranges derived from Dahl's extensive tables of individual model results. Table 2 highlights the wide range of estimates that have been made for price responses. For example, residential short-run electricity demand elasticities range from +0.57 to -0.97. For intermediate- and long-run residential electricity demand, the range is from +0.77 to -2.5.

In order to allow comparison of the NEMS elasticities presented in Table 1 with the results presented in Table 2, the ranges from Table 2 have been aggregated by sector and fuel in Table 3. Furthermore, to make the comparisons more meaningful, the ranges have been narrowed by eliminating poorly performing models that reported positive own-price elasticities. Also, because details on the scope of the new studies were readily available, only new studies with results that are

Figure 4. Commercial Distillate Price Sensitivity: Own and Cross-Price Effects



Source: Energy Information Administration, calculated from the following price path scenarios using NEMS *AEO2003*: regeneration of the reference case price path, ELAST03.D121203B; gas price doubling case, ELAST03.D121203H; distillate price doubling case, ELAST03.D121203I; all price doubling case, ELAST03.D121203J.

[29]C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract No. DE-AP01-93EI23499 (Washington, DC, October 1993).

nationally representative (i.e., not based on regional, State-level, or utility-level data) are included in the Table 3 ranges.

National-level studies are the most comparable to the national estimates for NEMS shown in Table 1. Finally, because the intermediate-run elasticities generally include effects beyond the initial short-run effects, they were combined with the long-run elasticities from Table 2. Comparing the third-year (i.e., full short-run effects) results from Table 1 with those in Table 3, the NEMS short-run and long-run own-price elasticities fall within the reported overall ranges, with the exception of distillate fuel oil in the commercial model, which falls just outside the range.

Table 2. Summary of Ranges of Residential and Commercial Elasticities from Dahl (1993)

Survey Source	Fuel	Data Type	Model Class	Short Run	Intermediate Run	Long Run
Residential Sector						
Taylor (1977)	Electricity	Grouped	Grouped	-0.07 to -0.61	-0.34 to -1.00	-0.81 to -1.66
	Natural Gas	Aggregate		0.00 to -0.16		0.00 to -3.00
Bohi (1981)	Electricity	Aggregate	Static	-0.08 to -0.45		-0.48 to -1.53
	Electricity	Aggregate	Dynamic	-0.03 to -0.49		-0.44 to -1.89
	Electricity	Aggregate	Structural	-0.16		0.00 to -1.28
	Electricity	Aggregate	Other	-0.18 to -0.54		-0.72 to -2.10
	Electricity	Household	Dynamic	-0.16		-0.45
	Electricity	Household	Static	-0.14		-0.7
	Electricity	Household	Structural	-0.25		-0.66
	Natural Gas	Aggregate	Static			-1.54 to -2.42
	Natural Gas	Aggregate	Dynamic	-0.15 to -0.50		-0.48 to -1.02
	Natural Gas	Aggregate	Structural	-0.3		-2
	Natural Gas	Household	Dynamic	-0.28		-0.37
	Natural Gas	Household	Static			-0.17 to -0.45
Bohi & Zimmerman (1984)	Electricity	Aggregate	Static		0.00 to -1.57	-0.18 to -0.52
	Electricity	Aggregate	Dynamic	0.00 to -0.35		-0.26 to -2.50
	Electricity	Household	Structural	-0.20 to -0.76		
	Electricity	Household	Static		-0.55 to -0.71	-0.05 to -0.71
	Electricity	Household	Structural	+0.04 to -0.67		-1.40 to -1.51
	Natural Gas	Aggregate	Dynamic	-0.23 to -0.35		-2.79 to -3.44
	Natural Gas	Aggregate	Dynamic	-0.03 to -0.05		-0.26 to -0.33
	Natural Gas	Household	Static			-0.22 to -0.60
Dahl (1993) Prior Surveys	Fuel Oil	Grouped	Grouped	0.00 to -0.70		0.00 to -1.50
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	+0.57 to -0.80	-0.11 to -1.11	+0.77 to -2.20
	Electricity	Household	Grouped	-0.02 to -0.97	-0.05 to -0.97	-0.38 to -1.40
	Natural Gas	Aggregate	Grouped	+0.02 to -0.35	1.86 to -2.41	1.56 to -3.44
	Natural Gas	Household	Grouped	-0.63 to -0.88	-0.08 to -1.80	-1.09 to -1.49
	Fuel Oil	Aggregate	Grouped	-0.10 to -0.59	-0.77 to -1.22	-1.85 to -3.5
	Fuel Oil	Household	Grouped	-0.18 to -0.19	-1.09 to -1.56	-0.62 to -0.67
Commercial Sector						
Taylor (1977)	Electricity	Aggregate	Grouped	-0.24 to -0.54		-0.85 to -1.22
	Natural Gas	Aggregate		-0.38		-1.45
Bohi (1981)	Electricity	Aggregate	Dynamic	-0.17 to -1.18		-0.56 to -1.60
	Natural Gas	Disaggregate	Static			-1.04
Bohi & Zimmerman (1984)	Electricity	Disaggregate	Grouped		0.00 to -4.56	0.00 to -1.05
	Natural Gas	Aggregate	Dynamic	0.00 to -0.37		0.00 to -2.27
Dahl (1993) Prior Surveys	Fuel Oil	Grouped	Grouped	-0.30 to -0.61		-0.55 to -0.70
Dahl (1993) New Studies	Electricity	Aggregate	Grouped	0.00 to -0.82	-0.59 to -0.98	3.36 to -4.74
	Natural Gas	Aggregate	Grouped	-0.16 to -0.37	1.92 to -2.68	0.06 to -2.27
	Fuel Oil	Aggregate	Grouped	-0.07 to -0.19	-0.3	-0.40 to -3.50

Notes: Single entries imply only one model/data combination in the category. Blanks denote no model/data combinations in the category. Static models do not include multi-period adjustments to prices. Dynamic models include lagged adjustments and distinguish short-run from long-run responses. Structural models include appliance stock data. Aggregate data usually are national or State-level data. Household data are observations on individual households. Grouped classifications denote ranges over multiple data types or model classes, or where a range of results is reported in Dahl (1993). Fuel oil elasticities from prior surveys include Taylor (1977) Bohi (1981), and Bohi and Zimmerman (1984), but the summary in Dahl (1993) aggregates across studies.

Source: C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract No. DE-AP01-93EI23499 (Washington, DC, October 1993).

Summary

This report provides an updated description of how the NEMS residential and commercial models respond to changes in energy prices. Since the previous study *(AEO99)*, there have been several updates and enhancements that could affect the models' price responsiveness. For both models, the base year survey data have been updated; the projected technology characterizations have been updated; behavioral adjustments in consumption induced by short-run price changes are now distributed over a 3-year interval; and distributed generation modules with explicit technology characterizations have been incorporated. The residential model also now incorporates discrete, price-sensitive building shell characterizations added since *AEO99*.

The changes in elasticities relative to *AEO99* can be characterized briefly as follows:

- Short-run behavioral responses are now distributed over 3 years—in the first year the effects are smaller than those reported for *AEO99*. By the third year, the differences vary by sector and fuel, with the largest change being a reduction in the long-run elasticity for distillate fuel consumption in the commercial model.
- Long-run own-price effects are generally somewhat larger than those reported for the *AEO99* models. Electricity elasticities are now notably higher for both sectors, natural gas elasticities are similar to those reported for *AEO99*, and the distillate fuel elasticity is significantly lower the for commercial sector.
- Long-run cross-price effects for the residential model were generally small for *AEO99* and remain so. For the commercial model, the distillate response to a change in natural gas price is larger than that for *AEO99*, and natural gas consumption now responds to electricity price changes.

Comparing NEMS results with those from other studies, both short-run (using the 3-year elasticities that include all short-run behavioral adjustments) and long-run own-price elasticities fall within the reported overall ranges, with the exception of commercial fuel oil, which falls just outside the range.

Table 3. Summary of Adjusted Overall Residential and Commercial Buildings Sector Own-Price Responses from Dahl (1993) by Fuel

Fuel	Short-Run Elasticity	Long Run Elasticity
Residential Studies		
Electricity	0.00 to -0.80	0.00 to -2.50
Natural Gas	0.00 to -0.88	0.00 to -3.44
Fuel Oil	0.00 to -0.70	0.00 to -3.50
Commercial Studies		
Electricity	-0.17 to -1.18	0.00 to -4.74
Natural Gas	0.00 to -0.38	0.00 to -2.27
Fuel Oil	-0.30 to -0.61	-0.55 to -3.50

Source: C. Dahl, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, Contract No. DE-AP01-93EI23499 (Washington, DC, October 1993).

Attachment 3.1

Outlook

Consumer price inflation in BC is forecast to be 1.0 per cent in 2009, as slower consumer spending is expected to put downward pressure on some prices. CPI inflation is forecast at 2.2 per cent in 2010 and at 2.1 per cent per year on average in the medium-term. The Canadian rate of inflation is expected to average 0.8 per cent in 2009 and 2.0 per cent in 2010. Over the medium-term, national CPI inflation is expected to be 2.0 per cent, in line with the Bank of Canada's inflation target.

Risks to the Economic Outlook

The balance of risks to the current economic forecast is weighted to the downside. The most significant risks to the BC outlook include:

- a more severe and prolonged US recession than assumed;
- slower than anticipated global demand resulting in reduced demand for BC's exports;
- continued turmoil in global financial markets;
- further weakening of domestic demand; and
- further commodity price volatility.

However, there is also upside risk to the forecast resulting from the potential impact of Federal and Provincial fiscal stimulus measures.

The Conference Board of Canada
Forecast Completed: Jul. 15 2009

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2008Q1	2008Q2	2008Q3	2008Q4	2009Q1	2009Q2	2009Q3	2009Q4	2010Q1	2010Q2	2010Q3	2010Q4	2008	2009	2010
G.D.P AT MARKET PRICES	197275	201621	202473	193137	187963	188134	189285	191502	196169	198390	201239	204235	198627	189221	200008
(MILLIONS $)	0.7	2.2	0.4	-4.6	-2.7	0.1	0.6	1.2	2.4	1.1	1.4	1.5	3.5	-4.7	5.7
	12.5	12.5	12.4	12.3	12.3	12.3	12.3	12.3	12.3	12.4	12.4	12.4	12.4	12.3	12.4
G.D.P AT BASIC PRICES	182181	186402	187205	178217	173406	173479	174500	176527	180959	182926	185185	187874	183501	174478	184236
(MILLIONS $)	1.3	2.3	0.4	-4.8	-2.7	0.0	0.6	1.2	2.5	1.1	1.2	1.5	4.2	-4.9	5.6
	12.3	12.2	12.2	12.1	12.1	12.1	12.0	12.0	12.1	12.1	12.2	12.2	12.2	12.1	12.2
G.D.P AT BASIC PRICES	150260	150900	150747	149047	146177	146126	146360	147201	149571	150775	152081	153350	150239	146466	151444
(MILLIONS $ 2002)	-0.9	0.4	-0.1	-1.1	-1.9	0.0	0.2	0.6	1.6	0.8	0.9	0.8	-0.1	-2.5	3.4
	12.3	12.3	12.2	12.2	12.2	12.2	12.2	12.2	12.3	12.3	12.3	12.3	12.3	12.2	12.3
CONSUMER PRICE INDEX (2002=1.0)	1.103	1.127	1.141	1.122	1.118	1.125	1.136	1.143	1.150	1.156	1.163	1.170	1.123	1.131	1.160
	0.2	2.2	1.2	-1.7	-0.4	0.7	1.0	0.6	0.5	0.6	0.6	0.6	2.1	0.6	2.6
IMPLICIT PRICE DEFLATOR -	1.212	1.235	1.242	1.196	1.186	1.187	1.192	1.199	1.210	1.213	1.218	1.225	1.221	1.191	1.216
GDP AT BASIC PRICES (2002=1.0)	2.2	1.9	0.5	-3.7	-0.8	0.1	0.4	0.6	0.9	0.3	0.4	0.6	4.4	-2.5	2.1
AVERAGE WEEKLY WAGE	761	765	770	766	770	768	770	776	780	785	790	795	765	771	788
($, INDUSTRIAL COMPOSITE)	0.4	0.6	0.6	-0.5	0.6	-0.2	0.3	0.7	0.6	0.6	0.6	0.7	2.1	0.8	2.1
PERSONAL INCOME (MILLIONS $)	159286	159013	159802	160480	159794	160441	161385	162935	164742	166044	167842	169453	159645	161139	167020
	3.0	-0.2	0.5	0.4	-0.4	0.4	0.6	1.0	1.1	0.8	1.1	1.0	5.2	0.9	3.6
	13.1	13.0	13.0	13.0	13.0	13.0	13.1	13.1	13.1	13.1	13.1	13.1	13.0	13.0	13.1
PERSONAL DISPOSABLE INCOME	124417	124967	125735	125917	125715	126199	126943	128188	129486	130456	131816	133063	125259	126761	131205
(MILLIONS $)	3.6	0.4	0.6	0.1	-0.2	0.4	0.6	1.0	1.0	0.7	1.0	0.9	6.8	1.2	3.5
	13.3	13.2	13.2	13.1	13.2	13.2	13.2	13.2	13.3	13.3	13.3	13.3	13.2	13.2	13.3
PERSONAL SAVINGS RATE	-2.7	-3.2	-3.3	-1.5	-0.6	-1.3	-1.8	-1.7	-1.9	-1.8	-1.8	-1.6	-2.7	-1.3	-1.8
	-47.6	-18.5	-2.3	55.5	61.5	-134.6	-33.1	5.5	-10.2	4.8	-4.5	14.1	-44.8	50.2	-31.2
POPULATION OF LABOUR	3615	3633	3652	3668	3681	3697	3705	3722	3745	3758	3771	3785	3642	3701	3765
FORCE AGE	0.5	0.5	0.5	0.4	0.4	0.4	0.2	0.5	0.6	0.4	0.4	0.4	2.0	1.6	1.7
	13.5	13.5	13.5	13.5	13.6	13.6	13.5	13.6	13.6	13.6	13.6	13.6	13.5	13.6	13.6
LABOUR FORCE ('000s)	2412	2429	2431	2432	2420	2445	2450	2461	2475	2484	2493	2501	2426	2444	2488
	0.9	0.7	0.1	0.1	-0.5	1.0	0.2	0.4	0.6	0.3	0.4	0.3	2.5	0.7	1.8
	13.3	13.3	13.3	13.3	13.2	13.3	13.3	13.3	13.4	13.4	13.4	13.4	13.3	13.3	13.4
EMPLOYMENT ('000s)	2310	2320	2320	2306	2257	2257	2255	2260	2269	2277	2289	2301	2314	2257	2284
	0.8	0.4	0.0	-0.6	-2.1	0.0	-0.1	0.2	0.4	0.4	0.5	0.5	2.1	-2.5	1.2
	13.5	13.5	13.5	13.5	13.3	13.4	13.4	13.5	13.5	13.5	13.5	13.5	13.5	13.4	13.5
UNEMPLOYMENT RATE	4.2	4.5	4.5	5.2	6.7	7.7	8.0	8.2	8.3	8.3	8.2	8.0	4.6	7.6	8.2
RETAIL SALES (MILLIONS $)	57575	57512	57148	54017	51878	52274	52704	53237	53884	54303	54915	55343	56563	52523	54611
	0.2	-0.1	-0.6	-5.5	-4.0	0.8	0.8	1.0	1.2	0.8	1.1	0.8	0.4	-7.1	4.0
	13.4	13.4	13.2	13.0	12.8	12.9	12.9	12.9	13.0	12.9	13.0	12.9	13.3	12.9	12.9
HOUSING STARTS (NUMBER OF UNITS)	39176	37863	34955	25290	13559	12433	14485	17683	17465	19886	21452	27276	34321	14540	21520
	-7.8	-3.4	-7.7	-27.7	-46.4	-8.3	16.5	22.1	-1.2	13.9	7.9	27.2	-12.4	-57.6	48.0
	16.7	17.4	16.9	13.7	9.7	9.9	10.8	12.4	11.8	12.4	12.6	15.2	16.3	10.8	13.1

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

TABLE 11: KEY ECONOMIC INDICATORS, BRITISH COLUMBIA

	2011Q1	2011Q2	2011Q3	2011Q4	2012Q1	2012Q2	2012Q3	2012Q4	2013Q1	2013Q2	2013Q3	2013Q4	2011	2012	2013
G.D.P AT MARKET PRICES (MILLIONS $)	207642	210256	213924	216982	219951	223328	226925	230306	233570	237037	240728	243995	212201	225127	238833
	1.7	1.3	1.7	1.4	1.4	1.5	1.6	1.5	1.4	1.5	1.6	1.4	6.1	6.1	6.1
	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
G.D.P AT BASIC PRICES (MILLIONS $)	190960	193138	196511	199281	201966	205053	208359	211452	214418	217588	220971	223931	194973	206707	219227
	1.6	1.1	1.7	1.4	1.3	1.5	1.6	1.5	1.4	1.5	1.6	1.3	5.8	6.0	6.1
	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.1	12.2	12.2	12.2
G.D.P AT BASIC PRICES (MILLIONS $ 2002)	154661	155981	157460	158895	160398	161850	163307	164743	166164	167557	168942	170302	156749	162574	168241
	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	3.5	3.7	3.5
	12.3	12.3	12.3	12.3	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.3	12.2	12.2
CONSUMER PRICE INDEX (2002=1.0)	1.177	1.184	1.191	1.197	1.204	1.210	1.217	1.222	1.228	1.234	1.240	1.246	1.187	1.213	1.237
	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	2.4	2.2	2.0
IMPLICIT PRICE DEFLATOR - GDP AT BASIC PRICES (2002=1.0)	1.235	1.238	1.248	1.254	1.259	1.267	1.276	1.284	1.290	1.299	1.308	1.315	1.244	1.271	1.303
	0.8	0.3	0.8	0.5	0.4	0.6	0.7	0.6	0.5	0.6	0.7	0.5	2.2	2.2	2.5
AVERAGE WEEKLY WAGE ($, INDUSTRIAL COMPOSITE)	802	808	815	821	828	835	843	850	857	865	873	881	812	839	869
	0.9	0.8	0.8	0.8	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	3.1	3.4	3.6
PERSONAL INCOME (MILLIONS $)	171676	173469	175992	178227	180508	182675	184856	186884	189283	191414	193573	195746	174841	183731	192504
	1.3	1.0	1.5	1.3	1.3	1.2	1.2	1.1	1.3	1.1	1.1	1.1	4.7	5.1	4.8
	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1	13.1
PERSONAL DISPOSABLE INCOME (MILLIONS $)	134692	136050	138006	139730	141386	143021	144718	146300	148046	149663	151359	153066	137120	143856	150533
	1.2	1.0	1.4	1.2	1.2	1.2	1.2	1.1	1.2	1.1	1.1	1.1	4.5	4.9	4.6
	13.3	13.3	13.3	13.3	13.3	13.3	13.3	13.2	13.2	13.2	13.2	13.2	13.3	13.3	13.2
PERSONAL SAVINGS RATE	-1.6	-1.8	-2.0	-2.1	-2.2	-2.5	-2.8	-3.1	-3.3	-3.5	-3.8	-3.9	-1.9	-2.7	-3.6
	-3.5	-9.9	-9.5	-7.1	-5.4	-14.1	-11.9	-9.1	-5.5	-6.2	-8.9	-3.8	-6.8	-42.3	-35.1
POPULATION OF LABOUR FORCE AGE	3798	3811	3824	3838	3851	3864	3877	3890	3903	3915	3929	3942	3818	3870	3922
	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.4	1.4	1.3
	13.6	13.6	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.6	13.7	13.7
LABOUR FORCE ('000s)	2509	2517	2527	2535	2541	2549	2556	2561	2565	2572	2578	2583	2522	2551	2574
	0.3	0.3	0.4	0.3	0.2	0.3	0.3	0.2	0.2	0.3	0.2	0.2	1.4	1.2	0.9
	13.4	13.3	13.4	13.4	13.3	13.4	13.4	13.3	13.3	13.3	13.3	13.3	13.4	13.4	13.3
EMPLOYMENT ('000s)	2312	2331	2353	2371	2382	2395	2408	2415	2424	2431	2440	2448	2342	2400	2436
	0.5	0.8	0.9	0.7	0.5	0.5	0.5	0.3	0.3	0.3	0.4	0.3	2.5	2.5	1.5
	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
UNEMPLOYMENT RATE	7.8	7.4	6.9	6.5	6.2	6.0	5.8	5.7	5.5	5.5	5.3	5.2	7.1	5.9	5.4
RETAIL SALES (MILLIONS $)	56246	57084	58232	59241	60112	61037	61985	62838	63702	64484	65275	66057	57701	61493	64880
	1.6	1.5	2.0	1.7	1.5	1.5	1.6	1.4	1.4	1.2	1.2	1.2	5.7	6.6	5.5
	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.8	12.8	12.8	12.9	12.9	12.8
HOUSING STARTS (NUMBER OF UNITS)	28675	28383	29146	29285	31382	31248	31419	31419	31140	30699	30316	30875	28872	31367	30757
	5.1	-1.0	2.7	0.5	7.2	-0.4	0.5	0.0	-0.9	-1.4	-1.2	1.8	34.2	8.6	-1.9
	15.3	14.9	14.8	14.7	15.6	15.5	15.6	15.6	15.6	15.5	15.3	15.6	14.9	15.6	15.5

Sources: Statistics Canada, CMHC, The Conference Board of Canada.

REAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	82/91	2006	2007	2008	2009F	2010F
CANADA	**-2.5**	**3.1**	**2.7**	**0.5**	**-2.4**	**1.4**
N. & L.	0.7	3.0	9.1	-0.1	-4.0	1.7
P.E.I.	0.3	2.4	2.4	0.9	-1.3	1.4
N.S.	1.4	0.9	1.7	2.0	-1.7	1.2
N.B.	0.9	2.4	1.7	0.0	-1.9	1.4
Québec	-3.2	1.7	2.6	1.0	-1.7	1.2
Ontario	-3.3	2.6	2.3	-0.4	-2.7	1.5
Manitoba	-3.0	4.0	3.3	2.4	-0.7	1.6
Sask.	-0.4	-0.3	2.5	4.4	-1.0	1.8
Alberta	-1.3	6.1	3.1	-0.2	-2.3	1.9
B.C.	-3.0	4.4	3.0	-0.3	-2.0	2.1

F: Forecast by TD Economics as at June 2009
Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	82/91	2006	2007	2008	2009F	2010F
CANADA	**3.1**	**5.7**	**5.9**	**4.4**	**-4.4**	**2.3**
N. & L.	6.4	18.5	13.6	6.6	-8.4	3.7
P.E.I.	6.0	4.1	5.3	3.7	-3.0	2.1
N.S.	9.6	1.5	4.0	3.6	-3.5	1.7
N.B.	6.3	4.4	4.3	1.3	-4.6	2.5
Québec	3.5	3.9	5.4	1.6	-1.8	1.4
Ontario	3.0	4.3	4.5	0.5	-2.9	1.8
Manitoba	1.2	8.2	8.1	4.8	-2.5	2.3
Sask.	1.2	5.5	11.0	24.6	-7.1	3.3
Alberta	2.9	8.7	8.1	12.6	-10.1	4.2
B.C.	1.7	7.9	5.4	3.5	-3.7	2.7

F: Forecast by TD Economics as at June 2009
Source: Statistics Canada / Haver Analytics

EMPLOYMENT
Annual average per cent change

	82/91	2006	2007	2008	2009F	2010F
CANADA	**-2.4**	**1.9**	**2.3**	**1.5**	**-2.0**	**-0.2**
N. & L.	-1.9	0.7	0.7	1.4	-4.0	-0.1
P.E.I.	-2.0	0.5	1.2	1.2	-3.5	0.0
N.S.	-1.7	-0.3	1.3	1.2	-0.2	-0.4
N.B.	-2.6	1.4	2.1	0.9	-0.5	-0.2
Québec	-3.6	1.3	2.3	0.8	-1.5	-0.3
Ontario	-2.8	1.5	1.5	1.4	-2.7	-0.5
Manitoba	-1.6	1.2	1.6	1.7	-0.4	0.2
Sask.	-0.2	1.7	2.1	2.2	1.5	0.0
Alberta	-0.5	4.8	4.7	2.7	-1.3	0.3
B.C.	-1.9	3.1	3.2	2.1	-2.5	0.5

F: Forecast by TD Economics as at June 2009
Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE
Annual average, per cent

	82/91	2006	2007	2008	2009F	2010F
CANADA	**10.7**	**6.3**	**6.0**	**6.1**	**8.7**	**9.9**
N. & L.	17.1	14.8	13.6	13.3	15.5	16.4
P.E.I.	14.6	11.1	10.3	10.7	13.4	14.1
N.S.	12.5	7.9	8.1	7.7	9.2	10.0
N.B.	13.4	8.7	7.6	8.6	9.3	10.0
Québec	13.1	8.0	7.2	7.3	9.0	10.1
Ontario	9.7	6.3	6.4	6.5	9.5	11.0
Manitoba	8.6	4.3	4.4	4.1	5.2	6.4
Sask.	6.8	4.6	4.2	4.1	5.1	6.7
Alberta	8.0	3.4	3.5	3.6	6.8	7.8
B.C.	11.1	4.8	4.2	4.6	7.8	8.8

F: Forecast by TD Economics as at June 2009
Source: Statistics Canada / Haver Analytics

RETAIL TRADE
Annual average per cent change

	2006	2007	2008	2009F	2010F
CANADA	**6.4**	**5.8**	**3.4**	**-3.3**	**2.9**
N. & L.	3.4	9.0	7.6	0.0	2.3
P.E.I.	6.2	7.7	5.6	-0.5	2.6
N.S.	6.0	4.2	4.2	-2.0	3.2
N.B.	5.9	5.7	5.9	-1.2	3.4
Quebec	5.1	4.6	5.1	-1.8	2.5
Ontario	4.1	3.9	3.5	-3.0	2.7
Manitoba	3.9	8.8	7.2	-2.5	3.5
Sask.	6.5	13.0	10.6	-2.0	3.7
Alberta	15.4	9.3	-0.1	-6.0	2.8
B.C.	7.2	6.7	0.3	-5.5	4.0

F: Forecast by TD Economics as at June 2009
Source: Statistics Canada / Haver Analytics

CONSUMER PRICE INDEX (CPI)
Annual average per cent change

	92-08	2007	2008	2009F	2010F
CANADA	**1.9**	**2.1**	**2.4**	**0.2**	**1.5**
N. & L.	1.8	1.4	2.9	-0.1	1.3
P.E.I.	2.0	1.8	3.4	-0.7	1.5
N.S.	2.0	1.9	3.0	-1.0	1.7
N.B.	1.8	1.9	1.7	-0.2	1.1
Québec	1.7	1.6	2.1	-0.1	0.8
Ontario	1.9	1.8	2.3	0.5	2.2
Manitoba	2.1	2.1	2.2	0.6	1.2
Sask.	2.2	2.9	3.2	0.9	1.1
Alberta	2.5	4.9	3.2	-0.1	1.2
B.C.	1.8	1.7	2.1	0.1	1.5

F: Forecast by TD Economics as at June 2009.
Source: Statistics Canada / Haver Analytics

Attachment 4.2

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 23.1.1

Customer Name	Association	Is the customer looking to reduce energy usage or GHG emissions?	Is the customer seeking to reduce energy costs?	Is the customer seeking TG's help in doing so?	Is the customer seeking TG's help in providing Alternative Energy Solutions	What Alternative Energy Solutions is the customer seeking? (NGV, Biogas, DES, GSHP, GeoX etc.)	Does the customer believe that Terasen Gas should be able to provide (own and operate) energy solutions that include both gas and alternative energy (or has the customer asked that TG provide the Alt. Energy solution)?
Aberdeen Highlands Dev; Pacific Way; Kamloops	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Acres Development - 955 Lorne Street, Kamloops	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Annaerobic Digester Innitiative Advisory Committee - made up of representatives from Ministry of Agriculture and Lands, Farming Community, Food Processors Association, Milk Producers Association and other stakeholders.	Government	yes	yes	yes	yes	biogas	yes - stakeholders and association believe that Terasen's participation in and investment in biogas upgrading and pipeline injection is critical for the development of anaerobic digestion and thus an important way for the farming community to manage wastes, reduce carbon emissions and increase farm viability.
Aplin and Martin	Builder / Developer / Engineer / Architec	yes	yes	yes	possibly	DES, GeoX, Biogas, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Aquilini Group	Builder / Developer / Engineer / Architec	yes	yes	yes	possibly	GeoX	Yes, currently evaluating alternative energy solutions
Aquilini Investment Group - 24 Condo, Kelowna	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	Solar & GSHP	Yes
Aragon Developments	Builder / Developer / Engineer / Architec	yes	yes	yes	possibly	GeoX	Yes, currently evaluating alternative energy solutions
ARES (formerly BC Buildings) - BLJC-WSI	Government	yes	yes	yes	yes	DES, GEOX, Solar	Yes, help the Provincial government reach their emissions targets. Likes that we are regulated utility and believes Terasen has to evolve into an energy delivery company
Army Navy Airforce Vets #284	Commercial Customer	Yes	Yes	Yes	Yes	GeoExchange/ngas backup	Yes, currently in design but wanting additional information
ASPAC Developments - John Ryan	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	Geo, DE, possilbe NGVV refuleing hub, Biogas	yes
Barber Creek Properties Ltd	Builder / Developer / Engineer / Architec	Yes	Yes	Yes	Yes	GeoExchange/ngas backup	Yes, wanting TG to provide alternative energy solution
BC Housing Management Commission	Government	Yes	Yes	Yes	Yes	GeoExchange/Solar/District Energy	Customer has done some of their own alternative energy systems and are looking to TG to provide additional/larger scale alternative energy systems
BC Rail Properties -	Government	yes	yes	yes	yes	Geo, DES, other	yes
Beedie Group - Ryan Beedie, Todd Yuen	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	Geo, DES, other	yes
Berezan Management Ltd - Central City Development, Surrey	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	DES/GSHP/ N.G. Boilers/vertical sub for lifestyle gas appl.	Yes
Berezan Management Ltd - Chateau Blanc, Big White	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	DES/GSHP	Yes
Bernd Hermanski Architect Inc - Carmel of St. Joseph, Spallumcheen	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
BFW Developments	Builder / Developer / Engineer / Architec	yes	yes	possibly	possibly	GeoX	Yes
Bing Thom Architecture	Builder / Developer / Engineer / Architec	Yes	Yes	Possibly	Possibly	Geo-exchange	Undetermined, project finalizing designs, first meeting to happen in August to review options
Boffo Construction	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	GeoX, Solar	Makes sense you guys are already the utility company
Bosa Properties Inc	Builder / Developer / Engineer / Architec	Yes	Yes	Yes	Yes	GeoExchange	Undetermined, first project meeting scheduled for September
Brook Development Planning - Gary Pooni	Builder / Developer / Engineer / Architect						Development Planners - extremely influential, major developers, Beedie (Fraser Mills), Dist of Maple Ridge etc
Canadian Home Builders Association of BC (CHBABC)	Trade Association	possibly	possibly	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Association that supports energy conservation in whatever ways possible
Canadian Home Builders Association, Fraser Valley (CHB/	Trade Association	possibly	possibly	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Association that supports energy conservation in whatever ways possible
Caretenders (Heaton Place)	Commercial Customer	Yes	Yes	Maybe	Maybe	GSHP	Maybe
Cariboo Friendship Society; 228 S 3rd Ave; Williams Lake	Commercial Customer	Yes	Yes	Yes	Yes	Yes	Yes

Cascadia Colsulting - Peter Goordon	Builder / Developer / Engineer / Architect						Development Consultant - encourages his developer clients to look at TG - Westmana, Squamish
Catalyst Paper -Carlo Dal Monte	Commercial Customer	Yes	Yes	Yes	Yes	GSHP	Yes
Century Group	Builder / Developer / Engineer / Architec	Yes	Yes	Yes	No	Solar/Geoexchange	Customer has decided to own/operate their own alternative energy system
Chard Development - David Chard	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	un-known	un-known
Chartwell Seniors Housings	Commercial Customer	Yes	Yes	Possibly	Possibly	Undetermined	Undetermined as first meeting has been postponed to do financial issues with new projects
City of Abbotsford - Peter Andzans	Municipality	yes	yes	maybe	possibly	DES, geo exchange, biogas	both
City of Burnaby - Stu Imre	Municipality	Yes	Yes	Yes	Yes	GSHP	Yes
City of Chilliwack - Frank VanNynatten	Municipality	yes	yes	yes	yes	Geo, DES, other	yes
City of Coquitlam	Municipality	yes	yes	yes	yes	DES, NGV	possibly - Stu working with this one
City of Coquitlam - John DuMont	Municipality				Yes	DES, various	both
City of Coquitlam - Peter Steblin	Municipality	yes	yes	yes	Yes	DES, various	both
City of Fernie - Fernie Aquatic Centre, 250 Pine Ave, Fernie	Municipality	Yes	yes	yes	yes	Refrigeration Waste Heat Recovery/GSHP	Yes
City of Kaslo	Municipality	Yes	Yes	Yes	Yes	GSHP	Yes
City of Kelowna - Alf Soros	Municipality	Yes	Yes	Yes	Yes	GSHP	Yes
City of Kelowna - YM/YWCA, 375 Hartman Rd, Kelowna	Municipality	Yes	yes	yes	yes	Solar	Yes
City of Kimberley	Municipality	Yes	Yes	Yes	Yes	GSHP	Yes
City of Langley	Municipality	yes	yes	yes	yes	biogas, DES, NGV	Yes - crucial part of solution as infrastructure owner
City of Merritt - Arena, 2075 Mamette Ave	Municipality	Yes	yes	yes	yes	GSHP	Yes
City of Penticton - Keith Manders	Municipality	Yes	Yes	Yes	Yes	Yes	Yes
City of Richmond	Municipality	yes	yes	maybe	possibly	DES, geo exchange, biogas	both
City of Salmon Arm	Municipality	both	yes	yes	yes	DES/waste heat capture	customer approached Terasen via Energy Assessment request
City of Surrey - Curtis Rhodes	Municipality	Yes	Yes	Yes	Yes	Yes	Yes
City of Surrey - Mary Ann Smith	Municipality				Yes	DES	both
City of Surrey - Vince LaLonde	Municipality				Yes	DES, waste to energy	both
City of Van. - Mani Deo	Municipality	Yes	yes	yes	yes	Central DES/GSHP	Yes
City of Vancouver	Municipality	yes	yes	yes	yes	biogas, NGV	Yes - landfill gas capture and offset use, crucial part of solution as infrastructure owner, rebate offers
City of Whistler - John Gysbers	Municipality	Yes	Yes	Yes	Yes	GSHP	Yes
City of Williams Lake - pool & arena	Municipality	Yes	yes	yes	yes	Central DES/GSHP	Yes
Columbia Shuswap Reg. Dist - Gary Holte	Municipality	GHG Emission Reductic	Yes	Yes	Yes	NGV	Yes
Columbia Shuswap Regional District (CSRD)	Municipality	yes	yes	yes	yes	biogas, NGV	Yes - want to incorporate biogas production into Landfill operations for sale through Terasen Infrastructure. Have identified that this will not be possible without TGI investment in upgrading system
Concordia Homes	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	GeoX, Solar	Yes, currently evaluating alternative energy solutions
Coquitlam School District	Schools	yes	yes	yes	yes	DES, GEOX, Solar	Yes, help the SD's reach their emissions targets.
Corporation of Delta	Municipality	yes	yes	maybe	possibly	geo exchange, DES	both
Craig Stowe - Eastpoint Residences, Vernon	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
CRC Development Ltd. - Gallagher Canyon Apartment, Kelowna	Builder / Developer / Engineer / Architect	Yes	yes	Maybe	Maybe	GSHP	Maybe
CREUS Engineering	Builder / Developer / Engineer / Architect						Engineering firm - promotes working with DES and GEO
Cushman & Wakefield LePage	Builder / Developer / Engineer / Architect						Their clients are builder-develoers and they have been influential in suggesting to them that they have discussions with us - EPTA, Beedie Group, Spire Development, Oxford, GWL, Hopewell, Cadillac Fairview, Bentall, etc
Dist of Mission - Kevin Poole	Municipality	yes	yes	yes	yes	geo	working with developers at the suggestion of the District
Dist of Squamish - Cameron Chalmers - Dist Planner	Muncipality	yes	yes	yes	yes	Geo, DES, other	yes - we are in talks with the district
DLO Management	Builder / Developer / Engineer / Architec	possibly	possibly	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Dominic J. Fiore (YVR)	Commercial Customer	Yes	Yes	Yes	Yes	Yes	Yes
DW Energy Advisors	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
E3 Eco Energy	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible

E3 Planning and Development	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Solar	Yes, currently evaluating alternative energy solutions
EA Games - Sarah Tutton	Commercial Customer	yes	yes	yes	yes	geo	yes
Epta Properties - Angelo Tsakumis	Commercial Customer	yes	yes	yes	yes	Geo	yes
Ethical Bean	Manufacturing	Energy Usuage	yes	yes	yes	Organic Rankin Cycle	Waste Heat capture from roasters and turning it to steam to create electricity. Looking at solutions and what this would look like. Early stages
Euroasia Transload - Coleman Tokei	Commercial Customer	Yes	Yes	Yes	Yes	GSHP	Yes
Fairmont Resort - Lake Okanagan Resort, Kelowna	Hotels	Yes	yes	yes	yes	GSHP/Solar	Yes
Frank Marasco (School Dist. Salmon Arm)	Schools	Yes	yes	yes	yes	Central DES/GSHP	Yes
Fraser Cascades School District	Schools	yes	yes	yes	yes	GeoX	Yes, currently evaluating alternative energy solutions
Fraser Health Authority	Health Authorities	yes	yes	yes	yes	DES, geo, solar	Yes, currently evaluating alternative energy solutions
Fraser Mills Properties Ltd. (The Beedie Group)	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	DES, Geox, Biomass	Yes, currently evaluating alternative energy solutions.
Gallagher Lake Mobile Home Park, Oliver - Swarnjit Chahal	Commercial Customer	Yes	yes	yes	yes	DES/GSHP	Yes
Genstar Developments	Builder / Developer / Engineer / Architec	yes	yes	possibly	possibly	DES, GeoX, Solar	Yes, is looking at alternative energy solutions
Greater Vancouver Home Builders Association (GVHBA)	Trade Associations	possibly	possibly	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Association that supports energy conservation in whatever ways possible
H.A. Berg Investments and Developments	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	HEF Boilers, Solar	Yes, currently evaluating alternative energy solutions
Hesperia Development Corporation, Vernon	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Hollyburn Country Club	Commercial Customer	both	yes	yes	yes	Geo Exchange and Solar	Customer looking to upgrade energy solutions. Willing to investigate alternative means of energy that proposes a"greener"solution. MOU issued
Hotson Bakker Boniface - Lean Nyrose3	Commercial Customer						Architects and planners -
HPF Engineering - Interior Savings Centre, Kamloops	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
HPF Engineering - Kamloops Native Urban Housing, Kamloops	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
Ice Kube Systems	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Indigo,Osoyoos	Commercial Customer	Yes	yes	yes	yes	Central DES/GSHP vertical sub for lifestyle gas	Yes
Institute of Real Estate Management (IREM)	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Association that supports energy conservation in whatever ways possible
Investgo Ventures Inc. - Condo development, Prince George	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Isaac-Renton Architect Inc	Builder / Developer / Engineer / Architec	Yes	Yes	Yes	Yes	Geo-exchange	Undetermined, first project meeting scheduled for September
Jean LaMontange	Commercial Customer				possibly	DES	both
Jim Perkins (Metrovan)	Commercial Customer	Yes	Yes	Maybe	Maybe	GSHP	Maybe
Joe Fantillo (Lordco)	Commercial Customer	Yes	Yes	Yes	Yes	Waste Heat Recovery	Yes
Kingma Brothers Construction	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	GeoX	Yes, currently evaluating alternative energy solutions
Kootenay Col Srs Housing Co-op - Grandview Manor, Castlegar	Commercial Customer	Yes	yes	yes	yes		Yes
L&M Engineering - Dragon Lake Estates, Quesnel	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Lakewood Developments	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	GeoX, Solar	Yes, currently evaluating alternative energy solutions
Landquest Management - Aspire, Kelowna	Builder / Developer / Engineer / Architect	No	No	No	No	None	No
Larco Developments - Jonathan Larzar	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	Geo and DES	yes
Ledingham McAllistar - John Odonnel	Commercial Customer	yes	yes	yes	yes		yes
Lee Ferrari (UBC)	Commercial Customer	Yes	Yes	Yes	Yes	Waste Heat Recovery	Yes
Lighthouse Sustainability Centre	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Maksim Mihic (DP World)	Commercial Customer	Yes	Yes	Yes	Yes	Yes	Yes
Mayor Peter Fassbender	Municipality				Yes	District Energy Systems, also interested to know about other options	Yes
Merrick Architecture - Greg Borowski	Builder / Developer / Engineer / Architect						architecture firm - major developers

MetroVancouver	Commercial Customer	yes	yes	yes	yes	biogas	Yes - want to incorporate biogas production into Wastewater Treatment operations for sale through Terasen Infrastructure. Have identified that this will not be possible without TGI investment in upgrading system
Millennium Development Corp	Builder / Developer / Engineer / Architec	Yes	Yes	Yes	Yes	GeoExchange/possibly others	Yes, customer understands TG energy solutions and our
MKS Resources - Waters Edge, Kelowna	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	Gas fired applicationVertiical sub "Piping to Suite Door" concept.Looking @ some solar	Yes
MMAL Architecture - Ron Kato	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	Geo, DES, other	Architect working with the NVSC
Morningstar Homes	Builder / Developer	yes	yes	yes	yes	GeoX, Solar	Yes, currently evaluating alternative energy solutions
MPC Intelligence - JennPodmore	Trade Associations						Major player in residential development
NAIOP - Jeff Rank, Jocelyn Legal	Trade Associations						Industry Organization - commercial properties. Supporter of our efforts to work with their members
Nata Farms	Agriculture	yes	yes	yes	yes	biogas	Yes - want to incorporate biogas production into farm operations for both sale and on-farm use through Terasen Infrastructure. Have identified that this will not be possible without TGI investment in upgrading system
New Future Building Group - Kutenai Landing, Nelson	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
New Future Building Group - Timber Ridge, Peachland	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	Propane/GSHP/ DES	Yes
New Town Architectural Service - The Heritage, West Kelowna	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
North Vancouver School District - Ian Abercrombie	Schools	yes	yes	yes	yes	Geo, DES, other	yes
Northern Health Authority	Health Authorities	yes	yes	yes	yes	DES, geo, solar	Yes, currently evaluating alternative energy solutions
Okanagan College - Centre of Excellence, Penticton	Schools	Yes	yes	yes	yes	GSHP/Solar	Yes
Osoyoos Indian Band - 120 acre ind/ com park, Osoyoos	Aboriginal	Yes	yes	yes	yes	GSHP/DES	Yes
Oxford Properties - Chuck We	Commercial Customer	yes	yes	yes	yes		yes
P218 Enterprises Ltd. - SOPA Square, Kelowna	Commercial Customer	Yes	yes	yes	yes	GSHP/Solar	Yes
Pacific Capital Real Estate Group - Orchard Beach, Kelowna	Commercial Customer	Yes	yes	yes	yes	GSHP/DES	Yes
Pan Pacific Hotels (2) - Whistler	Hotels	yes	yes	yes	yes	NGV for shuttle buses	possibly
Parklane Homes	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	DES, GeoX	Yes, currently evaluating alternative energy solutions
Patrick Matiowski, Langley Lodge	Commercial Customer	Yes. Customer is going	yes	yes	yes		
Paul Daminato, City of New Westminster	Municipality						both
PCI - Dan Turner	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	DES, Geo	yes
PDG - Ken Grassi, Larry Rank	Commercial Customer	yes	yes	yes	yes	Geo, DES, other	yes
Pennco Homes Inc. - Kaslo Bay Estates, Kaslo	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Pointe Developments - Copper Pointe Golf Resort, Invermere	Builder / Developer / Engineer / Architect	Yes	yes	Maybe	Maybe	GSHP	Maybe
Polygon - Hugh Ker	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	Geo	yes
Porte Realty	Commercial Customer	Yes	Yes	Yes	yes	Geo-exchange	Yes, wanting TG to provide alternative energy solution
Prestige Inns Hotels and Resorts - Prestige, Sooke	Hotels	Yes	yes	No	No	None	No
Pridam Developmen	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	Geo, DES, other	yes
Prince George Airport, 4141 Airport Road, Prince George	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
Provincial Health Services Authority	Health Authorities	yes	yes	yes	yes	DES, geo, solar	Yes, currently evaluating alternative energy solutions
Quadra Homes	Builder / Developer / Engineer / Architect	Yes	Yes	No	Yes	Geo-exchange proposed	Unknown
Qualex-Landmark Group	Builder / Developer / Engineer / Architect	Yes	Yes	Yes	Yes	GeoExchange/ngas backup	Customer has experience with Geo-exchange and wanted TG to make investment, own and operate
Qualico Developments	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	DES, GeoX, Solar	"Yes, makes sense you are already a utility operator"
Quantem Properties	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	DES, GeoX, Solar	Yes, currently evaluating alternative energy solutions

Rackforce - GigaCentre, Kelowna	Commercial Customer	Yes	yes	yes	yes	Collect waste heat for proposed Kelowna DES	Yes
ReEvolution - Communal Living Development, Kelowna	Commercial Customer	Yes	yes	yes	yes	GSHP/DES	Yes
Reign Developments - Castle Rock Resort, Invermere	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	GSHP	Yes
Renisary Homes	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	GeoX, Solar	Yes, currently evaluating alternative energy solutions
Resort Municipality of Whistler	Municipality	yes	yes	yes	yes	Geothermal, solar thermal	no to own & operate; yes to provide solution
Riddell Kurczaba Arch & Eng - Condo development, Windermere	Builder / Developer / Engineer / Architect	No	No	No	No	Nil	No
Rockridge Developments	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	GeoX	Yes, currently evaluating alternative energy solutions
Rocky Mountain Realty - Westside Park, Invermere	Commercial Customer	Yes	yes	Maybe	Maybe	GSHP	Maybe
Roger Schlosser - Kamloops Seniors Centre, Kamloops	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
Roman Catholic Archdiocese	Commercial Customer	yes	yes	yes	yes	GeoX,	Yes, currently evaluating alternative energy solutions
Russ Black (Wastetech)	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
Russdown Farms	Agriculture	yes	yes	yes	yes	biogas	Yes - want to incorporate biogas production into farm operations for sale a through Terasen Infrastructure.
Sahali Ridge Estates; 2046 Robson Pl; Kamloops	Commercial Customer	Yes	Yes	Yes	Yes	Yes	Yes
Sawchuk Developments - UBCO Dorm, Kelowna	Commercial Customer	Yes	yes	No	No	GSHP	No
School District # 10 - Arrow Lakes	Schools	Yes	yes	yes	yes	GSHP	Yes
School District # 19 - Revelstoke	Schools	Yes	yes	yes	yes	GSHP	Yes
School District # 23 - Central Okanagan	Schools	Yes	yes	yes	yes	GSHP	Yes
School District # 23 - Kelowna - Grant Davidson	Schools	Yes	yes	yes	yes	Central DES/GSHP	Yes
School District # 27 - Cariboo-Chilcotin [MOU] (Williams Lk)	Schools	Yes	yes	yes	yes	Central DES/GSHP	Yes
School District # 28 - Quesnel	Schools	Yes	yes	yes	yes	GSHP	Yes
School District # 34 - Abbotsford	Schools	yes	yes	yes	yes	GeoX	Yes, currently evaluating alternative energy solutions
School District # 35 - Langley	Schools	Yes	yes	yes	yes	Central DES/GSHP	Yes
School District # 36 - Surrey	Schools	yes	yes	yes	yes	DES, GEOX, Solar	Yes, help the SD's reach their emissions targets.
School District # 48 - Sea to Sky - Squamish, Whistler	Schools	yes	yes	yes	yes	geo	Yes
School District # 5 - Southeast Kootenay	Schools	Yes	Yes	Yes	Yes	GSHP	Yes
School District # 58 - Nicola-Similkameen (Merritt) [MOU]	Schools	Yes	yes	yes	yes	Central DES/GSHP	Yes
School District # 8 - Kootenay Lake	Schools	Yes	Yes	Yes	Yes	GSHP	Yes
Seabird Island Indian Band	Aboriginal	Yes	Yes	Yes	Yes	Undetermined to date	Customer has asked TG to provide alternative energy solution that fits with their existing alternative energy system
Selkirk College - Castlegar	Schools	Yes	yes	No	No	GSHP	No
SH001 Enterprises Corp. - Sedric's Adventure Resort, Kamloops	Commercial Customer	Yes	yes	yes	yes	GSHP	Yes
Shato Holdings	Commercial Customer	Yes	Yes	Yes	Yes	GeoExchange/ngas backup and ngas appliances	Yes, customers understands ownership model
Shuswap Villas Development; Sicamous	Builder / Developer / Engineer / Architect	Yes	Yes	Yes	Yes	Yes	Yes
Society of Hope	Commercial Customer	Yes	Yes	Yes	Yes	GSHP	Yes
Solterra Development Corp - Michale Bosa	Builder / Developer / Engineer / Architect	yes	yes	yes	yes	Geo and possibly solar	yes
Squamish First Nation	Aboriginal	Yes	Yes	Yes	Yes	Undetermined to date	Initial discussions about Ngas, alternative energy options to be discussed in future meetings not yet scheduled
Stephen Maarhuis (Aldon Waste)	Commercial Customer	Yes	yes	yes	yes	Yes	Yes
Strata KAS926 - 100 Lakeshore Drive, Penticton	Commercial Customer	Yes	yes	yes	yes	Solar	Yes
Summerhill Winery - Kelowna	Agriculture	Yes	yes	yes	yes	GSHP	Yes
SunSelect Produce	Agriculture	reduce energy usage	yes	yes	yes	Biomass	Customer has new Biomass boiler and looking for Terasen to own the asset as well as add CHiP component.

Support from approximately 120 Stakeholders at Biogas RFEOI Information Sessions - see attached summary results	Support from approximately 120 Stakeholders at Biogas RFEOI Information Sessions - see attached summary results						
Taylor Monro Energy Systems	Commercial Customer	yes	yes	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Teck Coal	Mining	yes	yes	yes	yes	NGV	Yes
Terrasphere Systems (food production)	Manufacturing	yes	unsure	possibly	yes	Low carbon alternatives, including biogas	Customer wants to explore the potential benefit of utilizing biogas through Terasen's distribution system to reduce carbon footprint - other potential alternatives also interesting - as per discussion with UBC grad student Tegan Adams
Thermal Environmental Comfort Association (TECA)	Trade Associations	yes	yes	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Consultant/Supplier that supports energy conservation in whatever ways possible
Tolko Industries Ltd., Kelowna	Forestry	Yes	yes	yes	yes	Collect waste heat for proposed Kelowna DES	Yes
Township of Langley	Municipality	yes	yes	maybe	possibly	DES	both
Tranquille on the Lake; BC Wildernes Tours; Kamloops	Commercial Customer	Yes	Yes	Yes	Yes	Yes	Yes
Treegroup Developments	Builder / Developer / Engineer / Architec	yes	yes	yes	yes	GeoX, Solar	Yes, currently evaluating alternative energy solutions
Troika Developments Inc - West Harbour, West Kelowna	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	Central DES/GSHP	Yes
UBC Properties Trust	Commercial Customer	Yes	Yes	We approached	Possibly	Geo-exchange	Yes, customer is aware of our ownership model
Urban Analytics - Michael Ferriera	Trade Associations						Development consultant and market research
Urban Development Institute (UDI)	Trade Associations	yes	yes	possibly	possibly	DES, GeoX, Biogas, Solar	Industry Association that supports energy conservation in whatever ways possible
Vancouver Airport Authority	Commercial Customer	yes	yes	yes	yes	biogas	Yes - crucial part of solution as infrastructure owner
Vancouver Coastal Health Authority	Health Authorities	yes	yes	yes	yes	DES, geo, solar	Yes, currently evaluating alternative energy solutions
Vesta Properties	Commercial Customer	yes	yes	possibly	possibly	GeoX	Yes
Village of Midway	Muncipality	Yes	Yes	Yes	Yes	Waste Heat Recovery	Yes
Wastech Environmental Services	Commercial Customer	yes	yes	yes	yes	biogas, LNG, NGV	Yes - requires partner for LNG Vehicle fueling, also possible anaerobic digester to pipeline quality gas
Wesgroup	Commercial Customer	yes	yes	yes	yes	GeoX, DES	Yes, currently evaluating alternative energy solutions, "makes sense you are already a utility operator"
West Beach Dev; New Futrure Corp; Kamloops	Builder / Developer / Engineer / Architect	Yes	yes	yes	yes	Yes	Yes
West Vancouver Rugby Club	Commercial Customer	yes	yes	yes	yes	Boiler Upgrades	Yes
West Vancouver School District	Schools	yes	yes	yes	yes	geo	yes
Westmana - Rene David	Commercial Customer	yes	yes	yes	yes	Geo, DES, other	yes
Weststone Properties	Commercial Customer	yes	yes	yes	yes	GeoX	Yes, currently evaluating alternative energy solutions
Zellstoff Celgar	Forestry	yes	yes	yes	yes	Biogas, Biomass	Yes

Alternative Energy

Depth Interview Summary

August 13, 2009
R1524

Presented to:
Terasen Gas

infocanada@tns-global.com
www.tns-global.com

Contents

At TNS, we know that being successful in today's dynamic global environment requires more understanding, clearer direction and greater certainty than ever before. While accurate information is the foundation of our business, we focus our expertise, services and resources to give you greater insight into your customers' behavior and needs.

Our integrated, consultative approach reveals answers beyond the obvious, so you understand what is happening today – and what will happen tomorrow. That is what sets TNS apart.

Thank you for allowing us to explore your business needs. We hope you will continue to trust TNS to provide the insight you need to sharpen your competitive edge.

Appendix

Foreword

Background

Terasen commissioned this research to learn about customer views on providing alternative and integrated energy systems.

Objectives

Specifically, this report addresses the following objectives:

- The level of respondent awareness of, and knowledge about, integrated and alternate energy solutions among key members of the target market;
- Interest in Terasen's participation in providing alternative energy technology solutions;
- Identify key drivers and barriers to alternative energy solutions;
- Explore the value target market members place on integrated and alternate energy;

Research Methodology

TNS Canadian Facts conducted fourteen in-depth interviews (IDI's) to discuss the research objectives. Survey research will likely be required later on to quantify opinions and attitudes but these interviews were designed to explore the range of issues and opinions on this topic.

Each IDI session lasted between forty-five minutes to one-hour and was conducted by an experienced, senior interviewer. Respondents were identified as individuals who influence energy purchase decisions. The format was:

Target	Quantity
Elected Municipal Representatives	4
Real Estate Developers	6
Industrial Operations	4
Total Interviews	**14**

TNS Canadian Facts, using our in-house services, recruited all respondents.

The interviews were conducted between July 28 and August 12, 2009. All interviews took place through teleconference.

Note of Caution

Please bear in mind the clearly qualitative nature of this phase of the research study. These findings are not quantitative conclusions, but rather the qualitative insights of the interviewer based on the response of a limited sample. They are not statistically valid unless quantified by more rigorous population sampling techniques.

August 2009

Key Findings

Results of the research are presented under the following main headings:

- Perspective on Respondents
- Terasen's role in providing alternative energy products and services
- Respondent awareness of alternative energy forms
- The value respondents place on alternative energies
- The level and type of "push" that respondents feel in moving to alternative energy
- The drivers and barriers associated with converting to alternative energies
- Appendix
    - Recruiting Questionnaire
    - Discussion Guide

Perspective on Respondents

As noted earlier, we conducted interviews with:

- Elected Municipal Representatives
- Real Estate Developers
- Industrial Operations

Combined, all three groups held similar opinions about alternative energies and how they are delivered. What differed was their approach to the topic. This section discusses the background they represent when talking about alternative energy products and services.

Elected Representatives

All elected representatives understood the need and inevitability of alternative energy solutions. At some point, they said, the world will turn away from traditional energy fuels towards sustainable forms. Between them and their staff, they saw the need to implement alternative solutions and had a good grasp of the economics that surrounds non-traditional heat delivery.

Of primary concern was how to implement changes in heat delivery. While no one reported any significant "push" to adopt alternative energy solutions, they did say that the topic has taken on greater importance over the few years, particularly in the form of recommendations by civic staff. In fact, some communities already had alternative energy solutions (usually geothermal) operating in their communities.

The most frequently cited problem was overcoming the up-front costs of adoption especially in a troubled economic environment. They said that it was very hard to rationalize the initial costs to taxpayers for two reasons:

1. Taxpayers have no appetite for increased government spending to help fund such projects; and,

2. Many citizens are fearful of changing to alternatives (e.g. reliability, greater environmental damage).

Another concern of elected representatives was knowing how to implement solutions. While their staff is aware of how to deal with the technologies associated with alternative heat delivery, navigating a path through taxpayers, special interest groups and business communities to a workable, cost effective solution was the area where they sought the most help.

Developers

Among all respondent groups, real estate developers were the most lacking in knowledge about alternative energies. With one exception, their understanding was superficial and geared more toward alternative energy as a sales feature for a real estate development. As a result, their concerns revolved completely around up-front costs and how easily they could be passed on to their buyers.

"Costs we can pass on… reliability [of the system] *is key."*
- Real Estate Developer

"[Alternative energy] *is the icing, not the cake."*
- Real Estate Developer

They reported that some buyers had asked about the availability of alternative energy heating solutions but that the concept had little to do with the ultimate purchase decision. At the same time, they speculated that integrating alternative energy solutions into future developments could potentially overcome municipal government resistance to proposed zoning and bylaw changes.

Industrial Operators

Most respondents in this category were professional or plant engineers. It follows, then, that they were the most knowledgeable about alternative energy solutions. While they recognized the environmental sustainability of some alternative energy forms, they were more drawn to the potential of a consistent cost of, for example, geothermal or biomass heat technologies over the commodity price of natural gas.

They also were more likely to have a "top-of-mind" answer to what payback over time they seek. For the most part, ten years was the appropriate time it would take to recover the increased initial costs.

In these ways, industrial operations approached the situation much more pragmatically by seeking firm answers to mostly technical questions.

Terasen's Role

Respondents were asked if Terasen has a role to play in planning for and promoting the use of alternative energy systems and the technologies that deliver heat. All respondents agreed that Terasen should seriously consider such choices because it has an obligation to do so. At a minimum, they said, alternative energy delivery should be part of its normal, long-term planning process.

Reasons for Support

Respondents pointed to the following factors as reasons that Terasen should move into this area:

- As a reliable deliverer of heating fuel to British Columbia, Terasen has the credibility to move into this area;

"They would build [an alternative energy] *plant we can believe in."*
- Elected Representative

"They would create credibility in waste burning heat."
- Elected Representative

- Terasen has the expertise (engineering and corporate infrastructure) to support meaningful ventures into alternative heating opportunities;
- Terasen has a long history in BC and has the cash resources necessary to ensure long-term reliability of any alternative energy projects or installations. At the same time, Terasen could form effective partnerships with municipalities and large industrial operations that would benefit both;
- The alternative energy concept is a natural extension of Terasen's current brand and operations.

"Terasen's profile is high and they need to make a commitment for sure."
- Elected Representative

Reasons Against Support

When asked for reasons why Terasen should not move into the field of alternative energies, respondents were hard-pressed to come up comments. Initially, they would typically answer that there was nothing but with continued probing, a few came up with some reasons against the initiative:

- Terasen is too large an organization to implement such measures quickly and effectively;
- Terasen could corner the market on alternative energy sources and in doing so, create a near monopoly that would increase prices;

"Terasen has not done well in mitigating the perception that they cornered the market and jacked up the prices."

- Elected Representative

- The costs for research and development would be passed on to consumers through rate increases.

Awareness of Alternative Energies

Respondents were asked to list any alternative energy sources they were aware of followed by a prompted list of other sources not mentioned.

Most likely to receive top-of-mind mention:

- Geothermal (prime)
- Wind
- Solar (mostly for electricity production)
- Biomass

Less likely to be mentioned (or recalled once mentioned) were:

- Biogas
- Solar (for water heating)
- Sewage Heat Recapture
- Waste Heat Recapture

District Energy Systems

Respondents rarely mentioned District Energy Systems (DES) in the interviews and were most likely to say they were unaware of this concept. That said, once the concept was very briefly explained, it was easily understood and grasped. More than once, respondents described the DES concept without actually knowing that it exists. For the most part, these respondents believed such a facility would be more of a dream than a current reality.

> *"I've been waiting for someone to come up with that idea."*
>
> \- Real Estate Developer

Developers were particularly interested in this concept because the costs could be recouped by whoever runs the facility after its construction, thereby lowering up-front costs to buyers.

In general, respondents regarded this as a worthwhile solution to alternative energy problems because:

- It removed them from the need to have a deep understanding of the individual energy sources; and,
- It mitigated fears of reliability because a DES would combine a few alternative energy systems into one heat output.

Default to Electricity

When asked about top-of-mind energy sources, respondents were most likely to report those that produce electricity. In this way, “solar” was most often considered as an electricity source rather than for heating hot water. Nevertheless, the notion of using such energy to deliver heat was not lost on them but rather less likely to be their first consideration.

Geography

Another important element in alternative energy awareness was the location of the respondent. In this way, those from BC’s interior were more likely to be aware of solar as an alternative whereas those from areas where logging plays a major economic role were quick to report biomass as a viable solution.

Value of Alternative Energies

This section explores the merits of alternative energies in terms of sustainability, reliability and costs.

Sustainable Energy

First, respondents said that the main value of developing alternative energies was using sustainable solutions over consumption of non-renewable resources. When discussing this aspect, respondents were most apt to use terms such as “the right thing to do” or “leaving a better place for my kids.” They were quick to point out that sustained supplies of energy would rely on a number of energy alternatives and not just one in particular.

As for specific forms, respondents expressed some caution over those sources that rely on combustion. Inevitably, these forms produce green house gases (GHG). Elected representatives were especially concerned over these forms because it would be difficult to “sell” to an electorate that considers such processes as environmentally harmful.

Industrial respondents said that having a corporate “story” that includes sustainable practices is important for two reasons:

- Shareholders demand that the businesses they invest in use sustainable practices;

“Investors are always asking about our carbon footprint.”
- Industrial Operator

- Being “green” is part of their corporate reputation. Using or investing in alternative energies is an important reinforcement of this image.

“We can take a longer payback period because [sustainability] *is part our corporate story.”*
- Industrial Operator

Overcoming Price Fluctuations

Respondents did see value in using alternative energies because it relies on using local resources (e.g. sewage, waste wood, and abundant sunshine) rather than having to bring fuels into their areas. This fact, they said, would mitigate price fluctuations of natural gas. Many respondents defined this benefit as “improved reliability” as opposed to the traditional definition of service interruptions.

Industrial respondents were especially interested in this aspect of alternative energies. They said it would contribute to budget stability and in doing so, increase the affordability of equipment that actually produces or transfers the heat.

Inevitability

Developers and elected representatives were most likely to see alternative energies as unavoidable. More than one said that he must learn about it and begin using it now before their use becomes legislated or fuel sources simply disappear altogether.

Making a Decision on Which to Use

In terms of value, all respondents agreed that they really do not have enough information to make a credible decision on which alternative energy is best for them to use. This gap, they said, is an important one to fill because they could see the benefits of any one energy source but whether or not it is best suited to their situations was information not widely held.

The "Push"

One of the key questions in this research was whether respondents felt any kind of "push" to implement alternative energy solutions. Generally, respondents reported that they had not. Elected representatives felt some push from their constituents, developers felt a bit from buyers and industrial users regarded it as a means of improving profits by increasing efficiencies.

Overall Lack of a Coordinated Plan

The net effect, then, was that respondents did not report a sustained, coordinated effort to move them into alternative energies. During the interviews, there was a distinct sense that respondents mostly felt on their own to implement such strategies and, despite the many knowledge resources available to assist in decision-making, there was no over-arching plan providing guidance in the form of targets, legislation or authentic consultation.

> *"The Provincial Government seems scattered in addressing the issue."*
>
> \- Elected Representative

The Media and Public Opinion

Elected representatives were most likely to cite the media as leaders in creating an impetus for using alternative energies. Although intermittent, media reports did serve to stir public opinion in favour of, or in opposition to, any one alternative energy source.

Unfortunately, elected representatives often reproached such reports saying that they did little good in disseminating unbiased information but rather instigated public fear and skepticism on such initiatives.

Municipal Staff

A few elected representatives also mentioned that their staff often encourages them to look for alternative energy solutions, particularly in scenario planning. They said that their staff has generally kept abreast of developments in this area and advocate for it whenever they have the opportunity to do so.

Drivers and Barriers

All respondents seemed generally resigned to the notion that, someday, everyone would be using alternative energies but that time is somewhat further down the road. Eventually, they said that through a combination of legislation and reduced up-front costs, all heat would be obtained through fuels other than natural gas.

Key Drivers

Avoided Costs

A number of respondents saw alternative energies as a means for avoiding price fluctuations particularly in the case of geothermal heating and solar power. They said that the heat would always be there, along with the pipes, so therefore the only cost is the equipment that extracts or transfers the heat. In this way, fuel no longer has to be brought in (through pipelines or other means) and commodity price fluctuations are therefore avoided.

Increasing Energy Costs

Related to avoided costs, but nonetheless distinct, is the cost of energy itself. Industrial respondents in particular said that it is increasingly difficult to accurately budget for traditional energy costs. Such instability makes it difficult to plan for business changes. At least one respondent said that past increases in natural gas prices prevented his organization from implementing changes they had planned elsewhere. He added that some energy alternatives such as geothermal or sewage heat recovery could cut through these fluctuations and bring stability to prices.

Belief that the Technology Exists

Most respondents said that the technology exists to take full advantage of alternative energy systems. Increasing pressure to avoid high energy costs and increased interest from major governments has produced a higher degree of effectiveness and reliability in delivering heat from alternative sources.

> *"I think the technology is 'there' but we aren't ready for the commitment to act."*
> - Elected Representative

Positive Reputation and Image

All respondents had examples of how using alternative energies could be used to promote a positive image. For example:

- One municipality who is already involved in alternative energy felt it was a "proof-point" for constituents on how their community is becoming more sustainable;
- A developer used geothermal heating as a means of promoting home sales in one of his developments;
- An industrial operation said that shareholders were asking when they would make better use of alternative energy to produce their goods.

Barriers

Upfront Costs

Of all the barriers that present themselves when considering alternative energies, upfront costs was the most common barrier to implementation. Developers seemed least concerned about this aspect because they pass the costs for alternative energy directly onto the purchaser.

"Buyers are asking for it but unwilling to pay for it. The cost [associated with installing alternative energy] *is prohibitive for mid to lower range units."*
- Real Estate Developer

Meanwhile, elected representatives and industrial operations considered it as the primary reason for not pursuing the issue further – particularly in this poor economic climate.

Here are some examples of how upfront costs affected implementation of alternative energy solutions:

- One elected representative said he could not justify the cost outlay to implement a recovery system for sewer gas recapture without causing a "taxpayer revolt" over the infrastructure costs.
- Civic representatives asked a developer to include alternative energies in a development but not increase the cost of the homes developed on the site.
- A greenhouse operation liked the idea of using geothermal for winter heating but said they only needed it for a few months out of the year so the payback they sought was not available.

Lack of Incentives

Except for being environmentally responsible, respondents had difficulty finding any meaningful incentives for implementing energy efficiency alternatives. They said that current natural gas prices are reasonable enough to make active consideration of alternatives truly worthwhile but still recognized the long-term opportunity of energy cost savings. To this end, they looked for tax credits or rebate programs that would decrease the payback period for installing alternative energy systems.

Lack of Knowledge

Respondents freely admitted that they did not know enough about alternative energies to make informed decisions. Among other things, they said that they lacked understanding of the following areas:

- The full range of alternative energy solutions;
- Which systems are most appropriate for the application at hand;
- Ongoing reliability of such systems;
- Fear of tainting a process (e.g. using sewer gas to fire baking ovens);

"The whole situation needs balance and perspective. Knowledge that we are moving in a safe direction."

- Elected Representative

"How do we get to place of public confidence?"

- Elected Representative

- Low understanding of how alternative energies could deliver direct heat rather than producing electricity.

Appendix

- Recruitment Screener
- Discussion Guide

1140 W. Pender Street
Suite 610
Vancouver, British Columbia V6E 4A1

Tel: (604) 668-3344
Fax: (604) 668-3333
infocanada@tns-global.com

www.tns-global.com

TERASEN GAS ALTERNATIVE ENERGY INTERVIEWS
R1524

NAME :____

ORGANIZATION: ____

HOME PHONE :____

BUSINESS PHONE :____

CELL PHONE:____

E-MAIL:____

RECRUITER:_________________________________

RECRUIT ACCORDING TO THE FOLLOWING SPECIFICATIONS:

Target Quotas	Quantity
Elected Representative	4
Developers	6
Industrial	4
Total Interviews	**14**

LOCATE APPROPRIATE INDIVIDUAL AND INTRODUCE:

Hello, may I speak to _________ [NAME FROM LIST]? My name is _________ and I am calling from TNS Canadian Facts, a professional market research firm in Vancouver, on behalf of Terasen Gas. Currently Terasen Gas is looking for qualified people to participate in confidential interviews about your opinions on alternative energy.

The interview will last about 30 to 45 minutes and can take place either over the telephone or in person. The discussion is confidential and as such, your identity will remain anonymous in any reporting to Terasen Gas.

As a thank you for your time, we will donate $100 on your behalf to a charity of your choice (you will receive the tax receipt).

Let me assure you that this project is being conducted for research purposes only, and that no one will try to sell you anything.

PERSUADERS [IF NECESSARY]:

- We are undertaking this study rather than Terasen Gas to maintain strict confidentiality for your responses. We will report the responses back to Terasen without identifying who said them.
- You are welcome to call my supervisor, Gerry Keane at 604.668.3321. Or you may call Walter Wright at Terasen Gas to verify this call at 604.592.7653.
- The interview is part of on-going research to improve services for customers.
- We are not selling anything at all. Terasen will use your responses to improve its services. Your number was selected randomly from a list provided by Terasen Gas.

Q: How did you get my information?

A: Your name and phone number were randomly chosen from a list of people provided by Terasen Gas as we are conducting this work on their behalf. Participation in this study is completely voluntary.

Q1. Region (**FROM LIST – AIM FOR A GOOD MIX**)

____

Q2. Target Group (**OBSERVE TARGET QUOTAS**)

____

Q2. May we ask you a couple of questions to see if you might participate?

Yes .... 1 **CONTINUE**
No .... 2 **TERMINATE**

GENDER: (**OBSERVE**): Male
Female

Q3a. **IF RESPONDENT IS AN ELECTED REPRSENTATIVE, GO TO INVITATION.**

Q3b. **IF RESPONDENT IS A <u>BUILDER/DEVELOPER/ARCHITECT</u>, ASK:**

If a decision had to be made regarding the choice of heating systems or technologies going into a new building, would you have influence, even in part, on that decision?

Yes	**CONTINUE (SKIP TO INVITATION)**
No	**GO TO Q4**
Not Sure	**GO TO Q4**
Don't Know	**GO TO Q4**

Q3c. **IF RESPONDENT IS A <u>TERASEN COMMERCIAL CUSTOMER</u>, ASK:**

If a decision had to be made regarding the choice of heating fuels or technologies in an existing building, would you have influence, even in part, on that decision?

Yes	**CONTINUE (SKIP TO INVITATION)**
No	**GO TO Q4**
Not Sure	**GO TO Q4**
Don't Know	**GO TO Q4**

Q4. Can you think of the person who would have influence on that decision that you could put us in touch with?

Yes **OBTAIN NAME, CONTACT THAT PERSON AND RESTART INTERVIEW**

____

No/Not willing to provide	**THANK AND TERMINATE**
Don't Know	**THANK AND TERMINATE**

Invitation to Interview Session

IDENTIFY CONVENIENT DATE AND TIME FOR INTERVIEW. NON-STANDARD BUSINESS HOURS ARE OKAY (i.e. earlier than 9AM and later than 5PM but not after 7:00PM)

Date: _______________ Time: __________________________

Method:

☐ Telephone

☐ In-Person **(LOWER MAINLAND ONLY) RECORD ADDRESS:**

____

Thank you. We will call you the day before to reconfirm the appointment.

In appreciation for your participation, you will receive a $100 honorarium or we can donate it directly to your favourite charity. To whom should we make the cheque payable and where should it be sent?

RECORD NAME AND ADDRESS OF RECIPIENT. IF RESPONDENT DOES NOT KNOW THE ADDRESS OF THE CHARITY, TELL HIM OR HER THAT WE WILL LOOK IT UP FOR THEM.

Cheque payable to: ____

Address: ____

Your interview will take place on:

RESTATE DATE AND TIME FROM ABOVE

If you cannot attend for any reason, please call (1) 604.668.3325 and leave a message.

Terasen Gas
R1524: Alternative Energy Interviews
Discussion Guide – FINAL
July 27, 2009

1) **Introduction**
   a) Assurance of confidentiality, confirmation of incentive distribution.
   b) Interview procedures, etc.
   c) Questions for interviewer
2) **Awareness**
   a) What kinds of alternative energy sources are you aware of (all forms)?
   b) What kinds of alternative sources are you aware of that deliver direct heat (*IF NECESSARY, CLARIFY BETWEEN HEAT ALTERNATIVES VS. ELECTRICAL*)?
      i) Probe for:
         (1) District Energy Systems –
            (a) Biomass
            (b) Sewage heat recapture
            (c) Waste heat recapture
         (2) Geothermal
         (3) Solar
         (4) Biogas –sewage and agricultural gas capture (secondary)
         (5) NGV (secondary)
3) **Value**
   a) Of all the individual alternative energy sources, which ones:
      i) Sound most interesting? Least interesting? Why?
      ii) Most practical (cost and otherwise)
   b) Where, or in what situations would you put in alternative energies? Which ones? Why?
   c) How much "push" are you feeling to implement alternative energy sources of all kinds? Of heat alternatives only? Is there a difference? How?
   d) Where is the "push" coming from? *PROBE FOR*:
      i) Legislation or policy(including GHG targets)
      ii) General public
      iii) Clients (professionals and developers only)
      iv) Energy cost reduction initiatives
   e) What would motivate you to implement an alternative energy solution? *IF NECESSARY, PROMPT ON*:
      i) Avoiding spot price fluctuations
      ii) GHG reduction and targets
      iii) Presence of existing incentive programs (if so which ones?)
      iv) Positive public recognition
   f) What are the barriers to implementing alternative energy solutions and integrated heat solutions? *PROBES*:
      i) Initial costs
      ii) Higher ongoing fuel/energy costs

iii) Perceived reliability of alternative energy sources

4) **Demand**
   a) What level of demand exists for integrated solutions?
   b) How will demand change/not change in the future? For what reasons?
   c) What needs to happen or change for alternative heat sources/integrated systems to improve demand? *PROBES*:
      i) Costs
      ii) Legislation
      iii) Technology
      iv) Public perceptions
      v) Customer locations (geothermal and solar only)

5) **Terasen's Role**
   a) Which other options come to mind when talking about alternative energy solutions? Does Terasen have role in this? How?
   b) What are the "upsides" of Terasen providing these services? The downsides? Be as specific as possible.

6) **Information Needs**
   a) What do you need to know about this idea? What should Terasen be telling you about it?
   b) What are the key topics that they need to address? Why?
   c) What are the best ways to reach you with information?

7) **Summary**
   a) Thinking about our entire discussion today, what are the two main points that you think Terasen needs to know? Why those ones?
   b) Thank you.

[Table 1](#)

Gender

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K+ (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Gender	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	Male	COL %	49%	49%	48%	49%	51%	100%	0%	50%	49%	48%	46%	54%	57%	52%	47%	45%
		SIG																
		COUNT	391	201	71	89	30	391	0	109	156	127	122	157	75	160	154	77
	Female	COL %	51%	51%	52%	51%	49%	0%	100%	50%	51%	52%	54%	46%	43%	48%	53%	55%
		SIG																
		COUNT	411	211	76	94	30	0	411	109	164	137	145	136	56	146	171	94

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 2

Age

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
AGE	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	18-34	COL %	27%	30%	22%	23%	29%	28%	27%	100%	0%	0%	29%	23%	20%	20%	29%	35%
		SIG															A	A
		COUNT	218	125	33	43	17	109	109	218	0	0	77	69	26	62	96	60
	35-54	COL %	40%	41%	38%	38%	43%	40%	40%	0%	100%	0%	32%	45%	55%	33%	48%	36%
		SIG												A	A		A C	
		COUNT	320	168	56	70	26	156	164	0	320	0	86	131	72	102	156	62
	55+	COL %	33%	29%	40%	39%	28%	32%	33%	0%	0%	100%	39%	32%	25%	46%	23%	29%
		SIG											C			B C		
		COUNT	264	118	58	71	17	127	137	0	0	264	105	94	33	142	74	49
	MEAN		47.0	45.2	49.6	49.2	46.1	46.7	47.3	27.4	45.7	64.6	48.1	47.6	46.3	50.3	45.1	44.5
	SIG				A	A					A	A B				B C		
	STDDEV		15.5	15.5	14.9	16.3	13.7	16.0	15.1	4.5	5.7	6.8	16.8	14.2	12.5	16.5	14.4	14.9
	MEDIAN		47.0	45.0	51.0	50.0	49.0	45.0	49.0	28.0	46.0	64.0	49.0	48.0	48.0	53.0	46.0	42.0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Results are based on two-sided tests assuming equal variances with significance level 0.05. For each significant pair, the key of the smaller category appears under the category with larger mean.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts in some subtables are not integers. They were rounded to the nearest integers before performing pairwise comparisons.

Table 3

Age_Gender

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
AGE/Gender	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	Male 18-34	COL %	14%	15%	12%	12%	15%	28%	0%	50%	0%	0%	14%	12%	11%	11%	15%	15%
		SIG																
		COUNT	109	62	17	21	9	109	0	109	0	0	38	36	14	33	50	26
	Male 35-54	COL %	19%	20%	18%	18%	22%	40%	0%	0%	49%	0%	15%	23%	31%	18%	21%	18%
		SIG												A	A			
		COUNT	156	83	27	33	13	156	0	0	156	0	39	68	41	56	70	30
	Male 55+	COL %	16%	14%	19%	19%	14%	32%	0%	0%	0%	48%	17%	18%	16%	23%	11%	13%
		SIG														B C		
		COUNT	127	56	28	34	9	127	0	0	0	127	44	54	21	71	34	22
	Female 18-34	COL %	14%	15%	11%	12%	14%	0%	27%	50%	0%	0%	14%	11%	9%	9%	14%	20%
		SIG																A
		COUNT	109	63	16	21	9	0	109	109	0	0	39	33	12	29	46	34
	Female 35-54	COL %	20%	21%	20%	20%	22%	0%	40%	0%	51%	0%	17%	21%	24%	15%	26%	19%
		SIG															A	
		COUNT	164	86	30	36	13	0	164	0	164	0	46	63	31	46	86	32
	Female 55+	COL %	17%	15%	21%	20%	14%	0%	33%	0%	0%	52%	23%	14%	9%	23%	12%	16%
		SIG										B C			B		
		COUNT	137	62	31	37	8	0	137	0	0	137	60	40	12	71	39	27

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 4

Region

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Region	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	GVRD	COL %	51%	100%	0%	0%	0%	51%	51%	57%	53%	45%	43%	49%	65%	47%	50%	62%
		SIG								C					A B			A B
		COUNT	411	411	0	0	0	201	211	125	168	118	114	142	85	145	161	105
	Vancouver Island	COL %	18%	0%	100%	0%	0%	18%	18%	15%	18%	22%	18%	22%	16%	19%	19%	17%
		SIG																
		COUNT	147	0	147	0	0	71	76	33	56	58	48	64	20	57	62	29
	BC Southern Interior	COL %	23%	0%	0%	100%	0%	23%	23%	20%	22%	27%	31%	22%	13%	24%	25%	17%
		SIG											C					
		COUNT	183	0	0	183	0	89	94	43	70	71	82	64	17	75	80	28
	BC North/Interior	COL %	8%	0%	0%	0%	100%	8%	7%	8%	8%	6%	9%	8%	6%	10%	7%	5%
		SIG																
		COUNT	60	0	0	0	60	30	30	17	26	17	23	23	8	29	22	9

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 5

Education

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Education	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	HS or less	COL %	38%	35%	39%	41%	48%	41%	36%	29%	32%	54%	46%	35%	23%	100%	0%	0%
		SIG										A B	B C	C				
		COUNT	306	145	57	75	29	160	146	62	102	142	124	103	31	306	0	0
	College/ Tech school	COL %	41%	39%	42%	44%	37%	39%	42%	44%	49%	28%	38%	43%	43%	0%	100%	0%
		SIG								C	C							
		COUNT	325	161	62	80	22	154	171	96	156	74	100	127	57	0	325	0
	Univ+	COL %	21%	26%	19%	15%	15%	20%	23%	27%	19%	19%	16%	22%	33%	0%	0%	100%
		SIG		C											A B			
		COUNT	171	105	29	28	9	77	94	60	62	49	43	63	44	0	0	171

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 6

Income

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Income	All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
		UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
	<$50K	COL %	33%	28%	33%	45%	38%	31%	35%	35%	27%	40%	100%	0%	0%	40%	31%	25%
		SIG				A						B				B C		
		COUNT	267	114	48	82	23	122	145	77	86	105	267	0	0	124	100	43
	$50-99K	COL %	37%	35%	44%	35%	38%	40%	33%	31%	41%	36%	0%	100%	0%	34%	39%	37%
		SIG						B										
		COUNT	293	142	64	64	23	157	136	69	131	94	0	293	0	103	127	63
	$100K+	COL %	16%	21%	14%	10%	14%	19%	14%	12%	23%	13%	0%	0%	100%	10%	18%	26%
		SIG		C				B			A C						A	A
		COUNT	132	85	20	17	8	75	56	26	72	33	0	0	132	31	57	44
	DK/REF	COL %	14%	17%	10%	11%	10%	9%	18%	21%	10%	12%	0%	0%	0%	16%	12%	12%
		SIG							A	B C								
		COUNT	110	70	14	20	6	37	73	47	31	32	0	0	0	49	41	21

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 25

1. How familiar are you with the terms Alternative Energy or Green Energy?

		TOTAL	Region				Gender		Age			Income			Education		
		(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
	UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
Very familiar	COL %	26%	23%	31%	28%	28%	35%	17%	31%	27%	20%	23%	28%	40%	19%	28%	34%
	SIG						B		C					A B		A	A
	COUNT	208	94	45	52	17	139	69	68	87	53	61	82	53	57	93	58
Familiar	COL %	43%	43%	45%	43%	41%	44%	42%	41%	38%	50%	44%	44%	36%	42%	45%	41%
	SIG										B						
	COUNT	344	175	66	78	25	174	171	90	122	132	117	130	47	128	146	70
Heard of them	COL %	26%	29%	24%	19%	29%	17%	34%	21%	28%	27%	27%	22%	23%	30%	24%	22%
	SIG							A									
	COUNT	207	120	35	35	17	67	140	45	91	71	72	65	30	93	77	37
Never heard of them	COL %	5%	5%	1%	10%	2%	3%	8%	7%	6%	3%	6%	6%	1%	9%	3%	4%
	SIG				B			A							B		
	COUNT	43	22	1	18	1	12	31	15	20	8	17	17	2	27	9	6

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 26

2. How aware are you of the following energy sources? - Solar

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Solar	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Very aware	COL %	60%	60%	57%	64%	63%	61%	59%	63%	59%	59%	58%	66%	64%	56%	62%	64%
		SIG																
		COUNT	458	232	84	106	37	233	226	129	177	152	146	182	83	156	196	106
	Aware	COL %	40%	40%	43%	36%	37%	39%	40%	36%	41%	41%	42%	34%	36%	44%	38%	36%
		SIG																
		COUNT	300	157	62	59	22	147	154	74	123	104	104	94	47	122	120	59
	Not at all aware	COL %	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
		SIG																
		COUNT	1	1	0	0	0	0	1	1	0	0	0	0	0	0	0	1
	Total Aware	COL %	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
		SIG																
		COUNT	759	389	146	165	59	380	379	202	300	256	250	276	130	279	316	164

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 27

2. How aware are you of the following energy sources?- Biomass

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Biomass	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Very aware	COL %	13%	11%	14%	17%	10%	20%	6%	16%	12%	11%	10%	15%	18%	4%	16%	22%
		SIG						B									A	A
		COUNT	98	43	21	28	6	75	22	32	36	29	25	40	23	10	51	37
	Aware	COL %	40%	37%	41%	42%	46%	49%	31%	40%	40%	40%	42%	42%	44%	45%	36%	37%
		SIG						B										
		COUNT	303	146	60	70	27	187	116	81	119	103	104	116	58	126	115	61
	Not at all aware	COL %	47%	51%	44%	41%	44%	31%	64%	44%	48%	48%	48%	43%	38%	51%	48%	40%
		SIG							A									
		COUNT	359	200	65	68	26	117	241	89	145	124	120	120	49	142	150	67
	Total Aware	COL %	53%	49%	56%	59%	56%	69%	36%	56%	52%	52%	52%	57%	62%	49%	52%	60%
		SIG						B										
		COUNT	400	189	81	97	33	262	138	114	155	132	130	156	81	136	166	98

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 28

2. How aware are you of the following energy sources?- District Heating Systems

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
District Heating Systems	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Very aware	COL %	7%	6%	6%	8%	9%	10%	4%	3%	8%	8%	6%	7%	11%	2%	10%	8%
		SIG						B			A	A					A	A
		COUNT	51	25	8	13	5	36	15	6	25	21	14	20	14	6	32	14
	Aware	COL %	33%	36%	31%	32%	18%	40%	25%	29%	33%	35%	26%	37%	35%	40%	28%	28%
		SIG		D				B						A		B C		
		COUNT	248	139	45	52	11	151	97	59	98	90	66	102	46	113	89	46
	Not at all aware	COL %	61%	58%	64%	61%	73%	51%	71%	68%	59%	57%	68%	56%	54%	57%	62%	64%
		SIG							A	C			B C					
		COUNT	461	225	93	100	43	193	268	138	177	145	170	153	70	160	195	105
	Total Aware	COL %	39%	42%	36%	39%	27%	49%	29%	32%	41%	43%	32%	44%	46%	43%	38%	36%
		SIG						B				A		A	A			
		COUNT	299	165	53	65	16	187	112	65	123	111	80	123	60	118	121	59

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 29

2. How aware are you of the following energy sources?- Ground Source Heat Pumps

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K+ (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Ground Source Heat Pumps	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Very aware	COL %	31%	25%	27%	46%	39%	39%	23%	27%	27%	39%	24%	35%	43%	27%	36%	27%
		SIG				A B		B				A B		A	A		A	
		COUNT	235	96	39	77	23	147	88	55	81	99	61	96	55	75	115	45
	Aware	COL %	46%	49%	55%	38%	25%	47%	45%	42%	49%	45%	45%	49%	44%	50%	39%	53%
		SIG		D	C D											B		B
		COUNT	348	191	80	63	15	178	171	85	148	115	112	136	57	138	122	88
	Not at all aware	COL %	23%	26%	18%	15%	36%	14%	32%	31%	24%	16%	31%	16%	14%	24%	25%	19%
		SIG		C			B C		A	C			B C					
		COUNT	176	103	27	25	21	55	121	64	71	42	77	44	18	66	79	32
	Total Aware	COL %	77%	74%	82%	85%	64%	86%	68%	69%	76%	84%	69%	84%	86%	76%	75%	81%
		SIG			D	A D		B				A		A	A			
		COUNT	583	286	119	140	37	325	258	139	229	215	173	232	112	213	237	133

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 30

3. How would you assess your knowledge of the following energy sources and technology?- Solar

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Solar	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Extremely knowledgeable	COL %	10%	10%	9%	11%	11%	14%	7%	11%	11%	9%	8%	12%	12%	6%	14%	9%
		SIG						B									A	
		COUNT	77	40	12	19	6	52	25	23	32	22	19	34	16	17	46	15
	Very knowledgeable	COL %	29%	28%	29%	29%	31%	36%	21%	30%	25%	31%	28%	32%	29%	30%	28%	28%
		SIG						B										
		COUNT	218	110	42	49	18	136	81	62	76	80	70	88	37	84	88	46
	Somewhat knowledgeable	COL %	55%	55%	57%	56%	49%	47%	64%	55%	54%	57%	56%	51%	54%	60%	50%	57%
		SIG							A									
		COUNT	420	215	83	93	29	177	242	111	161	147	141	142	70	166	159	94
	Somewhat unknowledgeable	COL %	5%	5%	6%	3%	7%	2%	8%	3%	8%	2%	5%	4%	4%	2%	7%	5%
		SIG							A		A C						A	
		COUNT	36	19	8	5	4	7	29	6	25	5	13	11	5	6	21	9
	Not at all knowledgeable	COL %	1%	2%	1%	0%	3%	2%	0%	1%	2%	1%	3%	0%	1%	2%	1%	1%
		SIG																
		COUNT	9	7	1	0	2	7	2	1	6	2	7	1	1	6	2	1
	Top2box	COL %	39%	38%	37%	41%	41%	50%	28%	42%	36%	40%	36%	44%	41%	36%	42%	37%
		SIG						B										
		COUNT	295	149	54	67	24	188	107	84	108	102	89	122	53	101	134	60
	Low2box	COL %	6%	6%	6%	3%	10%	4%	8%	4%	10%	3%	8%	4%	5%	4%	7%	6%
		SIG							A		A C							
		COUNT	45	25	9	5	6	14	31	7	31	7	20	12	6	12	23	10

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 31

3. How would you assess your knowledge of the following energy sources and technology?- Biomass

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Biomass	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Extremely knowledgeable	COL %	2%	2%	4%	2%	4%	3%	1%	3%	3%	2%	1%	4%	4%	1%	3%	4%
		SIG													A			
		COUNT	18	7	5	3	2	12	5	6	8	4	1	10	5	2	10	6
	Very knowledgeable	COL %	5%	6%	5%	5%	3%	9%	2%	5%	6%	5%	5%	6%	8%	1%	7%	10%
		SIG						B									A	A
		COUNT	41	25	7	7	2	33	9	10	19	12	13	16	11	3	23	16
	Somewhat knowledgeable	COL %	28%	27%	22%	32%	37%	37%	18%	27%	27%	30%	22%	32%	34%	25%	26%	35%
		SIG						B						A	A			
		COUNT	210	103	32	52	22	140	69	54	80	76	56	88	44	70	81	58
	Somewhat unknowledgeable	COL %	20%	18%	26%	22%	17%	23%	18%	22%	20%	20%	25%	18%	24%	26%	19%	14%
		SIG						B								C		
		COUNT	155	71	37	37	10	89	67	44	61	50	63	49	31	72	61	22
	Not at all knowledgeable	COL %	44%	47%	44%	40%	39%	28%	61%	44%	44%	44%	47%	41%	30%	47%	45%	38%
		SIG							A				C					
		COUNT	335	184	64	65	23	105	230	90	132	114	117	114	38	132	141	62
	Top2box	COL %	8%	8%	9%	6%	7%	12%	4%	8%	9%	7%	6%	9%	12%	2%	10%	13%
		SIG						B									A	A
		COUNT	59	32	13	11	4	45	14	16	27	17	14	25	16	5	33	22
	Low2box	COL %	65%	65%	69%	62%	56%	51%	78%	66%	64%	64%	72%	59%	54%	73%	64%	52%
		SIG							A				B C			B C	C	
		COUNT	491	254	101	102	33	194	296	133	193	164	180	162	70	204	202	85

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 32

3. How would you assess your knowledge of the following energy sources and technology?- District Heating Systems

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
District Heating Systems	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Extremely knowledgeable	COL %	1%	1%	1%	2%	3%	2%	0%	1%	1%	1%	1%	1%	3%	0%	2%	1%
		SIG																
		COUNT	8	2	1	4	2	6	2	1	4	3	1	2	4	0	6	1
	Very knowledgeable	COL %	5%	5%	3%	5%	4%	7%	2%	2%	7%	4%	2%	5%	12%	3%	5%	5%
		SIG						B			A				A			
		COUNT	35	19	4	8	2	28	7	3	21	11	5	14	15	10	17	8
	Somewhat knowledgeable	COL %	23%	25%	24%	19%	18%	28%	18%	20%	23%	26%	18%	26%	24%	26%	21%	22%
		SIG						B										
		COUNT	174	96	35	32	11	107	67	41	68	65	45	73	31	71	67	36
	Somewhat unknowledgeable	COL %	20%	21%	17%	19%	19%	19%	20%	18%	18%	23%	21%	21%	20%	25%	16%	18%
		SIG														B		
		COUNT	149	82	25	31	11	74	75	36	55	58	51	57	26	70	49	30
	Not at all knowledgeable	COL %	52%	49%	56%	55%	56%	43%	60%	60%	51%	47%	59%	47%	42%	46%	56%	55%
		SIG							A	C			B C					
		COUNT	394	190	81	90	33	164	229	121	153	120	148	129	54	128	176	90
	Top2box	COL %	6%	6%	3%	7%	7%	9%	2%	2%	8%	5%	2%	6%	14%	3%	8%	6%
		SIG						B			A				A B			
		COUNT	42	21	5	12	4	34	8	5	24	13	6	16	19	10	24	9
	Low2box	COL %	71%	70%	73%	73%	75%	63%	80%	78%	69%	69%	80%	68%	62%	71%	71%	73%
		SIG							A				B C					
		COUNT	543	272	106	121	44	238	305	158	208	178	199	187	80	198	225	120

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 33

3. How would you assess your knowledge of the following energy sources and technology?- Ground Source Heat Pumps

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Ground Source Heat Pumps	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Extremely knowledgeable	COL %	5%	3%	3%	10%	10%	8%	2%	1%	6%	7%	5%	6%	8%	3%	7%	5%
		SIG				A		B			A	A						
		COUNT	39	12	5	16	6	32	7	2	19	18	12	16	11	10	22	8
	Very knowledgeable	COL %	14%	11%	18%	16%	19%	18%	10%	9%	16%	16%	12%	16%	18%	11%	17%	14%
		SIG						B										
		COUNT	107	42	26	27	11	68	39	18	48	41	30	44	23	31	53	23
	Somewhat knowledgeable	COL %	41%	40%	40%	48%	29%	48%	34%	43%	35%	46%	34%	44%	47%	45%	36%	42%
		SIG						B				B			A			
		COUNT	310	154	59	80	17	181	129	87	105	118	86	122	61	126	115	69
	Somewhat unknowledgeable	COL %	15%	18%	17%	8%	9%	13%	17%	15%	17%	13%	14%	18%	12%	15%	14%	18%
		SIG		C														
		COUNT	115	71	25	14	6	50	65	31	51	32	36	50	16	42	44	29
	Not at all knowledgeable	COL %	25%	28%	21%	17%	32%	13%	37%	32%	26%	18%	35%	16%	15%	25%	26%	22%
		SIG		C					A	C			B C					
		COUNT	188	110	31	28	19	49	140	64	78	46	87	44	19	70	83	36
	Top2box	COL %	19%	14%	21%	26%	29%	26%	12%	10%	22%	23%	17%	22%	26%	15%	24%	19%
		SIG				A	A	B			A	A					A	
		COUNT	146	55	31	43	17	100	46	20	66	59	42	60	34	41	75	31
	Low2box	COL %	40%	46%	38%	25%	41%	26%	54%	47%	43%	31%	49%	34%	27%	40%	40%	39%
		SIG		C					A	C	C		B C					
		COUNT	303	181	56	42	24	99	204	96	129	78	123	94	35	112	127	65

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 34

4. If you were buying or building a new home or renovating an existing home, how willing would you be to incorporate an alternative energy source?

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Willing to incorporate an alternative energy source	Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
		UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
	Extremely willing	COL %	32%	29%	36%	34%	33%	31%	32%	34%	31%	30%	40%	30%	30%	22%	38%	35%
		SIG											B				A	A
		COUNT	240	111	53	57	19	119	121	70	94	77	101	84	38	62	119	58
	Very willing	COL %	37%	40%	30%	39%	29%	38%	37%	29%	37%	44%	32%	41%	34%	42%	34%	37%
		SIG										A						
		COUNT	283	157	44	65	17	144	139	58	112	112	81	113	44	116	106	60
	Somewhat Willing	COL %	27%	26%	29%	24%	37%	27%	27%	33%	26%	23%	25%	26%	27%	30%	26%	24%
		SIG								C								
		COUNT	205	102	42	39	22	101	104	68	78	59	63	71	35	83	83	39
	Somewhat unwilling	COL %	3%	4%	1%	2%	2%	2%	3%	1%	4%	2%	2%	2%	6%	4%	2%	2%
		SIG																
		COUNT	20	14	2	4	1	7	13	2	13	6	4	5	8	11	6	3
	Not at all willing	COL %	2%	1%	4%	1%	0%	2%	1%	3%	1%	1%	0%	1%	3%	2%	1%	3%
		SIG																
		COUNT	12	6	5	1	0	9	3	6	4	2	1	3	4	6	2	4
	Top2box	COL %	69%	69%	66%	74%	62%	69%	68%	63%	69%	74%	73%	71%	64%	64%	71%	72%
		SIG										A						
		COUNT	523	268	97	121	36	263	260	128	206	189	182	197	83	179	225	119
	Low2box	COL %	4%	5%	5%	3%	2%	4%	4%	4%	5%	3%	2%	3%	9%	6%	3%	4%
		SIG													A B			
		COUNT	32	20	7	4	1	16	16	8	16	8	6	8	12	17	8	7

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 35

5. Would you be prepared to pay extra for a home that uses an alternative energy source?

			TOTAL	Region				Gender		Age			Income			Education		
			(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Prepared to Pay extra	Willing to incorporate	BASE	728	370	139	161	58	364	364	195	284	248	244	268	118	262	308	158
		UNWT	745	386	155	162	42	359	386	193	282	270	224	286	144	113	375	257
	Yes, I would pay up to 10% extra for such a house or improve	COL %	19%	18%	16%	21%	18%	20%	17%	19%	19%	18%	23%	14%	22%	11%	21%	26%
		SIG											B				A	A
		COUNT	135	68	23	34	11	74	61	37	54	44	57	38	26	29	65	41
	Yes, I would pay up to 5% extra	COL %	41%	43%	40%	38%	33%	41%	40%	43%	41%	38%	32%	48%	43%	37%	41%	45%
		SIG												A				
		COUNT	295	159	56	61	19	151	145	85	116	95	79	130	50	97	128	71
	Yes, I would pay up to 2% extra	COL %	20%	22%	26%	14%	3%	17%	23%	16%	17%	25%	21%	19%	15%	28%	15%	14%
		SIG		D	D				A			A				B C		
		COUNT	142	81	36	23	2	60	82	31	49	62	53	51	18	74	46	22
	Yes, I would pay up to 1% extra	COL %	8%	6%	6%	12%	18%	9%	8%	7%	9%	8%	8%	8%	10%	10%	9%	5%
		SIG					A											
		COUNT	60	22	8	19	10	31	29	15	26	19	19	21	11	25	27	7
	No, I would not be prepared to pay more	COL %	13%	11%	12%	14%	29%	13%	13%	15%	13%	11%	15%	11%	10%	14%	14%	10%
		SIG					A B											
		COUNT	95	39	17	23	16	47	48	29	38	28	37	29	12	37	42	17
	Total Yes	COL %	87%	89%	88%	86%	71%	87%	87%	85%	87%	89%	85%	89%	90%	86%	86%	90%
		SIG		D	D													
		COUNT	632	331	123	137	41	316	316	166	246	220	208	239	105	225	266	141

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 36

6. Thinking of how alternative energy would be delivered to your home, do you think that Terasen Gas should provide these alternative energy sources for customers?

		TOTAL	Region				Gender		Age			Income			Education		
		(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
Heard of Alternative Energy/ Green Energy	BASE	759	390	146	165	59	380	380	203	300	256	250	276	130	279	316	165
	UNWT	773	401	162	167	43	376	397	200	293	280	230	292	155	119	386	268
Yes	COL %	33%	36%	29%	36%	24%	32%	35%	46%	34%	24%	29%	35%	36%	28%	38%	34%
	SIG								B C	C						A	
	COUNT	254	139	42	59	14	122	132	93	101	60	73	97	47	78	120	56
No	COL %	19%	18%	16%	27%	15%	25%	14%	13%	17%	26%	27%	19%	13%	23%	18%	16%
	SIG						B				A B	C					
	COUNT	147	70	24	44	9	93	53	27	52	68	67	52	17	64	57	26
Maybe	COL %	35%	35%	42%	26%	38%	33%	37%	30%	37%	35%	31%	34%	43%	38%	30%	39%
	SIG			C													
	COUNT	264	138	62	42	22	125	139	61	112	90	77	93	56	105	95	64
Don't know	COL %	12%	11%	13%	12%	23%	10%	15%	11%	12%	15%	13%	12%	8%	12%	14%	12%
	SIG					A											
	COUNT	95	43	19	20	14	39	55	22	36	38	34	34	10	32	43	19

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 37

7. Have you undertaken any Energy Efficiency improvements or do you plan to undertake any improvements in the next two years?

		TOTAL	Region				Gender		Age			Income			Education		
		(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
	UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
Have undertaken	COL %	34%	30%	37%	39%	32%	35%	32%	26%	34%	40%	32%	36%	36%	23%	40%	40%
	SIG										A					A	A
	COUNT	269	125	54	71	19	137	132	57	107	106	85	107	48	70	131	68
Plan to undertake	COL %	24%	25%	22%	25%	20%	24%	24%	26%	27%	19%	16%	31%	26%	24%	25%	22%
	SIG												A				
	COUNT	191	102	32	45	12	95	97	56	86	50	43	90	34	72	82	38
Have not and do not plan to undertake	COL %	29%	30%	30%	22%	40%	31%	27%	32%	26%	29%	34%	24%	31%	36%	23%	26%
	SIG					C						B			B		
	COUNT	231	122	45	40	24	121	110	69	84	78	90	71	41	111	75	45
Don't know	COL %	14%	15%	11%	15%	8%	10%	17%	17%	13%	12%	19%	8%	7%	17%	11%	12%
	SIG							A				B C					
	COUNT	111	62	16	27	5	39	72	37	43	31	50	25	9	53	37	21

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 38

8. What energy sources currently used in your home?

		TOTAL	Region				Gender		Age			Income			Education		
		(A)	GVRD (A)	Vancouver Island (B)	BC Southern Interior (C)	BC North/Interior (D)	Male (A)	Female (B)	18-34 (A)	35-54 (B)	55+ (C)	<$50K (A)	$50-99K (B)	$100K + (C)	HS or less (A)	College / Tech school (B)	Univ+ (C)
All Respondents	BASE	802	411	147	183	60	391	411	218	320	264	267	293	132	306	325	171
	UNWT	802	417	164	177	44	382	420	210	306	286	241	301	158	130	398	274
Natural Gas	COL %	58%	65%	24%	65%	73%	61%	55%	51%	60%	62%	45%	61%	76%	50%	63%	62%
	SIG		B		B	B					A		A	A B		A	A
	COUNT	464	266	36	119	44	237	228	110	190	164	120	178	100	153	206	105
Electricity	COL %	81%	87%	81%	76%	62%	80%	83%	90%	79%	77%	81%	82%	78%	78%	84%	83%
	SIG		C D	D					B C								
	COUNT	653	358	119	139	37	312	341	197	254	202	216	240	103	237	274	142
Piped Propane	COL %	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%
	SIG																
	COUNT	2	1	0	0	0	1	0	1	0	0	1	0	0	0	1	0
Propane in a Tank	COL %	8%	8%	7%	6%	13%	7%	8%	11%	5%	7%	8%	8%	7%	5%	9%	8%
	SIG								B								
	COUNT	61	31	11	11	8	26	35	25	16	19	21	22	10	16	31	14
Oil	COL %	5%	2%	18%	3%	4%	3%	7%	6%	5%	5%	7%	6%	2%	6%	4%	6%
	SIG			A C D				A									
	COUNT	41	6	26	6	2	12	28	12	15	14	18	19	3	17	12	11
Wood	COL %	15%	8%	29%	21%	12%	15%	16%	10%	18%	17%	15%	20%	13%	17%	17%	11%
	SIG			A D	A					A							
	COUNT	124	34	43	39	7	58	66	22	58	44	39	59	18	51	54	19
Other (Specify)	COL %	4%	2%	10%	6%	0%	5%	4%	1%	4%	7%	5%	2%	4%	5%	4%	3%
	SIG			A							A						
	COUNT	34	9	14	11	0	19	15	3	13	18	14	7	5	16	13	5

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column proportion.

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 1

Gender

			TOTAL	Currently used in home							
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Gender	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	Male	COL %	49%	51%	48%	75%	42%	30%	47%	55%
		SIG								
		COUNT	391	237	312	1	26	12	58	19
	Female	COL %	51%	49%	52%	25%	58%	70%	53%	45%
		SIG								
		COUNT	411	228	341	0	35	28	66	15

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 2

Age

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
AGE	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	18-34	COL %	27%	24%	30%	75%	41%	30%	18%	8%
		SIG			A F		A F G			
		COUNT	218	110	197	1	25	12	22	3
	35-54	COL %	40%	41%	39%	25%	27%	37%	47%	38%
		SIG								
		COUNT	320	190	254	0	16	15	58	13
	55+	COL %	33%	35%	31%	0%	32%	33%	36%	54%
		SIG								
		COUNT	264	164	202	0	19	14	44	18
	MEAN		47.0	48.1	45.8	25.4	44.0	46.9	49.9	57.1
	SIG			B					B	A B C D E
	STDDEV		15.5	15.2	15.7	9.2	17.4	15.2	15.0	12.0
	MEDIAN		47.0	48.0	46.0	25.0	44.0	47.0	51.0	61.0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Results are based on two-sided tests assuming equal variances with significance level 0.05. For each significant pair, the key of the smaller category appears under the category with larger

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts in some subtables are not integers. They were rounded to the nearest integers before performing pairwise comparisons.

Table 3

Age_Gender

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
AGE/Gender	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	Male 18-34	COL %	14%	12%	15%	75%	13%	12%	6%	8%
		SIG			F					
		COUNT	109	58	96	1	8	5	7	3
	Male 35-54	COL %	19%	21%	19%	0%	10%	8%	24%	21%
		SIG								
		COUNT	156	98	123	0	6	3	30	7
	Male 55+	COL %	16%	17%	14%	0%	19%	10%	17%	26%
		SIG								
		COUNT	127	81	93	0	12	4	21	9
	Female 18-34	COL %	14%	11%	15%	0%	28%	18%	12%	0%
		SIG			A		A F			
		COUNT	109	53	101	0	17	7	15	0
	Female 35-54	COL %	20%	20%	20%	25%	17%	28%	23%	17%
		SIG								
		COUNT	164	93	130	0	11	11	28	6
	Female 55+	COL %	17%	18%	17%	0%	13%	23%	19%	28%
		SIG								
		COUNT	137	82	110	0	8	9	24	9

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 4

Region

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Region	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	GVRD	COL %	51%	57%	55%	75%	51%	15%	28%	27%
		SIG		E F G	E F G		E F			
		COUNT	411	266	358	1	31	6	34	9
	Vancouver Island	COL %	18%	8%	18%	0%	18%	65%	35%	42%
		SIG			A			A B D F	A B	A B
		COUNT	147	36	119	0	11	26	43	14
	BC Southern Interior	COL %	23%	26%	21%	25%	17%	14%	32%	32%
		SIG							B	
		COUNT	183	119	139	0	11	6	39	11
	BC North/Interior	COL %	8%	9%	6%	0%	13%	5%	6%	0%
		SIG		B						
		COUNT	60	44	37	0	8	2	7	0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 5

Education

			TOTAL	Currently used in home							
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Education	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	HS or less	COL %	38%	33%	36%	0%	26%	43%	41%	47%
		SIG								
		COUNT	306	153	237	0	16	17	51	16
	College/ Tech school	COL %	41%	44%	42%	75%	51%	30%	44%	39%
		SIG								
		COUNT	325	206	274	1	31	12	54	13
	Univ+	COL %	21%	23%	22%	25%	23%	27%	15%	14%
		SIG								
		COUNT	171	105	142	0	14	11	19	5

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 6

Income

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Income	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	<$50K	COL %	33%	26%	33%	75%	35%	44%	32%	40%
		SIG			A					
		COUNT	267	120	216	1	21	18	39	14
	$50-99K	COL %	37%	38%	37%	0%	37%	47%	48%	21%
		SIG								
		COUNT	293	178	240	0	22	19	59	7
	$100K+	COL %	16%	22%	16%	25%	16%	8%	14%	14%
		SIG		B						
		COUNT	132	100	103	0	10	3	18	5
	DK/REF	COL %	14%	14%	14%	0%	12%	2%	6%	25%
		SIG								E F
		COUNT	110	67	94	0	7	1	8	9

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 25

1. How familiar are you with the terms Alternative Energy or Green Energy?

		TOTAL	Currently used in home						
		(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
All Respondents	BASE	802	464	653	2	61	41	124	34
	UNWT	802	490	666	3	65	36	125	32
Very familiar	COL %	26%	26%	27%	66%	34%	23%	30%	22%
	SIG								
	COUNT	208	119	179	1	20	9	37	8
Familiar	COL %	43%	44%	42%	34%	39%	39%	45%	52%
	SIG								
	COUNT	344	202	276	1	24	16	56	18
Heard of them	COL %	26%	26%	25%	0%	25%	36%	13%	26%
	SIG		F	F			F		
	COUNT	207	123	164	0	15	15	17	9
Never heard of them	COL %	5%	4%	5%	0%	2%	2%	11%	0%
	SIG							A B	
	COUNT	43	21	35	0	1	1	14	0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 26

2. How aware are you of the following energy sources? - Solar

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Solar	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Very aware	COL %	60%	59%	60%	41%	61%	72%	66%	59%
		SIG								
		COUNT	458	260	373	1	36	29	72	20
	Aware	COL %	40%	41%	40%	59%	39%	28%	34%	41%
		SIG								
		COUNT	300	184	245	1	23	11	38	14
	Not at all aware	COL %	0%	0%	0%	0%	0%	0%	0%	0%
		SIG								
		COUNT	1	0	1	0	0	0	0	0
	Total Aware	COL %	100%	100%	100%	100%	100%	100%	100%	100%
		SIG								
		COUNT	759	444	618	2	59	40	110	34

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 27

2. How aware are you of the following energy sources?- Biomass

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Biomass	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Very aware	COL %	13%	14%	13%	0%	13%	13%	12%	10%
		SIG								
		COUNT	98	61	82	0	8	5	13	3
	Aware	COL %	40%	39%	39%	100%	41%	28%	41%	60%
		SIG								
		COUNT	303	173	241	2	24	11	45	20
	Not at all aware	COL %	47%	47%	48%	0%	46%	59%	47%	30%
		SIG								
		COUNT	359	210	295	0	27	23	52	10
	Total Aware	COL %	53%	53%	52%	100%	54%	41%	53%	70%
		SIG								
		COUNT	400	233	323	2	32	16	58	24

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 28

2. How aware are you of the following energy sources?- District Heating Systems

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
District Heating Systems	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Very aware	COL %	7%	7%	7%	0%	8%	10%	11%	7%
		SIG								
		COUNT	51	31	42	0	5	4	12	2
	Aware	COL %	33%	34%	31%	59%	28%	21%	32%	58%
		SIG								A B E
		COUNT	248	149	191	1	17	8	35	20
	Not at all aware	COL %	61%	60%	62%	41%	64%	69%	58%	35%
		SIG			G			G		
		COUNT	461	264	386	1	38	27	63	12
	Total Aware	COL %	39%	40%	38%	59%	36%	31%	42%	65%
		SIG								B E
		COUNT	299	180	233	1	21	12	47	22

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 29

2. How aware are you of the following energy sources?- Ground Source Heat Pumps

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Ground Source Heat Pumps	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Very aware	COL %	31%	34%	29%	0%	32%	34%	31%	51%
		SIG								
		COUNT	235	152	180	0	19	13	34	18
	Aware	COL %	46%	42%	47%	100%	44%	55%	61%	43%
		SIG							A B	
		COUNT	348	188	292	2	26	22	67	15
	Not at all aware	COL %	23%	24%	24%	0%	24%	11%	8%	5%
		SIG		F	F		F			
		COUNT	176	105	146	0	14	4	9	2
	Total Aware	COL %	77%	76%	76%	100%	76%	89%	92%	95%
		SIG							A B D	
		COUNT	583	339	473	2	45	35	101	32

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 30

3. How would you assess your knowledge of the following energy sources and technology?- Solar

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Solar	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Extremely knowledgeable	COL %	10%	10%	10%	25%	15%	4%	15%	12%
		SIG								
		COUNT	77	46	63	0	9	2	17	4
	Very knowledgeable	COL %	29%	28%	28%	41%	28%	30%	27%	47%
		SIG								
		COUNT	218	125	173	1	17	12	29	16
	Somewhat knowledgeable	COL %	55%	55%	57%	34%	50%	59%	57%	42%
		SIG								
		COUNT	420	242	355	1	30	23	62	14
	Somewhat unknowledgeable	COL %	5%	5%	4%	0%	6%	7%	2%	0%
		SIG								
		COUNT	36	23	26	0	3	3	2	0
	Not at all knowledgeable	COL %	1%	2%	0%	0%	0%	0%	0%	0%
		SIG		B						
		COUNT	9	8	2	0	0	0	0	0
	Top2box	COL %	39%	39%	38%	66%	44%	34%	42%	58%
		SIG								
		COUNT	295	171	236	1	26	13	46	20
	Low2box	COL %	6%	7%	5%	0%	6%	7%	2%	0%
		SIG								
		COUNT	45	30	28	0	3	3	2	0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 31

3. How would you assess your knowledge of the following energy sources and technology?- Biomass

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Biomass	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Extremely knowledgeable	COL %	2%	2%	2%	25%	2%	0%	3%	2%
		SIG								
		COUNT	18	9	15	0	1	0	4	1
	Very knowledgeable	COL %	5%	6%	5%	0%	7%	2%	7%	5%
		SIG								
		COUNT	41	26	32	0	4	1	7	2
	Somewhat knowledgeable	COL %	28%	30%	27%	75%	27%	28%	28%	32%
		SIG								
		COUNT	210	131	168	1	16	11	31	11
	Somewhat unknowledgeable	COL %	20%	18%	20%	0%	16%	16%	17%	31%
		SIG								
		COUNT	155	79	125	0	10	6	19	10
	Not at all knowledgeable	COL %	44%	45%	45%	0%	47%	54%	44%	30%
		SIG								
		COUNT	335	198	278	0	28	22	49	10
	Top2box	COL %	8%	8%	8%	25%	9%	2%	10%	8%
		SIG								
		COUNT	59	35	47	0	6	1	11	3
	Low2box	COL %	65%	62%	65%	0%	63%	70%	62%	61%
		SIG								
		COUNT	491	277	403	0	37	28	68	21

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 32

3. How would you assess your knowledge of the following energy sources and technology?- District Heating Systems

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
District Heating Systems	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Extremely knowledgeable	COL %	1%	1%	1%	59%	1%	0%	1%	0%
		SIG								
		COUNT	8	5	6	1	0	0	1	0
	Very knowledgeable	COL %	5%	4%	5%	0%	8%	1%	8%	2%
		SIG								
		COUNT	35	18	29	0	5	1	9	1
	Somewhat knowledgeable	COL %	23%	23%	21%	0%	21%	27%	22%	57%
		SIG								A B D F
		COUNT	174	103	130	0	13	11	24	19
	Somewhat unknowledgeable	COL %	20%	20%	21%	0%	13%	15%	18%	9%
		SIG								
		COUNT	149	87	127	0	8	6	20	3
	Not at all knowledgeable	COL %	52%	52%	53%	41%	57%	57%	51%	32%
		SIG								
		COUNT	394	231	327	1	34	22	56	11
	Top2box	COL %	6%	5%	6%	59%	9%	1%	9%	2%
		SIG								
		COUNT	42	23	34	1	5	1	10	1
	Low2box	COL %	71%	72%	73%	41%	70%	72%	69%	41%
		SIG		G	G				G	
		COUNT	543	318	454	1	41	28	76	14

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 33

3. How would you assess your knowledge of the following energy sources and technology?- Ground Source Heat Pumps

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Ground Source Heat Pumps	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Extremely knowledgeable	COL %	5%	5%	5%	25%	3%	2%	3%	19%
		SIG								A B F
		COUNT	39	24	29	0	2	1	3	6
	Very knowledgeable	COL %	14%	13%	13%	34%	22%	9%	16%	37%
		SIG								A B
		COUNT	107	59	81	1	13	4	18	13
	Somewhat knowledgeable	COL %	41%	44%	41%	0%	41%	52%	58%	38%
		SIG							A B	
		COUNT	310	193	254	0	24	21	64	13
	Somewhat unknowledgeable	COL %	15%	14%	16%	41%	7%	9%	12%	0%
		SIG								
		COUNT	115	64	96	1	4	4	13	0
	Not at all knowledgeable	COL %	25%	23%	25%	0%	28%	28%	11%	6%
		SIG		F	F		F	F		
		COUNT	188	104	158	0	17	11	12	2
	Top2box	COL %	19%	19%	18%	59%	25%	11%	19%	56%
		SIG								A B D E F
		COUNT	146	83	110	1	15	4	21	19
	Low2box	COL %	40%	38%	41%	41%	35%	37%	23%	6%
		SIG		F G	F G		G	G		
		COUNT	303	167	254	1	20	15	25	2

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 34

4. If you were buying or building a new home or renovating an existing home, how willing would you be to incorporate an alternative energy source?

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Willing to incorporate an alternative energy source	Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
		UNWT	773	475	643	3	64	34	117	32
	Extremely willing	COL %	32%	27%	32%	25%	35%	38%	34%	44%
		SIG								
		COUNT	240	121	197	0	21	15	38	15
	Very willing	COL %	37%	40%	37%	75%	25%	26%	38%	34%
		SIG								
		COUNT	283	179	231	1	15	10	41	11
	Somewhat Willing	COL %	27%	29%	27%	0%	38%	34%	25%	22%
		SIG								
		COUNT	205	127	165	0	22	13	28	7
	Somewhat unwilling	COL %	3%	3%	2%	0%	0%	2%	2%	0%
		SIG								
		COUNT	20	13	15	0	0	1	2	0
	Not at all willing	COL %	2%	1%	2%	0%	1%	0%	1%	0%
		SIG								
		COUNT	12	4	11	0	1	0	1	0
	Top2box	COL %	69%	68%	69%	100%	61%	64%	72%	78%
		SIG								
		COUNT	523	300	427	2	36	25	79	27
	Low2box	COL %	4%	4%	4%	0%	1%	2%	3%	0%
		SIG								
		COUNT	32	17	26	0	1	1	3	0

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 35

5. Would you be prepared to pay extra for a home that uses an alternative energy source?

			TOTAL	Currently used in home							
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Prepared to Pay extra	Willing to incorporate	BASE	728	426	592	2	58	39	106	34
		UNWT	745	458	620	3	62	33	114	32
	Yes, I would pay up to 10% extra for such a house or improve	COL %	19%	17%	18%	25%	19%	22%	21%	24%
		SIG								
		COUNT	135	73	106	0	11	8	22	8
	Yes, I would pay up to 5% extra	COL %	41%	42%	42%	75%	40%	30%	44%	42%
		SIG								
		COUNT	295	178	249	1	23	12	46	14
	Yes, I would pay up to 2% extra	COL %	20%	18%	21%	0%	11%	24%	19%	13%
		SIG								
		COUNT	142	78	123	0	6	9	20	4
	Yes, I would pay up to 1% extra	COL %	8%	11%	7%	0%	5%	2%	5%	0%
		SIG		B						
		COUNT	60	46	44	0	3	1	6	0
	No, I would not be prepared to pay more	COL %	13%	12%	12%	0%	25%	22%	11%	21%
		SIG					A B			
		COUNT	95	51	69	0	15	9	12	7
	Total Yes	COL %	87%	88%	88%	100%	75%	78%	89%	79%
		SIG		D	D					
		COUNT	632	375	523	2	44	30	94	27

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 36

6. Thinking of how alternative energy would be delivered to your home, do you think that Terasen Gas should provide these alternative energy sources for customers?

		TOTAL	Currently used in home						
		(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
Heard of Alternative Energy/ Green Energy	BASE	759	444	618	2	59	40	110	34
	UNWT	773	475	643	3	64	34	117	32
Yes	COL %	33%	35%	33%	100%	33%	17%	34%	15%
	SIG								
	COUNT	254	157	207	2	20	7	38	5
No	COL %	19%	16%	20%	0%	13%	29%	18%	20%
	SIG								
	COUNT	147	73	121	0	7	12	20	7
Maybe	COL %	35%	35%	35%	0%	30%	40%	37%	61%
	SIG								A B D
	COUNT	264	154	219	0	18	16	40	21
Don’t know	COL %	12%	13%	12%	0%	24%	13%	11%	5%
	SIG					B			
	COUNT	95	59	72	0	14	5	12	2

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 37

7. Have you undertaken any Energy Efficiency improvements or do you plan to undertake any improvements in the next two years?

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	Have undertaken	COL %	34%	37%	32%	66%	46%	49%	41%	65%
		SIG								A B
		COUNT	269	171	210	1	28	20	50	22
	Plan to undertake	COL %	24%	25%	24%	34%	22%	13%	26%	8%
		SIG								
		COUNT	191	117	160	1	13	5	33	3
	Have not and do not plan to undertake	COL %	29%	26%	28%	0%	24%	26%	24%	18%
		SIG								
		COUNT	231	122	184	0	15	10	30	6
	Don't know	COL %	14%	12%	15%	0%	8%	13%	8%	8%
		SIG								
		COUNT	111	55	100	0	5	5	10	3

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Table 38

8. What energy sources currentlyu used in your home?

			TOTAL	Currently used in home						
			(A)	Natural Gas (A)	Electricity (B)	Piped Propane (C)	Propane in a Tank (D)	Oil (E)	Wood (F)	Other (G)
	All Respondents	BASE	802	464	653	2	61	41	124	34
		UNWT	802	490	666	3	65	36	125	32
	Natural Gas	COL %	58%	100%	53%	41%	55%	1%	38%	34%
		SIG			E F		E		E	E
		COUNT	464	464	349	1	34	1	47	12
	Electricity	COL %	81%	75%	100%	75%	93%	68%	86%	39%
		SIG		G			A E G		E G	
		COUNT	653	349	653	1	56	28	106	13
	Piped Propane	COL %	0%	0%	0%	100%	0%	0%	0%	0%
		SIG								
		COUNT	2	1	1	2	0	0	0	0
	Propane in a Tank	COL %	8%	7%	9%	0%	100%	11%	16%	5%
		SIG							A B	
		COUNT	61	34	56	0	61	4	20	2
	Oil	COL %	5%	0%	4%	0%	7%	100%	16%	4%
		SIG			A		A		A B	A
		COUNT	41	1	28	0	4	41	20	1
	Wood	COL %	15%	10%	16%	0%	32%	48%	100%	11%
		SIG			A		A B	A B G		
		COUNT	124	47	106	0	20	20	124	4
	Other (Specify)	COL %	4%	2%	2%	0%	3%	3%	3%	100%
		SIG								
		COUNT	34	12	13	0	2	1	4	34

: - BC Omni - July31 --- Angus Reid Strategies --- 8/2/2009 tl

Results are based on two-sided tests with significance level 0.05. For each significant pair, the key of the category with the smaller column proportion appears under the category with the larger column

Tests are adjusted for all pairwise comparisons within a row of each innermost subtable using the Bonferroni correction.

Cell counts of some categories are not integers. They were rounded to the nearest integers before performing column proportions tests.

Attachment 32.1

REFER TO LIVE SPREADSHEET

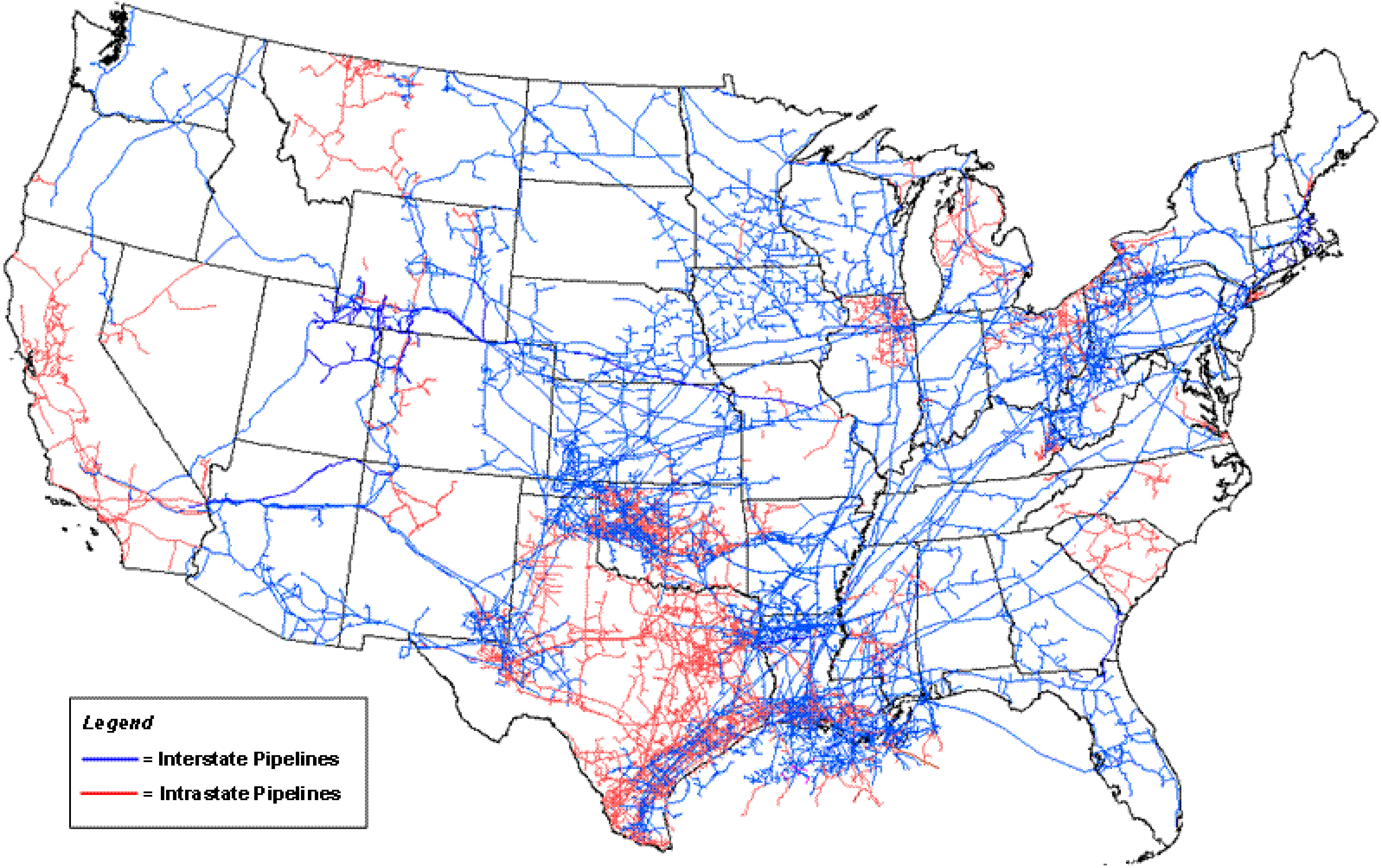
(accessible by opening the Attachments Tab in Adobe)

Attachment 40.2

American Gas Association

Factors Influencing Natural Gas Markets 2009

U.S. Natural Gas Pipeline Network



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

Key Features of U.S. Natural Gas Market

- **North American Market demand:**
  - USA (62 BCFD)
  - Canada (7 BCFD)
  - Mexico (5 BCFD)
- **US Imports:**
  - Canada (8 BCFD)
  - LNG (1 BCFD)
- **Highly liquid market**
  - Active day-ahead
  - Monthly "Bid Week"
  - "Long term" means >1 month.
  - Price risk can be hedged at multiple locations – using Nymex futures, electronic trading platforms, and broker markets.
- **Mature, coast-to-coast infrastructure enables creative solutions**
  - All interstate pipelines "open access".
  - Abundant underground storage facilities (>3.5 TCF).

AVERAGE HENRY HUB SPOT PRICE
(EIA Historical and Estimated, January 2009 Short-Term Outlook)

– $3.00 per MMBtu 2002

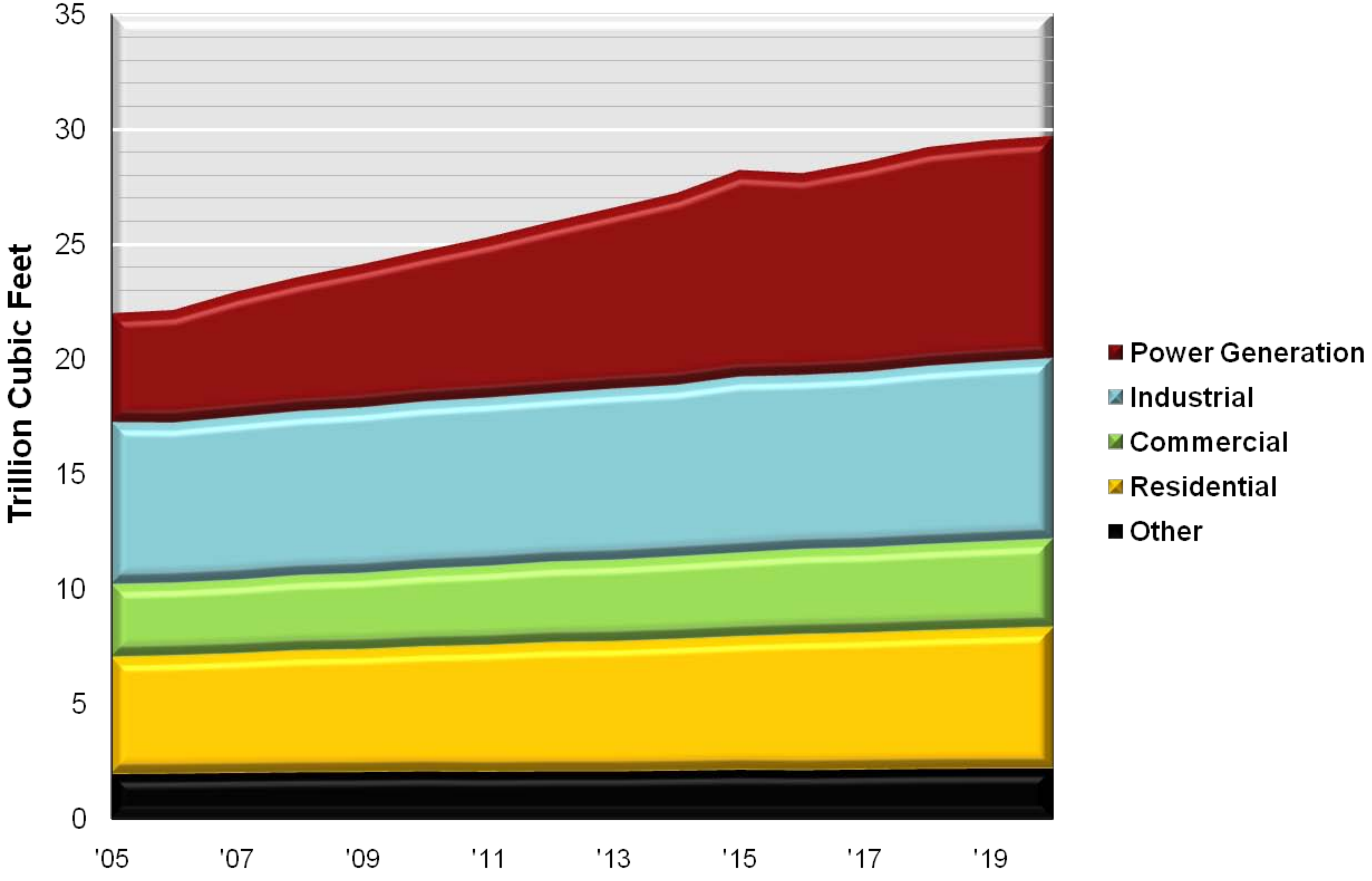
– $7.17 per MMBtu 2007

– $9.13 per MMBtu 2008 (+27%)

– $5.78 per MMBtu 2009 (-37%)

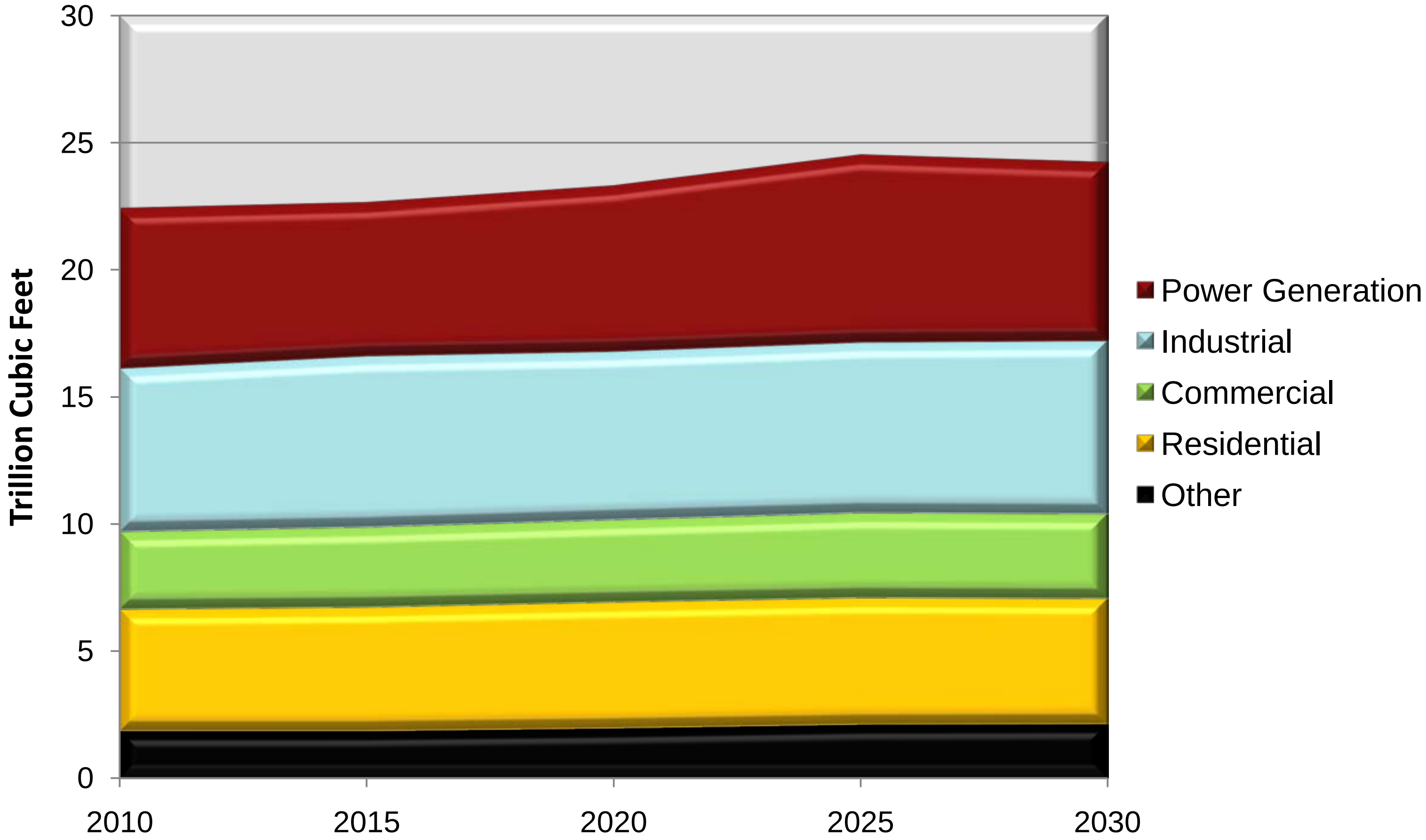
– EIA further anticipates 1.0 % natural gas consumption decline 2009 compared to 2008, with a 0.7 % increase in 2010

FUTURE NATURAL GAS DEMAND
(TYPICAL 2005 OUTLOOK)



Source: *Energy and Environmental Analysis.*

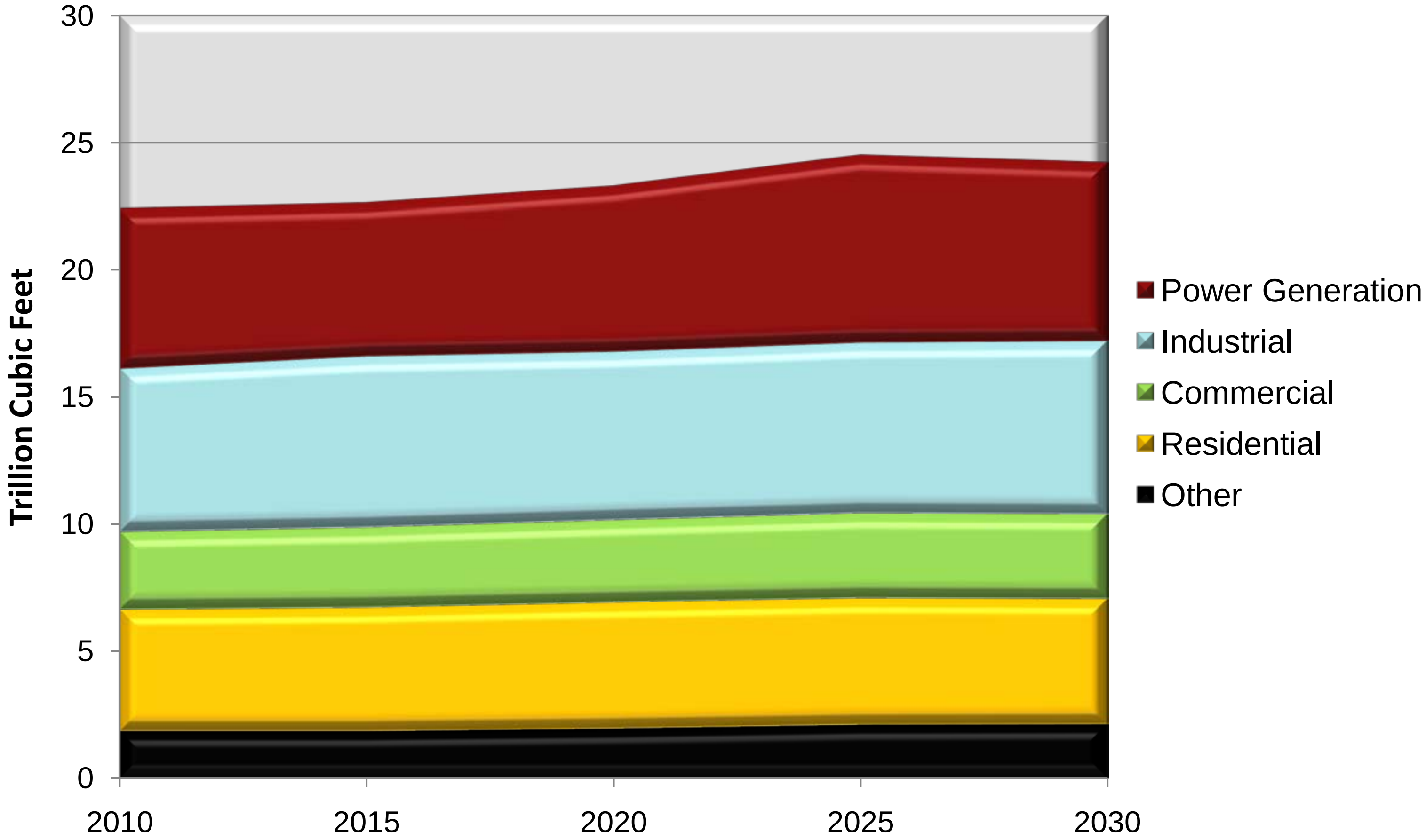
FUTURE NATURAL GAS DEMAND
(2010-2030)



Source: *Energy Information Administration, Annual Energy Outlook 2009-2030*.

AGA American Gas Association

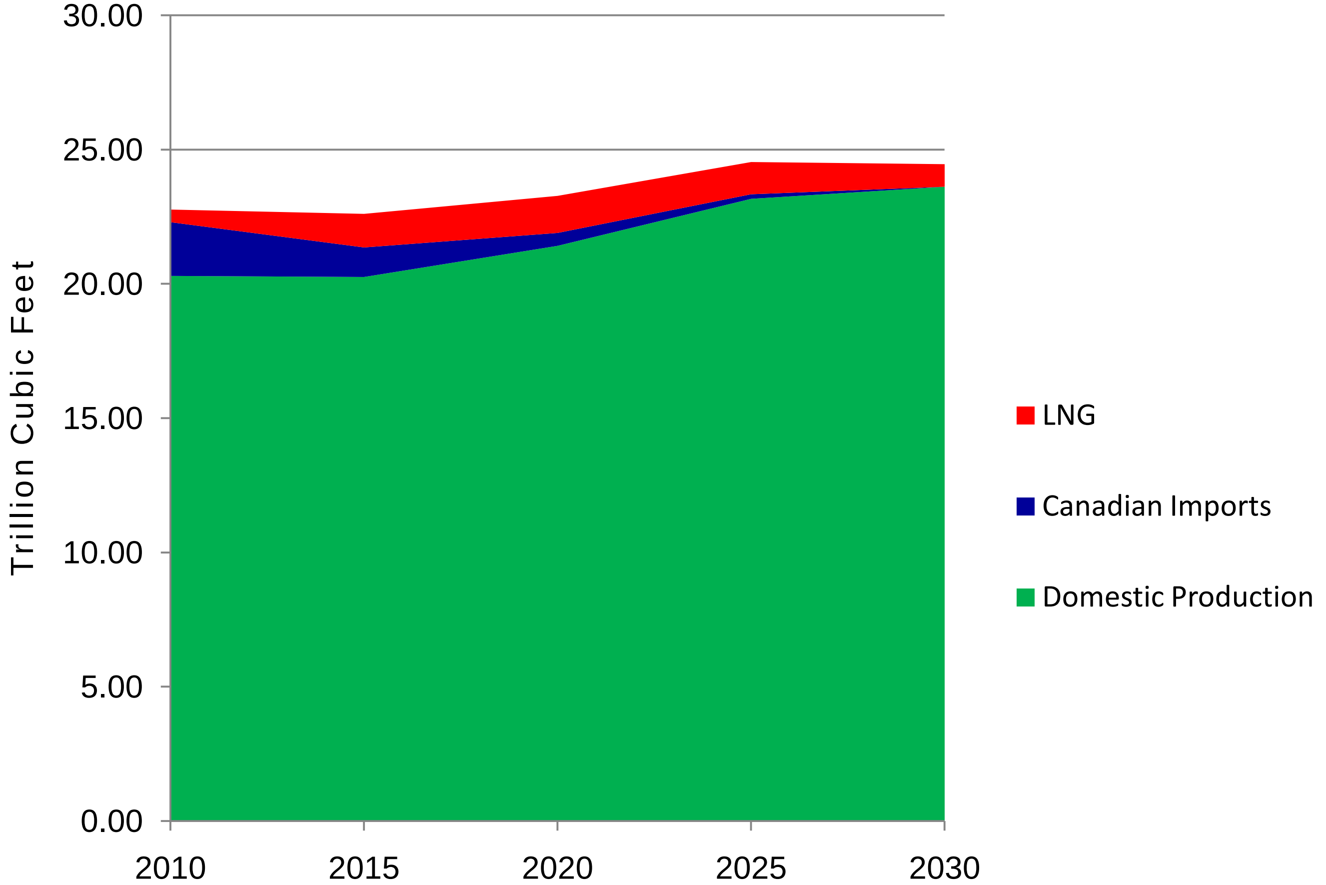
FUTURE NATURAL GAS DEMAND
(2010-2030)



AGA American Gas Association

Source: *Energy Information Administration, Annual Energy Outlook 2009-2030*.

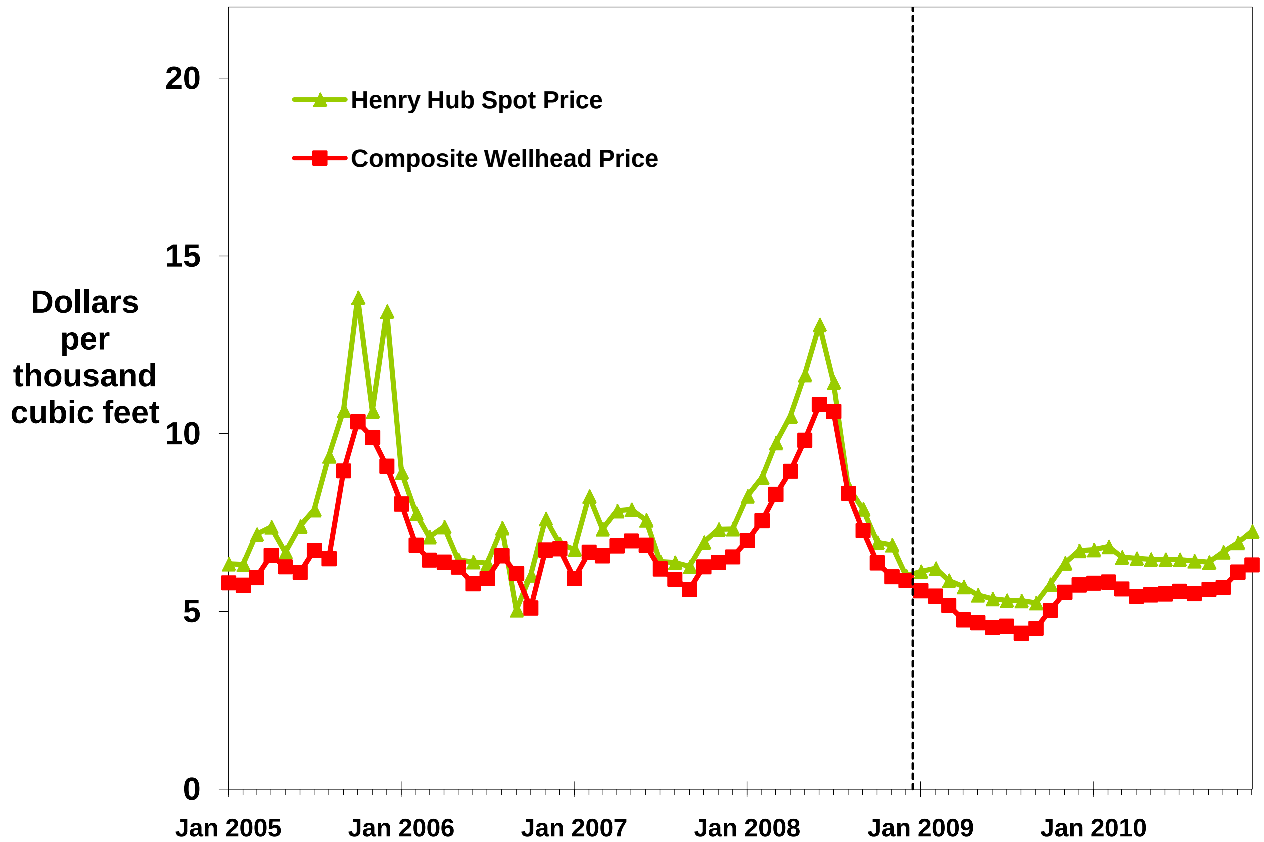
FUTURE NATURAL GAS SUPPLY (2010-2030)



Source: *Energy Information Administration*, *Annual Energy Outlook 2009-2030*.

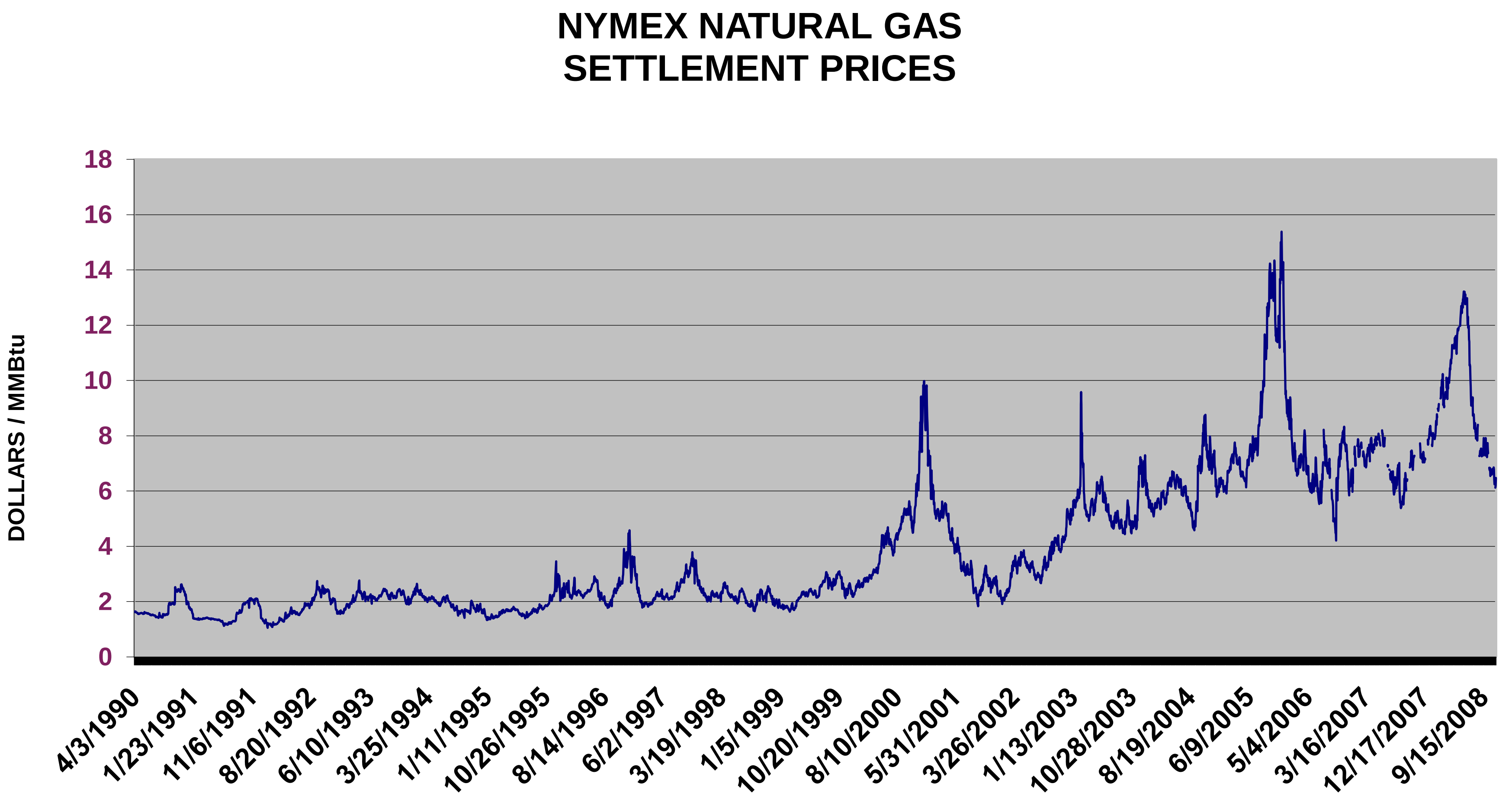
American Gas Association

NATURAL GAS PRICES



Source: *Energy Information Administration*, January 2009.

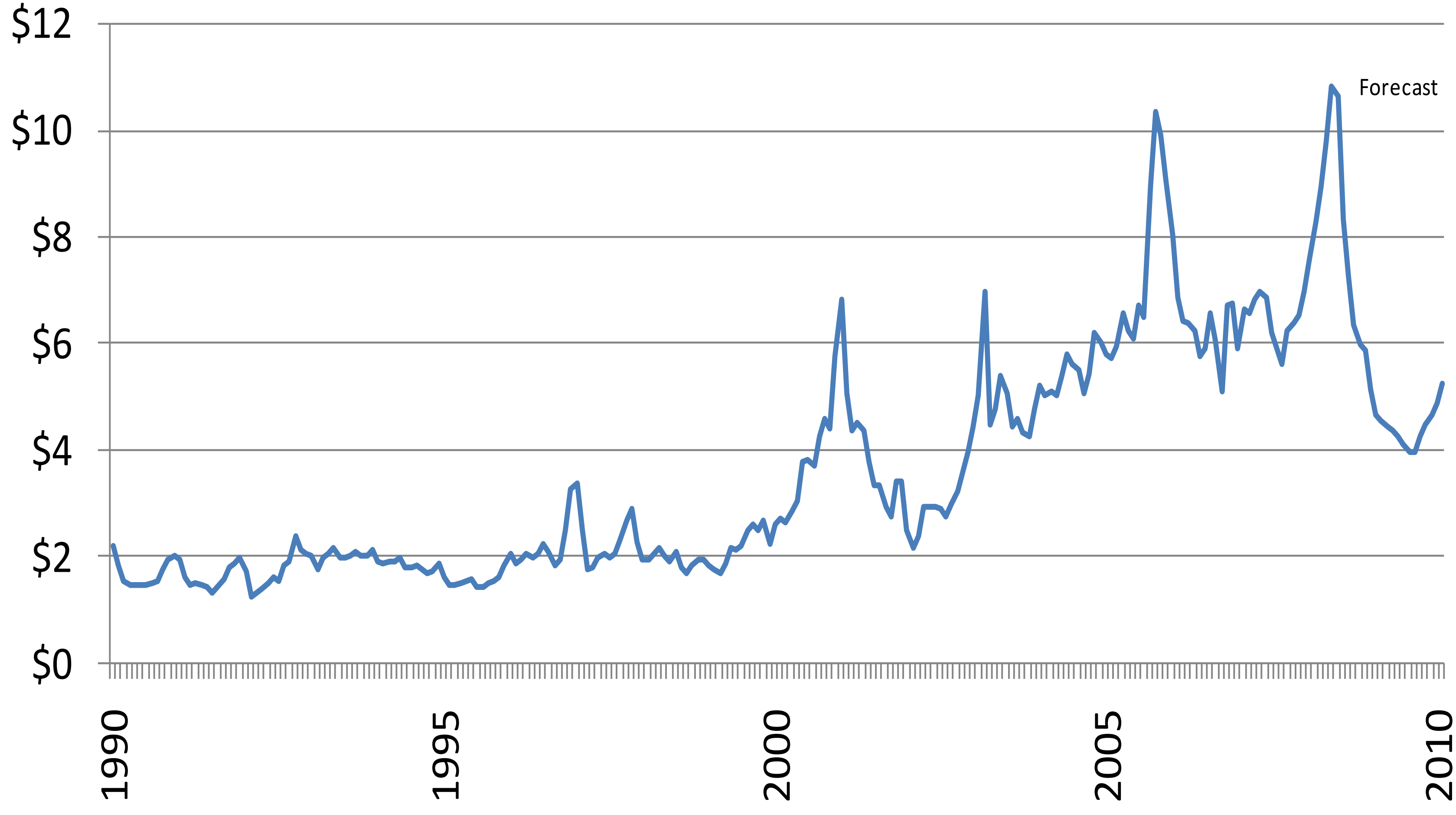
NATURAL GAS PRICES



AGA American Gas Association

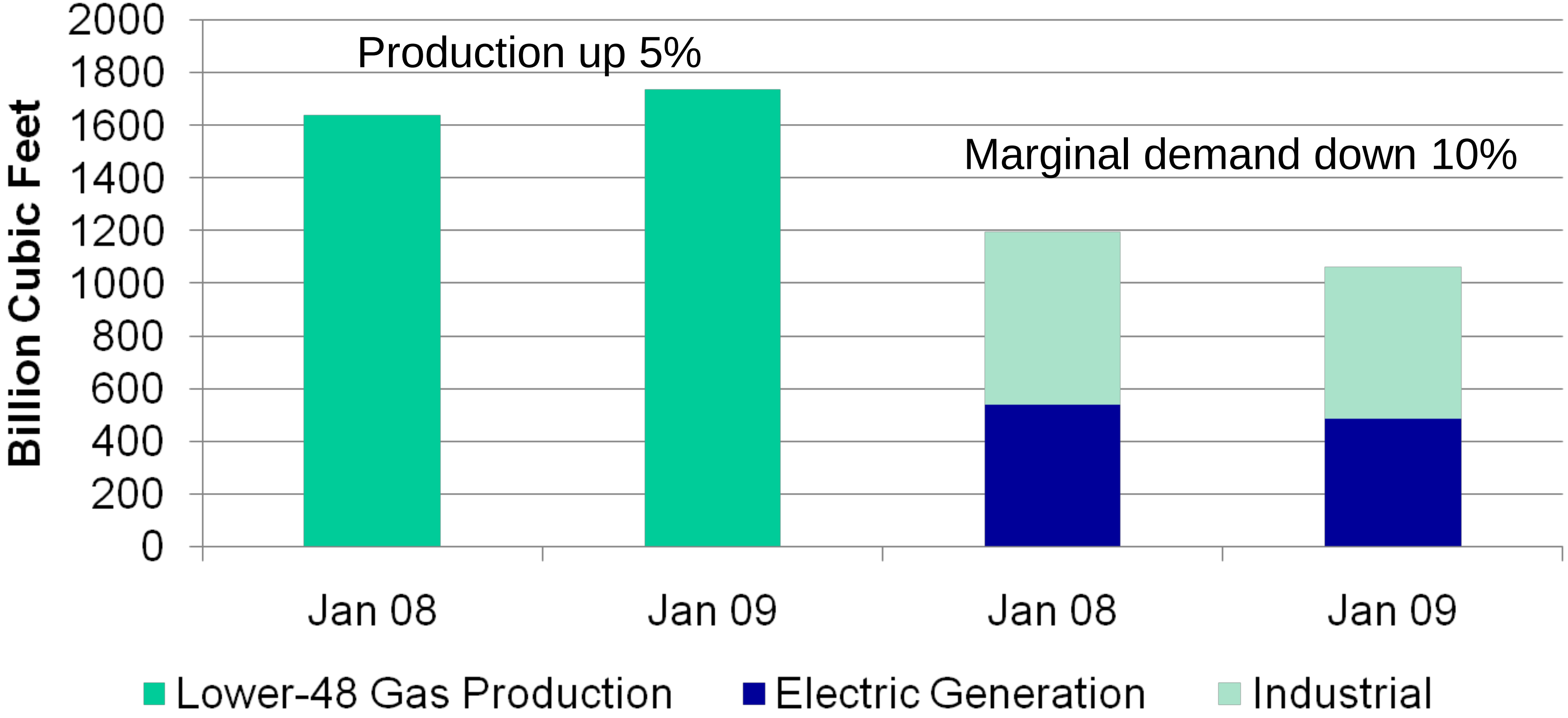
Source: *New York Mercantile Exchange*.

NATURAL GAS PRICES
(AVERAGE WELLHEAD PRICE, $/Mcf)



Source: *Energy Information Administration.*

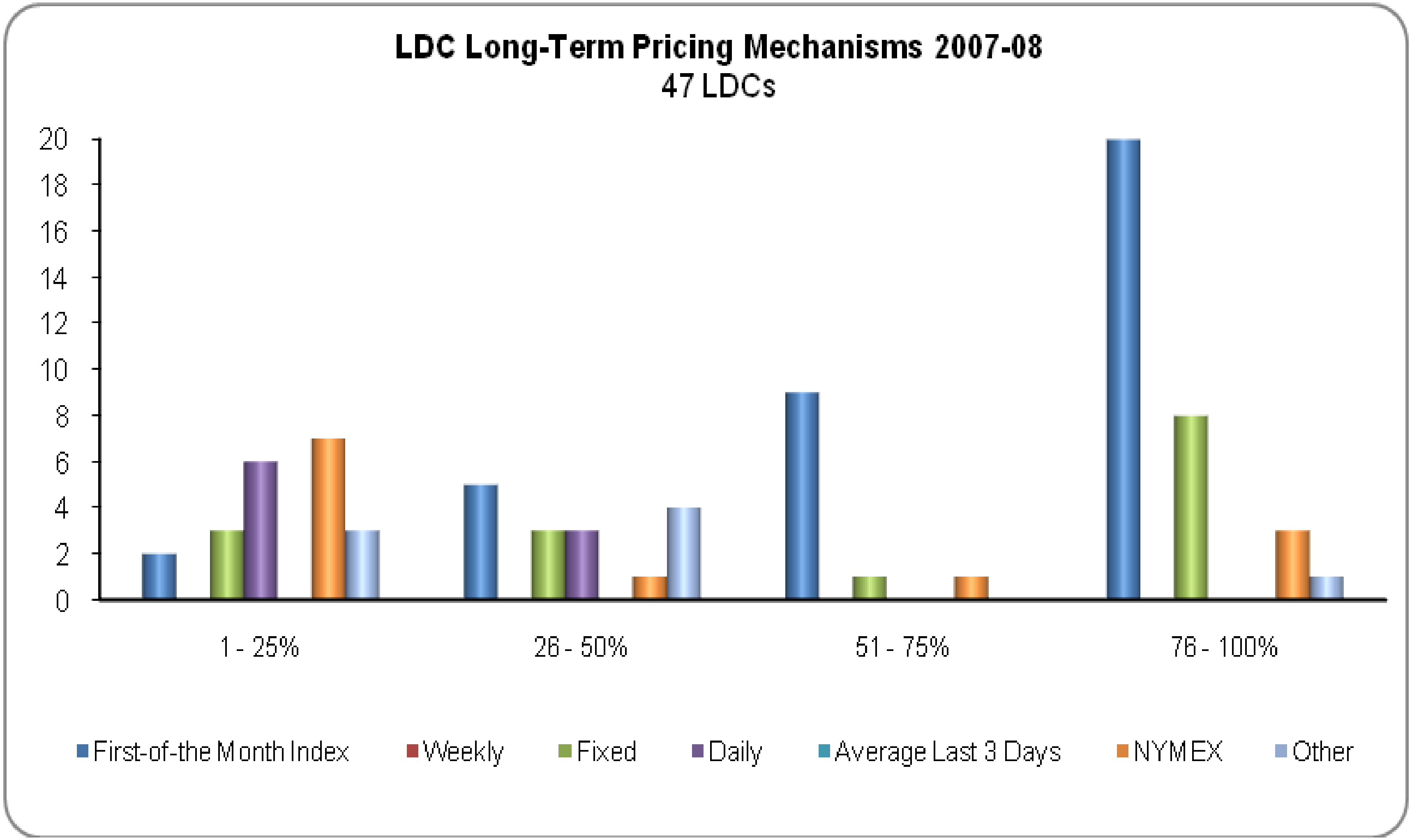
MARGINAL PRODUCTION UP WHILE MARGINAL DEMAND FALLS



Source: *Bentek Energy LLC*, *Energy Market Fundamentals*

AGA American Gas Association

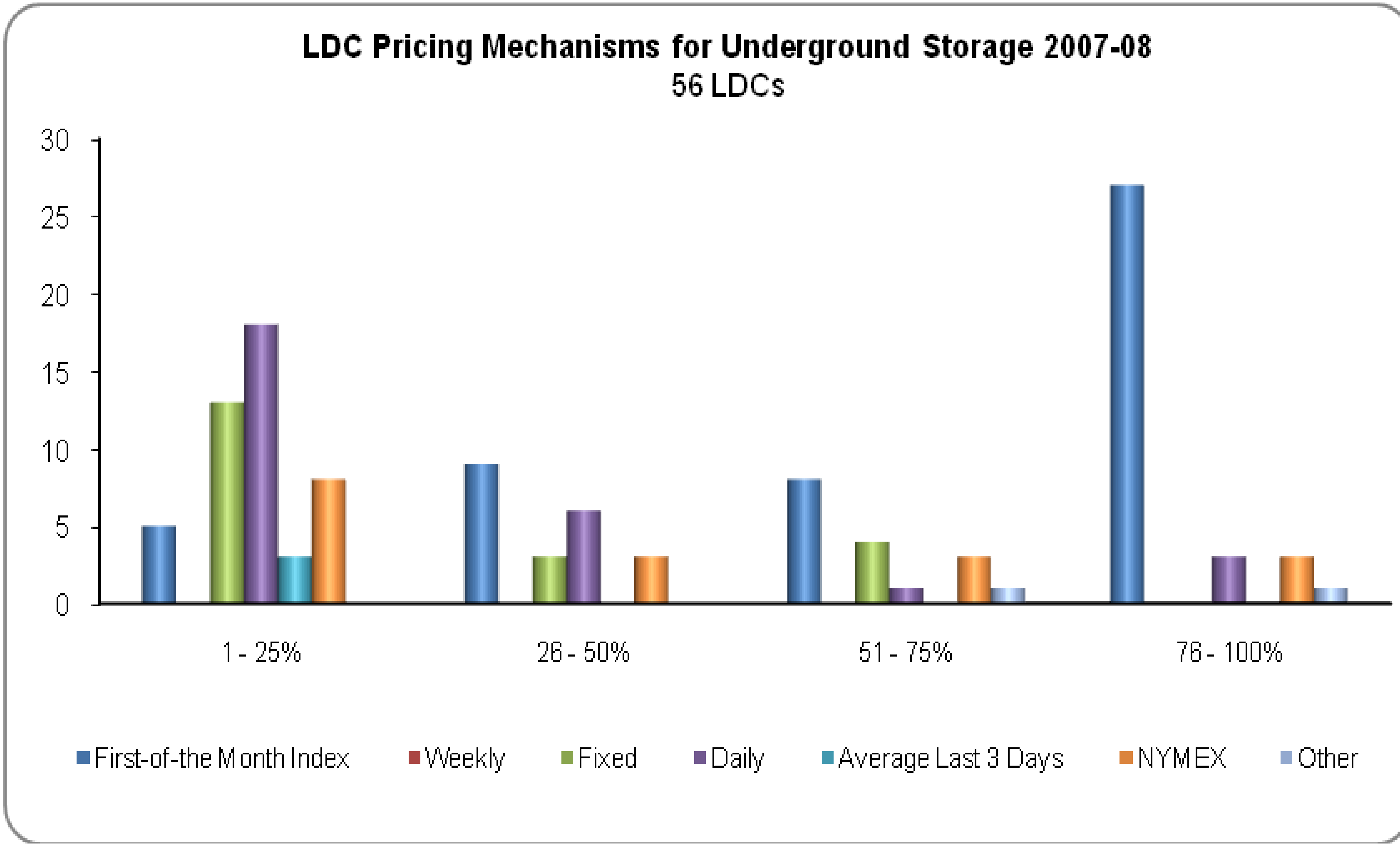
2007-08 WINTER HEATING SEASON



AGA American Gas Association

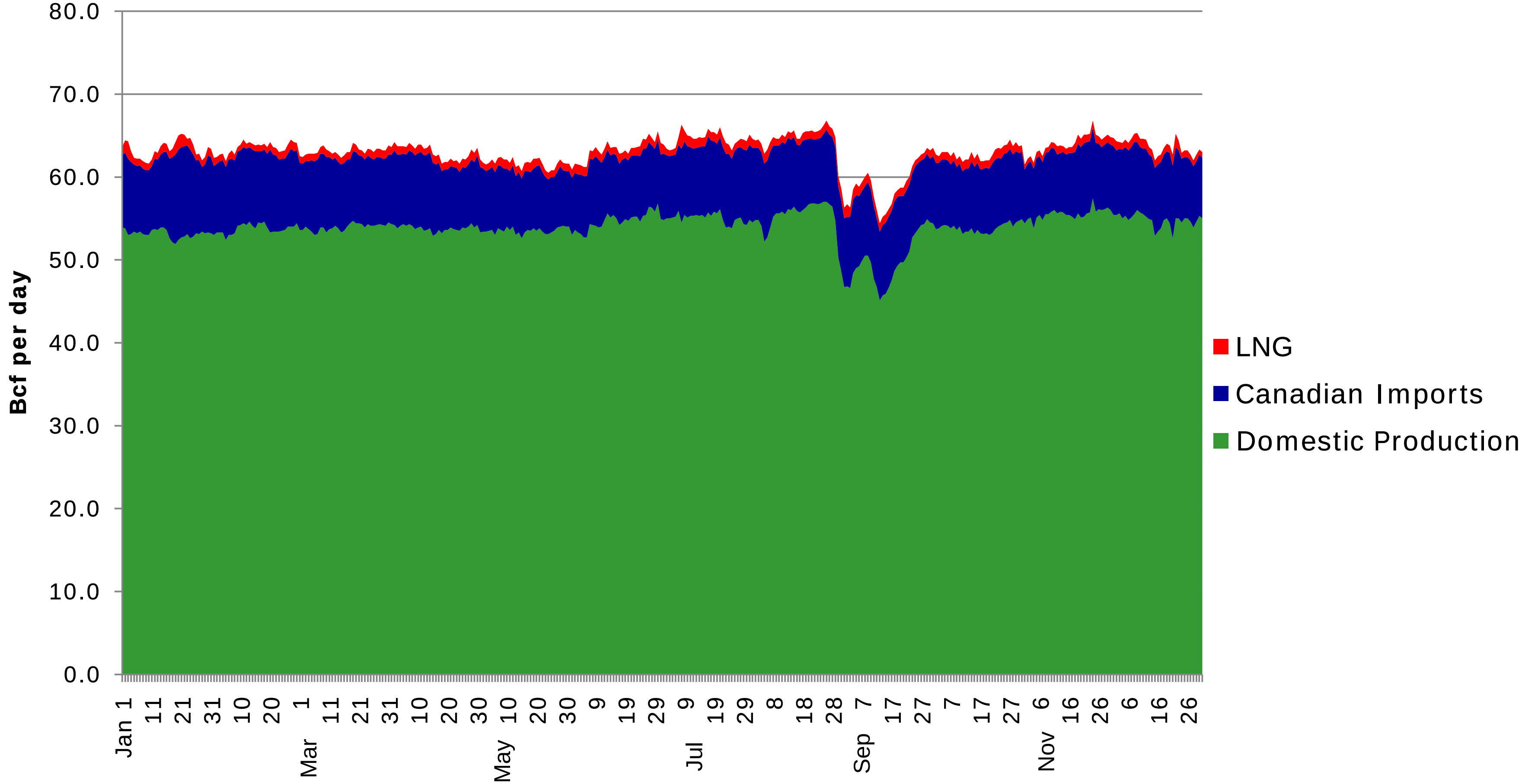
Source: *American Gas Association.*

2007-08 Winter Heating Season



Source: *American Gas Association.*

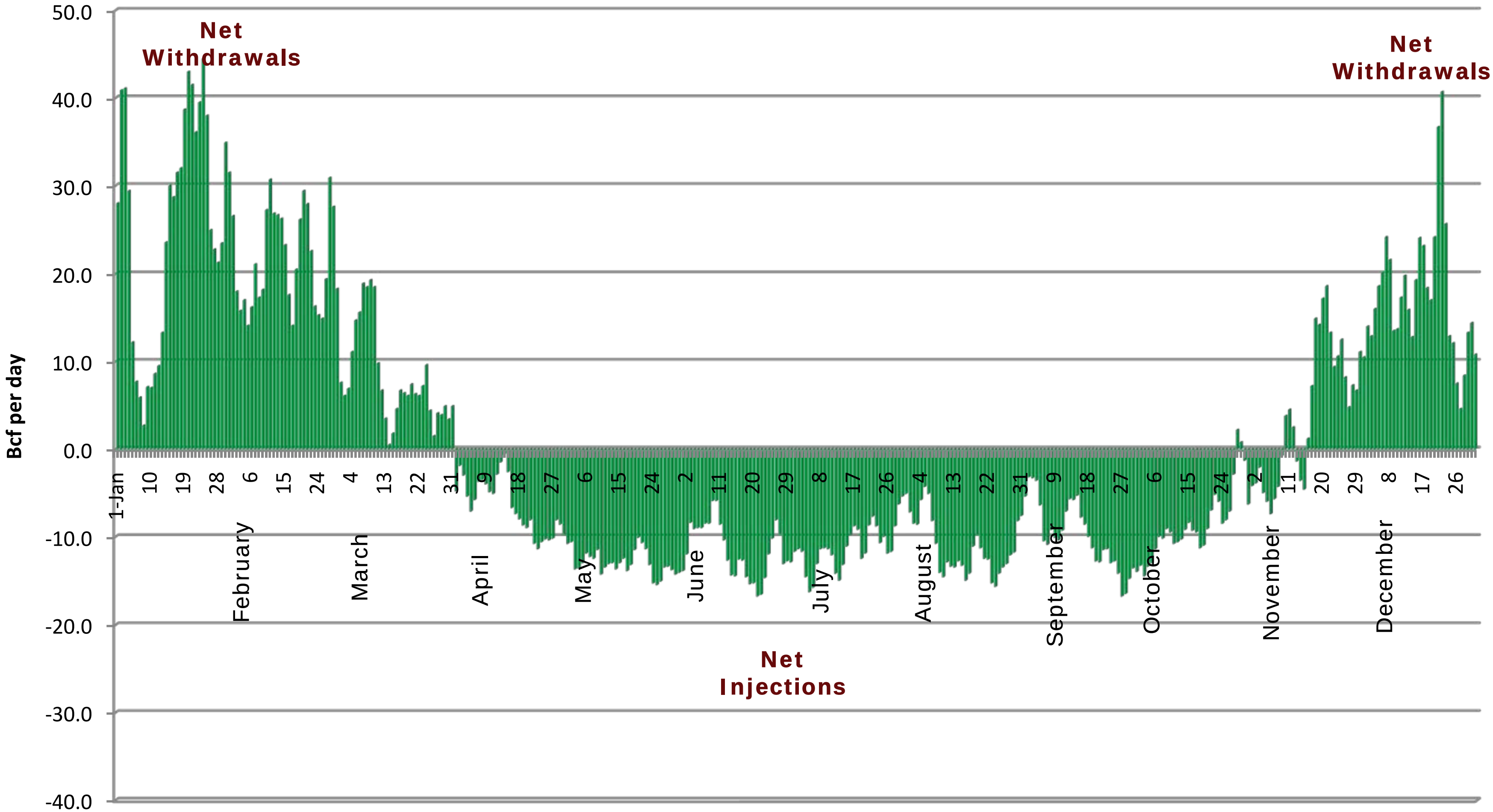
NATURAL GAS SUPPLY
(JANUARY 1-DECEMBER 31, 2008)



Source*: Bentek Energy LLC*, *Energy Market Fundamentals*, December 31, 2008.

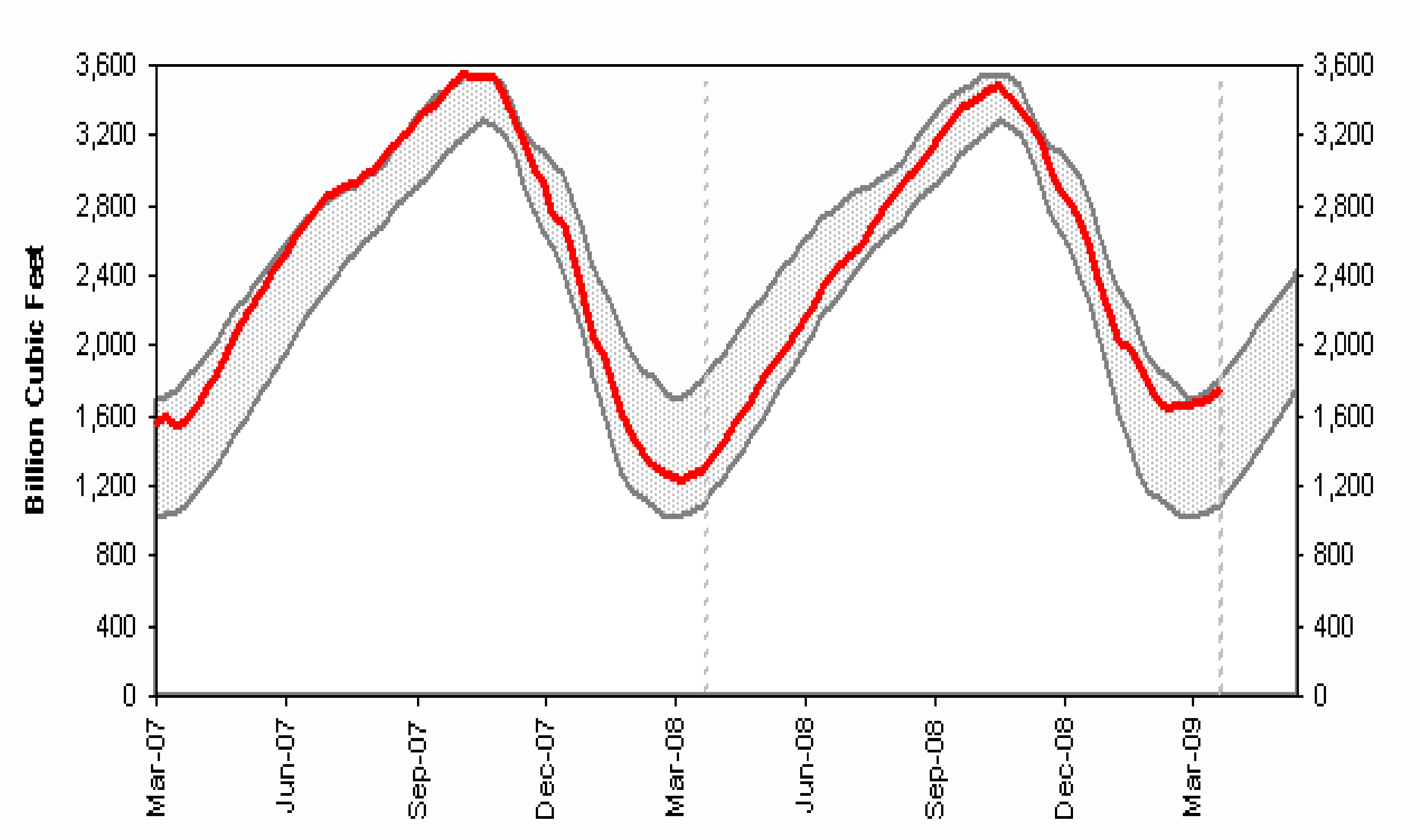
AGA American Gas Association

NET STORAGE ACTIVITY
(JANUARY 1-DECEMBER 31, 2008)



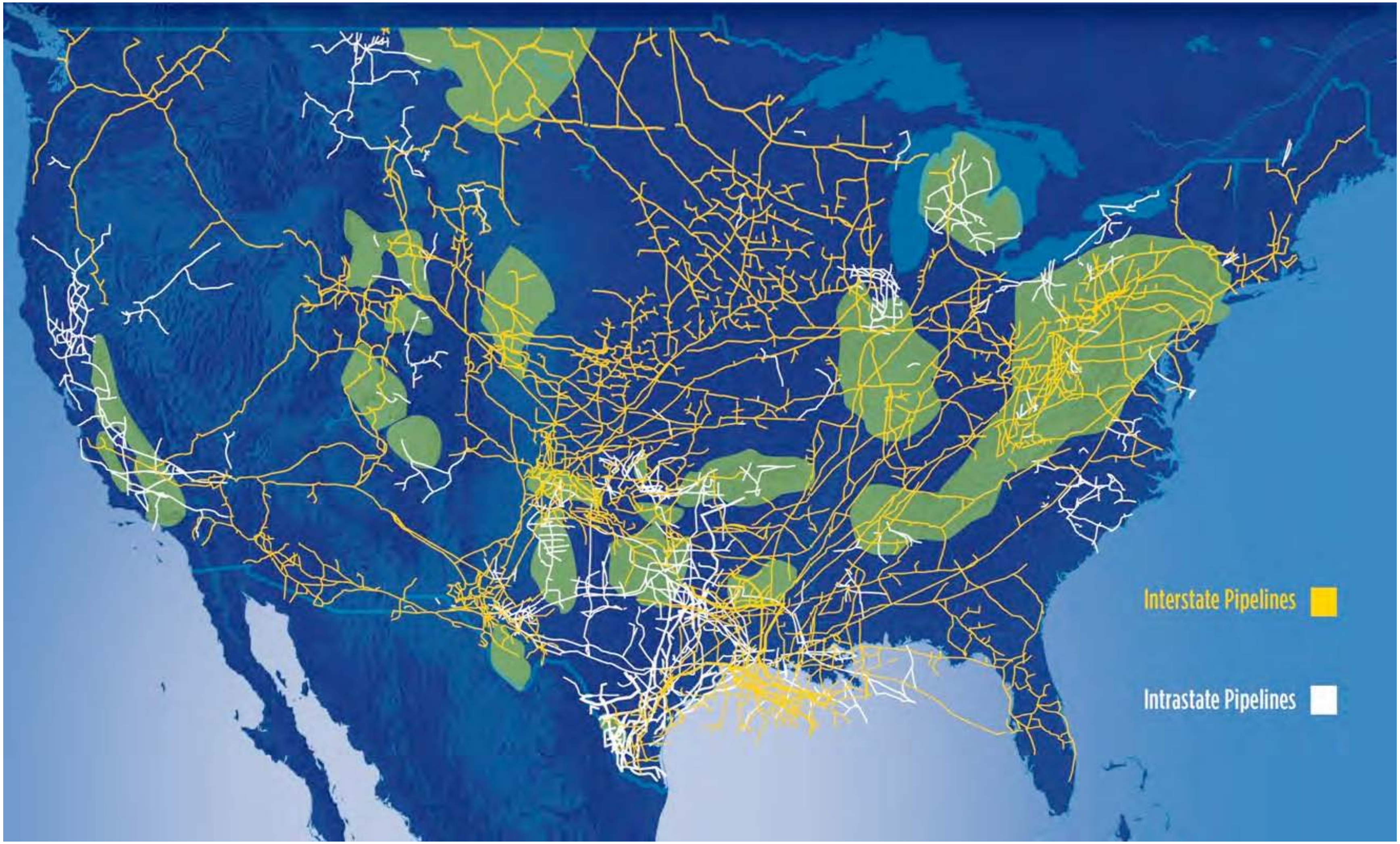
Source: *Bentek Energy LLC*, *Energy Market Fundamentals,* December 31, 2008.

U.S. WORKING GAS IN UNDERGROUND STORAGE



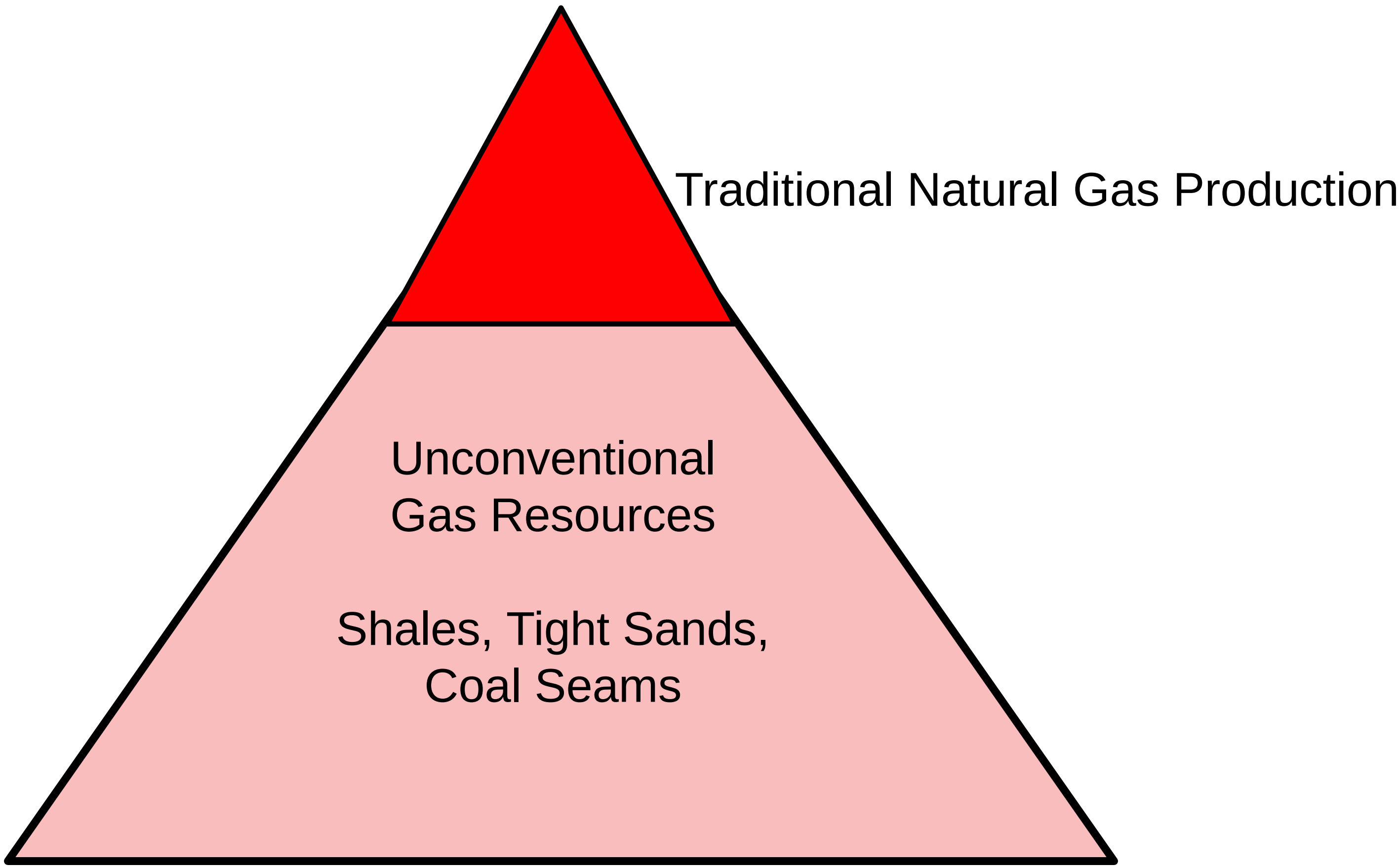
Source: *Energy Information Administration*.

SHALE BASINS AND THE U.S. PIPELINE GRID

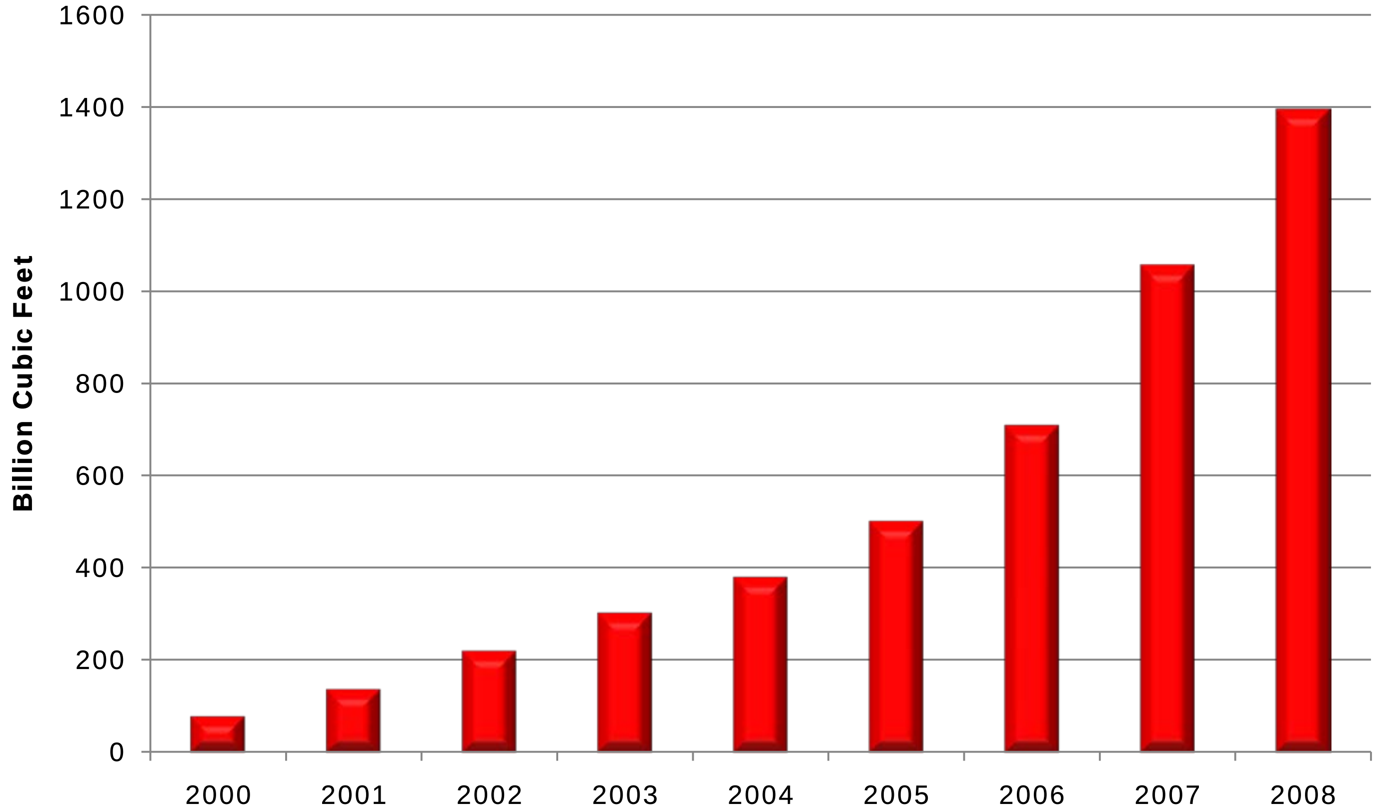


Source: *American Clean Skies Foundation*.

Unconventional Resource Development



NATURAL GAS PRODUCTION BARNETT SHALE 2000-2008



Source: *Texas Railroad Commission*

American Gas Association

SOUTHWESTERN ENERGY AND THE FAYETTEVILLE SHALE

- As of June 30, 2008, Southwestern had drilled and completed a total of 619 operated wells, of which 554 were horizontal

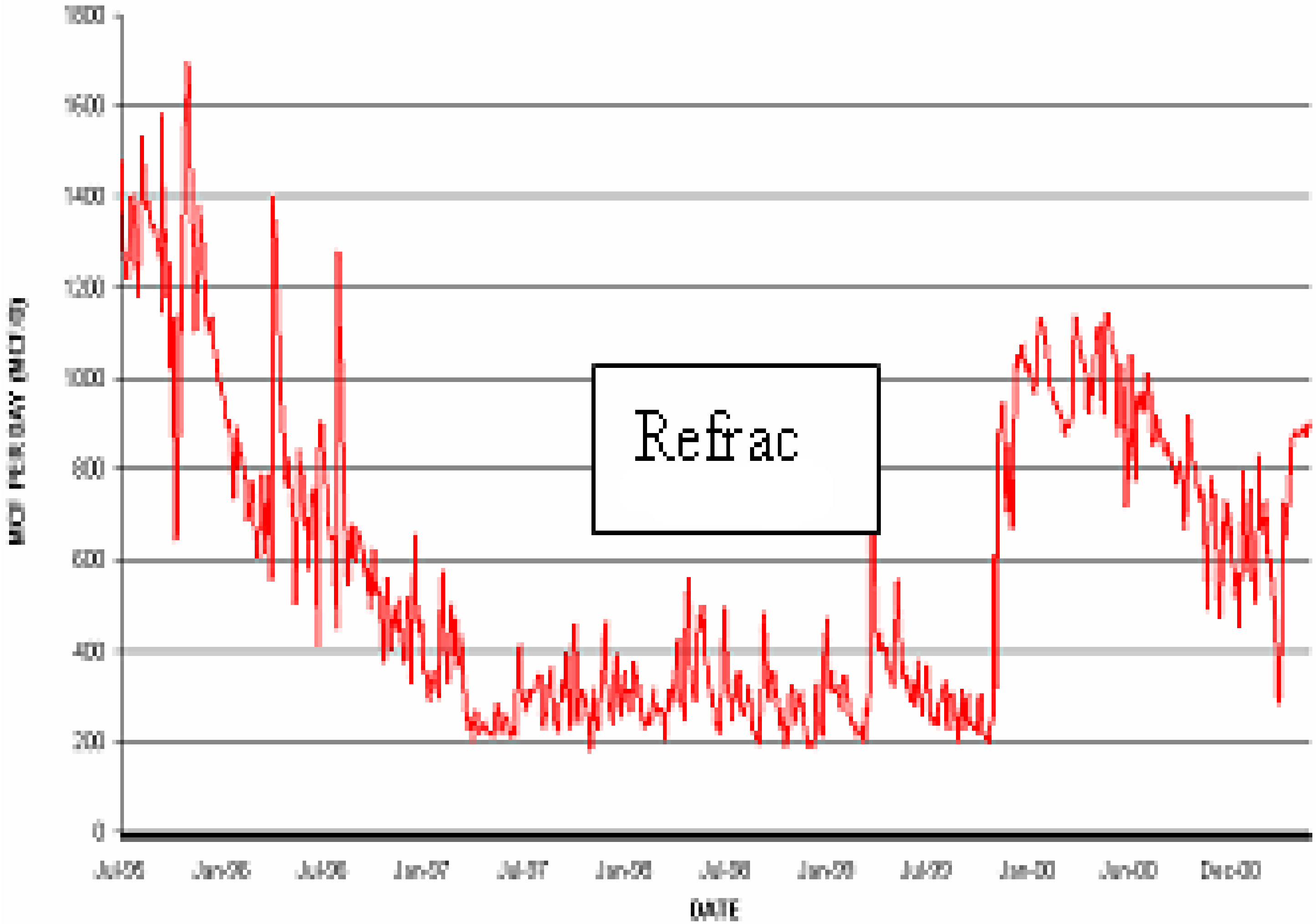
- Of the 554 horizontal wells, 507 had been fractured using slickwater or crosslinked gel fluids

- Production rates from the Fayetteville Shale play area was approximately 500 MMcf per day

- In 2008, the company had 22 drilling rigs running in the Fayetteville Shale, 15 capable of drilling horizontal wells and 7 smaller rigs spudding the vertical section of the wells

- Horizontal wells had an average completed well cost of $2.8 million per well, average horizontal lateral length of 3,562 feet and average time to drill to total depth of 14 days

GENERAL CHARACTERISTICS OF PRODUCTIVE SHALES



Source: William Grieser, Halliburton Company.

SHALE GAS RESOURCE ESTIMATES

Potential Gas Committee added about ***200*** *Tcf to U.S. resource assessment between 2004 and 2006 – almost all attributed to new shale-related data*

Navigant Consulting, Inc. (2008) estimates ***275-842*** *Tcf from 17 U.S. shale plays*

AGA American Gas Association

SELECTED SHALE GAS RESOURCE ESTIMATES

Shale Play	Estimate (Tcf)	Max Gas In-Place (Tcf)
Antrim	*13*	*76*
Appalachian	*70*	*1744*
Marcellus	*34*	*1500*
Haynesville	*34*	*717*
Fayetteville	*26*	*52*
Barnett	*26*	*168*
Lewis (New Mexico)	*10*	*61*
Lewis (Wyoming)	*14*	*98*

Mean estimate for U.S. shale resources, 274 Tcf
Gas in-place estimates as high as 3,765 Tcf
(Navigant Consulting, Inc.)

AGA American Gas Association

SHALE GAS PRODUCTION ESTIMATES

*Depending on the source, some analysts estimate that shale production now at about **5** Bcf per day will grow to **27-35** Bcf per day by the end of the next decade*

Will this be additive to current production rates or will it only replace other declining production capability?

American Gas Association

U.S. LNG IMPORT CAPACITY 2008

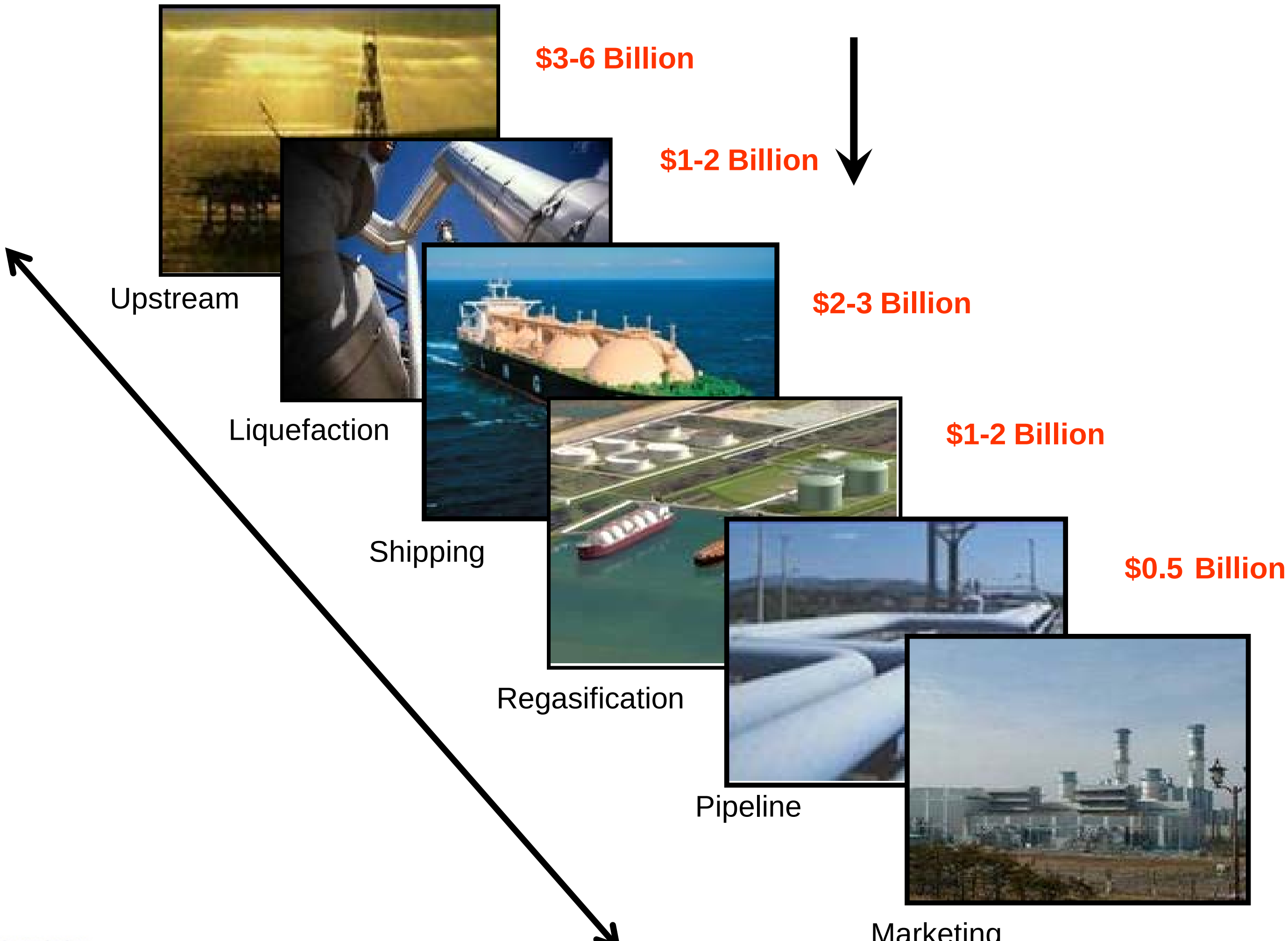
Everett, MA	1.035 Bcfd
Cove Point, MD	1.800 Bcfd
Elba Island, GA	1.200 Bcfd
Lake Charles, LA	2.100 Bcfd
Gulf Gateway, LA	0.500 Bcfd
Northeast Gateway, MA	0.800 Bcfd
Freeport, TX	1.500 Bcfd
Sabine, LA	2.600 Bcfd
Total	*11.535 Bcfd*

Source: Federal Energy Regulatory Commission

GLOBAL DEMAND GROWTH

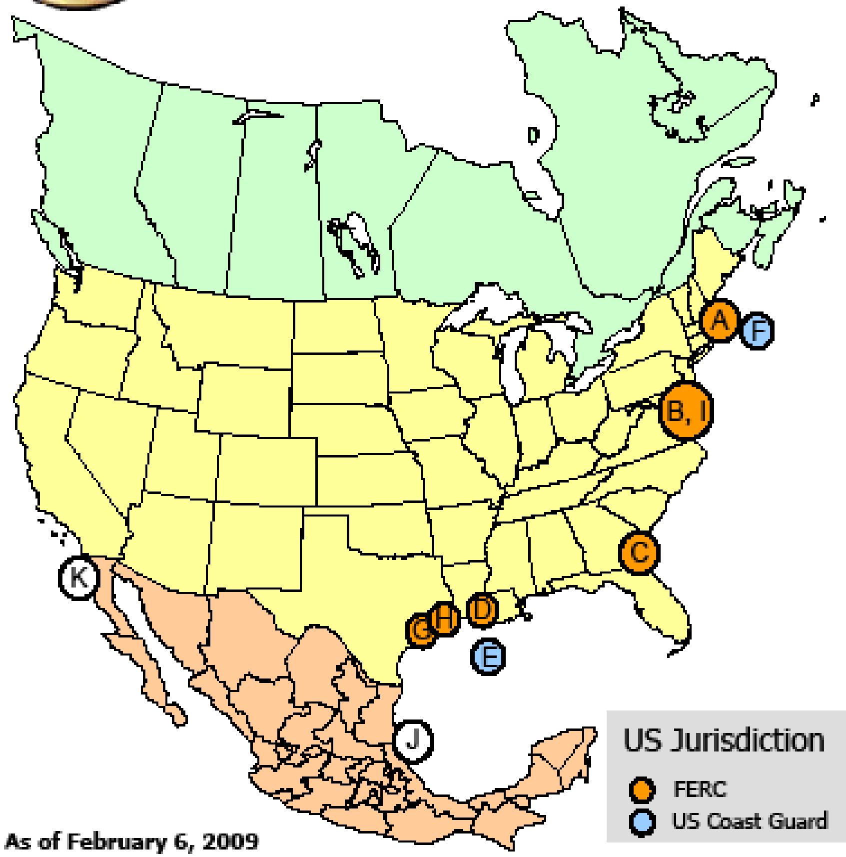
DRIVING LARGE INVESTMENTS ACROSS THE LNG VALUE CHAIN

Range of Investments by Sector (for 2 BCFD delivery)



North American LNG Terminals

Existing



As of February 6, 2009

Note: There is an existing import terminal in Peñuelas, PR. It does not appear on this map since it can not serve or affect deliveries in the Lower 48 U.S. states.

U.S.

A. Everett, MA : 1.035 Bcfd (SUEZ LNG - DOMAC)

B. Cove Point, MD : 1.0 Bcfd (Dominion - Cove Point LNG)

C. Elba Island, GA : 1.2 Bcfd (El Paso - Southern LNG)

D. Lake Charles, LA : 2.1 Bcfd (Southern Union - Trunkline LNG)

E. Gulf of Mexico: 0.5 Bcfd, (Gulf Gateway Energy Bridge - Excelerate Energy)

F. Offshore Boston: 0.8 Bcfd, (Northeast Gateway- Excelerate Energy)

G. Freeport, TX: 1.5 Bcfd, (Cheniere/Freeport LNG Dev.)

H. Sabine, LA: 2.6 Bcfd (Sabine Pass Cheniere LNG)

I. Cove Point, MD : 0.8 Bcfd (Dominion – Expansion)*

Mexico

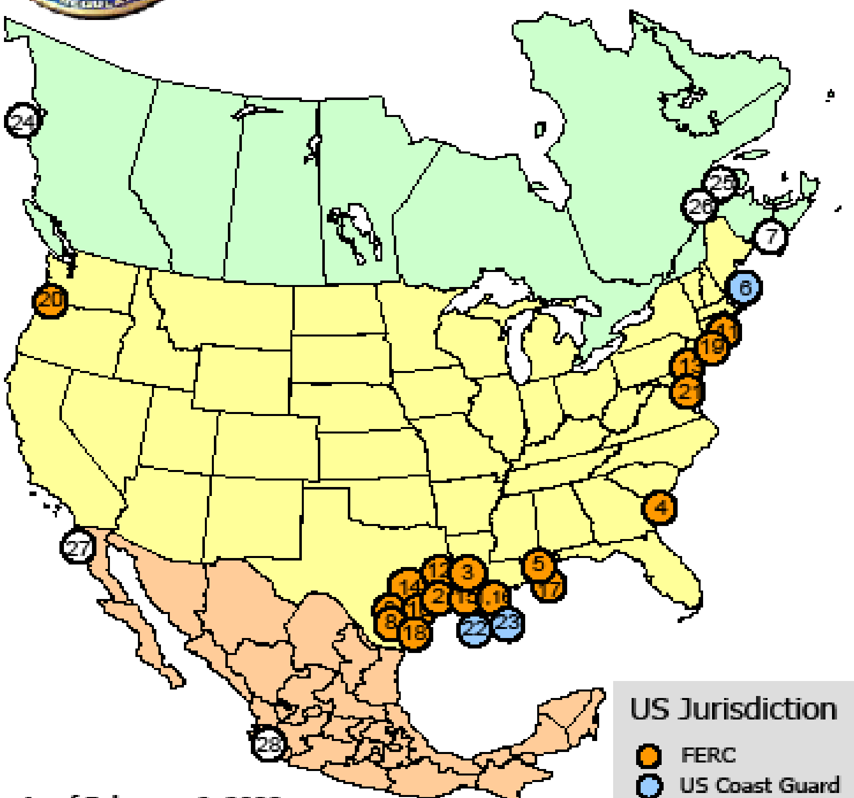
J. Altamira, Tamaulipas: 0.7 Bcfd, (Shell/Total/Mitsui)

K. Baja California, MX: 1.0 Bcfd, (Sempra)

Office of Energy Projects

North American LNG Terminals

Approved



As of February 6, 2009

* *Expansion of an existing facility*

APPROVED - UNDER CONSTRUCTION

U.S.

1. Hackberry, LA: 1.8 Bcfd (Cameron LNG - Sempra Energy)
2. Sabine, TX: 2.0 Bcfd (Golden Pass - ExxonMobil)
3. Sabine, LA: 1.4 Bcfd (Sabine Pass Cheniere LNG - Expansion)*
4. Elba Island, GA: 0.9 Bcfd (El Paso - Southern LNG Expansion)*
5. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Energy LLC)
6. Offshore Boston, MA: 0.4 Bcfd (Neptune LNG - Tractebel)

Canada

7. St. John, NB: 1.0 Bcfd, (Canaport - Irving Oil)

APPROVED - NOT UNDER CONSTRUCTION

U.S. - FERC

8. Corpus Christi, TX: 1.0 Bcfd (Ingleside Energy - Occidental Energy Ventures)
9. Corpus Christi, TX: 2.6 Bcfd, (Cheniere LNG)
10. Corpus Christi, TX : 1.1 Bcfd (Vista Del Sol - 4Gas)
11. Fall River, MA : 0.8 Bcfd, (Weaver's Cove Energy/Hess LNG)
12. Port Arthur, TX: 3.0 Bcfd (Sempra)
13. Logan Township, NJ : 1.2 Bcfd (Crown Landing LNG – BP)
14. Cameron, LA: 3.3 Bcfd (Creole Trail LNG - Cheniere LNG)
15. Freeport, TX: 2.5 Bcfd (Cheniere/Freeport LNG Dev. - Expansion)
16. Hackberry, LA: 0.85 Bcfd (Cameron LNG - Sempra Energy - Expansion)
17. Pascagoula, MS: 1.3 Bcfd (Casotte Landing - ChevronTexaco)
18. Port Lavaca, TX: 1.0 Bcfd (Calhoun LNG - Gulf Coast LNG Partners)
19. LI Sound, NY: 1.0 Bcfd (Broadwater Energy-TransCanada/Shell)
20. Bradwood, OR: 1.0 Bcfd (Northern Star LNG - Northern Star Natural Gas LLC)
21. Baltimore, MD: 1.5 Bcfd (AES Sparrows Point - AES Corporation)

U.S. - MARAD/Coast Guard

22. Port Pelican: 1.6 Bcfd, (Chevron Texaco)
23. Gulf of Mexico: 1.0 Bcfd (Main Pass McMoRan Exp.)

Canada

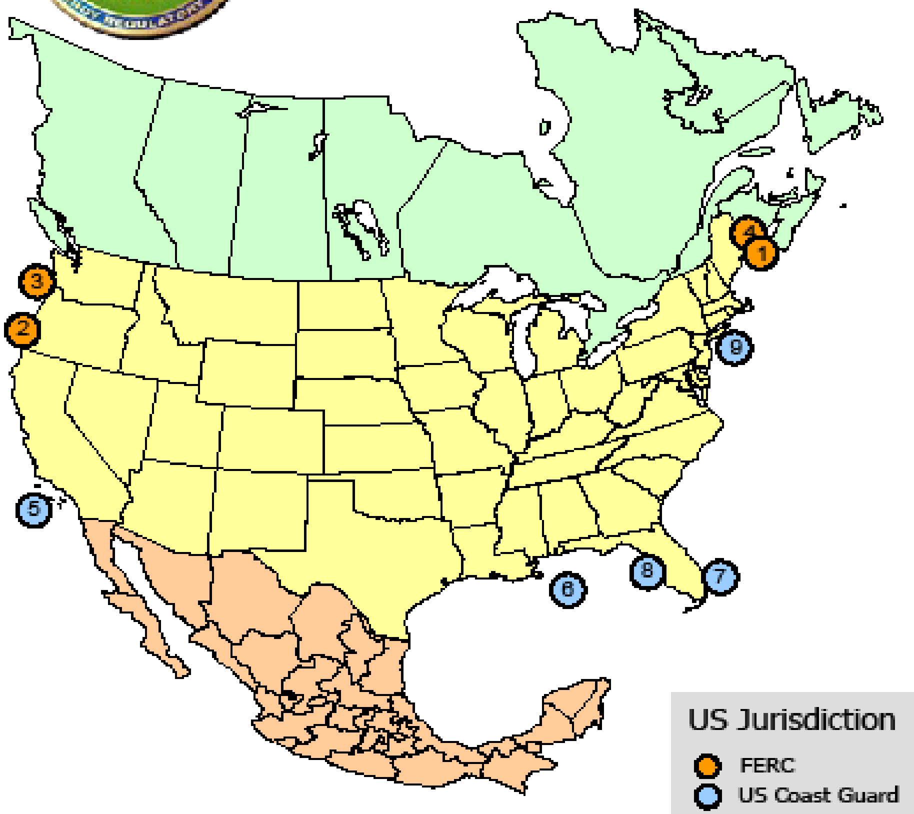
24. Kitimat, BC: 1.0 Bcfd (Galveston LNG)
25. Rivière-du- Loup, QC: 0.5 Bcfd (Cacouna Energy - TransCanada/PetroCanada)
26. Quebec City, QC : 0.5 Bcfd (Project Rabaska - Enbridge/Gaz Met/Gaz de France/Gazprom)

Mexico

27. Baja California, MX : 1.5 Bcfd (Energy Costa Azul - Sempra - Expansion)
28. Manzanillo, MX: 0.5 Bcfd (KMS GNL de Manzanillo)

North American LNG Import Terminals

Proposed



PROPOSED TO FERC

1. Robbinston, ME: 0.5 Bcfd (Downeast LNG - Kestrel Energy)
2. Coos Bay, OR: 1.0 Bcfd (Jordan Cove Energy Project)
3. Astoria, OR: 1.5 Bcfd (Oregon LNG)
4. Calais, ME: 1.5 Bcfd (BP Consulting LLC)

PROPOSED TO MARAD/COAST GUARD

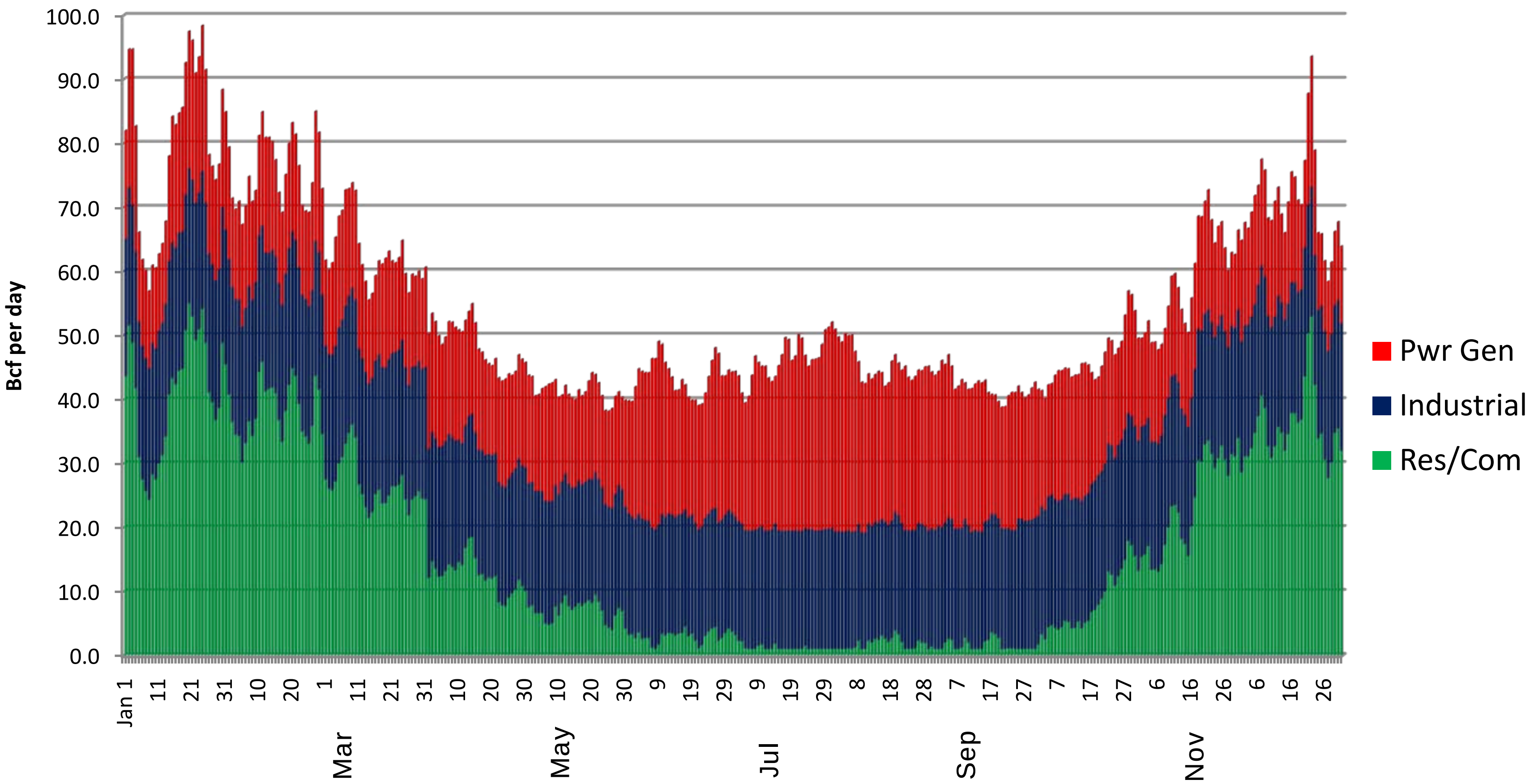
5. California Offshore : 1.4 Bcfd, (Clearwater Port LLC)
6. Gulf of Mexico: 1.4 Bcfd (Bienville LNG - TORP Technology)
7. Offshore Florida: 1.9 Bcfd (SUEZ Calypso - SUEZ LNG)
8. Offshore Florida: 1.2 Bcfd (Hoëgh LNG - Port Dolphin Energy)
9. Offshore New York: 2.0 Bcfd (Safe Harbor Energy - ASIC, LLC)

* *Expansion of an existing facility*

As of February 6, 2009

Office of Energy Projects

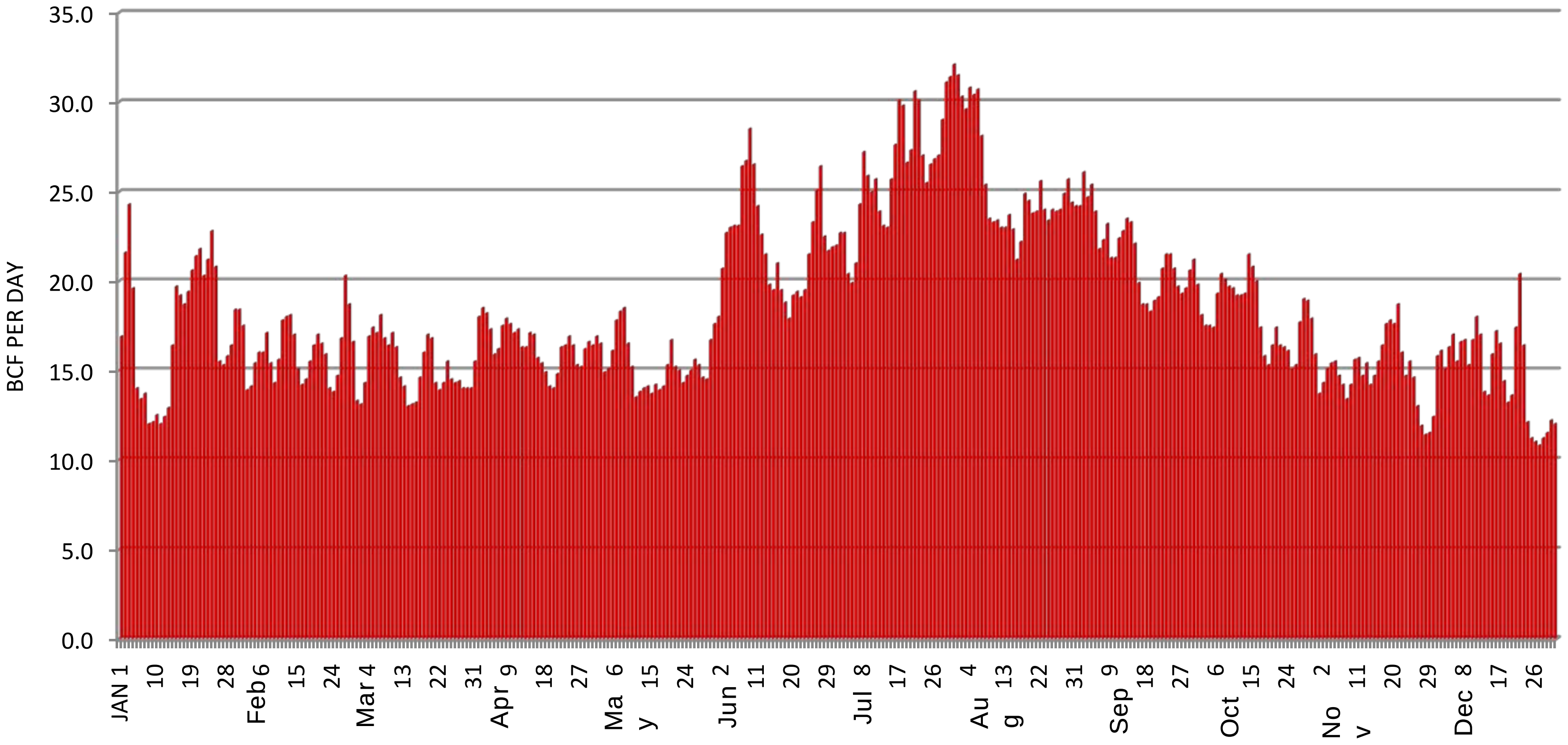
DAILY NATURAL GAS CONSUMPTION BY SECTOR
JANUARY 1-DECEMBER 31, 2008



Source: Bentek Energy LLC, *Energy Market Fundamentals*, December 31, 2008.

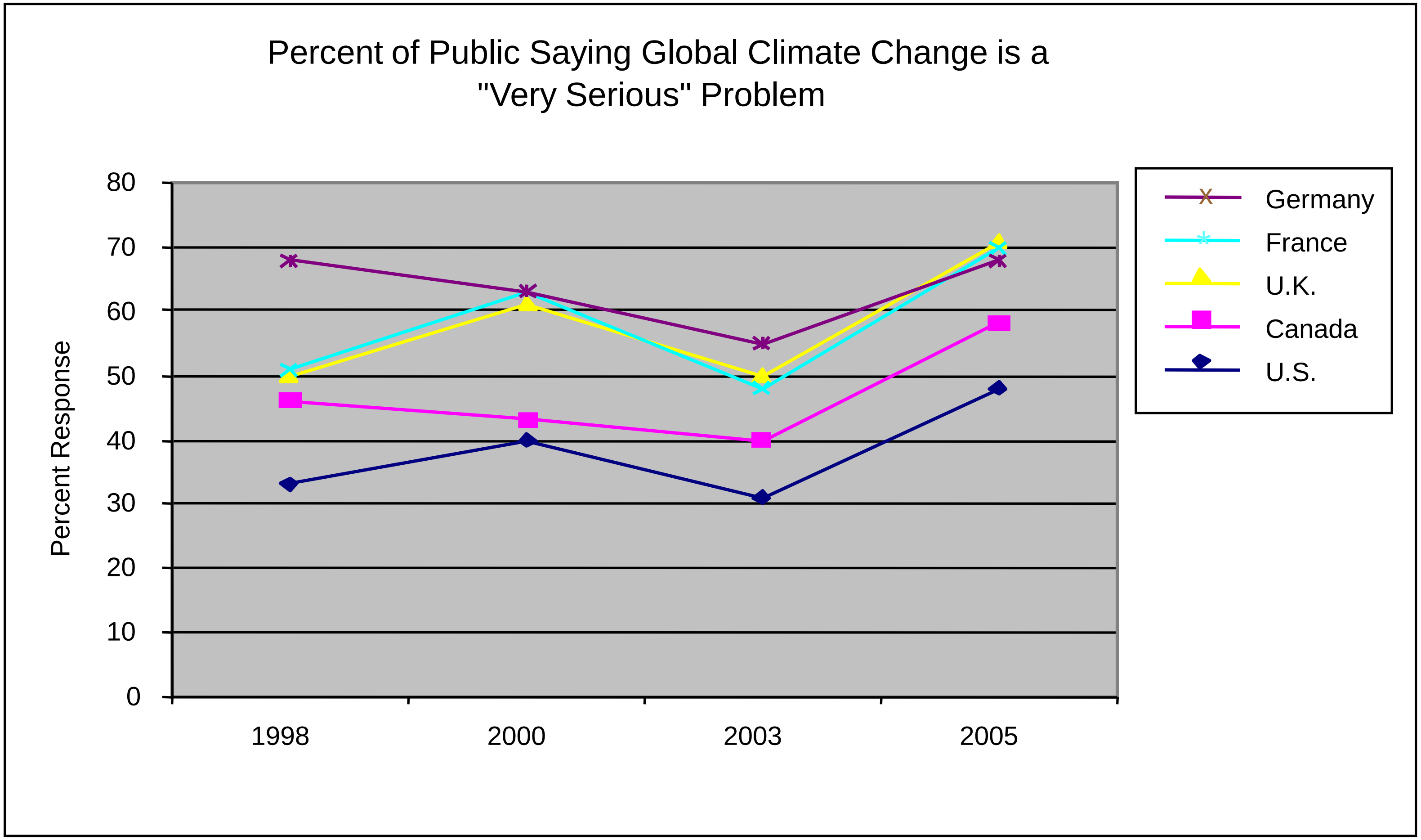
POWER GENERATION AVERAGE DAILY NATURAL GAS CONSUMPTION

JANUARY 1-DECEMBER 31, 2008



Source: Bentek Energy LLC, *Energy Market Fundamentals*, December 31, 2008.

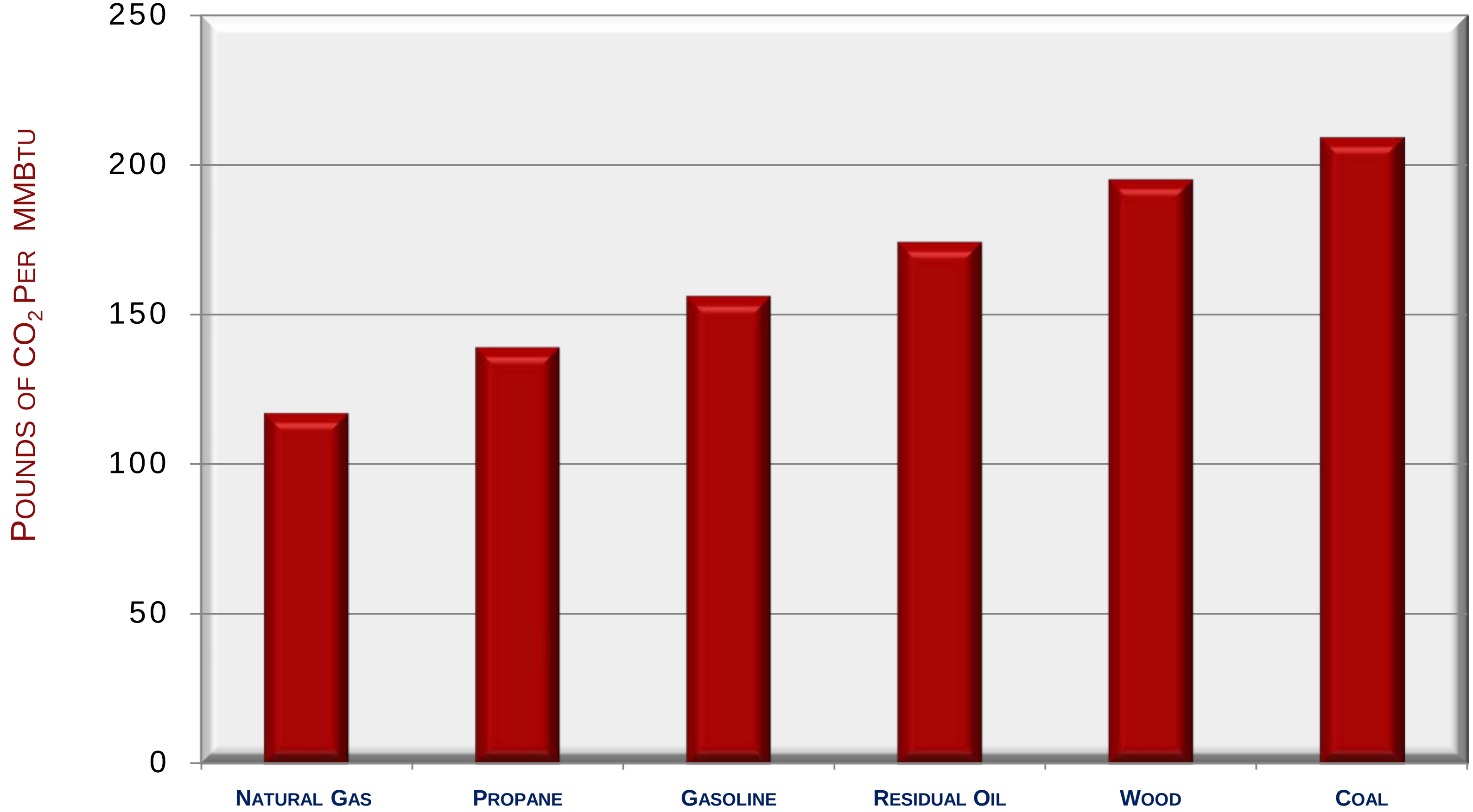
GLOBAL CLIMATE CHANGE



Source: *GlobeScan,* Presentation to G8+5 Legislators Forum, 6 December 2005.

AGA American Gas Association

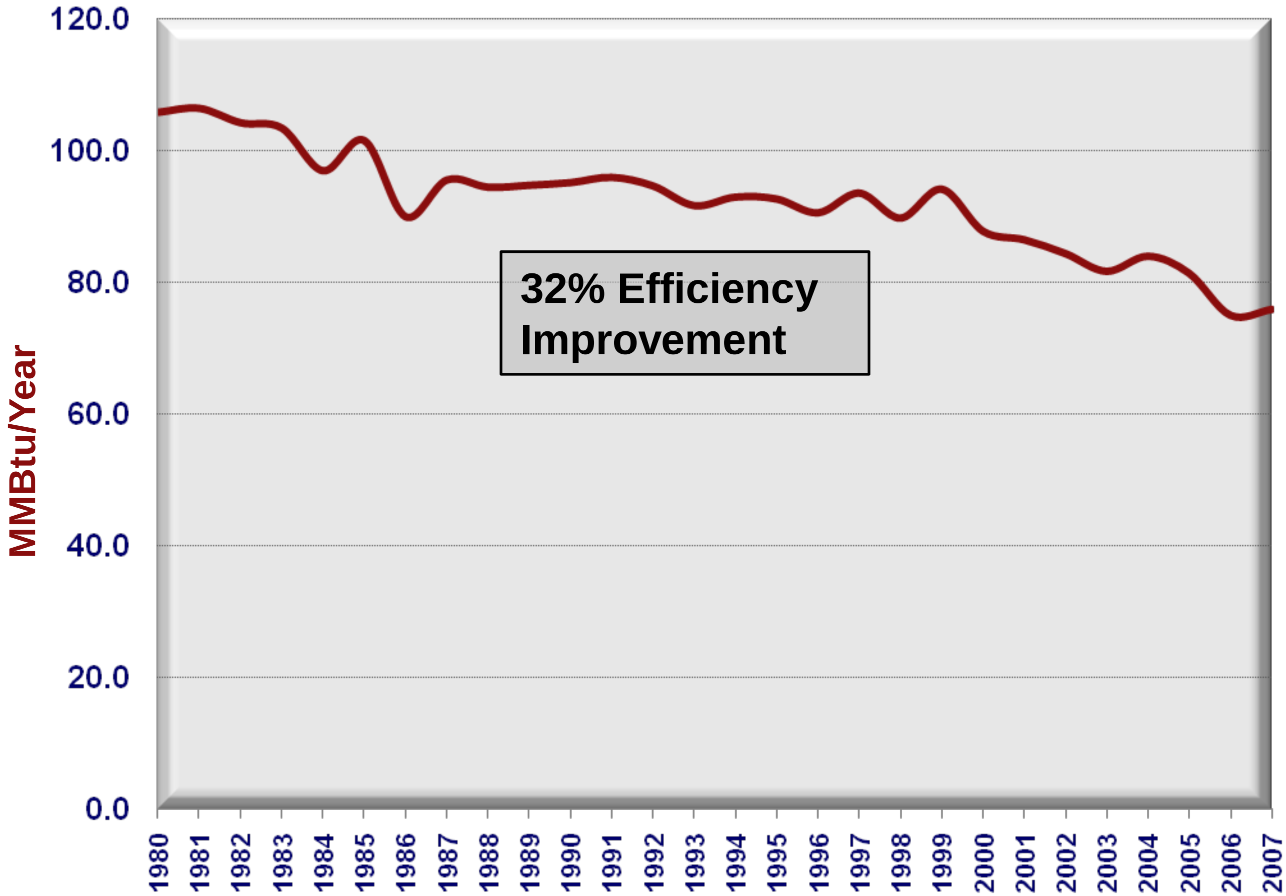
NATURAL GAS IS BY FAR THE CLEANEST OF ALL FOSSIL FUELS



Source: *U.S. Energy Information Administration.*

AGA American Gas Association

CONSUMPTION PER RESIDENTIAL NATURAL GAS CUSTOMER

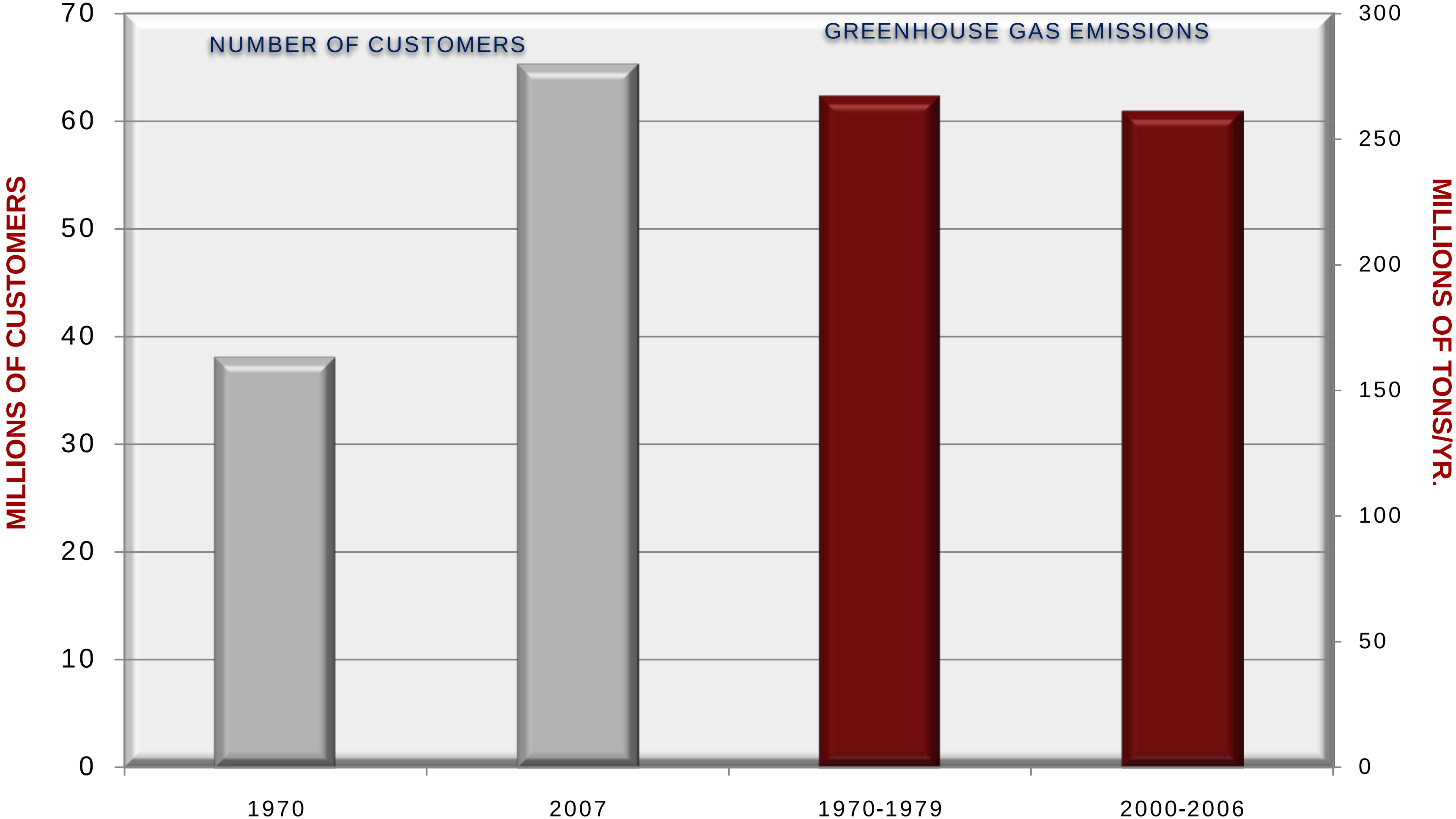


Source: *U.S. Energy Information Administration* and *American Gas Association*.

NOTE: Data is “weather normalized” or adjusted to reduce the impact of abnormally warm or cold weather.

AGA American Gas Association

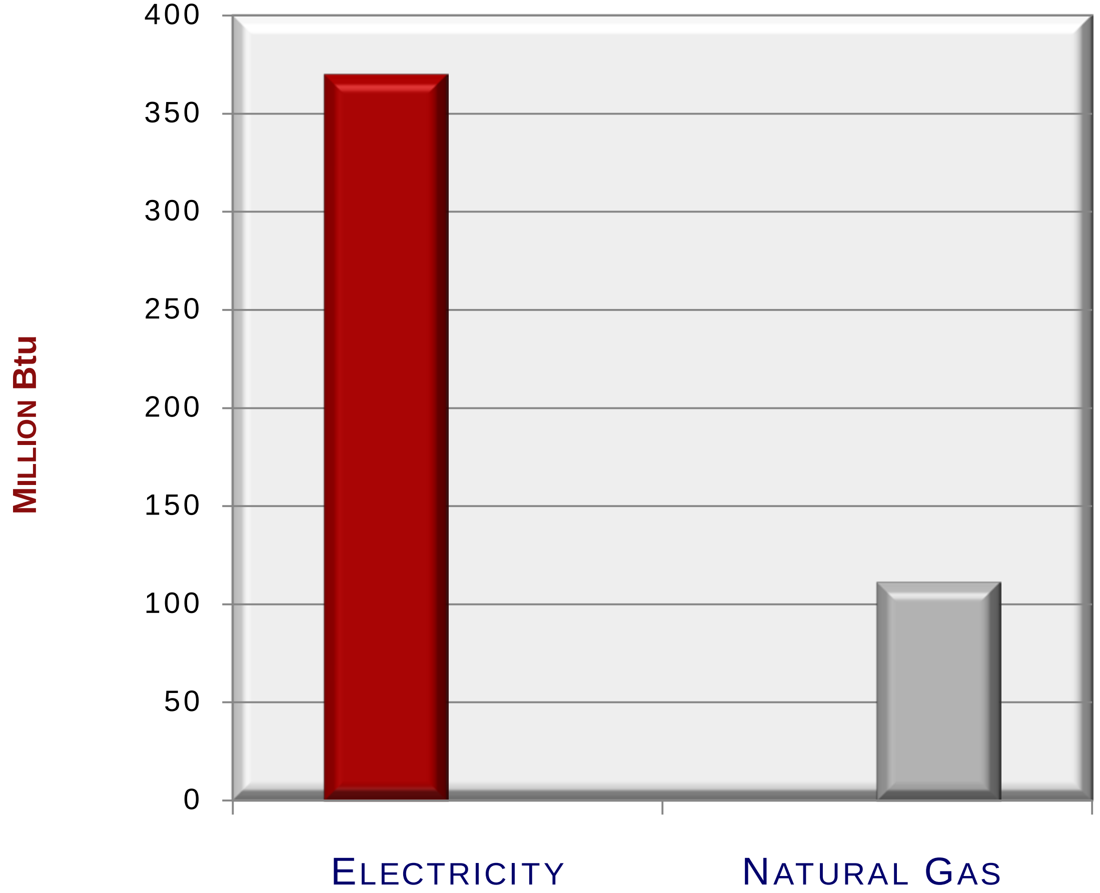
RESIDENTIAL NATURAL GAS CUSTOMERS ARE GROWING, BUT THEIR GREENHOUSE GAS EMISSIONS HAVE DECLINED



Source: *U.S. Environmental Protection Agency, U.S. Energy Information Administration* and *American Gas Association*.

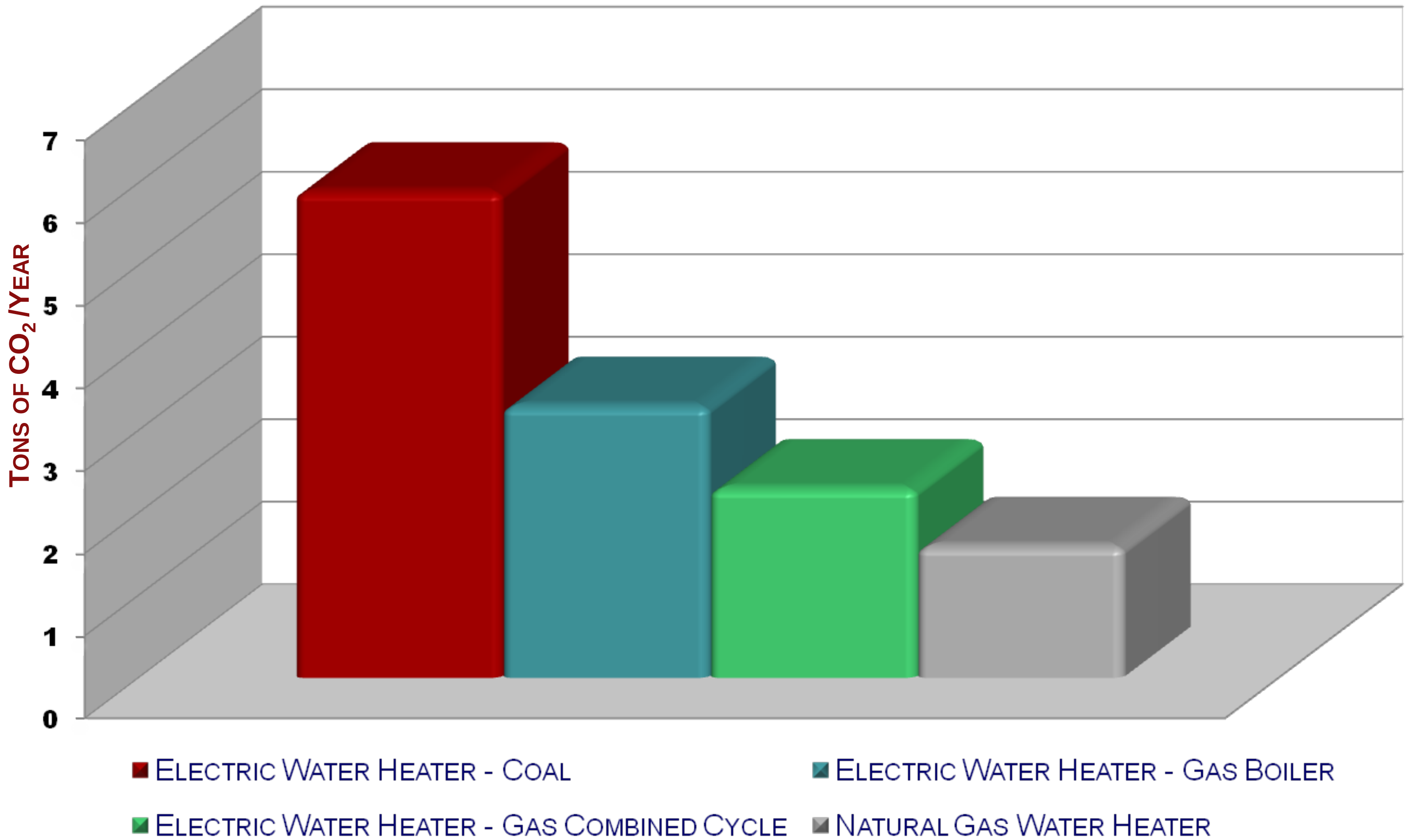
AGA American Gas Association

TOTAL ENERGY EFFICIENCY
(SOURCE ENERGY REQUIRED TO DELIVER 100 MMBtu TO END-USE CUSTOMER)



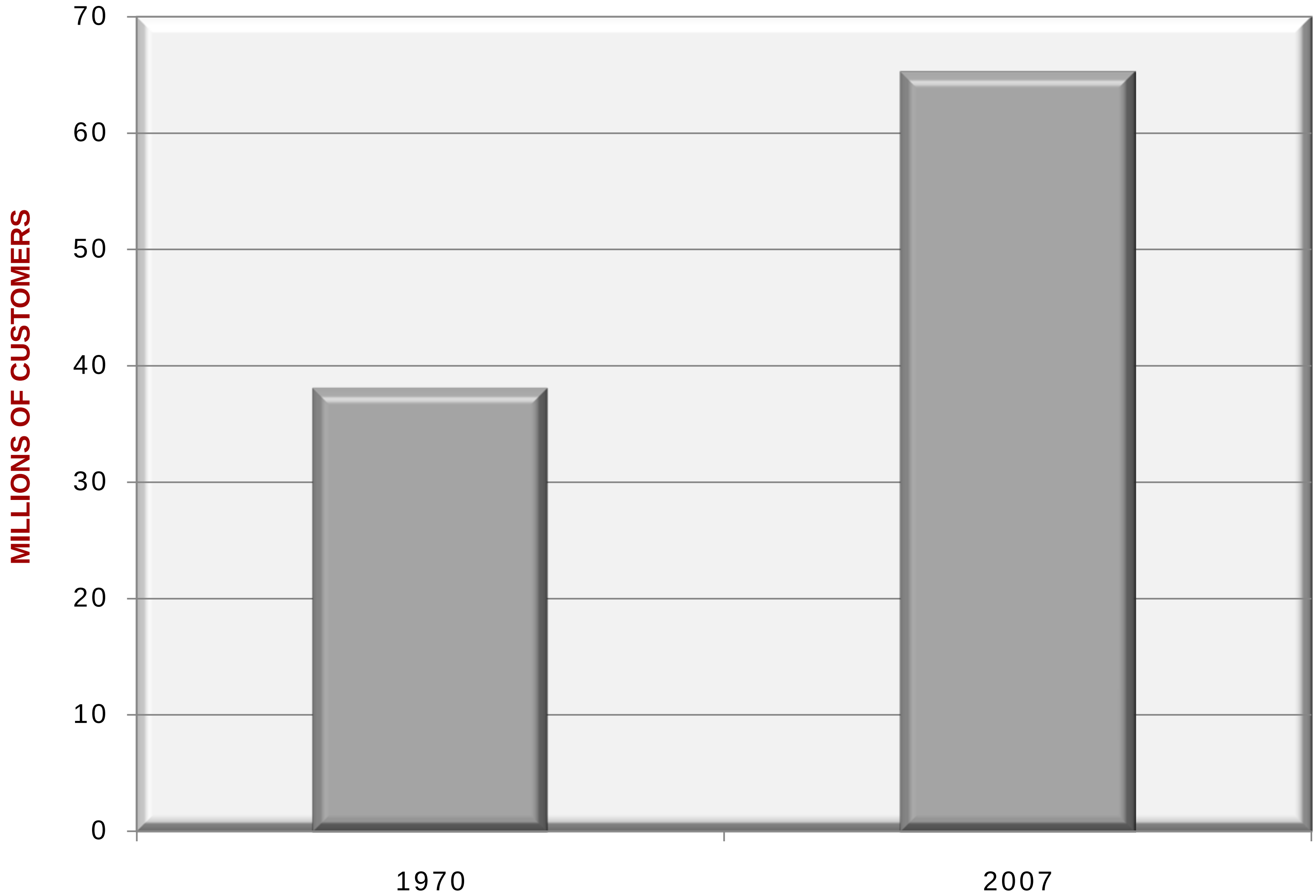
NOTE: National average electricity generation mix.

DIRECT NATURAL GAS USE REDUCES GREENHOUSE GAS EMISSIONS



AGA American Gas Association

NUMBER OF NATURAL GAS CUSTOMERS INCREASING



DECOUPLING TARIFFS
(AS OF JANUARY 2009)

APPROVED – 28 Companies, 16 States, 20 Million Res. Customers

1. AR – Arkansas Oklahoma
2. AR – Arkansas Western
3. AR – CenterPoint Energy
4. CA – Pacific Gas and Electric
5. CA - San Diego Gas and Elec.
6. CA – Southern California Gas
7. CA – Southwest Gas
8. CO – PSC of Colorado
9. IL – Integrys - Peoples Gas
10. IL – Integrys - North Shore Gas
11. IN – Citizens Gas & Coke
12. IN – Vectren Indiana Gas
13. IN – Vectren Southern Indiana Gas
    MA – Generic Proceeding
14. MD – Baltimore Gas and Elec.
15. MD – Washington Gas
16. NJ – NJ Natural Gas
17. NJ – South Jersey Gas
    NV – Generic Proceeding
18. NY – Consolidated Edison
19. NY – National Fuel Gas Dist.
20. NC - Piedmont Natural Gas
21. NC – PS Co. of North Carolina
22. OH – Vectren Ohio
23. OR – Cascade Natural Gas
24. OR – NW Natural Gas
25. UT – Questar Gas
26. VA – Virginia Natural
27. WA – Avista
28. WA – Cascade Natural Gas

PENDING – 11 Companies, 5 Additional States, 6 Million Res. Customers

1. CT – Connecticut Natural Gas
2. CT – Southern Connecticut Gas
3. IA – Black Hills Iowa Gas Utility
4. IL – Nicor
5. MA – New England Gas
6. MI – Consumers Energy
7. MN - CenterPoint Minnesota Gas
8. NY – Central Hudson Gas & Electric
9. NY – National Grid Niagara Mohawk
10. WA – NW Natural Gas
11. WI - Integrys - Wisconsin Public Service Co.

*** Of 65 Million US Residential Customers (2007) ***

AGA American Gas Association

INNOVATIVE UTILITY RATE DESIGNS: (GOOD FOR INVESTORS AND CUSTOMERS)

INVESTOR

- Promotes business sustainability
- Stabilizes margin recovery
- Reduces rate case frequency
- Reduces business risk

CUSTOMER

- Less natural gas used through efficiency/conservation programs
- Lower monthly bills through avoided gas costs
- Lower utility costs passed on
- Lower capital costs passed on

NATURAL GAS UTILITY INFRASTRUCTURE GROWTH PROJECTIONS

- To meet projected natural gas demand, as much as $100 billion may be spent by 2030 adding to distribution infrastructure.

OUR INDUSTRY'S FUTURE LOOKS BRIGHT

Abundant domestic supply resource base to meet demand growth at reasonable costs

Innovative rate designs to align interests of utility and customers

Increased direct use of natural gas can reduce energy consumption and costs, lower carbon emissions and enhance national energy security

Gas utility industry is a solid, safe, responsible investment

ADVOCACY SUMMARY

- Increase Supply
- Increase New Generation Diversity
- Increase Direct Use
- Increase LIHEAP
- Increase Recognition of Gas & Electric Differences
- Increase Conservation & Efficiency

American Gas Association

Thank You!

Declining Average Customer Use of Natural Gas: Issues and Options

Declining Average Use per Customer: Issues and Options for Canada's Natural Gas Distribution Utilities

This document was prepared for Canadian Gas Association by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

IndEco Strategic Consulting Inc.
77 Mowat Avenue, Suite 412
Toronto, ON, Canada
M6K 3E3

Tel: 416 532-4333
E-mail: **info@indeco.com**

IndEco report A6336

18 December 2006

Contents

List of figures and tables

Figures

Tables

Executive summary

Natural gas utilities across Canada are experiencing declining gas usage per customer. For some utilities the decline is across all sectors; for others the decline is centred on residential and on small commercial and small industrial customers. This decline has been happening in the market over time due to energy efficiency improvements in new construction and the turnover in stock to higher efficiency gas furnaces. The decline has gained greater notice in recent years because high and volatile gas prices are moving consumers to further reduce gas use. These prices are creating increased pressure on the utilities from governments and stakeholders to place greater emphasis on energy efficient gas use through the delivery of demand-side management (DSM) services to customers. In addition, there are specific factors pertinent to particular franchise areas that are magnifying the decline.

From a customer perspective, decline in average use is very positive; it means that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, decline in use per account has a positive benefit because this contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wise gas use and savings on gas bills. However, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

The Canadian Gas Association retained IndEco Strategic Consulting Inc. in June 2006 to explore at a high level the nature and extent of the decline in gas usage across Canadian natural gas utilities, to identify implications of this decline and to assess options for managing its negative consequences on the gas utilities. This paper documents the research and findings of this work.

Methodology

Ten natural gas utilities across Canada participated in this study. They are: AltaGas, ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Pacific Northern Gas (PNG) SaskEnergy, Terasen Gas and Union Gas. Each utility was asked to provide data from which to analyze actual declines in average use. Enbridge Gas New Brunswick and Heritage Gas in Nova Scotia were excluded from the study as these utilities are relatively new and are focused on adding customers to the distribution system.

In addition to obtaining data from the utilities relevant to analyzing declining average use, IndEco conducted telephone interviews in July and August 2006 with Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Terasen Gas and Union Gas, and in October 2006 with PNG and AltaGas to supplement the data analysis.

Findings and recommendations

A major finding of this work is that Canadian natural gas utilities have been experiencing a steady trend of declining natural gas use per customer. Analysis of actual use data, provided by the utilities over this period, and normalized by number of customers and weather, shows a decline in average use of natural gas across all sectors of 19% over the past 13 to 15 years, while across the residential sector, that decline has been 16%. This corresponds roughly to a decline in average use of 1.9% per year for all sectors and to a decline in average use in the residential sector specifically, of 1.1% per year.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to have, in general, a very minor effect on natural gas use change, other factors must be driving the decline.

Contributing factors to declining average use in Canada

Over time Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. In particular, there were improvements in the residential, and likely in the small commercial and institutional sectors, due to similar gas uses.

The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and is supportive of the 1.9% decline in all sectors together.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

We may be moving into a different era. In the past historical experience was a good predictor of the gas market in the future. Today, it may not be as reliable due to short to medium term supply shortages in natural gas, restructuring in the Canadian economy due to a high Canadian dollar relative to the US dollar, greater consumer awareness of energy efficiency and government pressure on gas utilities and others to assist customers to reduce gas bills. These factors could bring us to the tipping point of an accelerated declining average use.

Implications of declining average use for utilities and their customers

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, declining average use contributes to customer retention. This keeps natural gas competitive with alternative fuels. For utilities with DSM, their DSM programs will further help their customers to achieve wiser use.

A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas utility if the declines are not adequately captured in rates.

Utilities, such as ATCO Gas, AltaGas ,Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

How to address declining average use

The utility response to declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates. These conditions differ across the country and among the individual utilities.

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options are discussed in this paper, and they are: ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. These options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

Ignore declining average use

One option for dealing with declining average use is to ignore it. Rate design, load forecasting, or revenue recovery would not be adjusted to reflect any decline in average use per customer.

In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. For example, in a market that is nascent as the new infrastructure is being built based on the more recent gas use per customer data, any decline in customer usage year over year may be small and not have a significant impact on the utility's ability to recover its fixed costs in the short term. However, over time, the nascent utility will need to take declines in usage into account to protect the financial viability of the utility.

Incorporate declining average use in the load forecast

The most effective method of mitigating the effects of declining average use is through an offsetting increase in margin per unit rate. This can be accomplished through effective rate-setting either in cost-of-service or under PBR. The effectiveness of the methods will be largely dependent on the accuracy of the load forecast.

To the extent that the load forecast is accurate the utility and its customers are protected from declines in average use. In traditional rate-making the utility bears the full risk of underestimating declines in average use in the forecast and reaps the full benefits of overestimating declines. Underestimates lead to shortfalls in earnings for the utility until adjustments in rates are made to factor in a more appropriate estimate for decline in average use. Overestimates lead to higher than necessary rates for utility customers.

A utility can mitigate its risk associated with forecasting by trying to improve the accuracy of its forecast. For example, the utility could expand its efforts to obtain better data on both short-term and long-term trends regarding customer usage; it could work with other gas utilities across Canada to share knowledge on forecasting declining average use; and could encourage its provincial government and regulator to provide province-wide annual (and perhaps quarterly) data on trends in customer usage of energy, including natural gas. The regulator can also help to mitigate the utility forecasting risk by having annual rates cases.

Should experience reveal that the forecasts of declining average use are so unreliable that they result in significant margin erosion between offsetting adjustments, it may be necessary to track variances between forecast and actual declines in a declining average use tracker account, with true-ups made for under- and over-forecasting of the declines.

A simple tracking account, a Declining Average Use Tracker, would track variance between the forecast decline in average use and the actual decline for later disposition and true-up. True-ups would be made for both over-forecasting and under-forecasting the declines. Such an approach would eliminate the risk to the utility from the unpredictability of forecasting declining average use.

Revenue decoupling

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

RD is a blunt instrument that eliminates risks associated with revenue recovery related to sales. It is too blunt an instrument if the sole purpose is to address declining average use. Unless, a utility is experiencing other revenue loss risk factors in addition to declining average use (e.g. weather risks, debt recovery, infrastructure renewal) resulting in undue risk or there are other policy reasons for choosing RD, RD may not be appropriate.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM to create a more favourable climate for DSM. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin from reducing gas use per account.

For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

Adjustments to fixed and variable rate charges

Making adjustments to rate design to increase the amount of revenue recovered through fixed charges can address risk associated with declining average use to varying degrees. Its effectiveness as a tool for managing declining average use will depend on how much revenue recovery is embedded in the fixed charges. In theory, improvements to rate design that lead to a one to one match of fixed costs with fixed charges and variable costs with variable charges are preferred. However, in practice, this may be difficult to achieve due to customer opposition to increases in fixed charges. In jurisdictions where electricity prices are very competitive with gas prices, a slight increase in fixed gas charges for residential customers could be the tipping point for large scale fuel switching to electricity for heating needs. Even in jurisdictions with more competitive gas prices compared with electricity prices, increasing fixed charges may be unwelcome with customers to varying degrees depending on the franchise area. In particular, raising fixed charges is not likely to be well received in the Canadian context due to its impact on low volume customers and low-income customers, in particular.

Unless the rate design went to a rate based solely on fixed charges – a straight variable rate design – adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates. However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market, toward a better matching of fixed costs with fixed charges.

Addressing declining average use per customer in PBR

An Index Cap PBR caps a utility's prices or revenues using a formula.[1] This formula, called the Price Cap Index (PCI) or Revenue Cap Index (RCI), depending on which variable is being capped, restricts the growth

[1] Growth in PCI/RCI = P – X + Z

P is equal to the growth in an external inflation measure which can be economy-wide, industry-specific or for a peer group.

X is the X-factor which slows rate of revenue growth and which in North America is based on external industry productivity and input price information.

Z is the Z-factor which adjusts the PCI/RCI growth for external developments outside the company's control. Common Z factors include changes in government policy, change in industry accounting standards and natural disasters.

in allowed prices or revenues so that the growth must be less than or equal to the growth in the PCI or RCI. This is the most common form of PBR worldwide.

In Revenue Cap Index PBR or in Earnings Sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecast and actual declines in average use.

In a Price Cap Index PBR environment rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a load forecast and therefore, provides no opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added. Three alternatives for making this adjustment have been identified and discussed in this paper. One alternative would be to include a declining average use factor in the calculation of the price cap. A second alternative is to adjust the X-factor in determining the price to account for declining average use. A third alternative would be to make declining average use a Z factor and accumulate differences between the forecast decline in average use and the actual decline in average use in a tracker for later disposition. In general, making declining average use a Z factor may be less attractive to regulators than the other alternatives, as regulators try to minimize the number of Z factors. The alternative adopted should be tailored to the specific circumstances of the utility.

1 Introduction

1.1 Purpose of report

Natural gas utilities across Canada are experiencing declining gas usage per customer. For some utilities the decline is across all sectors; for others the decline is centred on residential and on small commercial and small industrial customers. This decline has been happening in the market over time due to energy efficiency improvements in new construction and the turnover in stock to higher efficiency gas furnaces. The decline has gained greater notice in recent years because high and volatile gas prices are moving consumers to further reduce gas use. These prices are creating increased pressure on the utilities from governments and stakeholders to place greater emphasis on energy efficient gas use through the delivery of demand-side management (DSM) services to customers. In addition, there are specific factors pertinent to particular franchise areas that are magnifying the decline.

From a customer perspective, decline in average use is very positive; it means that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, decline in use per account has a positive benefit because this contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wise gas use and savings on gas bills. However, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

The Canadian Gas Association retained IndEco Strategic Consulting Inc. in June 2006 to explore at a high level the nature and extent of the decline in gas usage across Canadian natural gas utilities, to identify implications of this decline and to assess options for managing its negative consequences on the gas utilities. This paper documents the research and findings of this work.

1.2 Methodology

The research and analysis of declining average natural gas use in Canada was based on data provided by AltaGas, ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Pacific Northern Gas (PNG) SaskEnergy, Terasen Gas and Union Gas. Enbridge Gas New Brunswick and Heritage Gas in Nova Scotia were excluded from the study as these utilities are relatively new and are focused on adding customers to the distribution system.[2]

In addition to obtaining data on declining average use provided by the utilities, IndEco conducted telephone interviews in July and August 2006 with Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, Terasen Gas and Union Gas, and in October 2006 with PNG and AltaGas. Interviews were used to obtain more detailed information on the gas utility experience with declining average use, the reasons the utilities have found for the decline, and steps taken and plans to address the decline. The data collection and interviews with the gas utilities was supplemented with a review of relevant published Canadian documents on declining average use and examples of the treatment of declining average use in US gas utilities, and informal consultations with various Canadian natural gas regulators.

It should be noted that the quantitative data submitted by each of the abovementioned Canadian utilities varied in completeness. In some cases, data were missing for earlier years within the range requested, while in other cases, sector specific data were not available. In analyzing and presenting this data herein, every effort is made to clearly present assumptions, omissions and limitations. Data were aggregated at the national level, as appropriate, to illustrate sector trends.

---

[2] Heritage Gas Nova Scotia has been providing natural gas distribution services since December 2003. By August 2006, the utility had over 500 customers and 100km of pipeline.
http://www.heritagegas.com/pipelinenews/pipelinenews.asp

Enbridge Gas New Brunswick has been providing natural gas distribution services since 1999, serving eight municipalities with a total of over 470 kilometers of distribution mains installed as of the end of 2005.
http://www.amazingenergy.ca/pdf/2006%20Construction%20Plan.pdf

2 Actual decline in average natural gas use per customer in Canada

This chapter describes the decline in average gas use in Canada experienced in natural gas distribution utilities over the last 13 to 15 years, based on an analysis of actual total gas use. Section 2.1 briefly describes the methodology used to analyse the gas use. Section 2.2 presents a discussion of the non-normalized total gas use. Section 2.3 describes the relationship between total gas use and changes in total number of customers. Section 2.4 normalizes total gas use by customer. Section 2.5 normalizes total gas use by customer and weather, and Section 2.6 presents the conclusions of the analysis.

2.1 Methodology for determining the actual decline

In July 2006, IndEco requested a standard set of data from seven gas utilities across Canada.[3] In October 2006, two additional utilities joined the study, PNG and AltaGas, and each was asked to provide the same standard set of data as the initial seven participants. Because of data availability, it was not possible to obtain a complete set of data from all utilities. The analysis has been carried out based on the data received. In addition to the data analysis, IndEco conducted telephone interviews in July-August 2006 with five of the seven initial utilities.[4] Interviews were conducted in October 2006 with PNG and AltaGas. The data were collected to determine whether the gas utilities across Canada were facing declining average use per customer and the interviews were used to identify what factors may be contributing to this decline.

PNG provided separate data for each of its two systems, PNG-West and PNG-Northeast (PNG-NE), and indicated that it would be inappropriate to aggregate and average this data across the company. The systems have very different market and geographic characteristics and are also treated separately for regulatory purposes.[5] As a result, IndEco treated each of the two systems within PNG as a 'separate company' for the purposes of the data analysis.

[3] ATCO Gas, Enbridge Gas Distribution, Gaz Métro, Manitoba Hydro, SaskEnergy, Terasen Gas and Union Gas.

[4] Telephone interviews were held with Gaz Métro, Enbridge Gas Distribution, Manitoba Hydro, Union Gas, and Terasen Gas.

[5] The PNG-NE system is located in the gas production area of British Columbia and as a result this area has very low transmission costs. The PNG-NE system experiences colder weather than the PNG-West system.

Total natural gas use was analysed and then normalized by customer and by weather. The results of this analysis reveal that in Canada, natural gas use per customer in both the residential sector and across all sectors has been steadily declining over the last 13 to 15 years.

2.2 Non–normalized total natural gas use

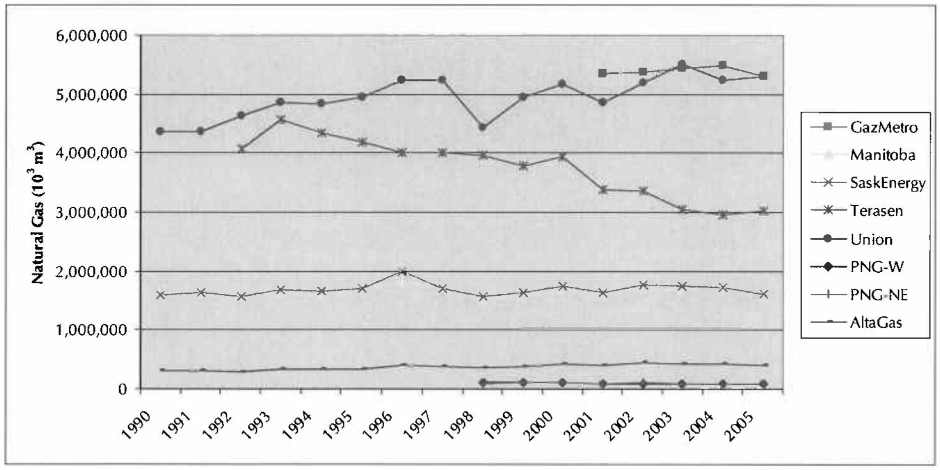
In the six utilities providing comprehensive data on actual natural gas use in and before 2005, a range in change in natural gas use was seen in both the residential and the non-residential sectors. Changes year to year in the numbers of customers served, in the climatic temperature (as characterized in this study as Heating Degree Days), and in the demand for natural gas per customer are contributing factors to the change.

As shown in Figure 1, total actual natural gas used across all sectors over the last 13 to 15 years ranged from a decline in total gas use of 25% for Terasen Gas to an increase in total gas use of 21% for Union Gas and 27% for AltaGas. The other utilities generally reported much smaller changes, with an average of a 5% increase over the period. Figure 2 aggregates the total natural gas use for the five utilities that provided IndEco with data from 1992 to 2005 and indicates that their total actual gas consumption over this period was relatively stable.

Change in actual natural gas use between 1990 and 2005 in the non-residential sectors ranged from a decline of 52% to an average value of an increase of 3%, to a maximum increase of 49%.[6]

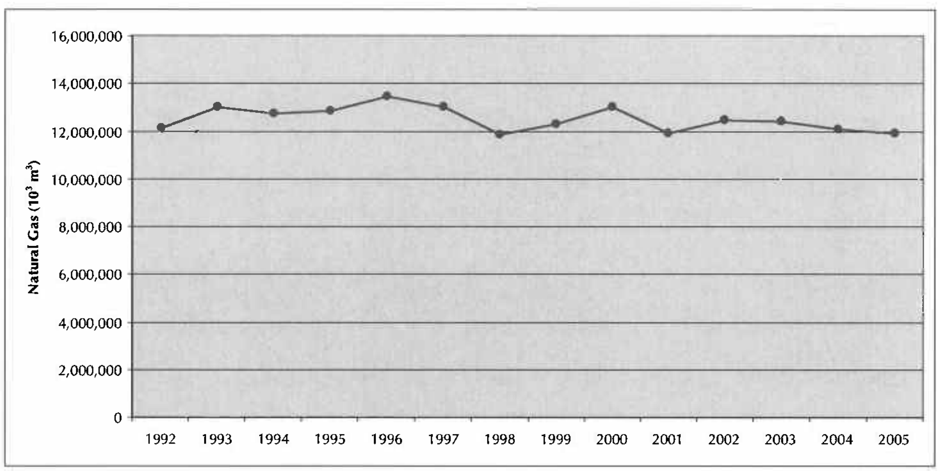
[6] Based on data provided by the participating gas utilities.

Figure 1 Annual natural gas use in all sectors, 1990 to 2005



Source: Survey of LDCs, July-November 2006.

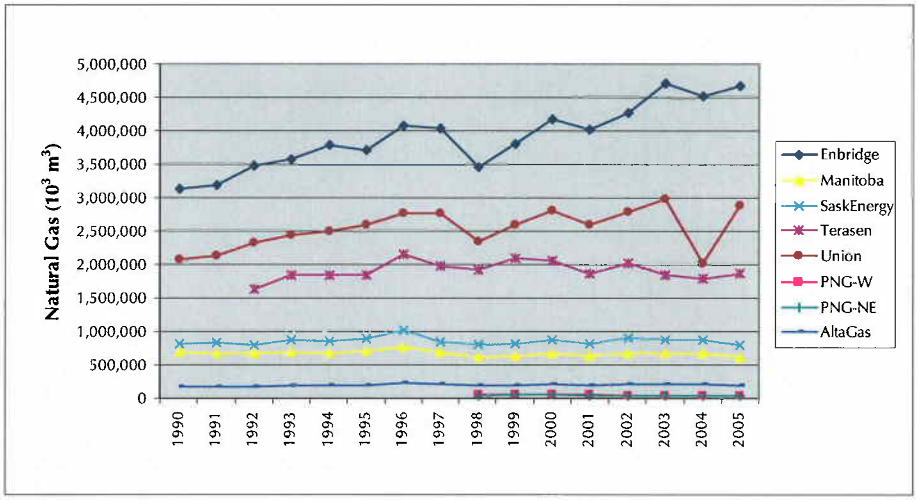
Figure 2 Annual natural gas use in all sectors, 1992 to 2005 (total from 5 utilities across Canada)



Source: Survey of LDCs, July-November 2006.

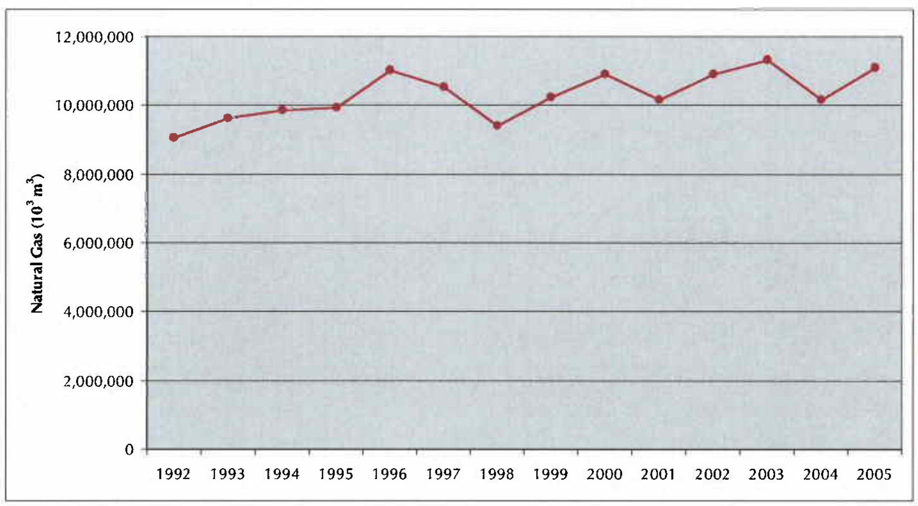
Actual natural gas use in the residential sector over the last 13 to 15 years, depicted in Figure 3, ranged from a decline in use of 11% to an increase in use of nearly 50%, and an average increase of 16%. Gas use for SaskEnergy remained at approximately the same level over the period, with Union, Terasen and AltaGas experiencing gradual increases in use, and Enbridge experiencing the largest increase. PNG and Manitoba Hydro showed decreases in use. When the utility data provided by the gas companies are aggregated over 1992 to 2005, as displayed in Figure 4, a gradual increase in total residential use is revealed.

Figure 3 Annual natural gas use in residential sectors, 1990 to 2005



Source: Survey of LDCs, July-November 2006.

Figure 4 Annual natural gas use in residential sectors, 1992 to 2005 (total from 7 utilities across Canada)



Source: Survey of LDCs, July-November 2006.

2.3 Total natural gas use and affect of change in number of customers

Variation in the number of customers is one factor that affects actual natural gas use year to year. The increase in the total numbers of customers from 1992 to 2005 for the six utilities providing data over this period ranged from 14 to 68% with an average increase of 37%, while increases in customers from the residential sector ranged from 14 to 72%

with an average of 39%. Numbers of total customers for each utility and the average annual increase are outlined in Table 1. Average annual total customer number changes ranged from -0.6% to 3.5% with an average increase across all utilities of 1.7%.

Table 1 Customer base by utility, 1990 to 2005

LDC	Customers 1990	Customers 1995	Customers 2000	Customers 2005	Average annual % increase	% Residential in 2005
ATCO	n/a	n/a	906,550[1]	939,598	0.7 %	92%[1]
Enbridge	1,034,654	1,232,989	1,479,413	1,735,907	3.5 %	91%
Gaz Métro	n/a	148,516[2]	151,082	162,040	1.3 %	66%[1]
Manitoba Hydro	218,248	229,418	245,720	254,936	1.0 %	90%
SaskEnergy	283,682	293,949	314,261	323,593	0.9 %	82%
Terasen	619,032[3]	685,400	755,079	791,593	1.9 %	90%
Union	789,462	963,762	1,122,718	1,247,916	3.1 %	91%
PNG-West	n/a	n/a	23,435	22,147	-0.6%	87%
PNG-Northeast	n/a	n/a	16,031	16,945	1.6%	87%
AltaGas	44,355	49,205	57,012	61,992	2.3%	89%

1. 2004 data from IndEco and B. Vernon & Associates. *DSM Best Practices*. CGA. 2005.
2. 1998 data.
3. 1992 data.

Source: July – November 2006 survey of LDCs.

The larger the proportion of residential customers a gas utility has, the greater the potential impact on profitability because of any declining average use per customer in this sector. The differences in the natural gas markets and the number of residential customers is primarily based on provincial fuel mix and the dominant residential heating fuel, which is largely based on the relative price of natural gas compared with electricity.[7] For example, Gaz Métro has a significantly smaller proportion of residential customers in their total customer base, compared to the other utilities. This reflects the fact that electricity is the dominant residential heating source in Quebec. This relative use of natural gas in the residential sector across Canada is depicted in Table 2.

[7] The average residential tariffs for natural gas are quite similar across the companies, with the exception of SaskEnergy and ATCO Gas, which are somewhat lower due in part to low transportation and storage costs.

Table 2 Residential sector secondary energy use by source, 2003

Region	Total energy use (PJ)	Share by energy source (%)				
		Electricity	Natural Gas	Heating Oil	Other[1]	Wood
Canada	1457.6	37.2	46.0	8.4	0.8	7.5
Newfoundland	22.1	55.4	0.0	26.9	0.7	17.1
Nova Scotia	42.9	33.7	0.0	53.6	1.8	10.9
PEI	4.6	12.1	0.0	73.7	3.6	10.6
New Brunswick	33.5	57.4	1.7	20.3	1.1	19.5
Quebec	349.0	59.4	8.1	13.9	0.3	18.4
Ontario	576.4	29.7	60.6	5.5	0.9	3.3
Manitoba	48.0	44.5	48.6	0.5	0.6	5.9
Saskatchewan	45.9	22.8	71.4	0.8	2.6	2.4
Alberta	190.2	14.3	84.5	0.0	0.9	0.2
BC	141.7	40.8	53.1	0.7	0.8	4.6
Territories	3.2	32.1	5.2	46.6	7.6	8.6

1. Other includes coal and propane.

Source: Comprehensive Energy Use Database, NRCan.
http://www.oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0

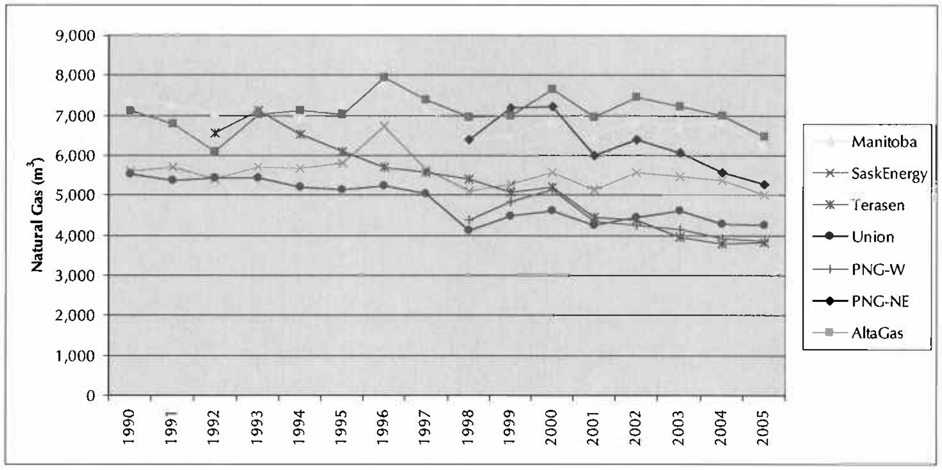
As Table 1 and Table 2 demonstrate, the residential market for gas utilities in Canada is an important market segment. In Canada about 46% of the energy use in the residential sector is natural gas, ranging from only 8.1% in Quebec to 84.5% in Alberta. All gas utilities in this study have more residential customers than other types of customers ranging from only 66% of total customers in Quebec to 92% in Alberta. Utilities, such as ATCO Gas, Enbridge Gas Distribution, SaskEnergy, Terasen Gas, Union Gas and AltaGas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

2.4 Total gas use normalized by customer

With the large increase in the number of customers removed from the equation, actual natural gas use per customer (normalization based on number of customers) allows an examination of trends in individual customer demand. Trends clearly show a decline in actual natural gas use per customer.

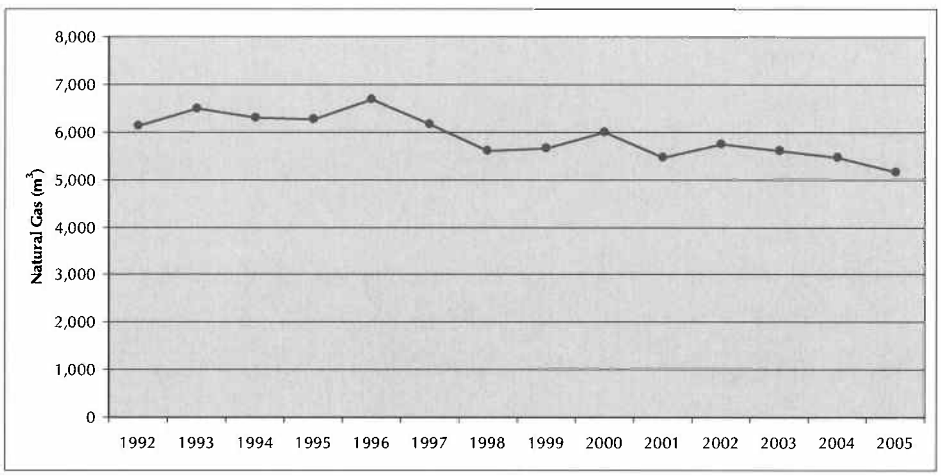
Decline in gas use per customer across all sectors from 1990 to 2005 ranged from 9% to 42%, with an average decline of 20%. The decline in the residential sector gas use per customer ranges from 11% to 24%, and an average of 16%. Gas use per customer in both the residential sector and across all sectors has been steadily declining over the last 13 to 15 years, as shown in Figure 5 through Figure 8.

Figure 5 Annual average natural gas use per customer in all sectors, 1990 to 2005



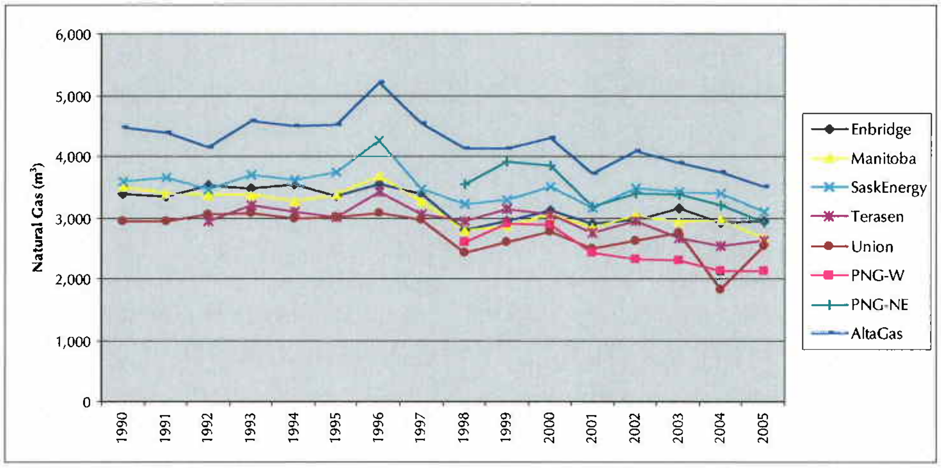
Source: Survey of LDCs, July-November 2006.

Figure 6 Annual average natural gas use per customer in all sectors, 1992 to 2005 (average from 5 utilities across Canada)



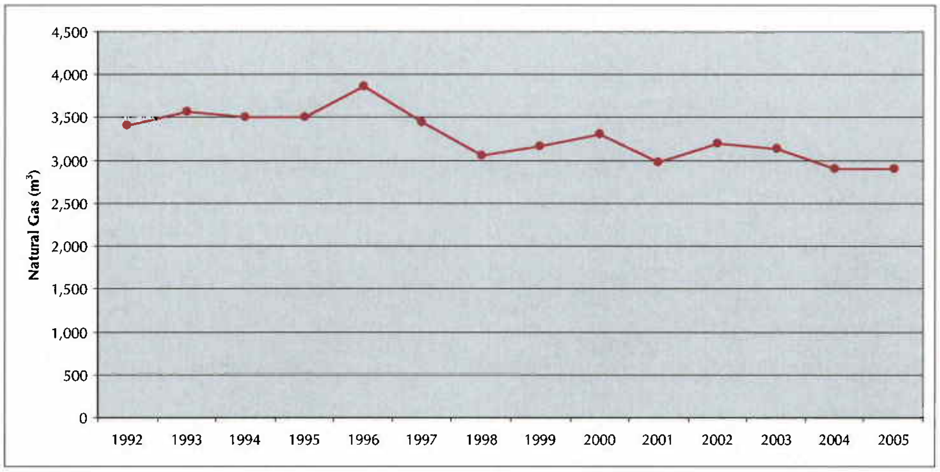
Source: Survey of LDCs, July-November 2006.

Figure 7 Annual average natural gas use per customer in residential sectors, 1990 to 2005



Source: Survey of LDCs, July-November 2006.

Figure 8 Annual average natural gas use per customer in residential sectors, 1992 to 2005 (average from 6 utilities across Canada)



Source: Survey of LDCs, July-November 2006.

2.5 Total gas use normalized by customer and weather

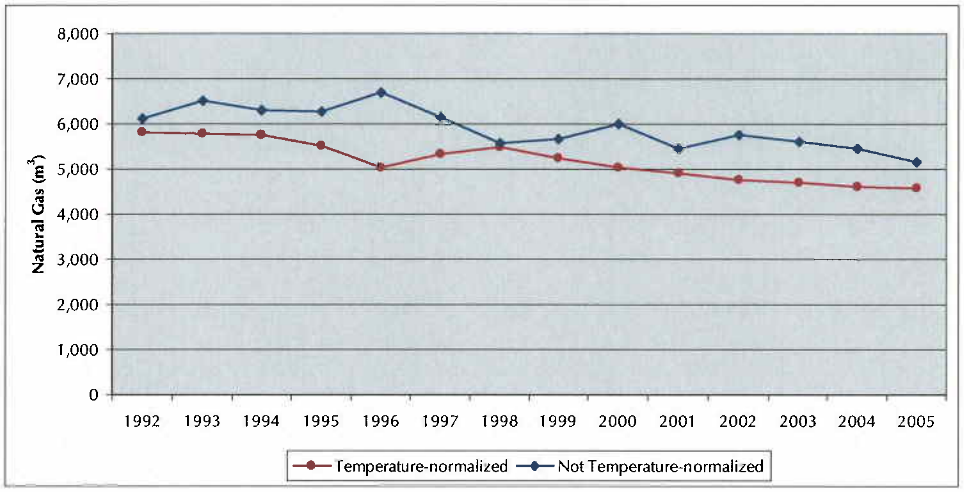
Taking the actual use data normalized by number of customers and further normalizing by climatic temperature gives a truer indication of gas use per customer over the last 13 to 15 years. Due to the variability in the methods of normalization each utility used to determine their reported normalized natural gas use values, the data were neither comparable across each utility nor in aggregate. Rather than using the reported normalized data, IndEco normalized for weather the reported actual natural gas use per customer from each utility by the utility's reported annual number of Heating Degree Days to provide a basis for comparison of natural gas use year to year across Canada. Specifically, each natural gas use value was normalized to 4000 Heating Degree Days, roughly the average reported across Canada, effectively providing actual natural gas use per customer per 4000 Heating Degree Days.[8]

These temperature-normalized natural gas values are illustrated along with non temperature-normalized values in Figure 9 and Figure 10, for all sectors and the residential sector, respectively. As the figures show, trends in temperature-normalized annual natural gas use per customer for both the residential sector and all sectors together are similar in nature to those non temperature-normalized. Decline in natural gas use per customer across all sectors ranges from 4 to 42% with an average of 19%, while decline in the residential sector ranged from 12 to 21% with an average of 16%. These numbers are very similar to those before temperature-normalization, showing that change in climatic temperatures over time (for example, due to climate change or natural year-to-year variability), in general, has had very little effect on natural gas use in Canada.

The minimal impact of weather is highlighted by the decline in average natural gas use per customer found in AltaGas' service territory. AltaGas has 14 operating districts spread geographically throughout Alberta from the border with the Northwest Territories to the U.S. border. Despite this wide geographic range, and accompanying difference in average temperature, AltaGas has found that they are experiencing the same decline in average use throughout all districts in their service territory.

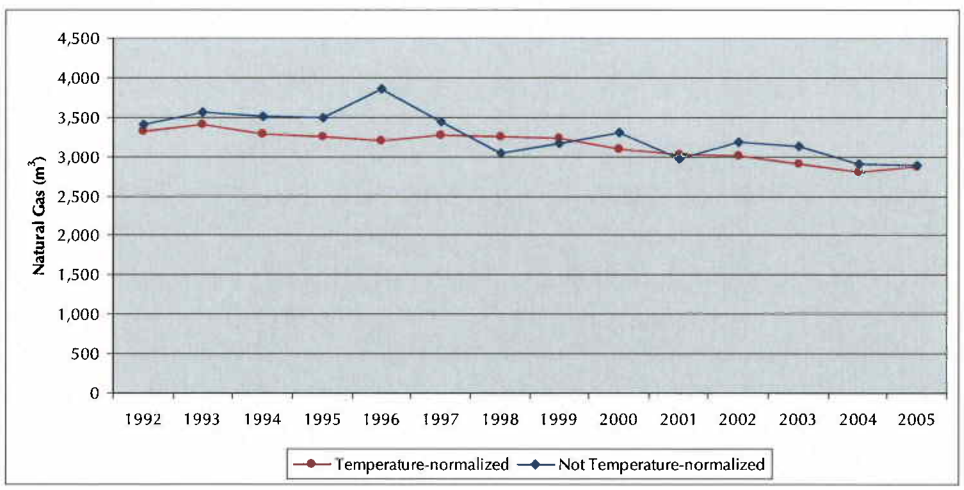
[8] It should be noted, however, that the utilities use different methodologies to calculate their heating degree days depending on their local circumstances. Thus, a reliable comparison of normalized natural gas use cannot be made, region-to-region, or utility to utility.

Figure 9 Temperature-normalized and non temperature-normalized annual average natural gas use per customer in all sectors, 1992 to 2005, (average from 5 utilities across Canada)



Source: Survey of LDCs, July-August 2006.

Figure 10 Temperature-normalized and non temperature-normalized annual average natural gas use per customer in residential sectors, 1992 to 2005, (average from 6 utilities across Canada)



Source: Survey of LDCs, July-August 2006.

2.6 Conclusions on declining average use

The analysis of the data provided by the natural gas distribution utilities shows a decline in average use of natural gas across all sectors of 19% over the past 13 to 15 years, while across the residential sector, that decline has been 16%. This corresponds roughly to a decline in average use of 1.9% per year on average for all sectors and to a decline in average use in the residential sector of 1.1% per year on average.

According to the American Gas Association (AGA), natural gas use per customer in the residential sector in the United States declined 21% over the 21 year period from 1980 to 2001, averaging 1% per year.[9] This number is relatively consistent with the 1.1% per year average decline in use per residential customer in Canada. These results point to the robustness of the Canadian numbers.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to generally have a very minor, if any, effect on natural gas use change, other factors must be driving the decline. These drivers are identified and discussed in Chapter 3.

---

[9] American Gas Association: Policy Analysis Group, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*. September 2004. p.1. Factors contributing to the decline include appliance efficiency, appliance penetration, and thermal efficiency. Home size increases dampened the effect of the decline per customer. ibid. p. 4. The AGA forecasts the average annual decline in use per residential gas customer to be .46% from 2001 to 2010 and .67% from 2010 to 2020, indicating that the decline is expected to continue but at a slower rate, with an annual average decline of .5%/yr, from 1980 to 2020. (ibid. p.1-3).

3 Drivers of declining average gas use in Canada

This chapter discusses the main drivers of declining average usage in Canada. Drivers at both the macro level (across Canada) and at the micro level (particular to certain utilities) are discussed.

A description of the common macro level drivers is presented below along with the impact that they are expected to have on declining average gas use in the future. These drivers are described in Sections 3.1 to 3.3 and include the price of natural gas, trends in energy efficiency and demand side management. The specific drivers for declines in average use affecting particular utilities are discussed in Section 3.4. Conclusions regarding these macro and micro level drivers are presented in Section 3.5.

3.1 Price of natural gas

One factor that can lead to declining natural gas use per customer is the price of natural gas. To the extent that the price signal will encourage customers to become more efficient gas users, we can expect price to have had an impact on historical per customer gas use and to have an impact on future per customer gas use.

During the 1990's, natural gas prices were relatively low, with an average price of CDN $1.68/GJ between 1991 and 1999.[10] However, since mid-2000, prices have been much higher, reaching a high in 2004 of CDN $6.52/GJ, up from CDN $5.00/GJ in 2000. This price spike occurred because of the inability of North American gas production to meet the increasing demand, coupled with high world crude oil prices.[11]

In the 1990's with gas prices relatively low, it is unlikely that price would have been a main driver in declining average use. However, since 2000 with record high natural gas prices, price becomes a more important driver for declines in average use. The impact of price on declines in average use in the future is likely to become more important based on the forecast of continued high gas prices.

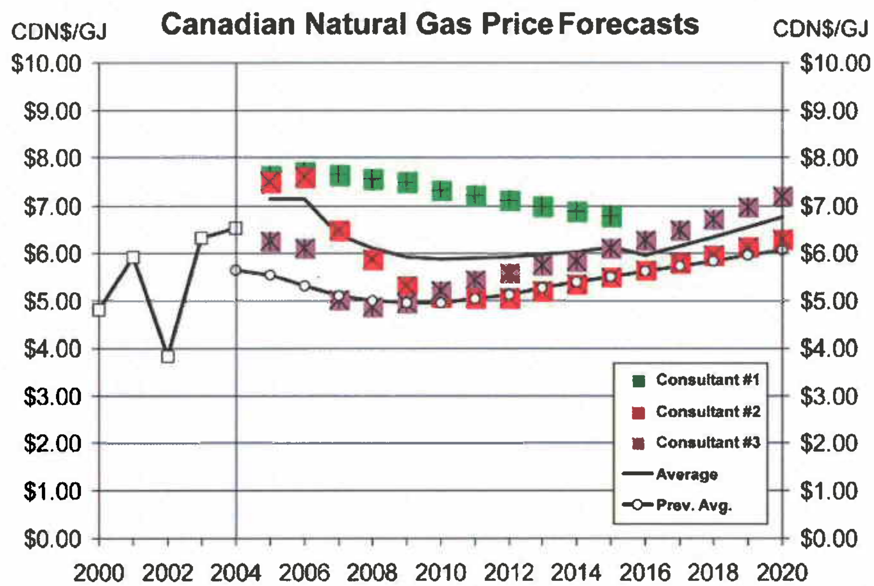
---

[10] Based on intra-Alberta, AECO or NIT, which is Canada's natural gas pricing point) Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Oulook to 2020.* January 2006. p.ii.

[11] Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Outlook to 2020,* January 2006. p. v.

Figure 11 shows NRCan's forecast for Canadian natural gas prices to 2020. The average forecast indicates that prices are expected to be above CDN $5.00/GJ over the forecast period, with a slight dropping off of prices between 2007 and 2010, and then gradual price increases to 2020. Gas prices are forecast to remain high over the medium-term, primarily because of the inability of North American gas production to meet increasing demand.

Figure 11 Canadian natural gas price forecasts



Source: Various consultants. **Notes:** (1) Historical are AECO actuals from GLJ. (2) Forecast prices are AECO. (3) Some forecasts were converted from $US to $CDN using an exchange rate of US $1.00 to CDN $1.30 over the entire forecast period. (4) Nominal dollars.

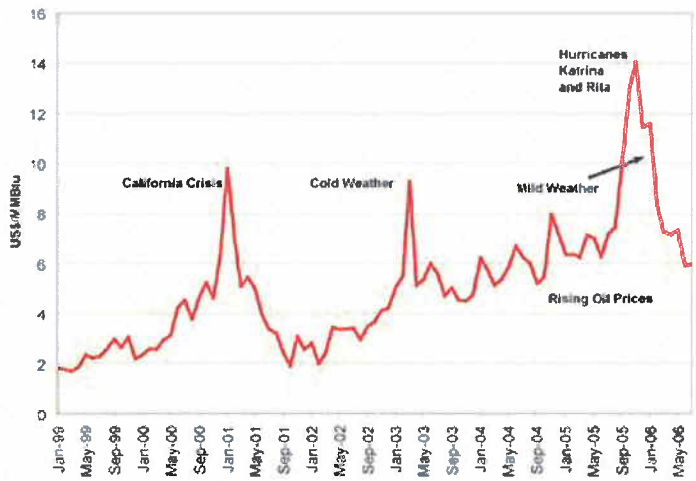
Source: Natural Resources Canada. *Canadian Natural Gas Review of 2004 & Outlook to 2020*, January 2006. p. 47.

During the period from 1999 to 2006, there was significant volatility in North American gas prices. As shown in Figure 12[12], the general trend in increasing prices is accentuated with small peaks and troughs due to seasonal variations and large peaks due to world and extreme weather events. Overall, price has tripled (from approximately US$2/MMBtu to US$6/MMBtu) since late 2001. Since 2001, North American natural gas supply growth has not kept pace with growth in demand, contributing to high and volatile gas prices. Price volatility creates uncertainty in the market. Customers lose confidence and those most risk adverse take the strongest steps to minimize risks, especially during periods of high prices.

[12] National Energy Board website. **www.neb-one.gc.ca/energy/EnergyPricing/HowMarketsWork/NG_e.htm.** Accessed August 15, 2006.

As a result, it is likely that since 2000, natural gas price volatility has been a contributing factor to declines in average use. If price volatility continues over the forecast period to 2020, it is likely to increase the impact on declining customer natural gas use due to high gas prices.

Figure 12 Canadian natural gas price volatility



Source: National Energy Board. *3 Day Average Natural Gas Price*. http://www.neb-one.gc.ca/energy/EnergyPricing/HowMarketsWork/NG_e.htm

3.2 Canadian trends in energy efficiency

Over time, Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. In particular, there were improvements in the residential, and likely in the small commercial and institutional sectors, due to similar gas uses.

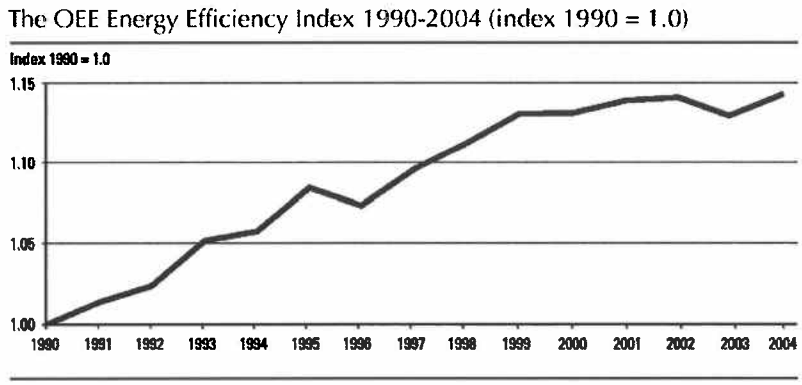
Overall energy efficiency gains

Between 1990 and 2004, there have been significant improvements in energy efficiency. Natural Resources Canada's Office of Energy Efficiency (OEE) reports on energy efficiency trends in Canada, with its most recent 2006 publication reporting on trends from 1990 through 2004.[13] The report estimates the impact of energy efficiency on energy consumption for each of the residential, commercial/institutional, industrial and transportation sectors, as well as for all of these sectors in

[13] Natural Resources Canada Office of Energy Efficiency, *Energy Efficiency Trends in Canada 1990 to 2004*, August 2006.

aggregate. The aggregate evaluation is expressed as a single index for all of Canada, referred to as the OEE Energy Efficiency Index (Index).[14] The OEE reports that the Index grew relatively steadily from 1990 to 2004, averaging an increase in 1% per year, with a total increase of 14%.[15] This growth is illustrated in Figure 13.

Figure 13 The OEE Energy Efficiency Index 1990-2004



Source: Natural Resources Canada Office of Energy Efficiency, Energy Efficiency Trends in Canada 1990 to 2004, August 2006. p.10.

As energy use continued to increase due to increases in sector activity (number of residences, new commercial and industrial applications, etc.) and other factors, improvements in energy efficiency served to slow this energy use increase. Without improvements in energy efficiency, energy use (normalized by weather) was projected to increase by 36%, while with improvements in energy efficiency, energy use actually increased by only 23%.[16] Thus energy efficiency improvements saved an additional 13% increase in energy use between 1990 and 2004.

Energy efficiency improvements were largest in the residential sector. Improvements in energy efficiency in other sectors have shown to be more variable, with different influencing factors.

---

[14]This Index shows changes in the efficiency of how Canadians use energy to heat and cool their homes and workplaces and to operate appliances, vehicles and factories. The analysis by the OEE does not distinguish between energy end-use from electricity or natural gas, nor from fuel type used in generation of energy. Natural gas end-use burner tips and appliances account for a much smaller percentage of total energy end-use than the electricity end-uses.

[15] Natural Resources Canada, *Socio-Economic Trends Versus Space and Water Heating Energy Use,* May 2004. p.10.

[16] Natural Resources Canada, *Socio-Economic Trends Versus Space and Water Heating Energy Use,* May 2004. p.5.

Energy efficiency gains in the residential sector

In the residential sector, improvements in energy efficiency are estimated to have resulted in a 21% reduction in energy use. This improvement is due to upgrading in the thermal envelope of houses and to the increased efficiency of residential space heating and cooling equipment, water heating equipment and appliances. In the residential sector, space heating accounts for 59% of energy end-use, water heating accounts for 22% of energy end-use, and appliances account for 13% of energy end-use, with major appliances representing 8%.[17]

While no specific energy efficiency improvement data are discussed for a small commercial/institutional sector, it is likely that both the residential and the small commercial/institutional sectors have experienced similar improvements in energy efficiency (due to building code improvements, retrofitting with more energy efficient equipment etc.) as the use of natural gas in both of these sectors is primarily for space and water heating (space heating and cooling equipment accounting for 61% and lighting accounting for 13%[18]).

Improvements in the energy efficiency of building stock have made a significant reduction in natural gas use per customer in the residential sector due to improvements in building design. For example, homes built between 1946 and 1969 had a total natural gas intensity in Ontario of 0.9GJ/m2, in the Prairies an intensity of 1.28GJ/m2, and in BC 0.72GJ/m2; whereas homes built between 1990 and 2003 had an intensity of 0.62GJ/m2 in Ontario, 0.91GJ/m2 in the Prairies and 0.65GJ/m2 in BC.[19]

These reductions in natural gas intensity are due to improvements in building envelope as well as the efficiency of heating equipment. Energy efficient practices and technology improvements in mainstream construction resulted in a drop of approximately 60% in air leakage in housing built in 2000 to 2004 from housing built prior to 1945, and an

---

[17] Natural Resources Canada, Socio-Economic Trends Versus Space and Water Heating Energy Use, May 2004, p.2, p.13.

[18] Natural Resources Canada, Office of Energy Efficiency, The State of Energy Efficiency in Canada, Report 2006, 2006, p.13.

[19] Natural Resources Canada Office of Energy Efficiency. 2003 Survey of Household Energy Use. http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/data_e/sheu03/publ...

average decrease in energy use in this housing of 13% after an EnerGuide for Houses retrofit.[20]

In Canada in 1990, 41.1% of the residential space heating system stock was a normal efficiency gas furnace and only 2.1% was high efficiency; in 1994 the normal efficiency percentage had dropped to 37.4%; the high efficiency furnace percentage had risen to 3.4%.[21] In Union Gas's franchise area in 2006, 90% of all new houses and 2/3 of the furnace replacement market are going to high efficiency gas furnaces.[22]

Continuation of improvements in energy efficiency

High gas prices, together with higher efficiency gas furnaces/boilers going into new construction, continued turnover of lower efficiency natural gas furnaces/boilers to higher efficiency ones, and tighter building envelopes will likely result in the continuation of declines in average gas use, particularly in the residential as well as the small commercial/institutional sectors. There is some evidence to suggest that the implementation of these improvements in energy efficiency of gas use may accelerate in the short and medium term due to sustained high natural gas prices, greater consumer awareness of energy efficiency, and government pressure on gas utilities and others to assist customers to reduce gas bills.

Declining average customer use of gas due to the continuation of this energy efficiency trend, and the possible acceleration of the adoption of energy efficiency improvements, will make it increasingly difficult for gas utilities to recover their fixed costs from the volume-based charges in rates for residential and small commercial/institutional customers.[23]

3.3 Regulated demand side management in Canadian gas utilities

Demand side management (DSM) activities are another factor that can result in declining average use per customer. These activities can contribute to increases in the use of more energy efficient gas equipment and to changes in customer behaviour that lead to reductions of gas

---

[20] Natural Resources Canada, Office of Energy Efficiency, The State of Energy Efficiency in Canada, Report 2006, 2006, p.17.

[21] Natural Resources Canada Office of Energy Efficiency. Residential End-Use Model, Ottawa, February, 2006. http://oee.ncrcan.gc.ca/corporate/statistics/neud/dpa/tableshandbook2/r...

[22] Telephone interview with Union Gas. August 25, 2006.

[23] Assumes all other things being equal.

usage. Historically, regulated gas DSM has not been a major driver of overall declines in average use as it is a relatively new pursuit for many Canadian jurisdictions and did not exist in Canada before 1995.

The DSM regulatory environment under which a utility operates influences whether utilities implement DSM programs, the programs that are selected for implementation and the preferred outcome of DSM activities. In jurisdictions with DSM regulated by an arms-length agency (e.g. Ontario, BC and Quebec), the primary driver for DSM tends to be achieving cost effective energy savings. At SaskEnergy, on the other hand, the primary driver for its DSM program is residential customer satisfaction and retention. Table 3 summarizes the DSM regulatory environment of each of the companies included in the analysis.

Table 3 Regulatory environment of natural has companies conducting DSM in Canada[24]

LDC	DSM approval agency	DSM since
ATCO	n/a	2002
Enbridge	Ontario Energy Board	1995
Gaz Métro	Régie de l'énergie Québec	1999
Manitoba Hydro	Manitoba Public Utilities Board	n/a
SaskEnergy	Crown Investment Corporation	2001
Terasen	British Columbia Utilities Commission	1997
Union	Ontario Energy Board	1997

As Table 4 shows, from 2000 through 2005, more than 150 million dollars were invested in DSM by natural gas utilities in Canada. Annual DSM expenditures have increased steadily over this period, with the total expenditure in 2005 ($38.5M) being more than twice that of 2000 ($16.6M). This growth is due to both an increase in the number of companies participating in DSM over the time period, as well as an increase in DSM budgets within individual companies over the period.

[24] PNG and AltaGas do not conduct DSM.

Table 4 DSM expenditures and energy savings, 2000 to 2005[1]

	2000	2001	2002	2003	2004	2005
Number of utilities with DSM programs	4	6	7	7	7	7
LDC DSM expenditures (millions of $)	$ 16.6	$ 22.1	$ 23.4	$ 26.0	$ 30.9	$38.5
Natural gas annual end-use savings from LDC DSM programs (millions of m^3/yr)	91.8	138.2	150.2	153.4	170.9	192.5
Cost per m^3	$ 0.18	$ 0.16	$ 0.16	$ 0.17	$ 0.18	$0.20
Natural gas annual end-use savings from LDC DSM programs (millions of GJ/yr)	3.48	5.24	5.69	5.81	6.47	7.13
Cost per GJ	$ 4.76	$ 4.22	$ 4.12	$ 4.47	$ 4.78	$ 5.40

1 2001-2004 data from IndEco and B. Vernon & Associates. *DSM Best Practices*. CGA. 2005. 2005 data from survey of LDCs, July-August 2006.

2 2005 data does not include any data from ATCO, or data on end-use gas savings from Manitoba Hydro.

Table 5 illustrates DSM expenditures by company and as a percent of utility revenue. While the largest DSM budget is more than 15 times that of the smallest DSM expenditure, the percent of revenue that DSM expenditures represent is much more consistent across the companies, suggesting that much of the variance in DSM budgets is explained by variance in company size. On average, the utilities spent 0.38% of their total revenue and 1.29% of their revenue less commodity cost on DSM in 2005.

Table 5 2005 DSM expenditures, by company, as a proportion of revenue

LDC	DSM expenditure ($ millions)	Total utility revenue ($ millions)	% of total utility revenue	Utility revenue less cost of gas ($ millions)	% of utility revenue less cost of gas
ATCO	$ 4.30[1]	$ 1,550[1]	0.28%[1]	$ 407[1]	1.06%[1]
Enbridge	$ 15.50	$ 3,075	0.50%	$ 881	1.76%
Gaz Métro	$ 8.50	$ 1,578	0.54 %	$ 448	1.90%
Manitoba Hydro	$ 2.50	$ 555	0.45 %	$ 126	1.98%
SaskEnergy	$ 0.85	$ 537	0.16 %	$ 172	0.49%
Terasen	$ 3.00	$ 1,420	0.21 %	$ 463	0.65%
Union	$ 8.10	$ 2,084	0.39 %	$ 847	0.96%
PNG	n/a	n/a	n/a	n/a	n/a
AltaGas	n/a	n/a	n/a	n/a	n/a

1. From 2004, 2005 data not available. From www.ATCOgas.com/Regulatory/03-04_AG_GRA/APPL_UPDATED/SCH_REV.xls

Source: July – November 2006 survey of LDCs.

In order for regulated DSM to achieve significant declines in customer gas use, gas utilities need a regulatory regime that supports this endeavour. [25] The utility needs to be protected from revenue losses due to DSM and to be rewarded for successful DSM. Several utilities such as Enbridge Gas Distribution, Gaz Métro, and Union Gas have a lost revenue adjustment mechanism (LRAM) that allows the utilities to track and recover lost revenues due to their DSM activities. As concluded in the recent Ontario Energy Board decision on natural gas DSM,

> *"As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges) there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM."*[26]

Terasen Gas and PNG have a broader revenue recovery mechanism, the Revenue Stabilization Adjustment Mechanism (RSAM), which allows them to recover revenue losses from all sources, including DSM. All of these utilities, (except PNG which does not have regulated DSM), have an incentive mechanism to reward the utility for DSM performance; some mechanisms have been more effective than others in promoting aggressive DSM.[27]

Future role of regulated DSM in achieving declines in average use

The importance of regulated DSM as a driver in the decline in average use may increase in the future. Sustained high natural gas prices may lead to heightened government pressure on gas utilities to deliver more aggressive DSM and may drive customers to demand more energy efficiency services from their gas utility. With an LRAM and the right

---

[25] At least 29 US gas utilities have provisions that allow for the recovery of DSM program costs as well as the recovery of lost revenues caused by the reductions in sales due to DSM. AGA. *Natural Gas Roundup*, p.12.

[26]Ontario Energy Board, Decision with Reasons, EB-2006-0021. P.39. August 26, 2006.This was a generic proceeding to address a number of current and common issues related to demand side activities for natural gas utilities. In this proceeding, the OEB renewed its commitment to LRAM and to a strong incentive mechanism for the gas utilities to excel in DSM.

[27] Historically, the most successful incentive mechanism was Enbridge Gas Distribution's shared savings mechanism (SSM). In the Ontario Energy Board's most recent decision on natural gas DSM of August 25, 2006 (EB-2006-0021), the Board approved a new SSM for Enbridge and Union which rewards them for achievement of progressively higher percentages of the DSM target, based on a curve starting at up to 25% of the target ($225,000) and moving in 25% increments to up to $4,750,00 for achievement of the target, and capped at achieving in excess of 125% of the target $8,500,000). p.28.

DSM incentives, gas utilities could realize much more significant reductions in average customer usage from DSM.

3.4 *Specific local drivers of declines in average gas use*

Based on the telephone interviews conducted in this study, it became clear that there are utility specific drivers of declining average use per customer in addition to the common macro level drivers discussed above.

For example, in Manitoba, Manitoba Hydro is experiencing declining average use per customer due to increased market share of electric hot water heaters[28], increased market share of high efficiency gas furnaces, tighter building envelopes and higher natural gas prices.

In Quebec, higher natural gas prices, competitive advantage in the marketplace of electricity over natural gas, increases in average temperature and variations in wind velocity have contributed to declining average use per customer experienced by Gaz Métro.

For Terasen Gas, there has been a steady decline in average use per customer over time. The decline has been steeper on the mainland than on the island because gas service is newer on the island and the energy efficiency of the equipment stock on the island is therefore higher.

For PNG, a spike in natural gas prices in 2001, conservation and the use of high efficiency appliances have contributed to the declines in average use. PNG has experienced very similar declines in average use in both of the company's service territories (West and North East) despite the fact that these two regions have had very different economic fortunes in the last few years – in the West there has been a decline in wealth in the area due to the closure of facilities of local employers and the decline in the fishing industry, while in the North East the economy has been strong primarily in the oil and gas industry. This indicates that at least in the PNG service territories the local economies have not had a large impact on declining average use per customer.

In Alberta, AltaGas has experienced declining average natural gas due to newer and more efficient housing, retrofits leading to more efficient building stock, the use of more efficient appliances, the turnover of old stock, and high and volatile natural gas prices encouraging conservation.

---

[28] 95% of new homes and retrofits are going to electric hot water heaters.

In Enbridge Gas Distribution's (EGD) franchise area, the utility is experiencing load loss due to the Toronto Transit Commission moving away from NGV buses, Ford no longer making Crown Victoria NGVs which are the staple of NGV taxis, and Honda not bringing any new NGVs to the Ontario market. While the company is experiencing small growth in niche markets such as residential pool heaters[29], outdoor gas fireplaces, and commercial block heaters, and the company is working on the development of new technologies such as fuel cells, these efforts are not likely to have an impact on load in the short and medium terms. As a result, these new market opportunities will have a negligible impact on declining average customer use in the foreseeable future. Similar to Manitoba Hydro, EGD is also experiencing better insulated new homes, higher natural gas prices, effects of the company's DSM initiatives and increased market share of high and mid-efficiency gas furnaces as a result of ongoing customer growth.

In Union Gas's franchise area, as previously indicated 90% of all new houses and 2/3 of replacement furnaces are going to high efficiency gas furnaces. There is some fuel switching from gas to electric hot water heating, for example, in new construction low rise apartments, 80% of the market was gas hot water, whereas today it is 60%. There is also a change in household demographics with baby boomer children leaving home, resulting in household consumption dropping. Similar to EGD, Union Gas is experiencing new markets in pool heaters and commercial block heaters, but these are small niche markets, and will therefore, have a negligible impact on declining average use per customer; the bulk of Union's load is from space and water heating.[30]

3.5 Conclusions

Natural gas prices and energy efficiency are common macro drivers of declining average use. Local drivers may vary due to local market conditions.

The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the 1.1% decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and supportive of the 1.9% decline experienced in all sectors together.

[29] Enbridge Gas Distribution has 1.7 million customers; only a small percentage of customers have pool heaters.

[30] 4% of Union's customers are restaurants and only a small percentage of these have block heaters.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From the utility perspective, if declines in average use are not properly addressed through effective rate regulation, this could jeopardize the continued effectiveness of gas DSM, discourage utilities from promoting wise gas use and result in significant lost earnings for the utility.

There are a number of options that gas utilities can take to address the negative consequences of further declines in average use. These are discussed in Chapter 4.

4 Options for addressing declining average use

Achieving declines in the average use of gas per customer is not, per se, a problem. From a customer perspective, declining average use means that customers are using natural gas more wisely and saving on their gas bills. From a utility perspective, declining average use contributes to customer retention. For utilities with DSM, their DSM programs further help their customers to achieve wiser use. In fact, declining average use is the goal of DSM and of improving energy efficiency standards for heating equipment and building envelopes.

Some Canadian utilities have adopted a systems approach to DSM. This involves providing programs to ensure that the customer uses the most appropriate energy source for a given application in the most energy efficient manner, even though in certain situations, this approach could lead to fuel switching away from natural gas. A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas distribution utility if the declines are not adequately captured in rates.

A number of options for dealing with declining average use are described in the sections below. These options include:

- Ignore declining average use
- Incorporate declining average use in the load forecast
- Revenue decoupling
- Make adjustments to fixed and variable charges
- Address declining average use per customer in a PBR environment

It should be recognized that these options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

4.1 Ignore declining average use

One option for dealing with declining average use is to ignore it. Rate design, load forecasting, or revenue recovery would not be adjusted to reflect any decline in average use per customer. In pursuing this option, it would be prudent for a utility to continue to monitor the magnitude and impact of declining average use as well as its causation. Such information will assist the utility in designing an adjustment should one be necessary in the future.

In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. For example, in a market that is nascent as the new infrastructure is being built based on the more recent gas use per customer data, any decline in customer usage year over year may be small and not have a significant impact on the utility's ability to recover its fixed costs in the short term. However, over time, the nascent utility will need to take declines in usage into account to protect the financial viability of the utility.

Even if the utility is not in a nascent market, but is provincially-owned, this may be an appropriate option in the short term. This type of utility is less driven by profits and is more influenced by the broader objectives of the government. However, in the medium- and long-term, the declines in use could have a major impact on revenues, and should be taken into account in rates. In addition to providing a more accurate price signal for consumers to conserve, this will ensure that the utility will be collecting revenues to adequately support its infrastructure over the long-term.

4.2 Incorporate declining average use in the load forecast

Traditional rate design, which is based on cost-of-service regulation, incorporates declining average use per customer in the load forecast.[31] Utilities collect payments from consumers to cover the actual cost of natural gas[32] as well as the utility's costs to deliver gas to its customers. Typically, based on the customer's rate class, the utility charges customers a fixed customer charge and a volumetric customer charge. Most of the utility's costs are recovered through the volumetric charge even though most of the costs of running a gas utility are fixed. After delivering sufficient volumes to cover all the utility's costs, the utility has

[31] Utilities determine the level of the decline in average use to be incorporated into its load forecast in utility-specific ways. For example, Terasen Gas takes into account the AGA average projected decline in average use per customer of .5%year and an annual industry poll of projected customer consumption in determining its % decline in average use.

[32] Referred to as the gas commodity, which is a pass-through cost to consumers of Canadian gas utilities.

an opportunity to earn a profit subject to its regulatory constraints. When the amount of gas delivered declines, as can happen during periods of warmer weather, economic slowdown, or when natural gas consumers become more efficient, this can affect a utility's earnings.

Declining average use can become a problem if it is not properly captured in the load forecast. To the extent that the forecast is accurate the utility and its customers are protected. In traditional rate-making the utility bears the full risk of underestimating declines in average use in the forecast and reaps the full benefits of overestimating declines. If the forecast underestimates the decline, then the utility can suffer significant losses in margin. For example, the 2005 rates approved by the Ontario Energy Board for Enbridge Gas Distribution were based on a volume forecast that included a decline in average use of 0.7%; the actual decline was 2.8% due to higher gas prices than those included in the volume forecast and resulted in a margin loss of $6.6M, with a negative after tax impact of $4.3M.[33]

A utility can mitigate its risk associated with forecasting by trying to improve the accuracy of its forecast. For example, the utility could expand its efforts to obtain better data on both short-term and long-term trends regarding customer usage; it could work with other gas utilities across Canada to share knowledge on forecasting declining average use; and could encourage its provincial government and regulator to provide province-wide annual (and perhaps quarterly) data on trends in customer usage of energy, including natural gas. Even the best forecast models will only estimate use per customer within a margin of error. This margin of error, however small, could have a major impact on a utility's earnings.

The regulator can help to mitigate the utility forecasting risk by having annual rates cases. As well, the regulator could offer the utility a risk premium on its ROE for managing the risks associated with declines in average use. However, given the uncertainty surrounding the ability to predict this risk accurately, this is not likely to be an effective tool.

Forecast risk mitigation may be difficult to achieve. Historically, forecasts were based on historical data, however, with the current market dynamics of high gas prices, government conservation programs[34] and pressure on gas utilities for more aggressive DSM, it may be difficult to reduce forecast risk associated with expected declines in use. This difficulty may be magnified the longer the period between rates cases. Moreover, a particular market could be approaching a tipping point that

---

[33] Tom Ladanyi, *Implications of Declining Average Use.* Enbridge Gas Distribution. 2006.

[34] For example, Ontario has just gone through a process to update its Building Code, which included strengthening provisions for increasing energy efficiency.

could lead to an acceleration of the decline and this would be difficult to predict. Therefore, improvements in forecasting and forecast risk mitigation may be insufficient to address the full impact of declining average use.

Declining average use tracker

Improvements in forecasting and forecasting risk mitigation may be insufficient to address the risks associated with forecasting declining average use. If the level of uncertainty in predictions of declining average use results in undue risk to the utility, and this will likely be determined by the utility and its regulator on a case by case basis, then more aggressive action will be required.

A simple tracking account, a Declining Average Use Tracker, may be required that tracks variance between the forecast decline in average use and the actual decline for later disposition and true-up. True-ups would be made for both over-forecasting and under-forecasting the declines. Such an approach would eliminate the risk to the utility from the unpredictability of forecasting declining average use. This type of tracking account deals directly with, and is limited to, the risks associated with forecasting declining average use.

Where a utility faces broader revenue recovery risks from things beyond its control, a revenue tracker such as the Revenue Stabilization Adjustment Mechanism employed by Terasen Gas and Pacific North Gas, may be necessary.

Revenue stabilization adjustment mechanism

In 1994 Terasen Gas[35] received approval from the British Columbia Utilities Commission (BCUC) to establish a revenue stabilization account called the Revenue Stabilization Adjustment Mechanism (RSAM). This mechanism mitigates the effect on its revenues of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas price volatility.

The RSAM seeks to stabilize revenues from residential and commercial customers through a deferral account that captures variances between Terasen's forecast versus actual customer use throughout the year. This account reduces Terasen Gas' earnings exposure to related risks by deferring any variances between projected and actual gas consumption, and refunding or recovering those variations in rates in subsequent

[35] BC Gas changed its name to Terasen Gas Inc in 2003.

periods.[36] The RSAM account is refunded or recovered in rates as a rolling average amortized over three years.[37]

Terasen's RSAM was established in response to a series of warm winters in the early 1990's which resulted in a mismatch between Terasen Gas' forecasted revenues and actual revenues. Instead of continually arguing over the quality of the forecasts and to reduce the risks regarding earnings, Terasen Gas approached BCUC staff to introduce a mechanism that would take these variations into account.[38] The RSAM was introduced as a weather adjustment formula. Because of the difficulty in separating out revenue losses due to weather and other factors, the stabilization mechanism tracks all revenue variances from forecast. As a result, this tracker can true up variances between forecast and actual declines in average use.[39]

Prior to 1996 the RSAM was only used during the five winter months of November to March, inclusive. After 1996 it was extended to 12 months of the year resulting in Terasen Gas no longer being exposed to annual variations in revenues from its residential and commercial customers due to weather and other factors.[40]

The RSAM used by PNG was established in 2003 and is very similar to the Terasen RSAM.

US approaches to revenue recovery risk

In the US, the focus has been on implementing mechanisms to address revenue recovery risk broadly, but at the same time address declining average use. Two main types of mechanisms are common: revenue decoupling and changes to fixed and volumetric charges. Each is discussed in subsequent sections.

---

[36] Terasen Gas Inc. 2004 Annual Report.
http://www.terasengas.com/NR/rdonlyres/eyyzlqdjvuci46fktsqah4myzijeqw6xxxtgeo2tcouz4t2ux5lucnqhyhd4z4casvzftud5kfr6zivvqpoarf3auah/Terasen+Gas+Inc+Annual+Report+2004.pdf

[37] Jim Fraser. British Columbia Utilities Commission. Personal communication. September 7, 2006

[38] ibid.

[39]Terasen includes a declining average use adjustment in its annual load forecast. This adjustment is based on the 0.5% per year declining average use rate developed by the American Gas Association and on an annual industry poll of projected customer consumption.

[40] 1996 BC Gas Utility Ltd. Annual Report.
http://www.terasengas.com/NR/rdonlyres/e33l5wuijpzzrnhhcupzkpzpuxcuxkedqinxiyyw3dllmambwhdep74zxdtrt3oorb73oyp36miwlwo6azy43hhygpb/BC+Gas+Utility+Inc+Annual+Report+1996.pdf

4.3 Revenue decoupling

Revenue decoupling (RD)[41] is defined as a "regulatory mechanism that separates or decouples a utility's revenues from its sales of energy, in this case natural gas, and recouples revenues to some other factor, such as number of customers".[42] Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute. The basic approach to RD involves defining a revenue requirement and a baseline usage per customer level; over and under revenue collections from this level are placed in a deferral account for recovery in a subsequent period. RD essentially sets revenue per customer caps.[43]

There is growing interest in revenue decoupling among gas distributors particularly those that are dealing with declining average use per customer in environments with a growing customer base. The more rapid the rate of growth the larger the problem can become. New customers tend to use less gas than older customers due to newer homes having higher efficiency gas heating equipment and more energy efficient building envelopes, but the utility charges the same fixed charge, making it difficult to recover the full cost to serve the new customer in the volumetric charge.

In the US, declining average use, while a factor, is not the predominant driver of the approval of RD by regulatory utility commissions. For the most part, the key driver for public utility commissions that have approved gas utility RD is to establish a climate favourable to utility DSM to address high natural gas prices. Because of high prices, state commissions have increasingly pressured, and in some instances required, gas utilities to become more active in promoting DSM to reduce customer bills. Traditional rate structures encourage utilities to increase sales between rates cases. The RD enables the utility to recover the same level of revenues regardless of sales. RD therefore eliminates the utility disincentive to carry out DSM, however, it does not provide an incentive for DSM.

---

[41] RD mechanisms have many names, including for example, Conservation Margin Tracker, Conservation-Enabling Tariff, Conservation Tariff, Margin per Customer Balancing Provision, Delivery Margin Normalization, Usage per Customer Tracker, Customer Utilization Tracker.

[42] Joelle R. Stewart. Staff of Washington Utilities and Transportation Commission. *Natural Gas Decoupling, Rate Spread and Rate Design*. Testimony before the Washington Utilities and Transportation Commission. Docket No. UG-060256. Exhibit No. T(JRS-1T). August 15, 2006.

[43] Revenue decoupling can involve either a fixed revenue per customer cap with a true-up mechanism for variances between forecast and actual revenues, or revenue indexing. Revenue indexing decoupling is usually referred to as revenue indexing PBR. This latter definition of revenue indexing as a form of PBR has been adopted in this report rather than as an RD mechanism. See section 3.5 for further discussion of revenue indexing PBR.

RD reduces a utility's risk from under recovering revenues and therefore generates more stable revenues, cash flows and earnings. RD helps customers to the extent they are able to participate in any DSM the utility provides. Because of the reduced risk, utilities may suffer a reduced return on equity by the regulator as a condition of approval of the RD. Opponents of RD in the US argue that RD is too blunt a tool to deal with rate adjustments for revenue losses. They believe that it is important to determine the reasons for the decline in sales and make adjustments accordingly.

As of early 2006, several gas utilities had filed RD proposals in New York, Ohio, Utah and Washington.[44] Not all applications for RD are being approved by PUCs. Southwest Gas in Arizona, for example, proposed an RD for residential customers that would track in a balancing account the actual margin each month per customer versus the authorized level per customer and proposed a US $4M DSM program through a surcharge on customer bills, however the proposal did not receive support from commission staff, the consumer advocate's office and other stakeholders.[45] As well, in January 2006, the Connecticut Department of Public Utility Control rejected RD in the form of sales and per customer adjustments because of the shift of business risk from the utility to the customer.[46]

At least seven gas utilities in the US (Baltimore Gas and Electric, Cascade Natural Gas, Northwest Natural Gas, Southwest Gas, and Piedmont Natural Gas, Washington Gas Light) have received approval from their regulators for RD. Each utility and its RD is discussed below.

Baltimore Gas and Electric and Washington Gas Light

In 1998 Baltimore Gas and Electric received approval for an RD mechanism, referred to as a Monthly Rate Adjustment to be applied to residential and general service customers. In 2005 Washington Gas Light received approval for a similar RD. Both mechanisms are based on a revenue per customer cap and a monthly true-up.

Under this regime volumetric charges are adjusted to keep the revenue growth per customer the same. This adjustment takes place each month and is determined using test year data. The first step in making the rate

---

[44] Ken Costello. Briefing Paper: Revenue Decoupling for Natural Gas Utilities. National Regulatory Research Institute, April 2006: 18, 23. p4

[45] American Gas. December 2005/January 2006. p.25

[46] Ken Costello. Briefing Paper: Revenue Decoupling for Natural Gas Utilities. National Regulatory Research Institute, April 2006: 18, 23. p5

adjustments is to determine the change in the number of customers, which is determined by subtracting a test year number of customers from the actual current month number of customers. This change in the number of customers is then used to calculate the change in allowed revenues by summing the customer charge impact and the volumetric charge impact.[47]

The change in allowed revenues is then added to a test year base revenue and from this the actual base rate revenue is subtracted to determine the required revenue adjustment. This required revenue adjustment is then added to the variance account and recovered through volumetric charges. These calculations are done separately for the residential and general service customers. This decoupling does not normalize the data used for weather.

NW Natural

In November 2000 the price of natural gas in Oregon began to escalate and there were public appeals by the governor to conserve. The price shock coupled with these pleas led to a reduction in natural gas consumption per residential customer of almost 10%.[48] As consumption dropped, earnings dropped and this spurred NW Natural to request an RD from the Public Utility Commission (PUC).

In September 2002, the PUC of Oregon approved an RD, referred to as the Distribution Margin Normalization, "so that the utility can assist its customers with energy efficiency without conflict."[49] As part of the approval, NW Natural committed to promoting energy conservation and is required to collect from all of its residential and commercial customers a surcharge of 1.5% of total monthly bills which are passed on to the Energy Trust of Oregon to implement DSM programs.

NW Natural's RD consists of two components: a price elasticity factor that adjusts for increases and decreases in consumption of residential and commercial customer groups due to changes in commodity costs or periodic changes in the company's general rates; and an adjustment calculated monthly based on differences in volumes between forecast

---

[47] *Customer Charge Impact* = change in the number of customers x current customer charge. *Volumetric Charge Impact* = change in the number of customers x test year average use per customer x system charge per therm.

[48] American Gas Association" Frequently Asked Questions About Energy Efficiency and Innovative State Reform".

[49] This RD was in place until August 2005, when it was modified by the Oregon PUC to allow for 100% amortization of margin differentials instead of the 90% allowed in the 2002 approval. American Gas Association. Natural Gas Rate Round-Up Decoupling Mechanisms – 2006 Update. p.3.

and actual for residential and commercial customer groups. NW Natural has a separate mechanism to adjust for weather, its weather-adjusted rate mechanism (WARM) for all residential and commercial customers, which is approved until 2008.

A 2005 study conducted for NW Natural indicates that its RD mechanism has had a positive impact on the company. It reduced the utility's business and financial risks without reducing service quality. The company shifted its focus from marketing to promoting energy conservation; the utility's DSM through the Energy Trust has had a statistically insignificant effect on use per customer.[50]

Southwest Gas Co.

In 2004 the California Public Utilities Commission approved a RD mechanism for residential and master-metered customers of Southwest Gas. Under this regime volumetric charges are adjusted to keep the revenue growth per customer the same. In order to determine the required revenue adjustment each month, monthly baseline volumes of gas for a test year are multiplied by authorized volumetric charges for each customer type (e.g. residential, master-metered). The product of this is then subtracted from the actual revenues generated from these customers, which is then subsequently divided by the actual volume of gas for each customer type to give the revenue adjustment required. This required revenue adjustment is then added to a variance account and recovered from customers through volumetric charges.

Piedmont Natural Gas

In November 2005, the North Carolina Utilities Commission approved a Customer Utilization Tracker (CUT) mechanism for Piedmont Natural Gas as an experimental rate for three years, to November 1, 2008. In its decision the PUC indicated that the CUT would give the utility a conservation incentive to assist residential and commercial customers, while reducing the shareholder risk and the frequency of future rates cases.[51] During the life of the CUT, the utility is required to contribute $500,000 per year toward conservation programs and to develop effective conservation programs to submit to the PUC for approval and annual review.[52] The CUT has a more explicit adjustment for weather

---

[50] Christensen Associates. A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural. March 31, 2005.

[51] North Carolina Utilities Commission. Order Approving Partial Rate Increase and Requiring Conservation Initiative, Docket Nos. G-9, Sub 499; G-21, Sub 461;G-44 Sub 15. November3, 2005.p.24.

[52] *ibid*. p.8. As part of the approval, the PUC terminated the Weather Normalization Adjustment Mechanism. Ibid. p.8.

than similar RD mechanisms and is applied separately to residential, and small and medium general service customers. To determine the change in volumetric charges that will keep the revenue growth per customer the same and will take into account the impacts of weather, Piedmont produces a normalized measure of volume that is the sum of base load volumes and heat sensitive volumes.[53] The revenue adjustment required is then calculated by taking the normalized measure of volume and subtracting the actual volume and then multiplying the result by the existing volumetric charge per volume.

Cascade Natural Gas

In April 2006, Cascade Gas received approval for a RD for residential and commercial customers from the Oregon PUC. The RD is comprised of two deferral accounts: one that tracks monthly deviations in gas use from normal weather consumption and the other that tracks monthly deviations from non-weather related changes in customer gas use. The accounts will be amortized over the next year as increments to the commodity charge. The utility RD also includes a 0.75% of revenue contribution of the company to fund customer DSM, certain service quality requirements and a penalty for failing to meet targets for addressing customer complaints. The RD remains in effect until September 2010.

RD and declining average use per customer

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

A RD is a blunt instrument that eliminates risks associated with revenue recovery related to sales. It is too blunt an instrument if the sole purpose is to address declining average use. Unless, a utility is experiencing other revenue loss risk factors in addition to declining average use (e.g. weather risks, debt recovery, infrastructure renewal) resulting in undue risk or there are other policy reasons for choosing RD, RD may not be appropriate.

---

[53] *Base load volumes* = actual number of customers x base load sales.
Heat sensitive volumes = actual number of customers x heat sensitivity factors x normal degree days.

In the US declining average use, while a factor, is not the predominant driver of the approval of RD by regulatory utility commissions. For the most part, the key driver for PUCs that have approved gas utility RD is to establish a climate favourable to utility DSM to address high natural gas prices. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin for reducing gas use per account.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM. For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

4.4 Make adjustments to fixed and variable charges

Depending on the level of the decline in average use per customer, how quickly the utility customer base is growing and other factors, it may become harder for the utility to recover its costs in the volumetric charge. In addition to the options previously discussed, this problem can be addressed by altering the rate design to recover more of the utility's fixed costs in the fixed customer charge. An extreme version of this option is to eliminate the volumetric charge. This type of rate-setting is common in the cable and telephone industries, with monthly fixed fees for service. The AGA refers to this total fixed charge option as 'straight fixed variable rate design.[54]

Four examples of rate designs employed by US gas utilities that try to do a better matching of the utility's fixed costs with its fixed customer charges are discussed below. The four utilities are: Laclede Gas, Oklahoma Natural Gas, Atlanta Gas Light and Excel Energy.

Laclede Gas

Laclede Gas in Missouri has developed a rate structure for its residential customers that includes an infrastructure replacement charge and seasonal rates for volumes. The customer service charge for residential customers is a fixed cost, which includes an infrastructure system

[54] The AGA Glossary defines straight fixed variable rate design as a method of determining demand and commodity rates whereby all costs classified as fixed are assigned to the demand component AGA. AGA Glossary.
http://www.aga.org/Content/NavigationMenu/About_Natural_Gas_Glossary?Natural_Gas_Glossary_(R).htm

replacement surcharge. The charge for gas used consists of a charge for the delivery or distribution of the gas, plus a charge, known as the Purchased Gas Adjustment (PGA) charge that reflects Laclede's cost of gas purchased from various suppliers. Volume charges are seasonal and with a declining block structure, with summer rates cheaper than winter rates.[55]

Oklahoma Natural Gas

Oklahoma Natural Gas, a subsidiary of ONEOK, provides its customers with a choice in the rate plan they select. Customers can either choose a rate plan with a high fixed (demand) rate and a low variable (delivery) charge or a low fixed rate and high delivery charge. For example, Rate Plan A contains a monthly service charge of US$9 and a delivery charge per dekatherm[56] of $1.9967, while Rate Plan B offers customers a monthly service charge of $20 and a delivery charge per dekatherm of $0.2367.[57]

Atlanta Gas Light

Atlanta Gas Light (AGL) charges its residential and commercial customers a fixed base rate to recover the utility's cost of delivering the gas, maintaining the delivery infrastructure and reading the meter. The base rate charge - called the Dedicated Design Day Capacity Charge (DDDC) - is a fixed charge but is unique to each customer. The DDDC is calculated based on how much gas a customer uses during the coldest period of the year to ensure that AGL has enough capacity to meet all customer needs in cold weather and to allocate the customer's share of the cost on the delivery system. The DDDC charged to each customer will vary based on the size of the home and the number and types of the appliances and equipment used. The DDDC charge is recalculated annually for each customer and is based on the consumption in the previous year.[58]

---

[55] Laclede Gas website. **http://www.lacledegas.com/customer/rrsummary.htm.** Accessed September 7, 2006.

[56] A dekatherm is a measurement of energy content. One dekatherm is the approximate energy content of 1,000 cubic feet of natural gas.

[57] ONEOK website. **http://www.oneok.com/ong/customerservice/rateinfo/ong_understand_bill.jsp.** Accessed September 7, 2006.

[58] Atlanta Gas Light website. **http://www.aglc.com/RatesRegulations/CustomerCharges.aspx.** Accessed September 7, 2006.

Xcel Energy

In response to a trend of declining average use per residential customer of 2% per year, the North Dakota Public Service Utility Commission approved in 2005 a straight fixed variable rate for Xcel Energy's residential customers. There was little public opposition to this approach as it resulted in a 1% rate base increase, compared with previous rate base increases of 15% to 30%, because of changes in wholesale gas costs.[59]

Adjustments to fixed/volumetric charges and declining average use per customer

In theory, improvements to rate design that lead to a one to one match of fixed costs with fixed charges and variable costs with variable charges are preferred. In the case of the gas distribution industry this would mean that most costs would be embedded in the fixed charge.

In practice, however, this may be difficult to achieve due to customer opposition to increases in fixed charges. Raising fixed charges would have the greatest impact on low volume customers such as residential and small commercial customers and low-income customers, in particular. Placing a greater financial burden on low-income customers is likely to meet with significant opposition.

In jurisdictions such as Manitoba[60] where electricity prices are low and on par with gas prices, a slight increase in fixed gas charges for Manitoba Hydro's residential customers could be the tipping point for large scale fuel switching to electricity for heating needs. In Quebec for Gaz Métro, a similar situation of fuel switching could occur due to the competitiveness of electricity prices compared with those of natural gas. Even in jurisdictions with more competitive gas prices compared with electricity prices, such as Ontario, increasing fixed charges may be unwelcome with customers to varying degrees depending on the franchise area.

Unless the rate design went to a rate based solely on fixed charges – a straight variable rate design – adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates.

---

[59] *American Gas*. December 2005-January 2006. p.24.

[60] Manitoba Hydro has a small fixed charge for residential customers of $10/customer. With the larger customers (150 out of 260,000 are large customers), there is a better rate structure leading to more revenue stability.

However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market toward a better matching of fixed costs with fixed charges.

4.5 Address declining average use per customer in a PBR environment

Types of PBR

There are two main types of regulation that North America gas utilities are operating under: cost-of-service regulation (COS) and performance based regulation (PBR). PBR is a rule-based approach that is seen as an alternative to COS as it requires less regulatory oversight and relies less on the discretion of regulators. In PBR, rules are created to provide inherent incentives for utilities to achieve regulatory objectives and to try minimize the risks to the utilities and its customers.

PBR goes by a variety of names, depending on the jurisdiction, these include: alternative regulation, incentive regulation, and formula rate plans. For the purposes of this report this rule-based approach will be referred to as PBR. Within PBR there are a number of options for setting the PBR rules; these include:

- **Deemed caps or freezes** – a variable, such as price, revenue or revenue per customer is fixed for a specific period of time. In North America, these deemed caps are most commonly placed on price. An example of a deemed price cap would be customer rates being capped or frozen over the duration of a 5 year plan.

- **Indexed caps** – caps a utility's prices or revenues using a formula. This formula, called the Price Cap Index (PCI) or Revenue Cap Index (RCI), depending on which variable is being capped, restricts the growth in allowed prices or revenues so that the growth must be less than or equal to the growth in the PCI or RCI. This is the most common form of PBR worldwide.

- **Earning sharing mechanisms**[61] – adjust rates automatically for differences between the company's actual and target rate of return, most commonly return on equity (ROE). If the utility exceeds the target ROE then the surplus revenues are shared with its customers. Alternatively, if the utility does not meet its target, then the customers share the revenue shortfall. The percentage of the surplus or shortfall shared with customers can vary, but commonly the split is even at 50/50, with 50% going to the customer and 50% to the utility.

PBR and declining average use per customer

The formula for the indexed cap for both RCI and PCI is the same: the growth in the indexed price cap index or revenue cap index is equal to an external inflation measure (P) minus a productivity factor (X) plus any factors outside the company's control (Z).[62] In a RCI PBR or in earnings sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecasted and actual declines in average use.

In a PCI PBR environment[63] rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a volume forecast and therefore, provides no

---

[61] Teresan Gas operates under an Earning Sharing Mechanism PBR which adjusts rates automatically for differences between the company's actual and target return on equity (ROE). If Terasen exceeds its target ROE, then the surplus revenues are shared with its customers; alternatively, if the utility does not meet its target then the customers share the revenue shortfall. The split of the surplus or shortfall shared with customers is 50:50 (e.g. Terasen will retain 50% of its above target revenues and its customers will receive the corresponding above target savings). If Terasen meets its ROE target, then it retains 100% of the earnings.

[62] Growth in PCI/RCI = $P - X + Z$
P is equal to the growth in an external inflation measure which can be economy-wide, industry-specific or for a peer group.
X is the X-factor which slows rate of revenue growth and which in North America is based on external industry productivity and input price information.
Z is the Z-factor which adjusts the PCI/RCI growth for external developments outside the company's control. Common Z factors include changes in government policy, change in industry accounting standards and natural disasters.

[63] Union Gas and Enbridge Gas Distribution may face a price cap PBR in 2008. Gaz Métro currently has a hybrid PBR that involves a price cap and a cost-of-service component. The cost-of-service revenue requirement (RR) is compared to a theoretical price cap. If the RR is less than the price cap, then the utility shares this productivity with its customers, 25% for the company and 75% for its customers; if the RR is greater than the price cap then the RR is raised to the price cap level. Because a load forecast is required each year the utility files a rates case, declining average use can be incorporated into the load forecast.

opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added.

Three alternatives for making this adjustment to rates in a PCI PBR environment have been identified. One alternative would be to include a declining average use factor in the calculation of the price cap.[64] A second alternative is to adjust the X-factor in determining price to account for declining average use.[65] A third alternative would be to make declining average use a Z factor and accumulate differences between the forecast decline in average use and the actual decline in average use in a tracker for later disposition. In general, making declining average use a Z factor may be less attractive to regulators than the other alternatives, as regulators try to minimize the number of Z factors. The alternative adopted should be tailored to the specific circumstances of the utility.

4.6 Conclusions

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options were discussed above; ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. Some of these options have been shown to be more appropriate than others and which option a utility adopts to address declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates.

It should be recognized that the options presented for addressing declining average use are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

---

[64] New rate = old rate (1 + P + decline in average use – X) + Z factors.

[65] New rate = old rate [1 + P – X (declining average use adjustment factor)] + Z factors.

Conclusions and recommendations

Canadian natural gas utilities have been experiencing a steady trend of declining natural gas use per customer, corresponds roughly to a decline in average use of 1.9% per year for all sectors and in the residential sector specifically, of 1.1% per year. The Canadian decline in residential average use is consistent with US experience in the residential sector, with the US decline averaging about 1% per year.

The analysis of the Canadian situation has revealed that changes in number of customers and climatic variation are not the main drivers of declining average use. As numbers of customers have continually increased and climatic temperature variation has been shown to have, in general, a very minor effect on natural gas use change, other factors must be driving the decline.

Contributing factors to declining average use in Canada

Over time Canadian homes and businesses have become more energy efficient. Over the last ten years, it is this market trend that is likely to have been the most significant common driver for declines in average use. The OEE Index reveals a 1%/yr improvement in energy efficiency from 1990 to 2004. This 1% increase is in line with the decline in natural gas use per customer in the residential sector experienced by the gas companies over the same period, and is supportive of the 1.9% decline in all sectors together.

Based on the NRCan price forecast, high natural gas prices are likely to continue. This trend coupled with the trend toward higher efficiency gas equipment, tighter building envelopes and more pressure to achieve greater savings from DSM, means that it is likely that declines in average use will continue for the foreseeable future.

We may be moving into a different era. In the past, historical experience was a good predictor of the gas market in the future. Today, it may not be as reliable due to short to medium term supply shortages in natural gas, restructuring in the Canadian economy due to a high Canadian dollar in relation to the US dollar, greater consumer awareness of energy efficiency and government pressure on gas utilities and others to assist customers to reduce gas usage and bills. These factors could bring us to the tipping point of an accelerated declining average use.

Implications of declining average use for utilities and their customers

From a customer perspective, future declines in average use will likely mean that customers are using natural gas more wisely and are saving money on their gas bills. From a utility perspective, declining average use contributes to customer retention. This keeps natural gas competitive with alternative fuels. For utilities with DSM, their DSM programs will further help their customers to achieve wiser use.

A regulatory environment that enables the utility to recover all lost revenue due to declines in average use will protect the utility from earnings erosion due to the declines. Declining average use only becomes a problem for a gas utility if the declines are not adequately captured in rates.

Utilities, such as ATCO Gas, AltaGas ,Enbridge Gas Distribution and Union Gas, with the highest percentages of residential gas customers in markets where natural gas is the predominant residential fuel, have the largest potential impact on profitability because of any declining average use per customer in this sector.

How to address declining average use

The utility response to declining average use per customer should be tailored to the market conditions and the regulatory environment in which the utility operates. These conditions differ across the country and among the individual utilities.

There are a number of options for addressing declining average use per customer in Canadian gas utilities. Five options are discussed in this paper; ignore declining average use, incorporate declining average use in the load forecast, decouple revenue from gas use, make adjustments to fixed and volumetric charges and address decoupling in PBR. These options are not completely distinct or independent from one another and more than one option can be operating at the same time for a particular company.

Ignore declining average use

One option for dealing with declining average use is to ignore it. In the short term, ignoring declining average use may be the preferred choice for a utility, either investor- or provincially-owned; if it is not posing a problem. However, over time, a utility will need to take declines in usage into account to protect the financial viability of the utility.

Incorporate declining average use in the load forecast

The most effective method of mitigating the effects of declining average use is through an offsetting increase in margin per unit rate. This can be accomplished through effective rate-setting either in cost-of-service or under PBR. The effectiveness of the methods will be largely dependent on the accuracy of the load forecast.

Should experience reveal that forecasts of declining average use are so unreliable that they result in significant margin erosion between offsetting adjustments, it may be necessary to track variances in an account, with true-ups made for under- and over-forecasting of the declines. A simple tracking account, a Declining Average Use Tracker, could be established which would track variance between the forecast decline in average use and the actual decline for later disposition and true-up.

Revenue decoupling

Revenue decoupling breaks the link between the revenues earned by gas utilities and the amount of gas they distribute, thereby eliminating the need to recover a certain level of revenues from volumes. Rates would be set based on establishing a per customer revenue cap, and underages and overages from the cap would be trued up. However, there would still be risk associated with setting the appropriate revenue level per customer based on the forecast of decline in average use. To eliminate this risk, a Declining Average Use Tracker would be needed.

For Canadian gas utilities with well developed DSM portfolios, effective tools to allow for recovery of revenue losses due to DSM and incentives that achieve aggressive DSM, such decoupling mechanisms may be overkill if the sole purpose of the mechanism is to promote DSM. With increased government pressure to reduce customer gas bills, there may be renewed interest in RD in jurisdictions that carry out regulated DSM to create a more favourable climate for DSM. RD eliminates the utility disincentive for DSM as the utility's revenue is decoupled from the level of sales. The utility is protected from losses in margin from reducing gas use per account.

For Canadian utilities that are considering entry into regulated DSM, it may be appropriate to start with RD to eliminate any DSM disincentive.

Adjustments to fixed and variable rate charges

Making adjustments to rate design to increase the amount of revenue recovered through fixed charges can address risk associated with declining average use to varying degrees. Unless the rate design went to a rate based solely on fixed charges - a straight variable rate design -

adjustments to fixed and volume charges would leave the utility exposed to revenue recovery risks due to declining average use from the remaining volumetric portion in rates. However, even with a straight variable rate design, the utility would still be exposed to the risk associated with forecasting the declines in average use to be recovered in the fixed charge. An additional mechanism, such as a Declining Average Use Tracker, would be required to fully address this risk. Therefore, it is suggested as a matter of good rate design, rather than to deal with declining average use, to move incrementally and carefully to the extent reasonable for a particular utility and its market toward a better matching of fixed costs with fixed charges.

Addressing declining average use per customer in PBR

In a RCI PBR or in earnings sharing PBR, rates are adjusted to ensure a specified level of revenue recovery. Within this process, adjustments to rates can be made which capture declining average use. Depending on the size of the variances incurred between adjustments, the utility, may wish to create a Declining Average Use Tracker to adjust for variations between forecast and actual declines in average use.

In a PCI PBR environment rates are capped and the actual revenues are determined based on the cap set. There is no adjustment made if the utility over- or under-earns. This type of rate setting, in its purest form, does not require a load forecast and therefore, provides no opportunity to make adjustment for declines in customer use over the PBR period. To correct for this problem, an adjustment to rates to account for declines in average use must be added.

specializing in industrial ecology and strategic management
providing environmental and energy consulting to private, public and non-governmental organizations

IndEco Strategic Consulting Inc
77 Mowat Avenue Suite 412 Toronto ON M6K 3E3
416 532 4333 ***info@indeco.com indeco.com***

Natural Gas Outlook To 2020

The U.S. Natural Gas Market —
Outlook and Options for the Future

February 2005

American Gas Foundation
400 North Capitol St., NW
Washington, DC 20001
202-824-7270
www.gasfoundation.org

Natural Gas Outlook To 2020

The U.S. Natural Gas Market —
Outlook and Options for the Future

February 2005

Prepared for the American Gas Foundation by:

Paul Wilkinson and Chris McGill
American Gas Association

and

Kevin Petak and Bruce Henning
Energy and Environmental Analysis, Inc.

DISCLAIMER

American Gas Foundation

Founded in 1989, the American Gas Foundation is a 501(c)(3) organization that focuses on being an independent source of information research and programs on energy and environmental issues that affect public policy, with a particular emphasis on natural gas. For more information, please visit the website at www.gasfoundation.org or contact Gary Gardner, Executive Director, at 202.824-7270 or ggardner@gasfoundation.org**.**

American Gas Association

The American Gas Association represents 192 local energy utility companies that deliver natural gas to more than 53 million homes, businesses and industries throughout the United States. AGA member companies account for roughly 83 percent of all natural gas delivered by the nation's local natural gas distribution companies. AGA is an advocate for local natural gas utility companies and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international gas companies and industry associates.

Energy and Environmental Analysis, Inc.

Energy and Environmental Analysis (EEA), located in metropolitan Washington, D.C., is a nationally recognized consulting firm offering technical, analytical and management consulting services to a diverse clientele. Founded in 1974 to perform economic, engineering and policy analysis in the energy and environmental fields, EEA has exhibited leadership and innovation in investigating energy and environmental issues.

FOREWORD

Natural gas is a clean, efficient, safe and reliable source of energy that provides one-fourth of the total energy consumed in the U.S. Further, most natural gas consumed in the United States is derived primarily from North American sources. For these reasons natural gas is highly valued by residential, commercial and industrial customers as well as by electricity generators. Also for these reasons, policy makers have generally promoted the use of natural gas. However, natural gas markets have been strained since late in the year 2000 with both tight supplies and higher and more volatile prices than was the case historically. Questions have arisen with respect to the likely role that natural gas will play in terms of meeting future U.S. energy needs and in terms of the outlook for future supply sources and prices of natural gas. Further, what types of actions and energy policies may result in either an improvement or deterioration in the outlook for natural gas? The purpose of this document is to address these questions.

This report analyzes the outlook for natural gas under three alternative policy scenarios. Under none of these scenarios does the natural gas market return to the conditions that prevailed in most of the 1980s and 1990s – surplus supply and relatively low, stable prices. However, it is clear that a number of critical issues currently face both public policy makers and private industry decision makers that will have significant impacts on the availability and price of natural gas for decades to come. Failure to act swiftly, decisively and positively on issues such as the constructing of liquefied natural gas receiving terminals and an Alaskan gas pipeline, diversifying our electricity generating mix and increasing access to domestic supplies of natural gas would prolong and exacerbate problems affecting natural gas markets and all consumers of natural gas.

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

The American Gas Foundation study “Natural Gas Outlook to 2020” (February 2005) analyzes the U.S. natural gas market to the year 2020 under three alternative public policy scenarios: “Expected”, “Expanded”, and “Existing”. These scenarios, outlined below, were used to describe potential market conditions and to emphasize the key policy variables that will have an impact on markets through 2020. They were not constructed in an attempt to present the “best” and “worst” possible cases.

Expected

The moratoria on exploration & production in the eastern Gulf of Mexico and off the East and West Coasts continues and drilling in the Intermountain West remains partially restricted. Also assumes that an Alaskan natural gas pipeline is operational by 2014 and that liquefied natural gas (LNG) import capacity will be 18 billion cubic feet per day (Bcfd) by 2020. Natural gas fuels 40% of new electricity generation.

Expanded

Assumes a lifting of the drilling moratoria in the eastern Gulf of Mexico and off the East Coast, but not the West Coast. Under this scenario, access in the Intermountain West is less restricted but it is not unlimited. Also assumes the Alaskan pipeline will be operational by 2014 and LNG import capability is 23 Bcfd by 2020. New electricity generation capacity fueled by natural gas falls to 20% of the total fuel mix.

Existing

This “status quo” public policy scenario has the same exploration & production moratoria assumptions as in the Expected scenario. Also assumes that an Alaskan gas pipeline is NOT operational by 2020 and although the four currently operational LNG terminals are assumed to expand, no new terminals are completed. The LNG import capacity is 5.3 Bcfd by 2020. Natural gas fuels 40% of new electricity generation.

SUMMARY OF FINDINGS

The results of the study point to the need for public policy makers and industry decision makers to immediately address critical issues that will have a significant impact on the availability and price of natural gas for decades to come. Under none of these scenarios does the natural gas market return to the conditions that prevailed in most of the 1980s and 1990s – surplus supply and relatively low, stable prices. Therefore, failure to act swiftly, decisively and positively on issues such as constructing liquefied natural gas receiving terminals and an Alaskan gas pipeline, diversifying our electricity generating mix and increasing access to domestic supplies of natural gas would prolong and exacerbate problems affecting natural gas markets and all consumers of natural gas.

Natural Gas Prices

Expected: Natural gas prices remain in the $5 to $6 per MMBtu range for most of the study period with a 2020 nominal forecast price of $8.15.

Expanded: Prices average $5.50 over the entire study period with a 2020 forecast price of $5.47. ***This price is 33% lower than the Expected scenario and results in a savings of roughly $80 billion dollars for consumers in 2020.***

Existing: The supply constraints of this scenario push the 2020 nominal forecast price to $13.76 with an average price of $9.43 over the study period. Average natural gas prices are nearly 70% higher in 2020 under the Existing scenario. ***This represents over $120 billion dollars in additional natural gas costs to the U.S. consumer in 2020 versus the Expected scenario and $200 billion versus the Expanded scenario.***

Natural Gas Supply

Expected: Natural gas supply will become more diverse, in contrast to the traditional 85% Lower-48 and 15% Canadian supply mix that we have come to expect. This scenario projects much greater supply diversity in the future, including major contributions in the form of Alaskan natural gas and LNG. Delays or denials of these sources will shift supply to more expensive marginal sources of domestic natural gas.

Expanded: Despite the measures incorporated under this scenario to increase access to gas supply in the U.S. and Canada, both Lower-48 production and Canadian imports are lower relative to the Expected scenario. The higher level of LNG imports under this scenario acts to reduce exploration for higher cost traditional sources of gas in a lower price environment.

Existing: The lower demand level in this scenario is met primarily by a greater dependence on traditional Lower-48 sources of gas and increased Canadian imports. No Alaskan gas is shipped to the Lower-48 and LNG imports do not reach 2 quads per year.

Natural Gas Demand

Expected: In spite of higher prices, annual natural gas consumption is projected to exceed 30 quads by 2020. This growth is attributable primarily to continued rising demand for gas to power electricity generation, while residential and commercial demand increase at a modest rate, just over 1% per year. Electricity generation accounts for two-thirds of the natural gas demand growth over the period.

Expanded: Total overall consumption is very similar to the Expected scenario, but industrial consumption is higher in response to lower prices while consumption for electricity generation is lower.

Existing: Higher prices in this scenario reduce consumption in total and for each of the consuming sectors. Consumption is somewhat lower in the residential and commercial sectors, but two quads lower for electricity generation and one quad lower for industrial customers.

Critical Study Implications

- The extreme prices of the Existing scenario are the result of not expanding the natural gas infrastructure much beyond that which is in place today. Operating under the Expected or Expanded scenario would require a significant increase in the natural gas infrastructure, including LNG terminals and the Alaskan gas pipeline.

- Increased unemployment, plant closings and the movement of industrial operations overseas have occurred over the past four years, in part in response to higher natural gas prices. The industrial sector will remain the most sensitive sector to tight supplies and high prices.

- Due to expectations of continued access restrictions and declining deliverability, both Lower-48 and Canadian sources will struggle to keep production stable at the current levels.

- Expectations for persistent tight market conditions are not a negative reflection on the natural gas resource base – domestic or worldwide. Ample resources of natural gas exist to meet demand for generations to come. However, the U.S. industry is severely restricted in terms of exploring for, producing and delivering natural gas, and severe restrictions are likely to remain.

- The outlook for significant natural gas-fired demand growth by electricity generators is unlikely to be altered, particularly prior to 2015, due to increasing use of the vast number of gas units completed over the past five years and the difficulty in siting and constructing coal or nuclear generating units in less than 10 years.

- Natural gas demand will become less predictable as the relative share of total demand attributable to electricity generators increases, while the relative share attributable to the industrial sector declines.

- The lack of a contribution in the Existing scenario from new LNG operations and Alaskan gas most likely would occur as a result of environmental opposition to the siting and construction of new facilities. However, failure to construct these new facilities would result in a far greater reliance on Lower-48 sources of supply, increasing the need to drill in both onshore and offshore areas, which also will be subject to environmental concerns.

II. SCENARIOS AND IMPLICATIONS

This study analyzes U.S. natural gas markets through the year 2020 under three alternative scenarios. The focal point of the study is the "Expected Policies" scenario. This scenario assumes that U.S. energy policy decisions over the next 16 years are relatively consistent with those that are being made today or that have been made in the recent past. The "Expanded Policies" scenario employs a number of modifications to both natural gas supply- and demand-related assumptions that act to ease pressure in the gas market and that, by doing so, ultimately reduce the cost of gas to the consumer. The third scenario is the "Existing Policies" scenario. This scenario was constructed under the assumption that most projects to expand gas supply would be impeded, and that major modifications in terms of gas demand would not be undertaken.

These scenarios were not constructed in an attempt to present the "best" and "worst" possible cases. For example, it is possible that drilling restrictions in the Intermountain West could be even more severe than they are today, but that possibility was considered remote and it was not incorporated in the Existing Policies scenario. Conversely, it is possible that all offshore areas currently subject to a drilling moratorium could be opened, but the possibility of drilling off the West Coast is considered so remote that it was not included in the Expanded Policies scenario. Changes expected to have only a modest impact over the forecast period, such as changes to appliance efficiency standards, also were not included. (Some potential variables were considered but ruled out after preliminary model runs found their impacts to be minimal or inconclusive.) This study attempts to present plausible scenarios with an emphasis on the key policy variables that will have an impact on natural gas markets through 2020. Each of the scenarios is described below.

Expected Policies

Under the Expected Policies scenario it is assumed that domestic drilling opportunities will change little throughout the forecast. The moratoria on exploration and production in the eastern Gulf of Mexico and off the East and West Coasts will continue, and drilling activity in the Intermountain West will remain partially restricted. It is assumed that an Alaskan natural gas pipeline will be operational by 2014, and that liquefied natural gas (LNG) import capacity will be 18 billion cubic feet per day (Bcfd) by 2020. This LNG capability is based on an expansion of the four currently operational receiving terminals to 5.3 Bcfd and the construction of nearly 13 Bcfd of new capacity. In this case, LNG meets 22 percent of total gas demand in 2020. Electricity generating capacity under the Expected Policies scenario expands by roughly 150 gigawatts (GW), including 60 GW of gas-fired capacity, 50 GW of coal-fired capacity, and 40 GW of renewable capacity.

Expanded Policies

The Expanded Policies scenario assumes a lifting of the drilling moratoria in the eastern Gulf of Mexico and off the East Coast, but not the West Coast. Access in the Intermountain West is less restricted under this scenario than is currently the case, but it is not unlimited. The Alaskan pipeline assumption is the same as under the Expected Policies scenario – operational by 2014. LNG import capability is 23 Bcfd by 2020, 28 percent greater than under the Expected Policies scenario. LNG under this scenario ultimately provides 28 percent of U.S. gas supply. Natural gas-based electricity generating capacity increases by 30 GW under this scenario, half as much as under the Expected Policies scenario. Coal, nuclear and renewable capacity are each roughly 10 GW greater in this case – the nuclear increment results primarily from a greater utilization of existing plants, although 2.5 GW of new nuclear capability is also added.

Existing Policies

Under the Existing Policies scenario no changes were assumed with respect to the in-place offshore moratoria, nor were any changes assumed with respect to access in the Intermountain West. It was assumed that an Alaskan gas pipeline would not be operational by 2020, and although the four currently operational LNG terminals were assumed to expand, no new terminals would be completed. The LNG capacity of 5.3 Bcfd could supply roughly 7 percent of this case's (lower) total demand in 2020. The electricity generating addition assumptions are the same as in the Expected Policies scenario, including 60 GW of new gas-fired capacity.

Common Assumptions

A number of key variables were assumed to be the same in all three cases, including:

Annual GDP growth rate: 2.8% per year
Industrial production growth rate: 2.3% per year after 2003
Coal prices: increase at 1% per year
Oil prices: RACC declines to $28/bbl by 2010, and increases 2% annually thereafter
Electricity generating capacity additions: short-term additions based on existing development plans, long-term assumes 1.9% annual growth rate in electricity output
Capacity utilization of coal generating units: 70% today, 73% in 2010, and 78% in 2020
Nuclear generation: capacity utilization continues at current level, no major retirements

A. EXPECTED POLICIES SCENARIO

In spite of a higher price environment, annual natural gas consumption is projected to exceed 30 quads by 2020. Total U.S. consumption of natural gas is projected to increase nearly 40 percent by 2020, from 22.1 quads in 2003 to 30.5 quads in 2020. (See Exhibit II-1.) This growth is attributable primarily to continued rising demand for gas to power electricity generation, while residential and commercial demand will increase at a modest rate, just over 1 percent per year. Gas consumption by electricity generators is projected to increase by 6.0 quads by 2020 as compared with growth of 1.1 quads and 0.7 quads for residential and commercial customers, respectively. Industrial gas consumption is expected to rebound, after falling sharply between 2000 and 2003. The increase in industrial consumption from 7.4 quads in 2003 to 7.7 quads in 2020, however, is relatively modest.

Natural gas supply will become more diverse, in contrast to the traditional 85 percent Lower-48 and 15 percent Canadian supply mix that we have come to expect. The projected supply in 2020 is 61 percent Lower-48, 22 percent LNG, 9 percent Alaskan and 8 percent Canadian. Lower-48 gas will remain the primary source of supply, but even with higher prices production will struggle to stay between 18 and 19 quads per year. Canadian production will be similarly affected, and Canadian gas also will be used to satisfy growing Canadian demand, resulting in a decrease in exports to the U.S. from 3.3 quads in 2003 to 2.3 quads in 2020. LNG will be the

Exhibit II - 1

COMPARISON OF LONG-TERM SCENARIOS
2003 – 2020

		FORECAST - 2020		
CONSUMPTION (TBtu)				
	Actual 2003	Expected Policies	Expanded Policies	Existing Policies
Res	5,188	6,326	6,417	6,076
Com	3,287	3,944	4,074	3,610
Ind	7,412	7,739	8,268	6,718
EG [1]	4,230	10,203	9,526	8,226
Pipe [2]	777	993	976	930
L&P [3]	1,247	1,254	1,211	1,336
Total	22,141	30,459	30,472	26,896
SUPPLY (TBtu)				
L-48	18,655	18,966	18,325	20,671
Alaska [4]	362	2,724	2,700	406
Canada	3,300	2,326	1,266	3,944
Mexico	-350	-177	-177	-177
LNG	478	6,835	8,569	1,931
Total	22,445	30,674	30,683	26,775
PRICE ($/MMBtu, Henry Hub)				
Nominal	$ 5.49	$8.15	$5.47	$13.76
Nom. Avg (2004-2020)		$6.72	$5.50	$9.43

[1] Electricity generation.
[2] Pipeline compressor fuel.
[3] Lease and plant fuel.
[4] Includes gas consumed in Alaska and the Lower-48, but excludes LNG exports.

relief valve, increasing nearly 15-fold by 2020. LNG is projected to supply 2.9 quads to U.S markets by 2010 and 6.8 quads by 2020.

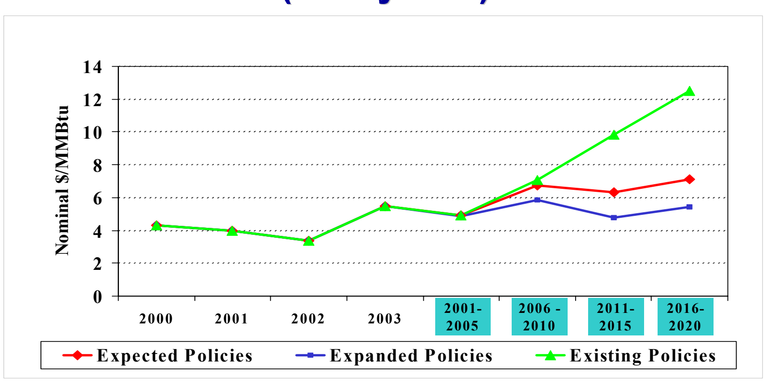
Natural gas prices are expected to remain in the $5 to $6 range for most of the forecast period, falling modestly in the 2010 to 2015 timeframe as new sources of LNG and Alaskan gas enter the market, but rising again between 2015 and 2020 as Lower-48 production is strained. (See Exhibit II-2.) Appreciably lower gas prices over the next several years – or prior to the construction of one or two new LNG terminals – is not considered likely under any of the scenarios examined. Although LNG would be competitive at significantly lower prices, lower prices would render some Lower-48 production uneconomic. It should be noted that, when adjusted for inflation, real natural gas prices actually fall – from $5.49 per MMBtu in 2003 to an average of $4.93 from 2011 through 2020 ($2003 per MMBtu at the Henry Hub).

Some of the key findings of the Expected Policies scenario are highlighted below.

Electricity generation will account for two-thirds of the natural gas demand growth over the forecast period. Gas consumption for electricity generation is projected to increase from 4.2 quads in 2003 to 6.8 quads in 2010 and to 10.2 quads in 2020. Sales of electricity are projected to increase by over 38 percent over the forecast period and gas is expected to account for 26 percent of the electricity generated in 2020 versus 15 percent today. Gas is not expected to capture as much of the new generation market in the future – down to 40 percent of the new market as opposed to the more than 90 percent it has realized in recent years. However, much of the generating capacity required in 2020 is already on line or under construction. There are 410 gigawatts of gas-fired capacity on line today with a projected total of 466 gigawatts by 2020.

Exhibit II-2

Actual and Projected Natural Gas Prices (Henry Hub)



Forecasted prices are in 5 year averages.

Environmental issues and lengthy lead times will limit the contribution of new coal-fired capacity prior to 2015, and the contribution of coal to the overall generation mix is projected to decline modestly, from 55 percent today to 50 percent in 2020. Despite a five-fold increase projected for renewable sources of electricity (solar, wind and biomass) over the forecast period, these sources will account for only 1 percent of the electricity generated in 2020. No new nuclear or hydroelectric capacity is anticipated.

Industrial natural gas demand will rebound and grow, but growth will be sluggish – at about one-third the rate experienced in the 1990s. Natural gas consumption by the industrial sector was 7.4 quads in 2003, about 15 percent below the 2000 consumption level. Higher prices over the past three years are in part responsible for this load loss, particularly in feedstock applications (ammonia, methanol and hydrogen). A further decline is projected in the gas feedstock industries, but this decline is expected to be offset by increases in boiler and "other" applications as the economy expands. A growth rate of 0.3 percent annually is projected for the industrial sector in total, with an overall consumption of 7.7 quads in 2020. Higher gas consumption growth rates are forecast for the stone-clay-glass, chemical and food industries – 1.0, 0.6 and 0.4 percent annually, respectively. Declines of 1.0 percent and 0.5 percent annually are projected for the steel and paper industries, in addition to an annual decline rate of 0.6 percent for petroleum refining. Growth is expected to be stronger in those industries that are less susceptible to foreign competition and in industries that benefit significantly from market proximity, such as the food and building products industries.

Modest growth is projected for the residential and commercial sectors, with continued efficiency improvements partially offsetting new customer hookups. Residential natural gas consumption is projected to increase from 5.2 quads in 2003 to 6.3 quads in 2020. The trend in declining gas usage per residential customer, attributable primarily to tighter homes and more efficient appliances, is expected to continue but at a rate roughly half that experienced from 1980 through 2001. An annual growth rate in residential consumption of 1.2 percent nationally is projected, but rates near or above 2 percent are projected for parts of the West and Northwest. Conversely, rates near or below 1 percent annually are projected in most of the Northeast, Middle Atlantic and Midwestern states. Competition for market share relative to electricity is expected to be intense, particularly in the warmer South Atlantic states.

The projected growth rate for commercial gas consumption (1.1 percent per year) is almost identical to that projected for the residential sector. Increasing consumption in the commercial sector faces the same obstacle as in the residential market. The average consumption per commercial customer fell by 18 percent from 1979 through 1999, limiting growth in commercial consumption to 20 percent despite a 46 percent increase in the number of commercial customers.

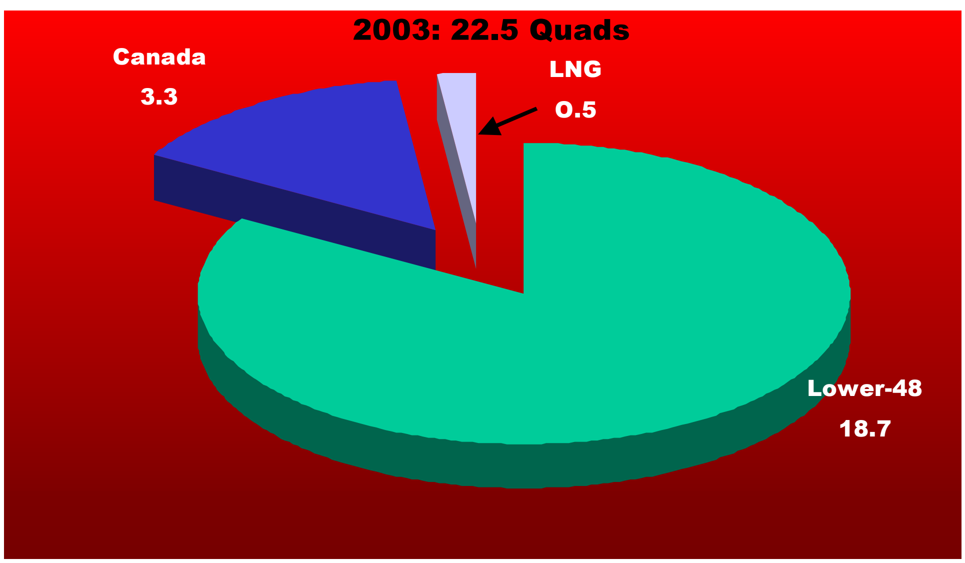
Lower-48 production will remain the largest component of U.S. gas supply, but producers will struggle to keep production between 18 and 19 quads per year. Projected Lower-48 production shows little movement in this outlook, staying mostly within a range of 18 to 19 quads per year. The percentage of the total supply mix accounted for by the Lower-48 therefore declines from 83 percent in 2003 to 61 percent in 2020. Although this scenario does not project significant growth in Lower-48 production, it does not forecast a dramatic decline either, as some analysts suggest.

Despite the fact that the U.S. is in the midst of a drilling boom, with 20,000 wells being completed annually, the supply response to this drilling has been modest, at best. In fact, discoveries per well drilled have flattened or decreased in recent years. A dramatic reversal in this trend is not anticipated. Relatively high gas prices have pushed producers toward marginal wells where gas is known to exist. These wells offer low risk and rapid potential depletion, but less volume recovered per well. Additionally, unconventional gas sources, including tight gas sands, coalbed methane and gas shales have become a significant portion of our total supply – almost 30 percent of the total. These sources are attractive in that they tend to produce for 10, 20 or even 30 years. However, unconventional resources usually come from low permeability reservoirs that require a relatively high number of modest production wells.

In this scenario domestic production is expected to remain constrained, both onshore and offshore, by access restrictions. These restrictions, including off the East and West Coasts, in the eastern Gulf of Mexico and the Intermountain West, affect areas believed to have significant production potential. There is no way to precisely quantify the size or quality of gas reserves to be found in restricted areas without exploratory drilling. Thus most analyses, including this one, may actually understate the actual gas resource.

Exhibit II-3

SOURCES OF CURRENT U.S. NATURAL GAS SUPPLY



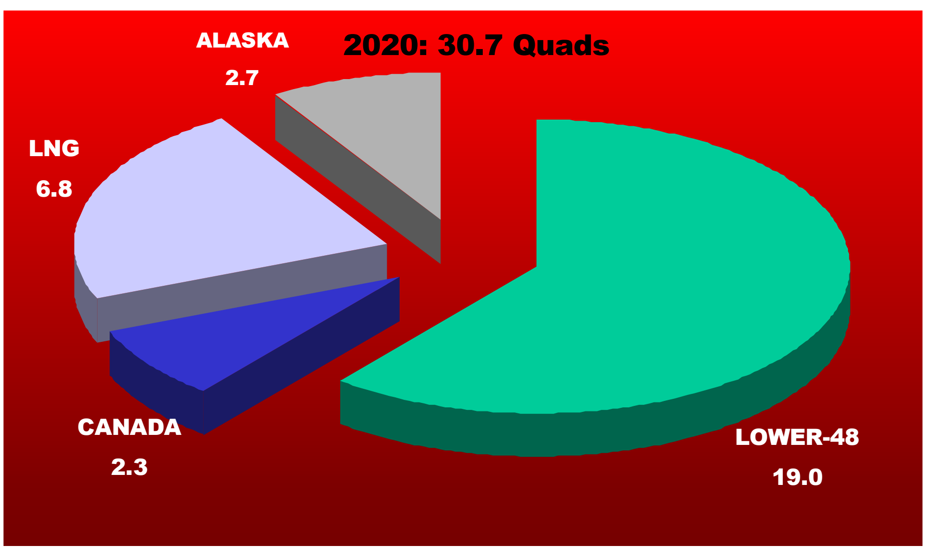
Canadian imports are expected to fall from 3.3 Quads annually to 2.3 Quads in 2020. Canadian imports provided 15 percent of total U.S. supply in 2003, but a decline to 8 percent of the total is projected by 2020. This decline is, in part, attributable to increasing gas demand within Canada. Canadian demand projections reflect normal economic and population growth, but they also reflect a significant increase in the use of gas to fuel electricity generation, to combat various forms of pollution and to enhance the production of oil from huge Canadian tar sands deposits.

On the supply side, Canadian producers are facing many of the same problems as U.S. producers. Virtually all Canadian gas production occurs in the Western Canadian Sedimentary Basin, which is reaching maturity. Canadian governmental estimates forecast overall production declines beginning as early as 2005. Efforts have begun to migrate production northward and eastward from traditional producing areas.

A potential offset to pending declines in production from traditional sources is production of coalbed methane (CBM). The Canadian CBM resource is vast, with estimates ranging from 500 Tcf to 2,700 Tcf. However, much of the CBM resource in Canada is unlike that in the U.S. and recovery will be difficult without significant technological advances. It is assumed in this analysis that 95 Tcf of the CBM resource in Canada is technically recoverable.

Exhibit II-4

SOURCES OF PROJECTED U.S. NATURAL GAS SUPPLY



LNG imports of 6.8 quads are projected in 2020, accounting for 22 percent of the total U.S. gas supply. A significant and rapid expansion in U.S. LNG imports is anticipated in this outlook. Imports increase from 0.5 quads in 2003 to 2.9 quads in 2010, to 5.3 quads in 2015 and to 6.8 quads in 2020. Expansions at the existing receiving terminals are assumed, as is the completion of new terminals as early as 2008 when imports account for over 7 percent of the total U.S. supply.

Approximately 93 percent of the world's natural gas resource base is outside of North America, and much of this gas is stranded and seeking a market. The U.S. is one of the most attractive markets for this gas. Additionally, LNG can be economically landed in the U.S. at a price in the \$3.50 to \$4.50 range – today and in the foreseeable future. The Expected Policies scenario assumes that LNG imports will, and in fact must, grow significantly in the very near future.

Huge quantities of gas at the North Slope are only the tip of the iceberg in terms of Alaska's total natural gas resource, but little progress in developing a transportation system for Alaskan gas has been made over the past 30 years. The total gas resource potential in Alaska, including the North Slope, Cook Inlet, coal seams and other onshore and offshore areas, is estimated at 251 Tcf. There is no doubt about the size of the Alaskan gas resource, yet this resource will remain stranded until an overland or LNG transportation system is put in place. Little progress has been made on a transportation option over the past three decades, primarily because of the scope of the project. For example, the estimate for the Alaskan natural gas pipeline system is roughly \$20 billion, with a 10-year construction schedule. Volatile natural gas markets and prospects for significant imports of competing LNG cloud the outlook for any Alaskan gas transportation project.

The Expected Policies scenario assumes 4 Bcfd of flowing gas from an Alaskan pipeline by 2014 and an expansion to 6 Bcfd by 2017. Alaska is projected to account for 9 percent of the total U.S. gas supply by 2020. Failure to have a transportation system in place to move Alaskan gas by this date would put further pressure on other sources of supply and prices would be pushed upwards.

B. EXPANDED POLICIES SCENARIO

Overall consumption under the Expanded Policies scenario is very similar to the Expected Policies scenario, but average natural gas prices are up to 33 percent lower. The combination of supply and demand measures taken in the Expanded Policies scenario has a significant impact on gas prices (although the impact is relatively modest prior to 2008-2010). Gas prices in this scenario are 33 percent lower in 2020 than under the Expected Policies scenario - \$5.47 per MMBtu versus \$8.15 per MMBtu. Prices averaged over the entire projection period - \$5.50 per MMBtu - are 18 percent lower in this scenario.

Total consumption of 30.5 quads in 2020 under this scenario is almost identical to the consumption in the Expected Policies scenario, although the breakout by consuming sector shows some key differences. Consumption in the Expanded Policies scenario is only marginally higher in the residential and commercial sectors, but in response to lower prices it is 0.5 quads higher in the industrial sector. Conversely, gas consumption for electricity generation is 0.7 quads lower in the Expanded Policies scenario, the result of an assumed more diverse generating mix.

Despite the measures incorporated under this scenario to increase access to gas supplies in the U.S. and Canada, both Lower-48 production and Canadian imports are lower relative to the Expected Policies scenario. Lower-48 production falls from 19.0 quads in the Expected Policies scenario to 18.3 quads in 2020, while Canadian imports fall from 2.3 quads to 1.3 quads. The higher level of LNG imports under this scenario – 8.6 quads or 28 percent of the supply mix – acts to reduce exploration for higher cost traditional sources of gas in a lower price environment.

C. EXISTING POLICIES SCENARIO

Average natural gas prices are nearly 70 percent higher in 2020 under the Existing Policies scenario. The supply constraints of the Existing Policies scenario push prices to $13.76 in 2020, with an average price of $9.43 over the forecast period. These higher prices, combined with a failure to construct new LNG terminals and the Alaskan pipeline, spur higher production from (higher cost) domestic sources. Lower-48 production reaches 20.7 quads in this scenario, 1.7 quads more than under the Expected Policies scenario. Canadian imports also are higher under this scenario, by 1.6 quads – responding in a similar manner to Lower-48 production.

Not surprisingly, higher prices in the Existing Policies scenario reduce consumption in total, and for each of the consuming sectors. Total consumption falls to 26.9 quads, with declines of 2.0 quads for electricity generators, 1.0 quads for industrial customers and 0.3 quads for both residential and commercial customers, relative to the Expected Policies scenario.

D. CRITICAL STUDY IMPLICATIONS

- Natural gas price projections are similar under all scenarios until roughly 2008. Some price relief is achievable at that point relative to the Existing Policies scenario due to the availability of LNG, supplemented in 2014 by Alaskan natural gas.

- Due to expectations of continued access restrictions and declining deliverability, both Lower-48 and Canadian sources will struggle to keep production stable at the current levels.

- Expectations for persistent tight market conditions are not a negative reflection on the natural gas resource base – domestically or worldwide. Ample resources of natural gas exist to meet demand for generations to come. However, the U.S. industry is severely restricted in terms of exploring for, producing and delivering natural gas, and severe restrictions are likely to remain.

- The Expected Supply scenario projects much greater supply diversity in the future, including major contributions in the form of Alaskan natural gas and LNG. Delays or denials of these sources will shift supply to more expensive marginal sources of domestic natural gas.

- The lack of a contribution in the Existing Policies scenario from new LNG operations and Alaskan gas most likely would occur as a result of environmental opposition to the siting and construction of new facilities. However, failure to construct these new facilities would result in a far greater reliance on Lower-48 sources of supply, increasing the need to drill in both onshore and offshore areas, which also will be subject to environmental concerns.

- The extreme prices of the Existing Policies scenario are the result of not expanding the natural gas infrastructure much beyond that which is in place today. Moving to the Expected Supply (or Expanded Supply) scenarios would require a significant increase in the natural gas infrastructure, including LNG terminals and the Alaskan gas pipeline.

- The outlook for significant natural gas-fired demand growth by electricity generators is unlikely to be altered, particularly prior to 2015, due to increasing use of the vast number of gas units completed over the past five years and the difficulty in siting and constructing coal or nuclear generating units in less than 10 years.

- Natural gas demand will become less predictable as the relative share of total demand attributable to electricity generators increases, while the relative share attributable to the industrial sector declines.

- Increased unemployment, plant closings and the movement of industrial operations overseas have occurred over the past four years, in part in response to higher natural gas prices. The industrial sector will remain the most sensitive sector to tight supplies and high prices.

III. Natural Gas Demand Overview

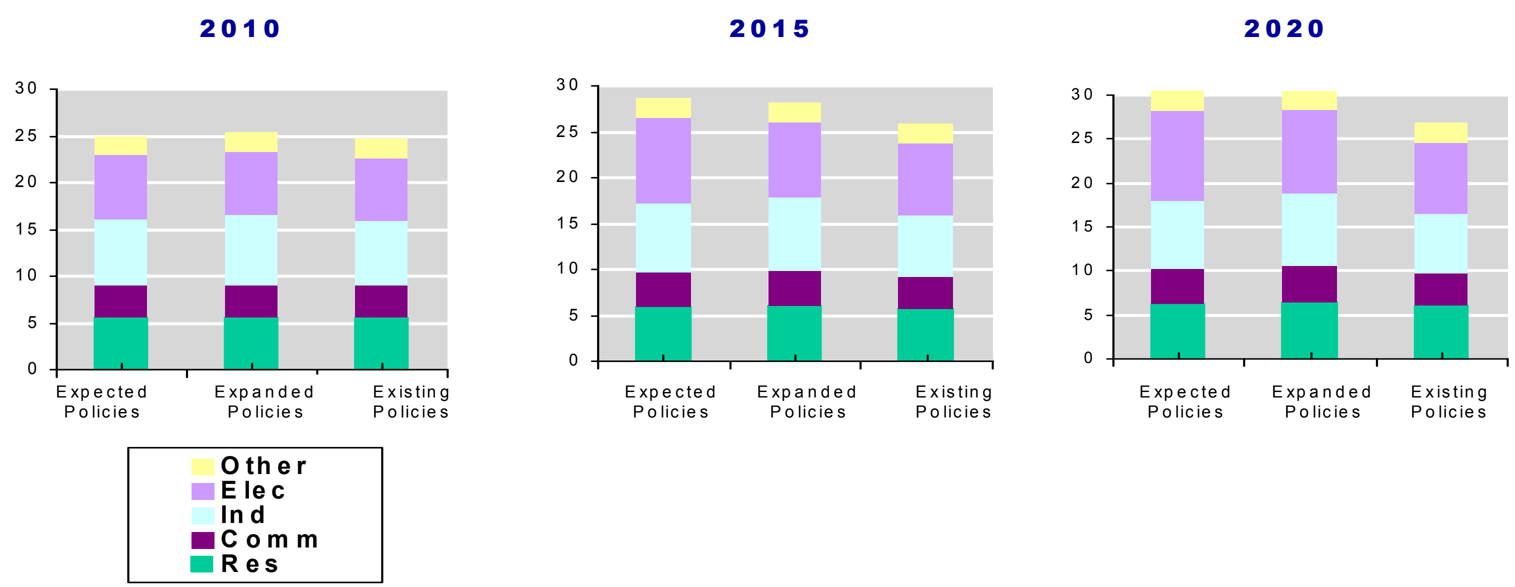
Exhibit III-1 depicts future consumption levels of natural gas in 2010, 2015 and 2020 for each of the three scenarios analyzed. Total consumption, which was 22.1 quads in 2003, is projected to reach 25.0 quads in 2010 under the Expected Policies assumptions and 30.5 quads in 2020. Nearly 72 percent of the total growth is attributable to the increasing demand for gas by electricity generators. Despite projected higher natural gas prices, generators continue to use gas because coal and nuclear units run at full capacity and significant additional coal capacity is not available until nearly 2015.

The alternative scenario consumption levels are not dramatically different than the Expected Policies scenario in 2010. However, total consumption in the Existing Policies scenario is 2.7 quads lower than in the Expected Policies scenario in 2015 and 3.6 quads lower in 2020. Consumption levels fall significantly in all consuming sectors in response to far higher prices, including declines of 1.9 quads by electricity generators and 1.0 quads by industrial customers.

Total consumption levels under the Expanded Policies scenario are quite similar in total to the Expected Policies scenario totals throughout the forecast period. However, there is a significant shift in the composition of the total. Consumption by residential, commercial and industrial consumers all increase – by over one-half quad for industrial consumers in 2020 – in response to lower prices. Additionally, more generating options are available to electricity generators as a result of a more diverse generating mix and, as a result, gas consumption by electricity generators falls by nearly 0.7 quads relative to the Expected Policies scenario.

Exhibit III-1

PROJECTED NATURAL GAS CONSUMPTION
QUADS



IV. ELECTRICITY GENERATORS WILL DRIVE OVERALL GAS DEMAND

The demand for electricity is projected to increase at a rate slightly less than 2 percent per year. The overall demand for electricity is driven primarily by the level of economic activity. In recent years, every 1 percent increase in GDP has resulted in a 0.72 percent increase in electricity sales. This GDP elasticity has declined in each decade over the past 50 years and a continued modest decline is projected - to 0.64 percent by 2020. As a result, a modest decline in the rate of growth for electricity sales is projected, falling from the current rate of 2.0 percent per year to 1.8 percent per year throughout the forecast period. Despite this falling growth rate, annual electricity sales of 3,482 billion kWh in 2003 are projected to reach 4,820 billion kWh by 2020, an increase of over 38 percent.

Electricity generators are expected to account for one-third of U.S. natural gas consumption in 2020 versus less than 20 percent today. Roughly 4.2 quads of gas were consumed to generate electricity in 2003, 19 percent of total U.S. gas consumption. This market share is projected to increase to 27 percent by 2010 (6.8 quads) and to 33 percent (10.2 quads) by 2020. Thus, by 2020 electricity generators are expected to be the dominant sector in terms of gas demand, with consumption 32 percent greater than that of the industrial sector and 61 percent greater than that of the residential sector.

Today gas is the source of about 15 percent of all electricity generated but this number is projected to increase to 26 percent by 2020. Conversely, 55 percent of all electricity generated today is coal-based but this percentage is projected to fall to 50 percent by the end of the forecast period.

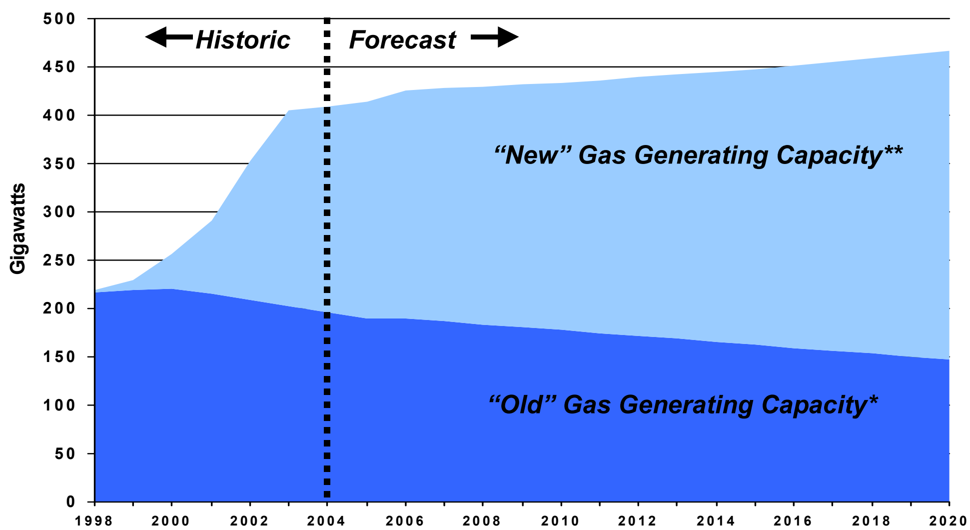
Gas consumption by electricity generators is lower in both the Expanded Policies and Existing Policies scenarios. The reduction in 2020 is 0.7 quads in the Expanded Policies scenario relative to the Expected Policies scenario due to more diversity in the construction of new generating capacity. It is 2.0 quads lower in the Existing Policies scenario in response to dramatically higher gas prices.

Growth in gas demand for electricity generation will be particularly strong in the Southeast, Intermountain West, Texas and along the West Coast while moderate to weak in the Midwest. The total projected increase in gas consumption for electricity generation from 2003 to 2020 is 6.0 quads. Of this amount, nearly 75 percent is attributable to the Southeast (1.8 quads), Florida (0.4 quads), Texas (0.8 quads), California/Nevada (0.8 quads), the Pacific Northwest (0.3 quads) and the Intermountain West (0.3 quads). Significant growth is also projected for the Middle Atlantic states, New York and New England, while little or no growth is expected the Midwest (ECAR, MAIN, MAPP and SPP NERC regions). The projected annual growth rates in gas consumption in a number of regions range from 10 to 20 percent for the 1999-2010 timeframe. In addition to the obvious gas supply issues that will be faced in these regions, infrastructure concerns will be critical, particularly for increased pipeline and storage capacity to accommodate more dramatic demand swings.

Most of the gas-fired generating capacity that will be required in 2020 is already on-line or under construction. Natural gas clearly has been the fuel of choice for new generating capacity in recent years. In fact, over 90 percent of the capacity added since the mid 1990s has been gas-based. However, somewhat greater diversity is anticipated for new generating capacity in the coming years, including anticipated contributions from both coal and renewable sources. It is projected that 40 percent of the electricity generating capacity added over the forecast period will be natural gas-based. Additionally, there is currently a generating surplus in most regions of the country, and new plant construction has slowed noticeably. Whereas roughly 200 GW of gas capacity was added over the past 5 years, only about half of that amount will be added over the next 15 years. Total gas-fired generating capacity in 2020 is estimated at 466 GW as compared with the roughly 410 GW that is operational today. That is, the gas-based capacity available today is nearly 88 percent of that expected to be operating in 2020.

Exhibit IV-1

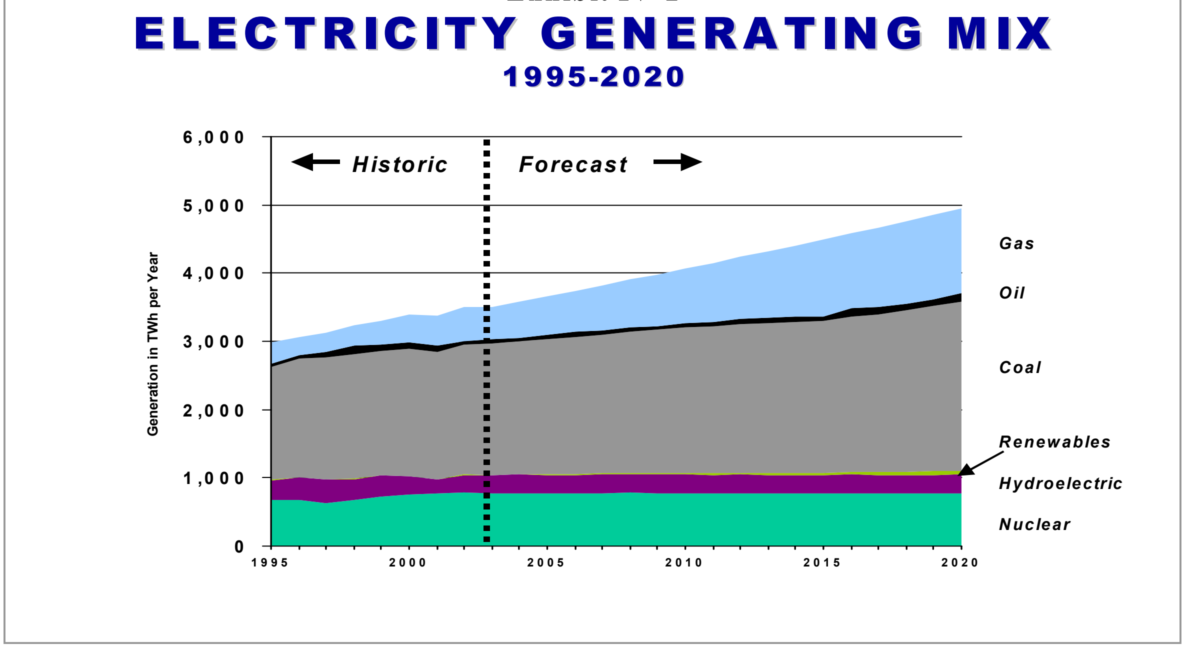
NATURAL GAS – BASED GENERATING CAPACITY 1998-2020



* Constructed prior to 1998; primarily boilers, but some combustion turbines and combined cycle units included; operated primarily on natural gas but includes some oil switching capability
**Constructed after 1998;operate almost exclusively on natural gas

This study does not assume significant changes in a number of environmental issues that could have an impact on the composition of electricity generation capacity. For example, the adoption of standards to control mercury (beyond those currently being considered) or CO_2 could significantly shift capacity away from coal and toward gas. On the other hand, a proliferation of aggressive renewable portfolio standards could reduce capacity additions for all conventional generating sources. These kinds of policies tend to have major economic and political consequences, and therefore their adoption is considered unlikely. Similarly, obstacles to the re-licensing of nuclear and/or hydro units – which combine to provide 30 percent of our current electricity supply – could have a dramatic impact on gas demand. Based on current trends, denials of a significant number of re-licensing applications were not considered likely.

Exhibit IV-2



The ability of other fuels to substitute for natural gas in periods of high gas demand continues to decline. In the mid-1970s there was a fairly high degree of substitutability between gas and oil in the electricity generation sector. Many generating units, particularly boilers, could operate on either gas or oil and it was common to switch from one fuel to the other as their relative economics changed. Additionally, oil and gas boilers tended to operate in an intermediate mode basis with annual capacity factors in the 20 to 40 percent per year range. Thus, if an individual boiler was not capable of switching from one fuel to another that boiler could be shut down and an available boiler could be started up on the competing fuel. The ratio of gas to oil consumed for electricity generation in the mid-1970s was about 50:50.

Changes in equipment and environmental regulations have combined to significantly reduce gas and oil substitutability. Combined cycle units have replaced boilers and although these units may be set up to operate on both gas and oil, most combined cycle units were installed in a gas-only mode to optimize environmental and operating performance. Additionally, oil backup requires the siting and installation of storage tanks. According to the National Petroleum Council, less than 20 percent of the generating capacity installed between 1998 and 2005 will have alternate fuel capability.[1] Further, ozone and other environmental standards preclude the use of oil in many parts of the country at some or all times. The combination of the evolution in equipment coupled with environmental restrictions has reduced gas/oil substitutability. Today, eight times more gas than oil is consumed for electricity generation.

While the construction of some new coal-fired generating units is anticipated, a modest decline in the contribution of coal to total electricity generation is projected. Coal-fired generating capacity is projected to increase from the current level of 314 GW to 364 GW in 2020. Based on this projection, coal will maintain just over one-third of total generating capacity over the forecast period. The rate of growth for coal-based capacity accelerates somewhat from 2010 to 2020 relative to the 1999 to 2010 growth rate – 1.0 percent per year versus 0.7 percent per year. Further, capacity additions of roughly 2.0 percent per year are expected after 2015. Coal consumption also is expected to increase over the forecast period, moving from 19.7 quads in 2003 to 24.1 quads in 2020. Despite this growth in both coal capacity and coal consumption, the share of coal in the generation mix is expected to fall somewhat – from 55 percent today to 50 percent in 2020.

Building new coal-fired capacity becomes economic when gas prices exceed roughly $4.50 per MMBtu. However, the lead-time for coal plants is 8 to 10 years. Thus, 33 of the 50 GW of new coal capacity is projected to come on-line after 2015. Additionally, environmental opposition and concerns over controlling CO_2 and mercury will continue to deter new construction. The utilization of available coal-capacity will be maximized, and an increase in capacity utilization from 70 percent to 78 percent is projected.

No new nuclear units are anticipated by 2020 and the contribution to total generation from nuclear sources is projected to fall from 22 percent to 16 percent. Nuclear power currently provides 22 percent of the U.S. electricity supply. However, under the Expected Policies scenario it is assumed that new nuclear plant construction remains infeasible and therefore no plants will be constructed. As a result, the contribution from nuclear sources is projected to fall to 16 percent by 2020. Nuclear units, similar to coal units, will be run in a full-out baseload mode, with capacity factors in excess of 90 percent. Under the Expanded Policies scenario 2.5 GW of nuclear capacity is constructed toward the end of the forecast period and all plants are run at a slightly higher capacity. As a result of these actions the nuclear share falls to 18 percent rather than 16 percent as in the Expected Policies scenario.

Despite a five-fold increase in renewable generating capacity, renewable sources are projected to account for only 1 percent of the electricity generated in 2020. Renewable sources, including wind, solar, biomass and geothermal, provide only 0.3 percent of U.S. electricity today. Renewable generating capacity, driven largely by wind projects, is projected to jump from about 10 GW today to 50 GW by 2020. Based on this forecast, renewable sources will represent 4 percent of the generation capacity in 2020 and 1 percent of the electricity generated. These sources tend to have a much lower utilization factor than do traditional generating modes – typically in the 10 to 20 percent range.

Additional hydroelectric capacity is not likely. Hydro capacity is expected to remain flat at 99 GW throughout the forecast period. Hydro provides 8 percent of the total electricity generated today, but this share is projected to fall to 6 percent by 2020. However, the availability of hydro will continue to have important implications for natural gas, particularly on the West Coast where hydro output is a function of snow and rainfall levels and where a lack of hydro translates directly into increased gas demand for electricity generation.

---

[1]National Petroleum Council, *Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy,* Volume II, September 2003, p. 90.

V. INDUSTRIAL NATURAL GAS DEMAND GROWTH WILL LAG SIGNIFICANTLY BEHIND GROWTH IN THE OTHER KEY DEMAND SECTORS

Natural gas consumption in the industrial sector is projected to increase at an annual rate of 0.3 percent through 2020 – only one-fifth the rate of growth experienced in the 1990s. Natural gas provides nearly 40 percent of the primary energy consumed in the industrial sector. In the decade of the 1990s, industrial gas consumption exceeded oil consumption in every year. However, oil consumption has exceeded gas consumption since 2001, with a difference of roughly 1 quad in 2003. Industrial coal consumption is about one-fourth that of natural gas or oil.

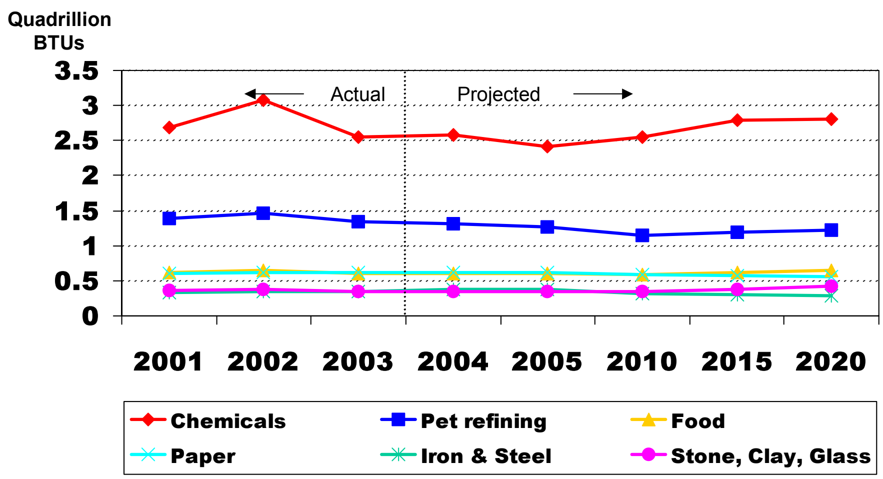
Gas consumption by industrial customers was 7.4 quads in 2003, a decline of roughly 15 percent from the levels experienced in the late 1990s. During the 1990s, industrial gas consumption increased at an annual rate of roughly 1.5 percent, but significant declines were realized in 2001 and 2003, with a modest rebound in 2002. The Expected Policies scenario projects an industrial gas consumption total of 7.7 quads in 2020, reflecting an annual growth rate of 0.3 percent per year.

The 2020 projection of the Expanded Policies scenario is roughly a half a quad higher (8.3 quads) than the Expected Policies scenario, while the Existing Policies scenario is about 1.0 quads lower (6.7 quads). These estimates reflect the prices of natural gas in the alternative scenarios relative to those of the Expected Policies scenario.

The declining market share projected for the industrial sector will result in a less steady national gas load. The industrial sector accounts for one-third of U.S. gas consumption today, but a decline to 25 percent is forecast by 2020. The industrial sector has not only been the largest single sector in terms of U.S. gas demand, but also it has been the sector with the most stable demand profile. Whereas residential, commercial and electricity generation demand are driven primarily by weather and they therefore exhibit extreme peaks and valleys in demand, major industrial customers often operate 24 hours a day, 365 days a year on a fairly constant gas flow. The load balancing potential of industrial customers is often enhanced through the use of interruptible contracts. Additionally, industrial facilities have traditionally provided economic justification for extending gas mains to areas without gas service, opening the way for residential and commercial gas growth. Local gas utilities deliver over half of the gas consumed by industrial customers.

Industrial natural gas demand growth will be constrained by limited growth in industrial production, increasing efficiency and global competition. Although the U.S. gross domestic product is projected to increase at an annual rate of 2.8 percent throughout the forecast period, growth in industrial production is expected to lag behind GDP, increasing at a rate of 2.3 percent per year. The high energy consuming portion of the industrial sector will not grow as rapidly as other segments of the economy, in part because basic manufacturing operations will continue to face higher costs at home and growing competition from other parts of the world. Not only will industrial production lag behind overall economic growth, but also energy consumption in the industrial sector will not even keep pace with industrial growth. The higher energy prices experienced since 2000 will motivate firms to seek out additional energy efficiency measures to further decrease the energy input required per unit of production. To illustrate the magnitude of the improvement in industrial energy efficiency since the first Arab oil embargo, industrial output has doubled since 1973, but the level of industrial energy consumption is virtually identical to what it was 30 years ago.

Exhibit V-1
ACTUAL AND PROJECTED INDUSTRIAL NATURAL GAS CONSUMPTION BY MAJOR INDUSTRIES



Although growth in industrial natural gas demand is expected to be lackluster, a continued dramatic decline in this market is not anticipated. Industrial natural gas consumption dropped sharply from 2000 to 2003 – by over 15 percent. This decline was concurrent with, and in part attributable to, the rapid rise in gas prices. Some plant operators have shutdown their facilities or moved overseas, often citing high gas prices as the sole reason. Feedstock industries were particularly hard hit. Some have argued that only the old, marginally competitive facilities were affected, and that surplus worldwide production capacity, a sluggish worldwide economy and the value of the dollar were the real culprits. Certainly all of these factors contributed. The question is whether or not the downward spiral in industrial demand will continue or whether a rebound is to be expected.

The slow growth projection of the Expected Policies scenario is based on a detailed examination of the key gas consuming industries as summarized below. Hundreds of billions of dollars have been invested in the stock of U.S. gas consuming industrial facilities. For some of these industries, energy costs represent a relatively minor share of the total cost of production. Additionally, it is very difficult to compete from abroad for some industries, such as foods and building products. It is expected that as the national and worldwide economies rebound, so to will these industries and so too will their gas consumption. However, the move toward greater efficiency and/or fuel substitution will only intensify with gas prices in or above the $4 to $5 range, although few major additional efficiency improvements are available and all-time high oil prices limit fuel switching options. The outlook is bleaker for domestic feedstock industries such as ammonia and methanol, whose gas consumption is expected to plummet by about 60 percent between 2000 and 2020.

The major domestic gas-consuming industries tend not to be high growth industries, and energy consumption growth, in most cases, will lag behind industry growth. However, both industrial output and gas consumption will respond to a rebounding world economy.

Exhibit V-2

INDUSTRIAL SECTOR GAS USE, 2002

Industry	Percent of Total Industrial Gas Use (%)	Gas Share of Value Added (%) [1]
Chemicals (all chemicals except ammonia production)	32	13
Ammonia Production	5	80
Refining	18	8
Pulp Paper Production	7	6
Food Processing and Manufacturing	8	3
Iron, Steel, Aluminum, Other Metals	7	6
Stone, Clay, and Glass	5	2
All Other Manufacturing and Non Manufacturing	18	2
All Industrial	100	7

[1] The dollar value of natural gas purchased divided by the dollar value of manufactured product.

The use of gas for boiler and "other" applications is projected to increase, while feedstock applications will experience declining gas usage. Nearly 80 percent of the gas consumed in the industrial sector is concentrated in six industries – chemicals (2.5 quads), petroleum refining (1.3 quads), paper (0.6 quads), food processing (0.6 quads), iron and steel (0.3 quads) and stone, clay and glass (0.3 quads).

The primary functions of gas are as a boiler fuel (2.4 quads); for other process heating applications (2.5 quads); as a feedstock, particularly for ammonia, methanol and hydrogen (0.6 quads); and for various "other" applications (1.7 quads). The projection shows slow growth for boiler fuel and "other" applications, but declines for gas process heating and feedstock uses.

Industrial growth in gas consumption is expected to be sluggish in all geographic regions. Roughly 54 percent of all industrial gas consumption occurs in two geographic regions, the West South Central (2.8 quads in 2003) and the East North Central (1.3 quads). Gas consumption in the West South Central region is heavily concentrated in chemicals and petroleum refining, and this one region accounts for over half of all gas consumed nationally as a boiler fuel or as a feedstock. A growth rate of 0.3 percent annually is projected for gas consumption in the West South Central region through 2020.

Gas consumption in the East North Central region is less than half that of the West South Central and it is distributed primarily between the chemical, iron and steel, food, petroleum refining and paper industries. An annual growth rate of 0.2 percent is projected for this region.

Growth in industrial gas consumption in all other regions is projected to fall in a fairly narrow range from 0.2 to 0.8 percent per year.

The demand for chemicals will continue to grow worldwide, and U.S. gas consumption will rise modestly in response. The U.S. chemical industry accounts for about one-fourth of worldwide chemicals production. This industry is energy intensive and natural gas intensive. In fact, it accounts for 11 percent of all U.S. gas consumption – a total of 2,544 TBtu in 2003. Geographically, roughly 60 percent of the gas consumption for chemicals is accounted for by the West South Central region. One-fourth of the industry's gas consumption is as a feedstock, primarily for ammonia, methanol and hydrogen. The other three-quarters are attributable to boilers (32 percent), process heaters (23 percent) and a variety of other uses (22 percent). Similar to other energy intensive industries, energy consumption per unit of production has been reduced significantly in recent years. According to the American Chemistry Council, this reduction has been nearly 40 percent since the mid-1970s.[1]

Plant shutdowns and layoffs in the chemical industry have received much attention since the winter of 2000-2001, and certainly higher natural gas prices have been a contributing factor. Feedstock operations have been particularly hard hit. However, a worldwide economic slowdown and a weaker dollar have also played a part. Chemicals remains a growth industry, with new products and new markets fueling new demand. As a result of this industry growth, natural gas demand also is expected to increase, although slowly. Consumption in 2020 is projected to reach 2,813 TBtu for the industry, reflecting a growth rate of 0.6 percent per year. However, gas consumption for methanol and ammonia production is expected to be cut nearly in half.

Petroleum refineries are expected to reduce natural gas consumption. Petroleum refineries consumed 1,347 TBtu of natural gas in 2003, nearly 20 percent of total industrial gas consumption. The refining industry is highly competitive, and many less efficient refineries have been shut down over the past three decades, while no new units have been constructed. Some environmental factors favor increased gas usage at refineries, such as the production of cleaner gasoline that requires hydrogen, for which natural gas is the typical feedstock. However, refineries have multiple energy options for most of their processes and they will move from fuel to fuel depending on relative prices. In addition to readily available fuel switching, refineries will continue to invest in energy efficiency, thereby reducing total energy demand in general and natural gas demand in particular. However, most of the easy energy efficiency opportunities have already been captured and future gains will be less dramatic. An annual decline in gas consumption of roughly 0.6

percent per year is projected for petroleum refining, resulting in a consumption level of 1,218 TBtu in 2020.

Natural gas consumption by the paper industry will decline as companies attempt to further increase energy efficiency. Gas consumption by the paper industry is fairly dispersed nationally, but it is particularly strong in the East North Central, West North Central and West South Central regions. Energy is a significant component of total operating costs in the paper industry. Although on-site energy production (primarily cogeneration fueled by wood by-products) supplies about 60 percent of the industry's energy needs, purchased fuels cost the industry roughly $8 billion annually. The paper industry faces significant foreign pressure and it will continue to seek ways to reduce purchased energy costs. It is projected that gas consumption by the paper industry will fall by 0.5 percent per year over the forecast period, declining from 613 TBtu in 2003 to 563 TBtu in 2020.

Modest growth is projected for natural gas consumption by the food industry. Natural gas consumption in the food industry is projected to increase at an annual rate of 0.4 percent, moving from 604 TBtu in 2003 to 642 TBtu in 2020. Much of this industry's energy consumption takes place in the East North Central and West North Central regions. Energy costs in the food industry are less than 1.5 percent of the value of total shipments and the industry is therefore less sensitive to price movement than are some other industries. Natural gas is also considered a premium fuel due to its cleanliness – a primary concern in this industry. Moderate growth is predicted for the food industry as a result of increasing population and disposable income, and foreign competition is not as significant a concern as it is in many other industries.

The growing demand for housing products and limited foreign competition will increase the natural gas demand of the stone, clay and glass industry. Energy is consumed in the stone, clay and glass industry primarily for the manufacturing of housing construction products – brick, concrete, gypsum, lime – as well as for various container products. Nearly 40 percent of the gas consumption in this industry occurs in the East North Central and South Atlantic regions. Transportation costs are relatively high in this industry relative to the value of the product, and thus foreign competition tends to be a less significant issue, as production near the actual market served is critical. Gas consumption in the stone, clay and glass industry is projected to increase at a rate of 1.0 percent per year, higher than the growth rate projected for any of the other primary industrial gas consumers. National gas consumption is projected to reach 417 TBtu by 2020 as compared to 350 TBtu in 2003.

Multiple factors will act to reduce natural gas consumption by the steel industry. Gas consumption by the steel industry is projected to fall at a rate of 1 percent per year, from 348 TBtu in 2003 to 293 TBtu in 2020. A number of factors suggest declining gas consumption, including: high energy intensity resulting in significant price sensitivity; a move towards minimills that tend to use less energy and relatively more electricity; excess production capacity worldwide; and, aggressive foreign competition. Energy costs account for about 15 percent of the total cost of manufacturing steel.

[1]National Petroleum Council, *Balancing Natural Gas Policy, Fueling the Demands of a Growing Economy,* Vol. II, September 2003, p. 54.

VI. MODEST GROWTH AND STIFF COMPETITION ARE ANTICIPATED FOR RESIDENTIAL NATURAL GAS DEMAND

Natural gas remains the primary energy source in the residential sector, although electricity has made significant inroads. Natural gas accounts for 45 percent of the energy consumed in the residential sector versus 38 percent for electricity and 13 percent for heating oil. The natural gas share has fallen slightly over the past three decades, down from 49 percent in 1973, while the drop in the share of heating oil has been much more dramatic, falling from 28 percent to 13 percent. In contrast, the share of electricity doubled over the same timeframe, moving from 19 percent to 38 percent.

Modest growth in natural gas demand is projected for the residential sector. Residential natural gas consumption reached 5.2 quads in 2003 and an increase to 6.3 quads is projected by 2020. This increase reflects an annual growth rate of 1.2 percent – roughly four times the rate projected for industrial consumption (0.3 percent), but significantly less than that projected for electricity generation (5.0 percent). Residential gas consumption is driven primarily by the weather (assumed to be normal throughout the forecast period), population growth, the share of gas heated homes and gas prices.

In the Expanded Policies scenario residential gas consumption is 1.4 percent higher in 2020 (6.4 quads) than in the Expected Policies scenario. However, in the Existing Policies scenario it is 4 percent lower (6.1 quads), primarily in response to higher prices.

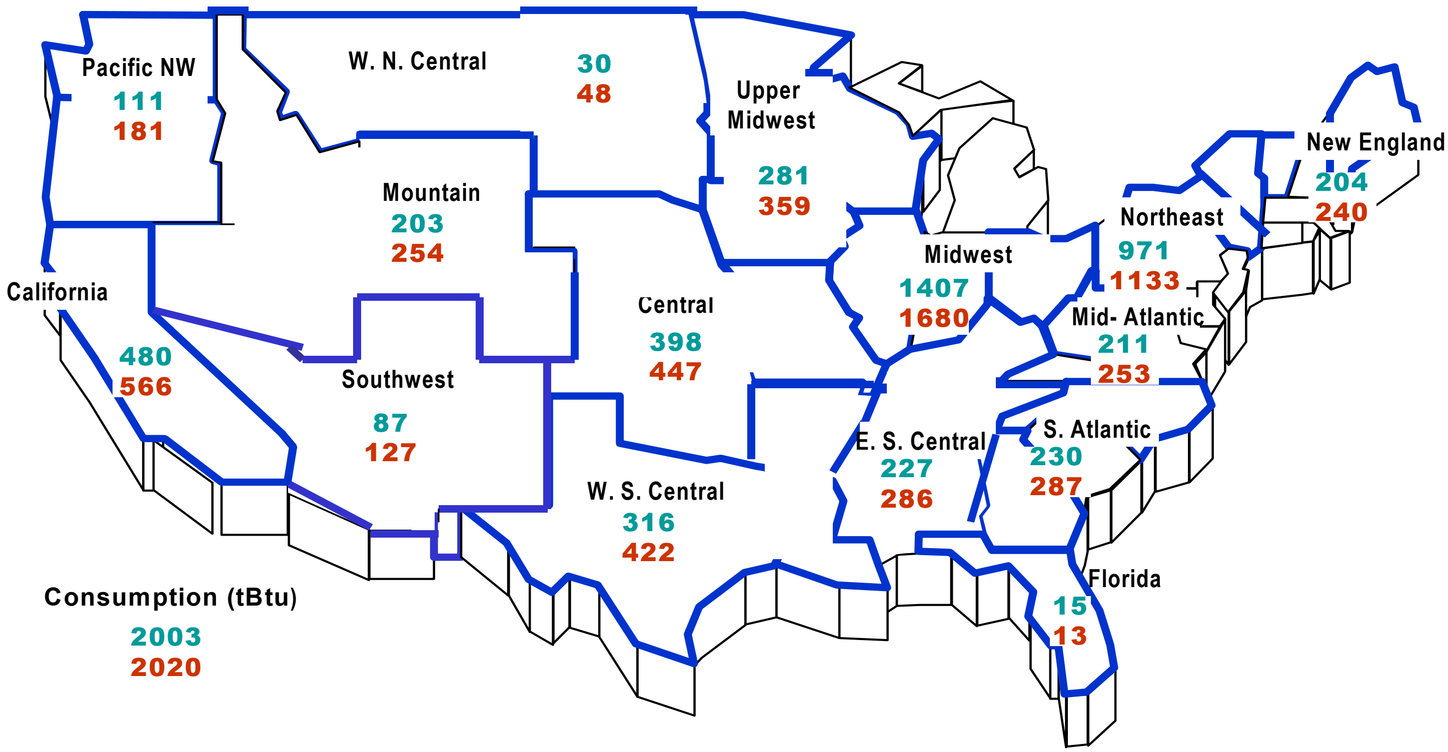
Growth rates will be higher in the West than in the East and Midwest. Residential gas demand growth is projected to be near or above 2 percent per year in parts of the West and Northwest, but near or below 1 percent annually in the Northeast, Middle Atlantic and Midwestern states. These projections reflect anticipated population shifts and new (larger) home construction.

Natural gas consumption per customer will continue to fall, but at a decreasing rate. Although the number of gas customers in the U.S. increased by nearly 33 percent between 1980 and 2001, overall consumption increased very little because of increased energy efficiency. The average use per residential gas customer (weather normalized) was 109 MMBtu per year in 1980, but only 85 MMBtu per year in 2001. Over half of this dramatic reduction is attributable to more efficient appliances and about one-quarter is due to tighter homes. The remainder is due to a variety of demographic and miscellaneous factors.[1]

It is expected that the average use per customer will continue to fall throughout the forecast period, but at a slower rate – roughly 0.5 percent per year versus the 1 percent annually experienced since 1980.[2] Two principal factors will tend to moderate the decline. First, the oldest and most inefficient appliances have already been replaced and potential improvements in new equipment are more modest. Second, consumers are demanding larger homes, thereby increasing the heating load. There is also a potential to reverse the use-per-customer trend as gas customers, similar to electricity customers, demand more and different energy related products - such as gas fireplaces and gas grills.

Exhibit VI-1

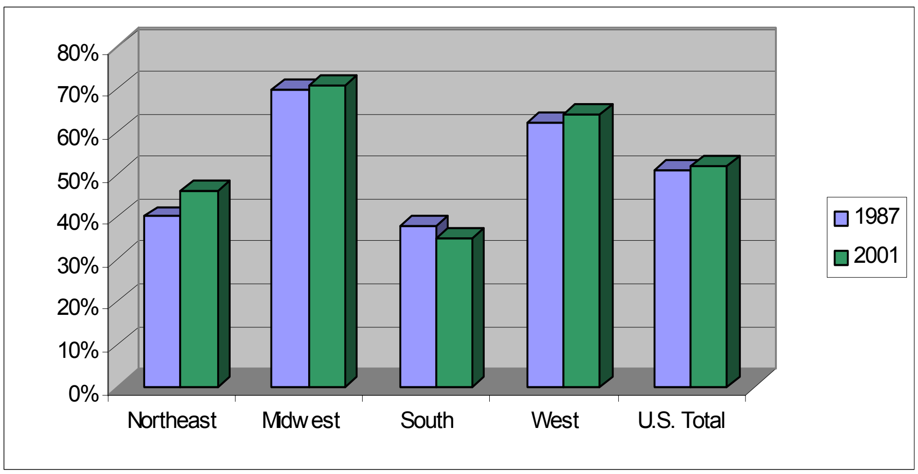
ACTUAL AND PROJECTED RESIDENTIAL NATURAL GAS CONSUMPTION BY REGION, 2003-2020



Competition for market share in the residential sector will be intense, particularly in warmer climatic areas, rural areas and in the smaller homes market. While electricity competes with natural gas in traditional markets – space heating, cooking, water heating and clothes drying – much of the growth in the electricity share is attributable to the proliferation of devices that only operate on electricity, such as computers, televisions, VCRs, DVDs, stereos, and the like. Natural gas remains very successful in the traditional markets, with market shares just over 50 percent for both space and water heating, 35 percent for cooking and 22 percent for clothes drying.[3]

Exhibit VI-2

RESIDENTIAL NATURAL GAS SPACE HEATING MARKET SHARES BY REGION, 1987-2001

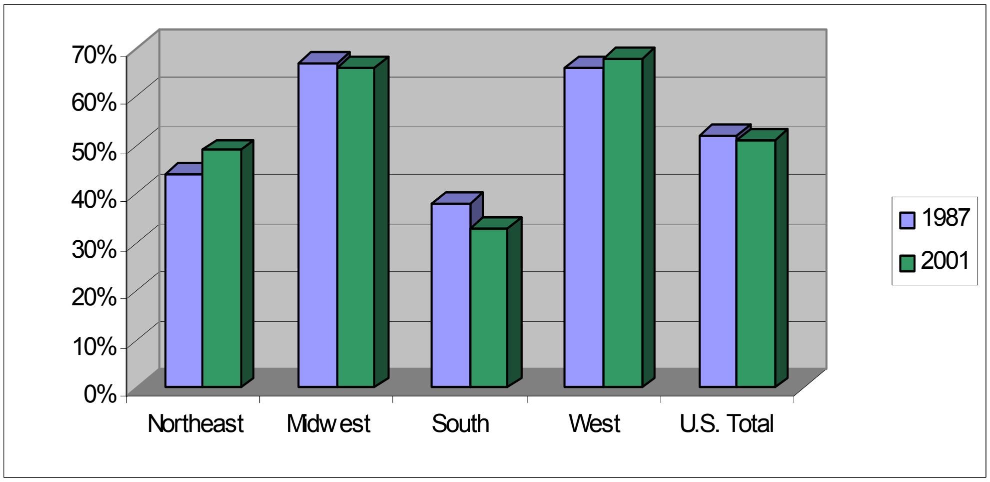


Source: American Gas Association, *Residential Natural Gas Market Survey*.

Market shares for the four primary energy applications have been quite steady on a national basis in recent years, although there has been variability among the geographic regions. Natural gas market shares in the Northeast increased from 1987 to 2001, from 40 percent to 46 percent for space heating and from 44 percent to 49 percent for water heating. In contrast, in the South the market share for gas fell: from 38 percent to 35 percent for space heating, from 38 percent to 33 percent for water heating, and from 26 percent to 22 percent for cooking. Gas market shares in the West have increased for all four applications – space heating (62 percent to 64 percent), water heating (66 percent to 68 percent), cooking (39 percent to 42 percent), and clothes drying (27 percent to 31 percent). Gas market shares in the Midwest have been high and increasing for space heating (70 percent to 71 percent), and high but slightly decreasing (by 1 or 2 percentage points) for each of the other three applications.

Exhibit VI-3

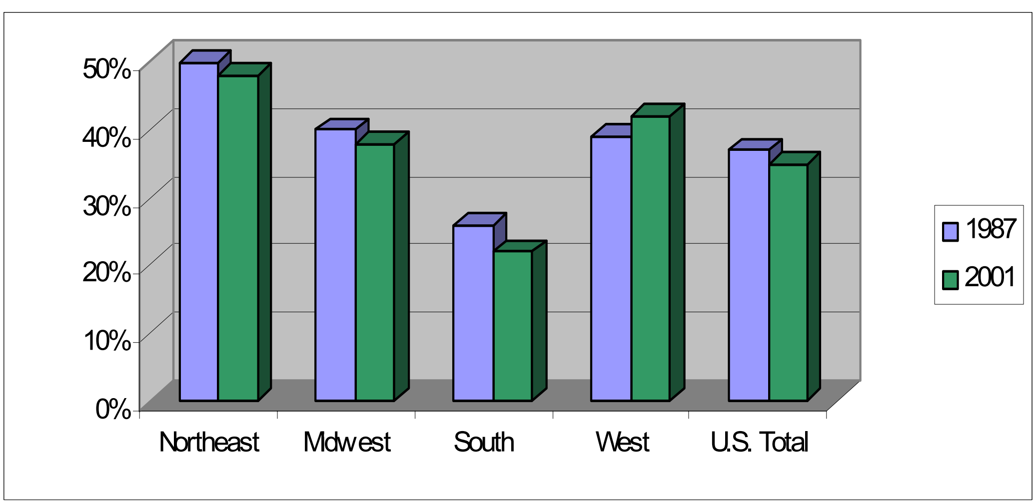
RESIDENTIAL NATURAL GAS WATER HEATING MARKET SHARES BY REGION, 1987-2001



Source: American Gas Association, *Residential Natural Gas Market Survey*.

Exhibit VI-4

RESIDENTIAL NATURAL GAS COOKING MARKET SHARES BY REGION, 1987-2001

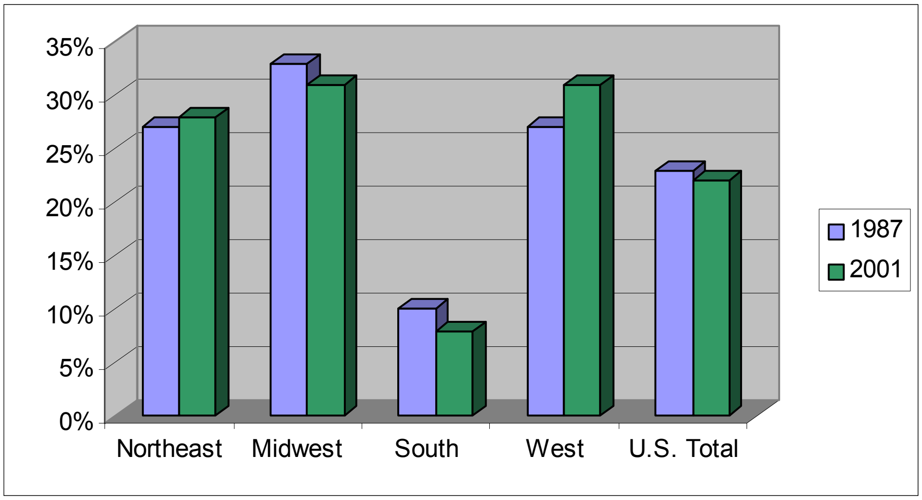


Source: American Gas Association, *Residential Natural Gas Market Survey*.

In the space heating market, the increased efficiency and reliability of the electric heat pump will continue to put pressure on natural gas in warmer climates. This has historically been the case, particularly in the South Atlantic states. However, advances in heat pump technology will

Exhibit VI-5

RESIDENTIAL NATURAL GAS CLOTHES DRYING MARKET SHARES BY REGION, 1987-2001



Source: American Gas Association, *Residential Natural Gas Market Survey*.

continue to expand the geographic areas where it is most competitive, both northward and westward. Electricity also will be very competitive in smaller, less expensive and space-constrained homes where gas presents incremental cost and space requirements relative to electricity. Gas has made significant inroads versus heating oil in the Northeast, and further gains are anticipated as gas pipeline and distribution systems expand. Gas will remain strongly preferred in colder climates where space heating is paramount.

---

[1]American Gas Association, *Patterns in Residential Natural Gas Consumption, 1997-2001*, June 16, 2003, p. 2.

[2]American Gas Association, *Forecasted Patterns in Residential Natural Gas Consumption, 2001-2020*, September 2004, p. 1.

[3]American Gas Association, *Residential Natural Gas Market Survey*, March 2004, pp. 13-14.

VII. COMMERCIAL SECTOR GAS DEMAND GROWTH WILL MIRROR THE RESIDENTIAL SECTOR – STEADY BUT UNSPECTACULAR

Natural gas accounts for 40 percent of the energy consumed in the commercial sector. The natural gas share of commercial sector energy consumption has fallen somewhat since 1973 – from 45 percent to roughly 40 percent today. On the other hand, the electricity share rose from 26 percent of the total to 45 percent over the same timeframe. Oil has fallen off sharply, with a reduction in share from 27 percent to 8 percent.

Lighting is the largest single energy-related application in the commercial sector. Space and water heating energy consumption combined is approximately equal to the total required for lighting. Gas has a 2:1 advantage in market share relative to electricity for space heating and the two are roughly equal for water heating. Gas has a modest advantage in market share for cooking.

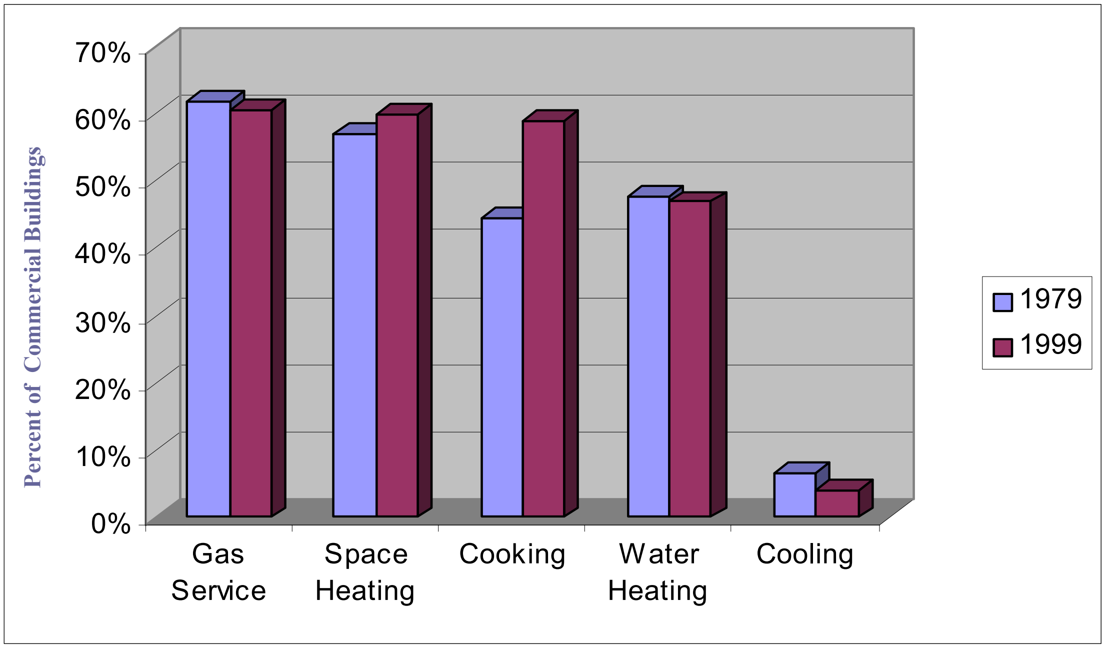
Commercial sector natural gas consumption is projected to increase by less than 1 quad over the forecast period. Commercial sector gas consumption is projected to increase by roughly 0.7 quads over the forecast period – moving from 3.3 quads in 2003 to 3.9 quads in 2020. This represents an annual growth rate of 1.1 percent, only marginally below the 1.2 percent rate forecast for the residential sector. The share of total gas consumption accounted for by commercial customers falls from 15 percent in 2003 to 13 percent in 2020.

Projected commercial sector consumption in the alternative scenarios responds in a fashion similar to the residential sector– driven primarily by gas prices – although the commercial response is about twice as great as the residential response. The commercial consumption level of 3.6 quads in the 2020 Existing Policies scenario is 8 percent lower than in the Expected Policies scenario. Conversely, the 4.1 quads projected in the Expanded Policies scenario are 3.3 percent higher than the Expected Policies projection.

Similar to the residential sector, the commercial sector has exhibited a dramatic increase in energy efficiency. Although the number of commercial gas customers jumped by 46 percent in the 1980s and 1990s, total consumption rose by only 20 percent. The average use per commercial customer fell by roughly 18 percent from 1979 through 1999.[1] Thus, consumption per customer, again similar to the residential sector, has been falling by about 1 percent annually. There has been significant variation in the use per customer trend on a regional basis. Use per customer in the Northeast increased by 47 percent due to increases in floor space and penetration by gas heating. However, in the Midwest and South respectively, declines of 27 percent and 30 percent were observed. The decline in the West was 18 percent, equal to the national average. A second measure of commercial energy efficiency is gas consumption per square foot of commercial space. This yardstick also indicates a dramatic decline over the past two decades, falling by 40 percent nationally.

Exhibit VII-1

NATURAL GAS MARKET SHARE IN COMMERCIAL BUILDINGS 1979-1999



Source: American Gas Association, *Trends in the Commercial Natural Gas Market.*

Newer and more efficient equipment, particularly for space and water heating, is responsible for over half of the reduction in use per customer. The remainder is largely attributable to more insulation, better windows and other building "envelope" improvements. A decline in the rate of reduction in consumption per customer is anticipated as these appliances approach their maximum efficiency.

Natural gas will not compete for many of the growth applications in the commercial sector. The strongest growth in terms of energy consumption for commercial sector applications is projected for various electrical devices – computers, copiers, imaging equipment and telecommunication devices. Annual growth rates for some of these applications are expected to be above 4 percent.[2] In contrast, the growth rate for many applications for which gas competes are projected in the 1 to 1.5 percent per year range. New applications, such as on-site electricity generation, offer some potential for greater gas growth.

---

[1]American Gas Association, *Trends in the Commercial Natural Gas Market*, October 23, 2002, p.1.

[2]U.S. Energy Information Administration, *Annual Energy Outlook, 2004*, January 2004, p. 5.

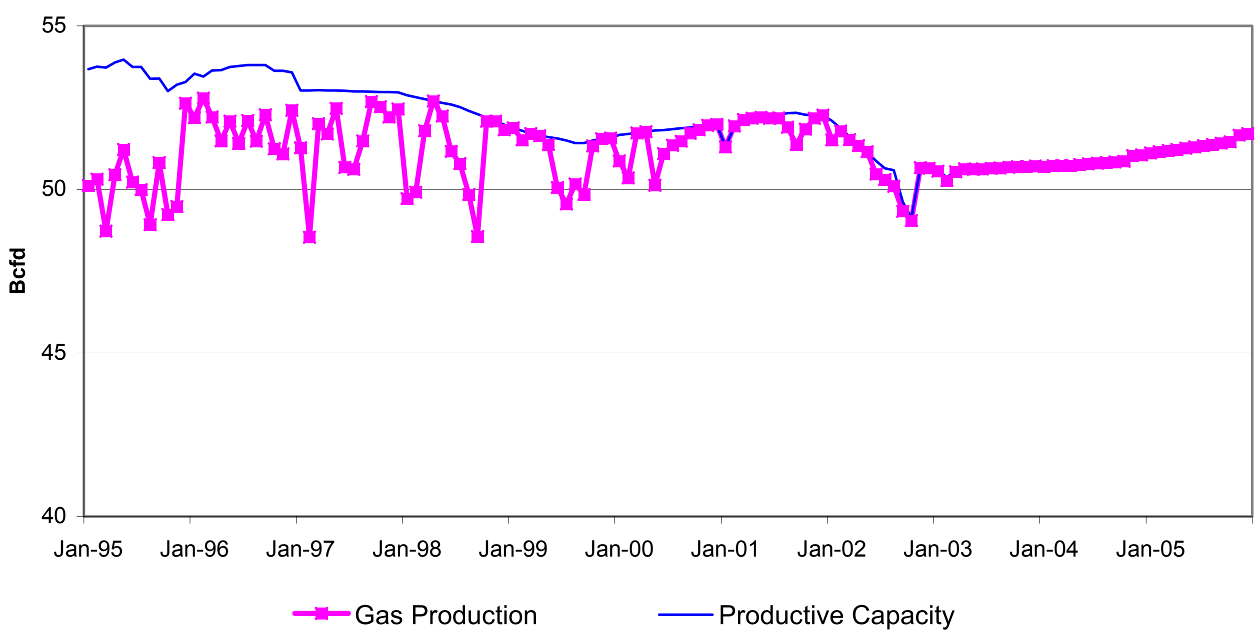
VIII. NATURAL GAS SUPPLY OVERVIEW

For much of the 1990s, U.S. natural gas markets were said to have excess supply, often described as a "bubble." In both the United States and Canada, natural gas production capability exceeded the requirements for produced gas even during most periods of peak demand. For purchasers of natural gas, the result was stable acquisition prices that were relatively low. In addition to North American supplies, liquefied natural gas (traded internationally) provided one to two percent of the natural gas consumed in the U.S.

Quite demonstrably since 2000, the relationship between producible natural gas and requirements for gas supply changed. The market today is often characterized as "tight" (supply strains to meet demand) or as supply-constrained - that is, domestic gas production is at or near 100 percent of production capability.

Exhibit VIII-1

U.S. NATURAL GAS PRODUCTION VS. PRODUCTION CAPACITY



Source: Energy and Environmental Analysis.

The tight market for U.S. gas production compared to demand requirements is not likely to change in the near-term. Sustaining natural gas production in the U. S. or growing it modestly presents significant challenges to gas producers, as well as to policy makers who have a strategic role in the future development of domestic natural gas resources.

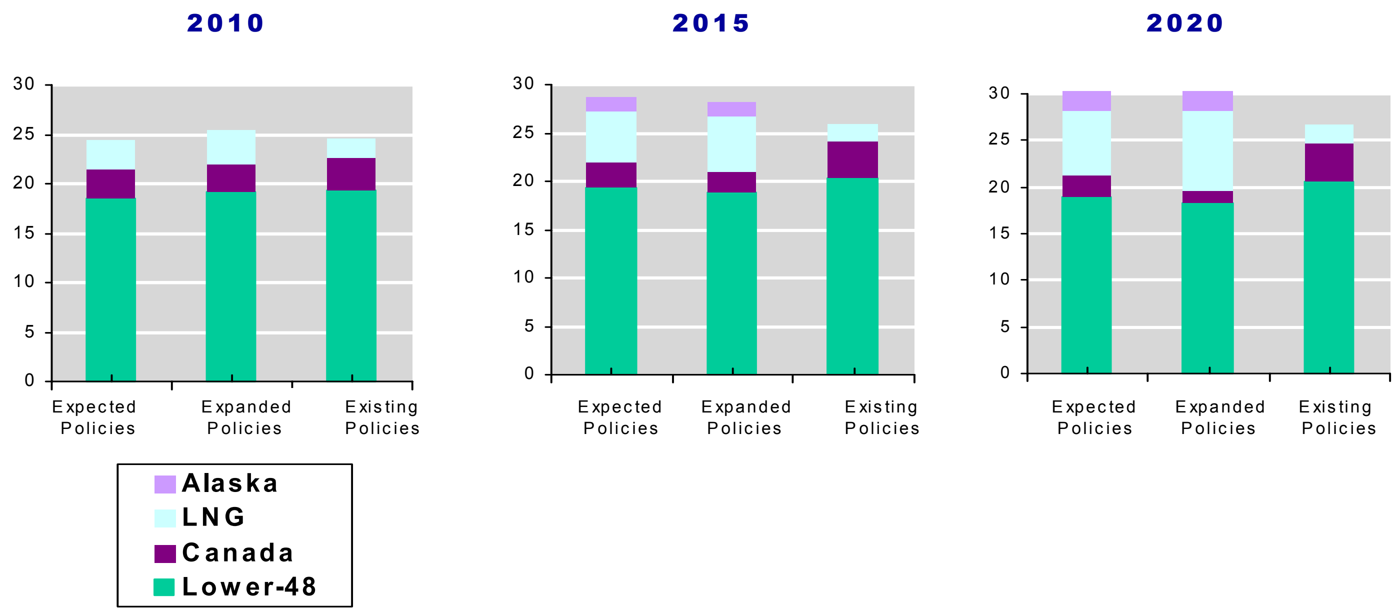
Exhibit VIII-2 shows key natural gas supply sources for the U.S., including Lower-48 states production, gas from Alaska, Canada and internationally traded LNG, and their estimated contribution to U.S. natural gas supply out to 2020. Each of the three scenarios - Expected Policies, Expanded Policies and Existing Policies - is shown in the exhibit. Each supply source is examined more closely in the following sections of this report.

In the Expected Policies scenario, Lower-48 production varies from 19.1 quads to 19.4 quads annually from 2010 to 2020. Offshore moratoria essentially stay in place and portions of federally owned land in the Intermountain West remain restricted. Nominal gas prices fluctuate between \$5.30 and \$8.15 per MMBtu and LNG followed by Alaskan gas (after 2013) meet incremental growth in demand. With a total market over 30 quads by 2020, Lower-48 supplies account first for about 81 percent of U.S. gas consumption in 2005, declining to 61 percent in 2020.

Under the Expanded Policies scenario, steps are taken to lift offshore moratoria and to open more areas of the Intermountain West to drilling. Roadblocks to LNG and Alaskan gas development also are overcome, resulting in the greatest estimate of these critical supplies among the three scenarios. With these sources of gas supply available, acquisition prices fall compared to the Expected Policies scenario to a nominal value of about \$5.47 per MMBtu by 2020. This results in a slightly smaller contribution of Lower-48 gas to the whole (about 60 percent in 2020) because lower prices do not support some of the more expensive domestic sources of gas compared to LNG and reserves in Alaska, once the pipeline infrastructure is in place.

The Existing Policies scenario produces a different result. Under this scenario, neither new LNG terminals nor an Alaskan pipeline are constructed. Thus, domestic production is left to meet more of a smaller overall gas market (just under 27 quads annually). Prices rise to \$13.76 per MMBtu in 2020, which supports Lower-48 production that still accounts for 77 percent of gas consumption. The irony is that, for reasons of environmental protection and security, less LNG is made available to the market, Alaskan gas is eliminated and, therefore, more drilling occurs in the Lower-48 states, particularly in tight sands and coal seams – activities that also raise environmental flags.

Exhibit VIII-2
PROJECTED NATURAL GAS SUPPLY
QUADS



IX. LOWER-48 SOURCES WILL ACCOUNT FOR A DECLINING SHARE OF OUR TOTAL NATURAL GAS SUPPLY

Even with substantial natural gas resources in the ground, merely sustaining annual gas production will challenge domestic producers. Estimates of annual Lower-48 gas production in this report (for all three scenarios) only vary 2.3 quads, from 18.3 to 20.7, for the period 2005-2020. Why? The Potential Gas Committee (Colorado School of Mines) estimates that over 1,200 Tcf of natural gas exists *in the ground* onshore and under the coastal waters of the United States (including Alaska). At current rates of production (approximately 19 Tcf annually) that is more than 60 years of natural gas resource development. In fact, even that number is not static and is likely to grow. However, very limited growth (or decline for that matter) in Lower-48 states production is forecast in this study.

The National Petroleum Council (NPC) report on natural gas released in 2003 noted that only 14 percent of its assessed North American resource base was proven, that another 17 percent could be attributed to field growth associated with known reserves and that a full 69 percent was still undiscovered. Admittedly, there is a great deal of uncertainty associated with our knowledge of the ultimate volume of natural gas to be recovered. That said, virtually all estimates of natural gas resources in North America are large. With all of this gas in the ground, why isn't future gas production expected to grow?

The answer lies primarily in the type of well being drilled today (and likely to be drilled in the future) and the locations available for gas and oil development. America is in the midst of a drilling boom. Rig activity in the U.S. has been sustained above 1,000 total rigs operating for more than a year. Operations in search of natural gas targets routinely account for 85 percent of all rig activity and as many as 20,000 wells are completed annually to be added to the current inventory of over 350,000 producing gas wells. All of those indicators are good. But a not-so-subtle change in quality and productivity of individual producing wells is also occurring.

Exhibit IX-1 shows some of the current trends. For example, rig counts have been rising with gas-directed operations growing from 55 percent of total activity to over 80 percent of total activity. Gas well completions have increased, particularly since 1999, but discoveries per well have flattened or decreased. This is typical when well completions increase dramatically, inasmuch as some marginal prospects are drilled along with better prospects during periods of price induced higher activity.

Exhibit IX-1
RIG COUNT, WELLS AND DISCOVERIES

Year	Annual Avg. Rig Count	Annual Avg. Gas Rigs	Percent Gas Rigs	Gas Wells Completed	Total Discoveries (Bcf)	Additions per Well (Bcf)
1994	775	427	55	9,538	12,315	1.291
1995	723	385	53	8,354	10,961	1.312
1996	779	464	60	9,302	12,318	1.324
1997	943	564	60	11,327	15,648	1.381
1998	827	560	68	11,144	11,433	1.026
1999	625	496	79	10,877	10,807	0.994
2000	918	720	78	16,455	19,138	1.163
2001	1,156	939	81	22,083	22,758	1.031
2002	830	691	83	16,155	17,795	1.102
2003	1,032	872	84	19,722	19,288	0.978

Source: Energy Information Administration, U.S. Department of Energy.

In addition, higher gas prices at the wellhead tend to support producer efforts to completely recover gas in areas where it is known to exist. Drilling in these mature areas presents less risk to producers but also leads to less volume recovered per well because the typical reservoir size declines. In addition, technology allows reservoirs to be drained more quickly and efficiently, which is an important factor in making these natural gas reservoirs economic to develop, but which also contributes to shorter reservoir life. This, in turn, requires producers to drill more to replace the decline in volume as reservoirs deplete. And so the cycle, or “treadmill” as it is often referenced, continues. This is happening in the mature areas of the Gulf of Mexico, onshore U.S. and Canada.

Gulf of Mexico gas production will decline as a portion of all North American gas production, particularly after 2010. Gulf of Mexico gas production, which was 30 percent of U.S. gas production in 1990, was only 23 percent of gas production in 2003. New frontier gas, primarily from deepwater, has to some extent offset declines in shallow water continental shelf production. However, even recent deeper drilling on mature shallow water leases (enhanced by royalty relief) coupled with deepwater gas will not compensate for the decline in traditional shelf production. During the period 2010 to 2020 this condition is expected to deteriorate further. Other gas sources will need to be more fully exploited in order to sustain overall Lower-48 production.

An increasing dependence on unconventional gas sources will increase a drilling focus in the Intermountain West, with lower producing but longer-lived wells. One activity offsetting the high decline rates and recovery factors of traditional sandstone and other reservoirs is the activity in less traditional reservoirs such as tight sands and coal seams. The NPC study of 2003 estimated that over half (55 percent) of the remaining *conventional* resource base in North America is located in the Gulf of Mexico, Western Canada Sedimentary Basin and Alaska. Only four percent of the conventional resource was attributed to the Intermountain West.

In contrast, 44 percent of the yet to be developed *unconventional* resource is expected to be found in the Intermountain West. It is generally recognized that a substantial portion of the total U.S. natural gas resource base is tied up in low permeability (perm) reservoirs such as Devonian Shale and coal seams in the Appalachians, shallow coals in Kansas (and other locations in the mid-continent) and tight sands and coals in the Rocky Mountains. Estimates of unconventional resource volumes vary but they are large for technically recoverable gas.

Advanced Resources International estimates that unconventional resources may total 760 Tcf. In addition, so-called unconventional sources of gas account for over a quarter of U.S. production today and they may account for more in the future.

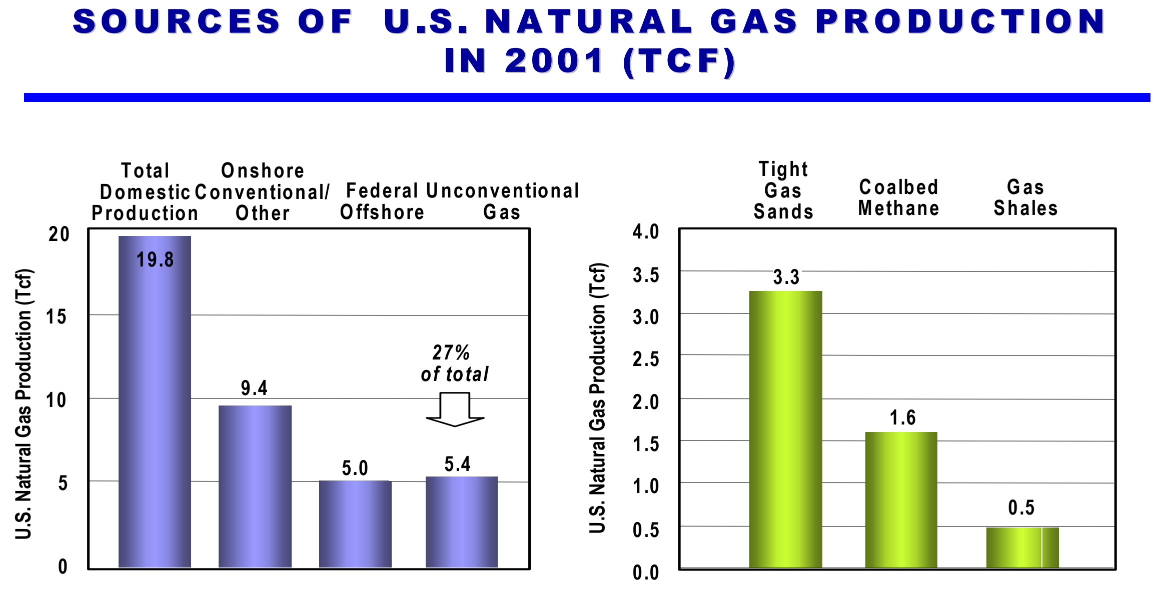
Exhibit IX-2

ESTIMATES OF TECHNICALLY RECOVERABLE U.S. UNCONVENTIONAL GAS RESOURCES

	Current Technology (Tcf)			Year 2025 Technology (Tcf)
	Proved Reserves/ Production	Undeveloped Resource	Ultimate Resource	Ultimate Resource
Tight Gas Sands	149	292	441	520
Gas Shales	13	62	75	90
Coalbed Methane	29	95	124	150
TOTAL	**191**	**449**	**640**	**760**

Source: Advanced Resources Int'l.

Exhibit IX-3



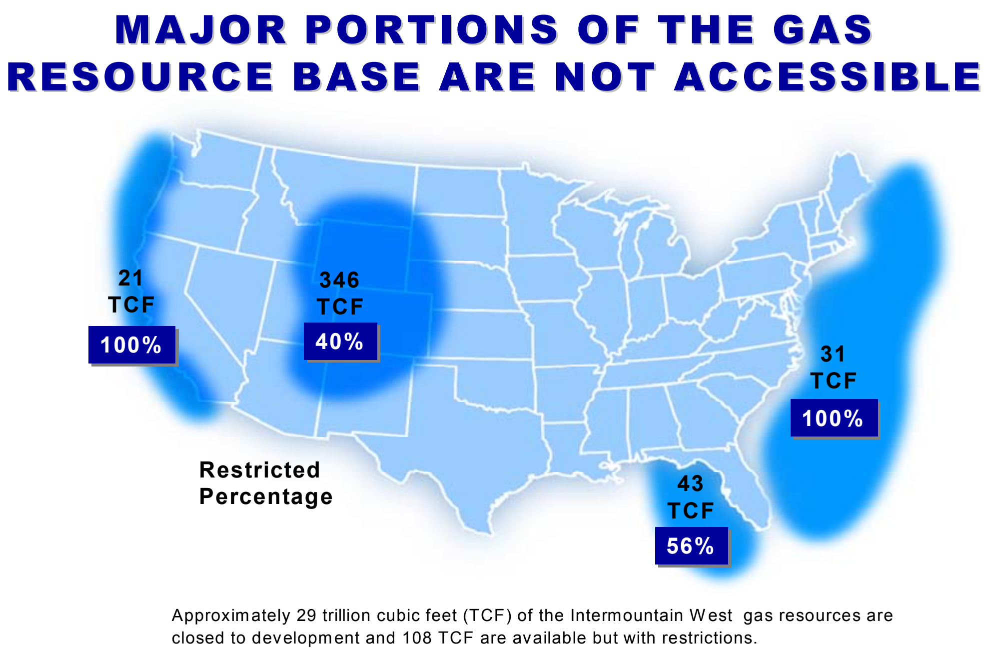
Source: Advanced Resources Int'l.

Unconventional gas resources are noted as such only because the geologic setting from which they originate is different from more traditionally productive sources of gas. Technology has been a key factor in permitting gas to be recovered from these sources and to be produced in commercial quantities. But low permeability reservoirs behave differently than sandstone high perm reservoirs. If a high perm reservoir produces at millions of cubic feet per day initially, a low perm reservoir produces at tens or possibly hundreds of thousands of cubic feet per day – often at one-tenth or less a high perm well. Therefore, to maintain the same initial production capability as traditional reservoirs, 10 or more coal seam or tight sand wells may need to be drilled. On a positive note, however, wells drilled and produced from less conventional reservoirs often produce for 15, 20 or even 30 years, albeit at more modest annual volumes. That said, the baseline of production that is established in these fields helps to support the long-term production capability of national natural gas inventories.

An example of recent success in an unconventional play where producing rates have improved significantly is that of the Jonah and Pinedale Fields in southwestern Wyoming. In 1995, the fields in aggregate produced 8 MMcf per day of natural gas from low permeability tight sands. Today, they produce over 1 Bcf per day (over a 100-fold increase) and remain prospective for additional production increases. It is estimated that 700 producing wells may grow to 2,500 successful wells in the future. A combination of new applications of well fracturing techniques, well spacing and 3D seismic has given field operators an opportunity to maximize economic recovery of the gas in-place – estimated to be over 6 Tcf.

A significant portion of the domestic gas resource is restricted from exploration and it is likely to remain so. Large portions of federally controlled lands and offshore locations are off limits to gas and oil exploration due to congressional moratoria and other land use restrictions. Included are the East and West coast (continental shelf and slope), areas of the eastern Gulf of Mexico and onshore acreage, particularly in the Intermountain West.

Exhibit IX-4



Source: National Petroleum Council.

Numerous locations in these areas have natural gas production potential. For example, natural gas discoveries have been made on the coasts of Canada and are, in fact, being produced offshore of the eastern Canada Maritime Provinces. Yet no gas exploration is permitted in East Coast U.S. waters. To date, the political process and positioning of strong environmental advocates have all but ensured that the moratoria on offshore drilling will remain in place for the foreseeable future. Some of these moratoria have been in place for three decades or more, and they do not recognize the significant improvements in exploration and development technology and business practices that are now available and in use.

Some positive developments for natural gas exploration and development have slowly materialized in recent years in the West where large tracts of federally owned and managed lands are designated for multi-use. However, moving the permit process along where there is federal jurisdiction (Bureau of Land Management and Forest Service, for example) is slow.

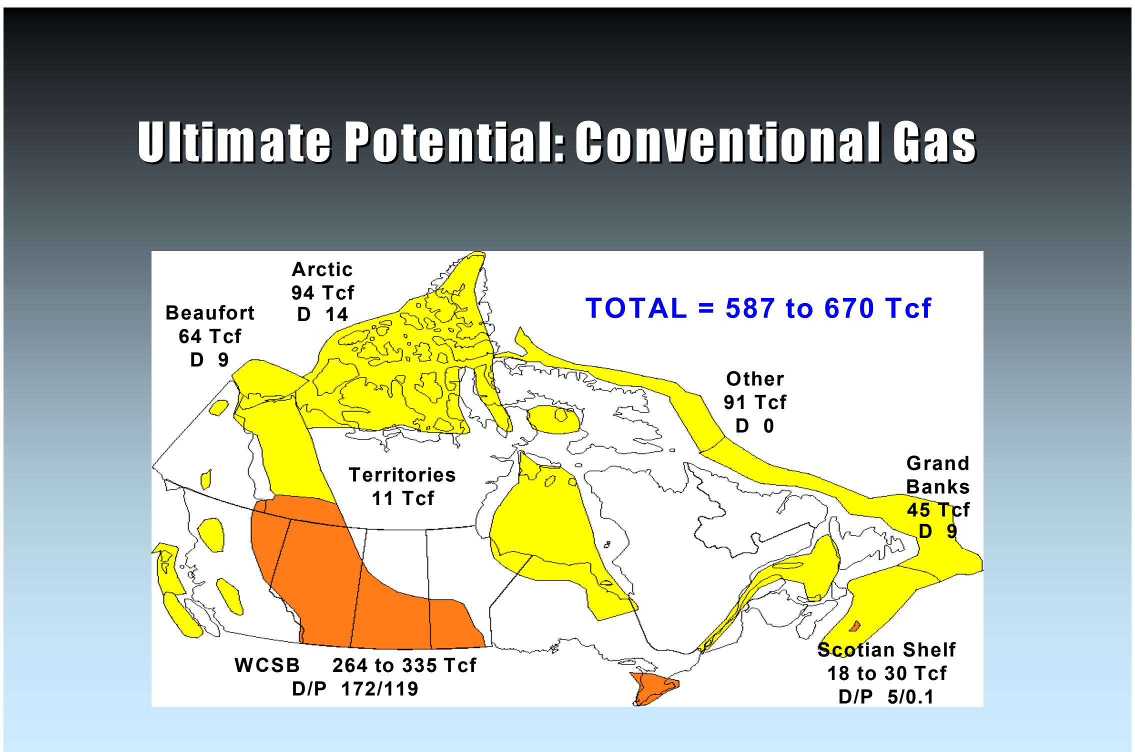
Critical land use and coastal resource management issues have a direct impact on hundreds of Tcf of potential gas resources. An exact estimate of the magnitude of the affected resource is not possible. The fact is that precise gas and oil assessments can only be made when the drill bit is permitted to explore.

Even with access restrictions and the introduction of new sources of gas supply such as LNG or gas from the Alaskan North Slope, domestic Lower-48 states production is still expected to supply about 60 percent of the gas consumed in the United States in 2020. Even with what would appear to be a difficult road ahead for E&P investment and land access for gas and oil drilling, Lower-48 states production is expected to be the primary source of U.S. gas supply well into the future. However, because Lower-48 production is expected to remain relatively flat while total supply/consumption continues to grow, the share of total supply accounted for by Lower-48 production will fall. This share was roughly 83 percent in 2003, but in the Expected Policies scenario falls to 77 percent in 2010, 67 percent in 2015 and 61 percent in 2020.

X. THE TREND OF STEADILY INCREASING NATURAL GAS IMPORTS FROM CANADA IS LIKELY OVER

Challenges to natural gas supply in Canada are similar to those in the United States at a time when Canadian requirements for natural gas are increasing. Over the last 20 years, estimates of Lower-48 and Canadian gas resources have grown more than the resource has been depleted. As a result, some analysts view the remaining resource potential today as much higher than it was 20 years ago, despite resource depletion. That is the good news. Prospects for continued growth in "ultimate" resource estimates are in question, however. Western Canadian "ultimate" resource recovery, particularly that based on in-place unconventional resources, needs to be demonstrated by industry activity, which is only in its infancy.

Exhibit X-1



Source: National Energy Board of Canada.

Sustaining natural gas production in Canada faces many of the same challenges that exist in the U. S., including declines in well productivity, applications of key technologies to gas sources such as coal seams and the need to invest in costly infrastructure connecting new supply areas to the existing pipeline grid. In addition, Canadian exports to the U.S. will be affected by increasing gas demand within Canada.

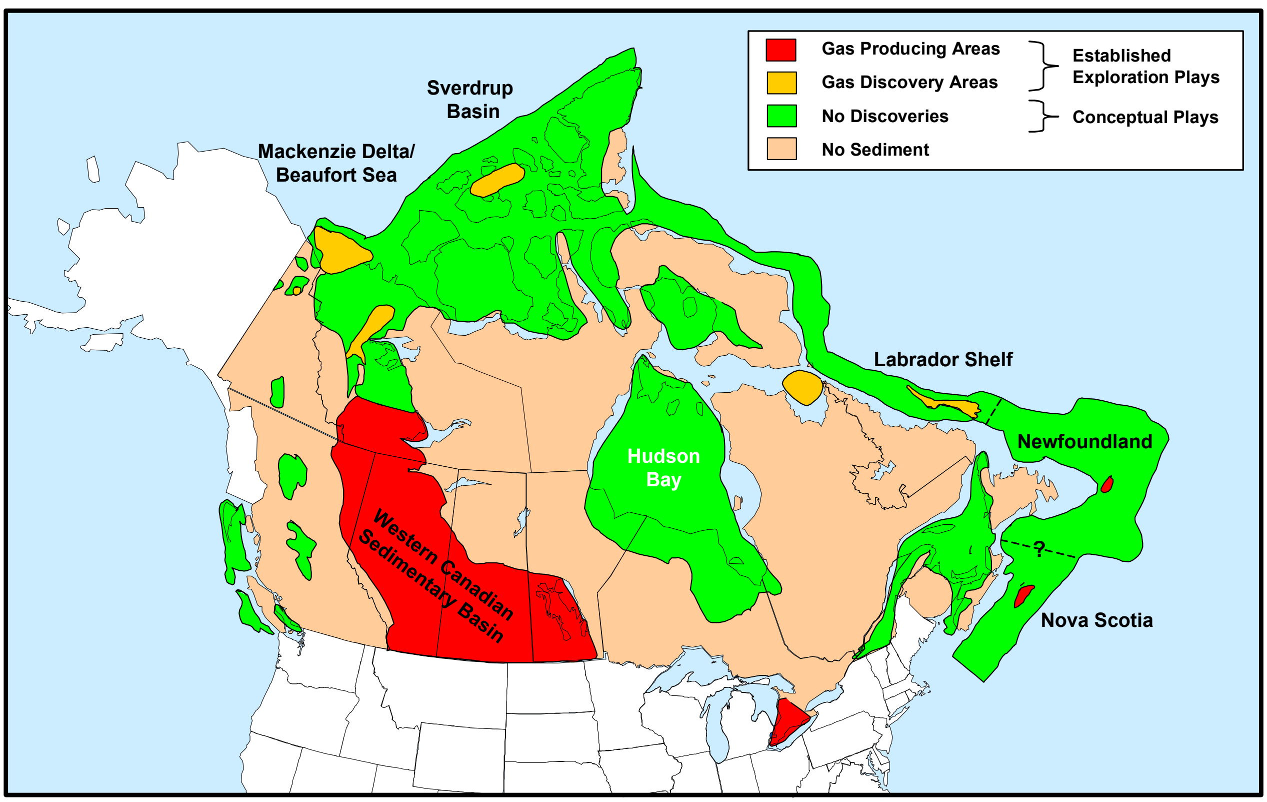
Since the mid-1980s, *marketed* Canadian gas production has more than doubled, reaching 6.4 quads in 2000, which is a quarter of North American gas production. When North American production peaked in 1973, Canada accounted for about 10 percent of North American gas production. However, growth in Canadian gas production has slowed since the mid-1990s.

Looking at the geologic make up of Canada reveals that sedimentary basins *do not* underlie most of the Canadian surface area (onshore and offshore). Almost all of Canadian gas production has come from the Western Canada Sedimentary Basin (WCSB), which underlies most of Alberta, and parts of British Columbia, Saskatchewan, Manitoba, and adjacent regions in the Yukon and Northwest Territories. The remaining production has come from Ontario and recently from Offshore Nova Scotia.

Canada, like the United States, will increasingly turn to frontier regions and less developed unconventional sources of gas (coalbed methane, for example) to maintain natural gas production capable of supporting domestic requirements and exports. However, both the Expected Policies and Expanded Policies scenarios in this report show declining levels of natural gas exports to the U.S. from Canada, particularly after 2010, for primarily the same reasons outlined above.

Exhibit X-2

SEDIMENTARY BASINS IN CANADA

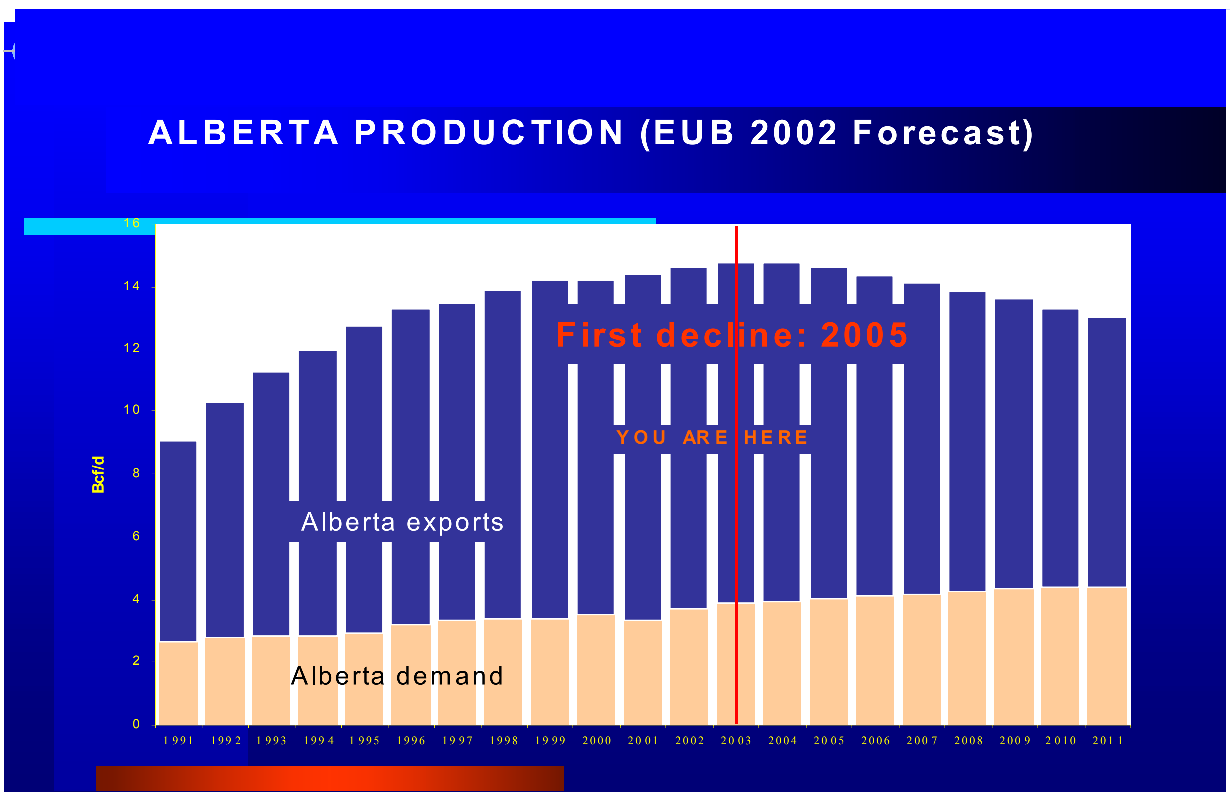


Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Lower 48 and Canada*.

By 2020, Canada likely will be exporting less natural gas to the U.S. than it does today. Several observations work against the notion that Canada will be an endless source of gas supply to U.S. consumers. They are demonstrated in the graphic below, which is based on a forecast of supply and demand for natural gas made by the Alberta Energy and Utilities Board (AEUB) in 2002. First, most analysts believe that natural gas consumption will increase in Canada during the next fifteen years. The most often cited reasons include economic growth, an increasing demand for natural gas to generate electricity, environmental (air quality) issues and increasing natural gas use for enhanced oil recovery (much of that oil for export to the U.S.).

Second, resource depletion impacts are expected to be gripping the largest supply area of Canada, the Western Canada Sedimentary Basin, within the next five years, if they haven't already. The exhibit below shows the anticipated growth of gas demand and forecast for natural gas production declines made by the AEUB specifically for Alberta. Many forecasts of total Canadian demand and production look similar. That is, Canadian natural gas production, which has supported incremental growth in domestic consumption along with significant growth in natural gas exports to the U.S., declines, while domestic consumption of gas in Canada inevitably increases.

Exhibit X-3



Source: Alberta Energy and Utilities Board.

Only in the Existing Policies scenario are Canadian gas exports to the U.S. maintained as 13-15 percent of total U.S. consumption. As with the explanation of this phenomenon in the Lower –48 states, environmental or other constraints do not permit the construction of LNG infrastructure, and the North American supply and demand balance, essentially supply constrained, results in gas acquisition prices in excess of $13.75 per MMBtu by 2020. That encourages the drilling of marginally economic resources in Canada (as in the U.S.) and gas production grows. Of course, this scenario is very dependent on the successful development of other natural gas sources such as methane from coal seams in Canada.

Both the Expected Policies and Expanded Policies scenarios, however, reduce the volume of gas from Canada to the U.S. and reduce the relative level of gas supply in the U.S. attributed to Canada. By 2020, gas imports from Canada fall by 1 Quad annually (accounting for 8 percent of U.S. gas supply compared to 15 percent in 2000) in the Expected Policies scenario and by 2 quads under the Expanded Policies scenario, reducing Canadian contributions to overall U.S. gas supply to only 4 percent. In both cases the difference is made up by LNG imports (some of which may originally land in Canada) and flowing gas from Alaska. Like the explanation offered regarding Lower-48 states supplies, with the addition of significant quantities of imported LNG and other possible frontier sources, gas acquisition prices are reduced so sufficiently that drilling in Canada is not robust enough to offset the depletion impacts on traditional gas reservoirs.

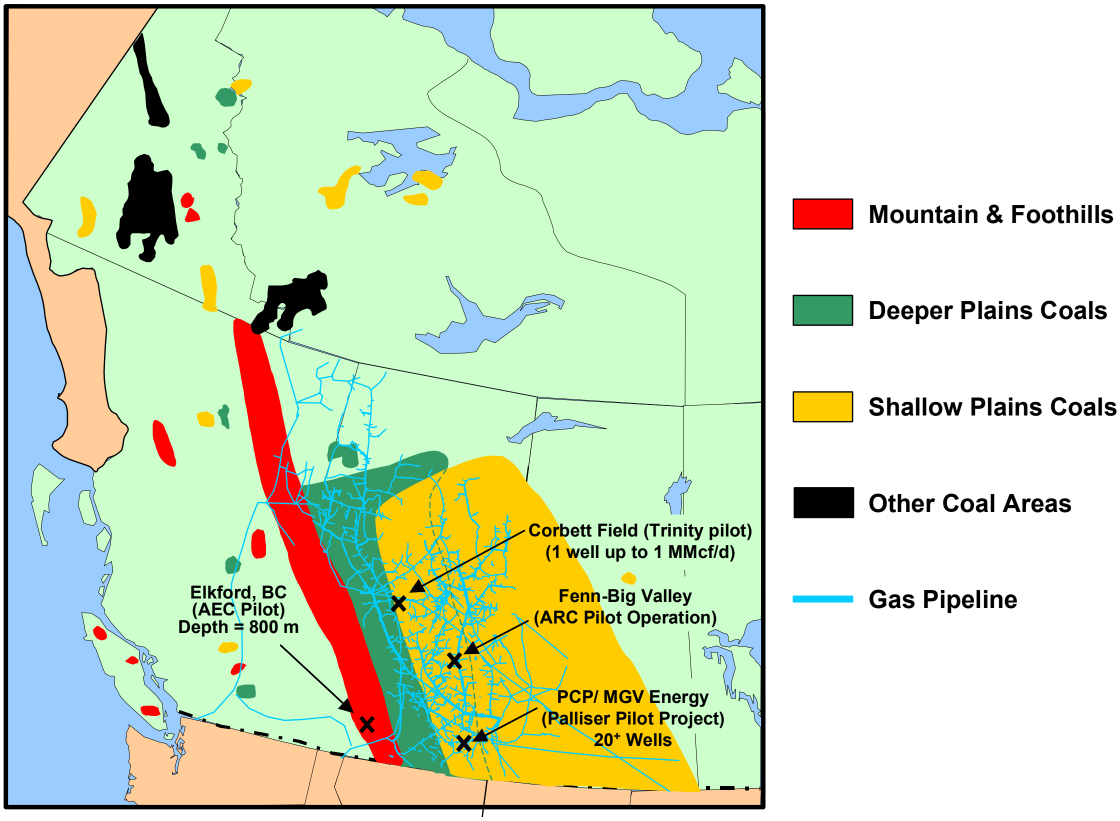
Unconventional resources of natural gas may become a larger player in Canada's gas supply, but important unconventional sources of oil are likely to require significant quantities of gas for primary and secondary recovery. There are four general coalbed methane areas in Canada - Shallow Plains, Deeper Plains, Mountains and Foothills - and other coal areas are scattered throughout British Columbia and North of 60°. The Shallow Plains and Deeper Plains coals overlap in Central Alberta. Several coalbed methane projects are active in Western Canada. However, coal rank, which is an indicator of coalbed methane potential, increases moving from East to West. At the same time, the coal resource extends to a greater depth moving East to West. As a result, while the in-place coalbed methane resource increases moving in a westward direction, greater burial depths make recovery of a growing share of this resource uncertain.

Over 350 coalbed methane wells have been drilled in Canada, but there is still little production. In some ways, knowledge of coalbed methane recovery in Western Canada today is comparable to knowledge in the United States in the mid-1980s before significant production developed. More recent attempts to develop methane from coal seams have targeted lower-rank coals, which are more like those currently being developed in the Powder River Basin in the United States. Because of the production experience to date in the United States, Western Canada coalbed methane prospects could develop more quickly.

While estimates of coalbed methane gas-in-place in Western Canada range up to about 2,700 Tcf of gas, a more reasonable estimate at this point in time, and in light of available technology, is much smaller (about 500 Tcf-about 80 percent of which is in Alberta). For the purposes of this report 95 Tcf is viewed as technically recoverable. The fact is that any estimate of coalbed methane production capability remains very speculative until better supported by industry activity.

Exhibit X-4

POTENTIAL WCSB COALBED METHANE REGIONS



Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources*.

A complicating factor for natural gas production requirements, particularly in western Canada, is that of the recovery of oil from tar sands in northern Alberta. The United States receives more crude oil and petroleum products (about 2 million barrels per day) from Canada than any other country in the world, including Saudi Arabia, Mexico and Venezuela.

Much of the future of oil production in Canada (billions of barrels) is locked up in tar sands that require a source of heat for steam production or other processes to separate the hydrocarbons from the sediments and bitumen in which they are contained. Estimates of natural gas requirements for these processes vary, but some analysts have speculated that all of the gas associated with a proposed pipeline from the Mackenzie Delta/Beaufort Sea (up to 1 Bcf per day) would be consumed by oil recovery associated with the tar sands. If so, other WCSB natural gas would be made available to domestic and U.S. markets. Nonetheless, the development of oil resources in Canada is expected to be a significant consumer of natural gas in the future.

Canada may become a focal point of world LNG trade. Numerous projects for siting LNG regasification facilities have been proposed, particularly in eastern Canada, which could become a part of the burgeoning Atlantic basin LNG trade. Gas imported at these points could serve the Canadian Maritime Provinces, as well as other eastern population centers in Canada and even markets in the U.S. Northeast.

XI. DOMESTIC NATURAL GAS SOURCES WILL COMPETE WITH LIQUEFIED NATURAL GAS TO SERVE U.S. MARKETS

The movement toward increased LNG imports has begun. Liquefied natural gas is renewing itself as an increasingly import factor in U.S. gas markets. There are 113 active LNG facilities in the U.S., including import and export marine terminals, storage and peak-shaving facilities. In 2003, all four marine import terminals were operational (for the first time since 1981) and import levels (over 500 Bcf) doubled the previous record set 24 years earlier. This report projects imported LNG as a source of gas to U. S. customers as high as 28 percent of natural gas supply by 2020 (Expanded Policies scenario). To illustrate the magnitude of LNG operations, the second-largest producer of natural gas in the U.S., ExxonMobil, produced nearly 2.8 Bcf per day in 2003. One large LNG tanker can unload the same volume equivalent in less than 24 hours at the Cove Point, Maryland marine terminal. Simply put, LNG has an enormous potential to supply natural gas to the U.S. pipeline grid.

Even though LNG import facilities received a record volume in 2003, the gas represented less than three percent of all U. S. gas supplies and only 13 percent of all U.S. imports. However, existing import terminals are expanding with regasification capacity expected to increase by nearly 40 percent by year-end 2005 (see Exhibit XI-1). Additional expansions are identified for 2008, which would raise current baseload sendout capacity from about 931 Bcf annually to 1,782 Bcf annually, with even more potential identified in the form of expanded peak-day capability.

This report views expanding LNG capability as inevitable. By adding import facilities primarily in the Gulf of Mexico, the Expected Policies scenario grows LNG imports to 6.8 quads annually, accounting for about 22 percent of U.S. gas supply. Under the Expanded Policies scenario, siting of facilities is even less encumbered and LNG grows to account for 28 percent of U.S. gas supply, or about 8.6 quads annually. Both of these cases act to depress domestic production and imports from Canada slightly inasmuch as abundant LNG supplies push some of the more costly to recover domestic resource out of the market.

Only in the Existing Policies scenario does LNG fail to grow dramatically. Under the conditions of the Existing Policies scenario, no new LNG facilities are constructed due to siting opposition. The result is an LNG contribution to U.S. gas supplies of about 7 percent annually, or 2 quads, which implies that the current planned facilities expansions are the only additions to LNG capacity that are realized through 2020.

Exhibit XI-1

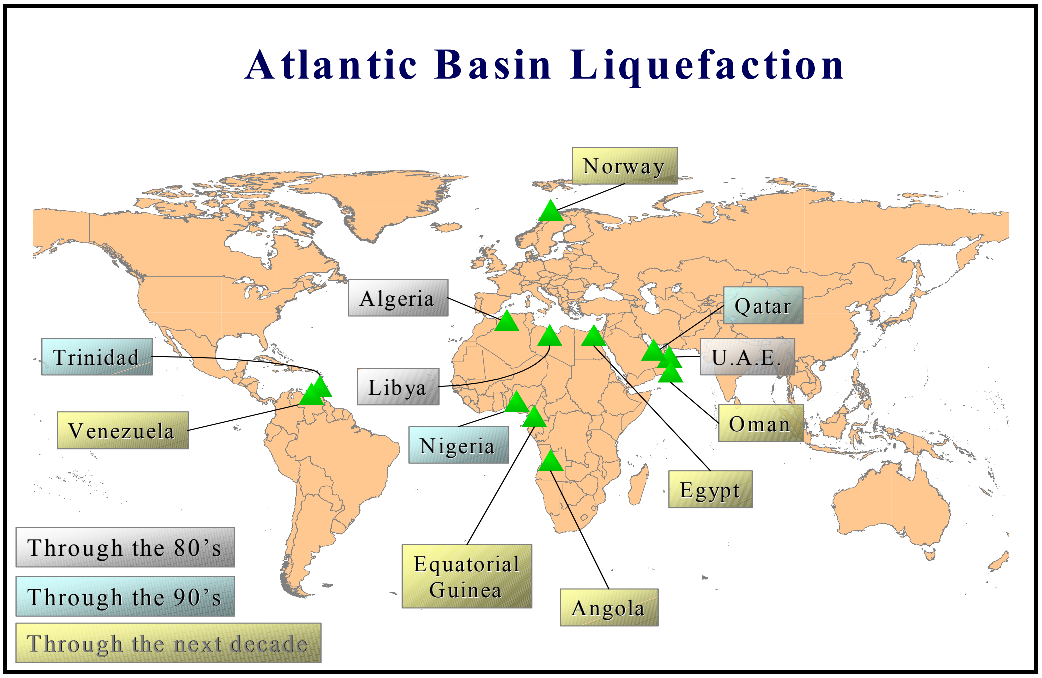
LNG CAPACITY AND PLANNED EXPANSIONS AT IMPORT TERMINALS

Facility Location		Owner	Storage Capacity (Bcf)	Daily Sendout Capacity (Bcf) Baseload	Peak
Everett, MA		Tractebel/Distrigas			
	Existing		3.5	0.725	1.035
Lake Charles, LA		Southern Union			
	Existing		6.3	0.630	1.000
	Planned Expansion 2005		3.0	0.570	0.300
	Planned Expansion 2007		0.0	0.600	0.800
Cove Point, MD		Dominion			
	Existing		5.0	0.750	1.000
	Planned Expansion 2005		2.8	0.000	0.000
	Planned Expansion 2008		6.8	0.800	0.800
Elba Island, GA		El Paso/Southern LNG			
	Existing		4.0	0.446	0.675
	Planned Expansion 2005		3.3	0.360	0.540
Total Existing Capacity			**18.8**	**2.551**	**3.710**
Total Planned Expansion			**16.4**	**2.330**	**2.440**
Total with Expansion (2008)			**35.2**	**4.881**	**6.150**

Source: Energy Information Administration, DOE, *U.S. LNG Markets and Uses: June 2004 Update*.

There are huge volumes of natural gas stranded around the world and many countries are focused on the current *window-of-opportunity* for developing international gas trade. There are a growing number of countries that are positioning themselves to monetize their otherwise stranded natural gas resources around the world. Some of them, like Venezuela, are in the western hemisphere and quite close to U.S. markets.

Exhibit XI-2



Source: Dominion Resources, Inc.

Transportation and distribution of LNG has a record of safe operations worldwide and it appears that current (and foreseeable) acquisition prices for natural gas lands LNG squarely in the competitive supply mix at roughly $3.50-$4.50 per mcf.

LNG facilities are likely to be constructed and expanded where there is the least public opposition. The list of competing LNG import facility proposals, once at about 35 announcements, has been reduced to about 27 during the past year. Those that have received regulatory approval include the Sempra Cameron LNG terminal in Hackberry, Louisiana, and the Port Pelican (ChevronTexaco) and Energy Bridge (Exelerate) offshore facilities (Louisiana), which have received licensing from the U.S. Coast Guard and Maritime Administration (MARAD). If even one of the offshore facilities for unloading LNG (Port Pelican or Energy Bridge) is constructed it will be the first of its kind in the world. Onshore LNG projects also have been proposed in Canada, Mexico and the Bahamas. These projects may directly serve U.S. markets or displace domestic gas so more production from these countries (Canada and Mexico) could be exported to the U.S.

Exhibit XI-3

PROPOSED LNG TERMINALS

Name	Location	Owner(s)	Capacity (MMcf/d)
West Coast			
Cabrillo Port LNG	Offshore Oxnard, CA	BHP Billiton	1,500
Crystal	Offshore Oxnard, CA	Crystal Energy	1,250
Terminal GNL Mar Adentro	Offshore Baja CA, Mexico	ChevronTexaco	750
Energia Costa Azul LNG	Onshore Baja CA, Mexico	Sempra/Shell	2,000
Sound Energy Solutions	Onshore Long Beach, CA	Mitsubishi	1,000
Gulf Coast			
Compass Port	Offshore Alabama	ConocoPhillips	1,000
Energy Bridge	Offshore Louisiana	Excelerate	500
Gulf Landing	Offshore Louisiana	Shell	1,000
Main Pass Energy Hub	Offshore Louisiana	McMoran	1,000
Port Pelican	Offshore Louisiana	ChevronTexaco	1,600
Altamira	Onshore Altamira, Mexico	Shell/Total	650
Cameron LNG	Onshore Hackberry, LA	Sempra Energy	1,500
Corpus Christi LNG	Onshore Corpus Christi, TX	Cheniere/BPU	2,600
Freeport LNG	Onshore Freeport, TX	Freeport/Cheniere/Contango	1,500
Golden Pass	Onshore Sabine Pass, TX	ExxonMobil	1,000
Ingleside Energy Center	Onshore Ingleside, TX	Occidental Petroleum	1,000
Port Arthur	Onshore Port Arthur, TX	Sempra Energy	1,500
Sabine Pass	Onshore Sabine Pass, LA	Cheniere	2,600
Vista del Sol	Onshore Quintana Isl, TX	ExxonMobil	1,000
Bahamas/Florida			
Calypso	Onshore Freeport, Grand Bahama	Tractebel Bahamas LNG	832
Ocean Express	Onshore Ocean Cay, Bahamas	AES	842
High Rock LNG/Seafarer	Onshore Grand Bahama	El Paso	820
East Coast			
Bear Head	Onshore Nova Scotia, Canada	Access NW Energy	1,000
Canaport	Onshore New Brunswick, Canada	Irving Oil	500
Crown Landing	Onshore Logan Twshp, NJ	BP	1,200
KeySpan LNG	Onshore Providence, RI	KeySpan/BG Group	525
Weavers Cove	Onshore Fall River, MA	Poten	800
Total			**31,469**

Yet opposition to new onshore facilities based on security and environmental concerns has arisen, particularly in market areas like the Northeast and Southern California. Even with the avoided costs of long-line transportation and the likelihood that a new market area source of natural gas would have a stabilizing impact on consumer prices, and even with proposals in areas with a rich history of maritime commerce, proposed onshore terminals have been defeated by local opposition – most notably and recently in Maine.

The path or strategy required to win approval for an import facility may be as simple as locating it where there is less local opposition. For example, in the Gulf Coast where the general public is well aware of the necessity for, and benefit of, large scale energy projects. Obviously, gas placed in the grid eventually finds its way to customers throughout the U.S. by direct transportation or displacement no matter where it initially enters.

Increased LNG imports can expand available natural gas supply and help moderate prices. Some analysts argue that although LNG can be landed in the U.S. at costs well below those seen in the market today (see exhibit XI-4), the price of LNG will be bid up to the prevailing market level set primarily by domestic gas and Canadian imports. Others suggest that the price of these traditional sources will be pulled down to the LNG price level.

Exhibit XI-4

Delivered Cost of LNG in the U.S. ($ per MMBtu)
Energy and Environmental Analysis (EEA)

	Everett	*Cove Point*	*Elba Island*	*Lake Charles*
Middle East Production Costs, including processing and transport to liquefaction facilities	0.65	0.65	0.65	0.65
Liquefaction	1.09	1.09	1.09	1.09
Representative LNG Shipping Rates				
Algeria	0.52	0.57	0.60	0.72
Nigeria	0.80	0.83	0.84	0.93
Norway	0.56	0.61	0.64	0.77
Venezuela	0.34	0.33	0.30	0.35
Trinidad and Tobago	0.35	0.35	0.32	0.38
Qatar	1.37	1.43	1.46	1.58
Australia	1.76	1.82	1.84	1.84
Regasification Cost	0.30	0.30	0.30	0.30
Total Cost of Middle East LNG	3.41	3.47	3.50	3.62

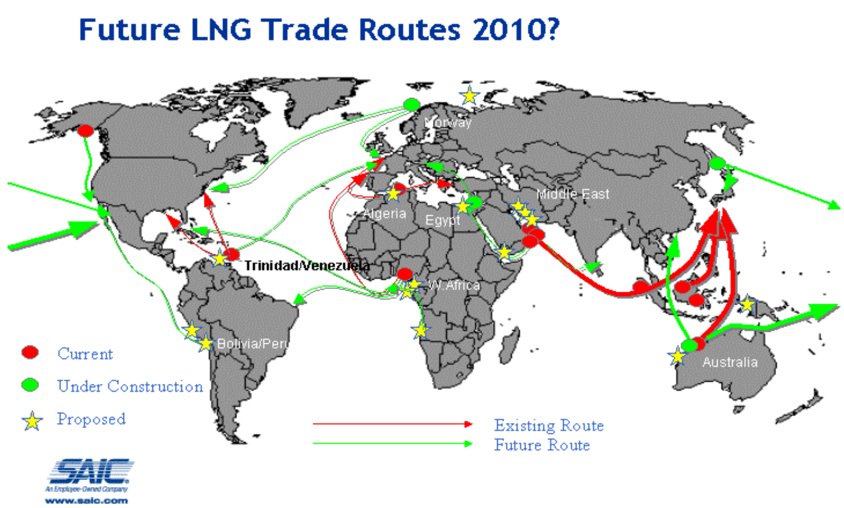
All imported LNG is likely to be competitive at a delivered cost of about $3.50 per MMBtu.

Sources: DOE Technical Report Nine, Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, published in January 1993, *James Jensen, LNG Shipping Solutions, U.S. Energy Information Administration, The Global Liquefied Natural Gas Market: Status and Outlook*, December 2003.

It is the view of this report that given the construction of a sufficient number of receiving terminals, LNG facilities will operate at a high load factor and tend to push some higher cost domestic sources of gas out of the market. The worldwide gas resource is vast and diversely distributed. Roughly 93 percent of the world's gas reserves is located outside of North America. Further, based on existing infrastructure and gas demand, the U.S. is the most logical market for the bulk of the developing LNG supply worldwide for the foreseeable future. This view, however, does not preclude the knowledge that worldwide natural gas markets are expanding (for example, China) and that other countries are likely to increasingly compete with U.S. markets for LNG.

This report projects that increased LNG capability will lead to higher consumption levels and lower prices than otherwise would be the case. If LNG import capabilities are not significantly expanded, natural gas demand will be satisfied via higher cost domestic and Canadian sources.

Exhibit XI-5



Sources: British Gas and British Petroleum.

XII. ALASKAN NATURAL GAS REPRESENTS A CRITICAL UNCERTAINTY

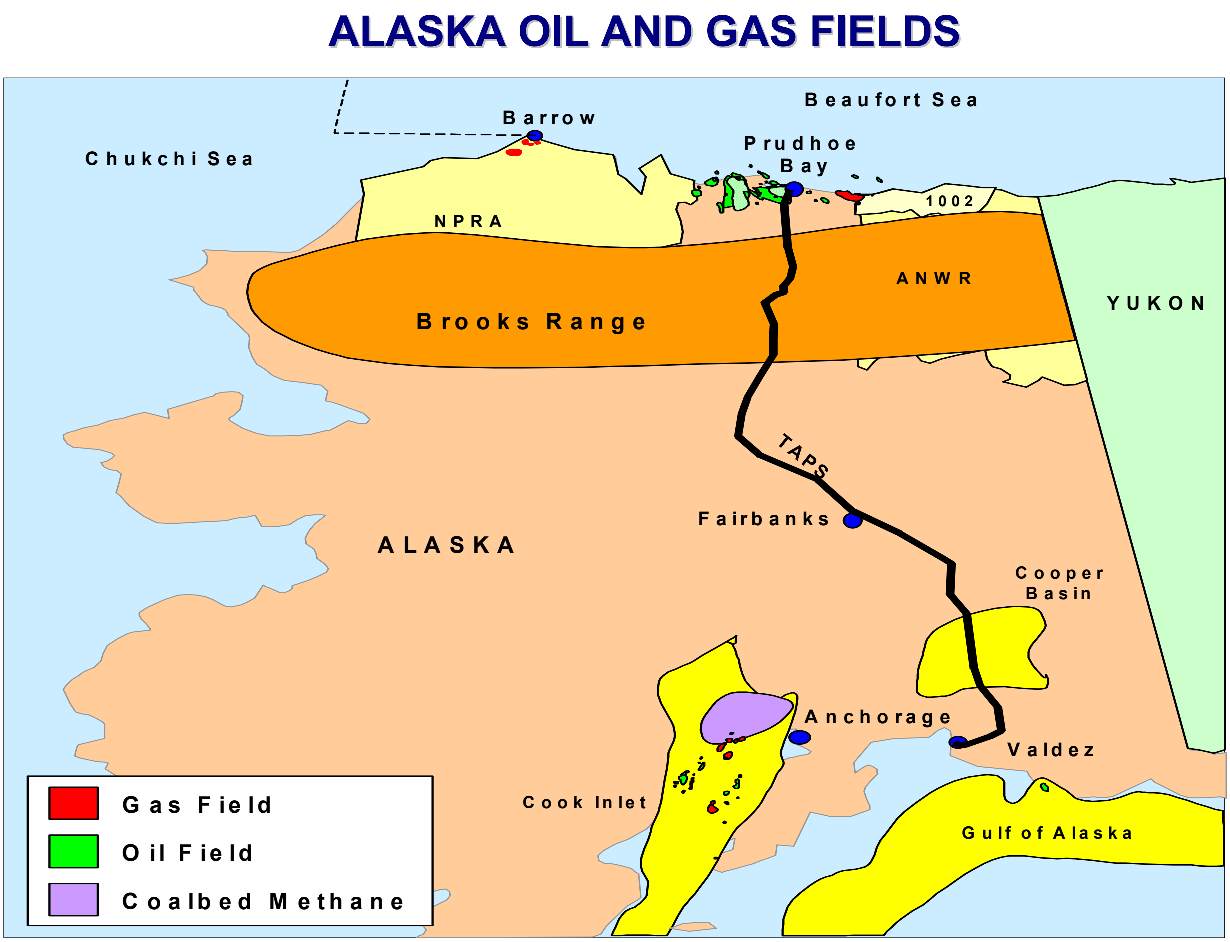
Achieving a 30 quad natural gas market is unlikely without a significantly expanded supply contribution from Alaska. To reach 30 quads of annual natural gas consumption in the United States will require new sources of gas for consumers. Alaska is poised to be one of those new sources. However, it is very difficult to predict the political process or economic supports that may be necessary to realize this potential. That said, if the political process, economic hurdles and logistical challenge of actually manufacturing the pipe are overcome, the gas is available and ready to flow.

No supply case in this report assumes the delivery of new incremental supplies of gas to the Lower-48 states from Alaska before 2014. In the Expected Policies and Expanded Policies scenarios, gas from Alaska delivers about 4 Bcf per day into Lower-48 markets, growing to over 6 Bcf per day (2.2 quads per year) by 2020, accounting for about 9 percent of total U.S. gas supply. The Existing Policies scenario does not allow for permitting or construction of the line through 2020 and therefore no incremental gas is supplied to the Lower-48 from Alaska. This supply constraint is one reason why the overall gas market grows to only 27 quads annually under this case.

Most gas produced in Alaska today is reinjected rather than consumed. Gas production in Alaska dates back more than 50 years, beginning in 1949 at the Barrow gas field in North Alaska. Production, however, did not exceed 1 Bcf/year until 1961, after production began in the Cook Inlet area. Production did not average more than 1 Bcfd until 1977, when commercial oil production from Prudhoe Bay began. Additional areas for future gas production may include the National Petroleum Reserve, the Arctic National Wildlife Refuge (ANWR) and coalbed methane area in South Alaska.

At the wellhead, Alaska is the third largest gas producing state in the United States, exceeded only by Louisiana and Texas. Since 1995 wellhead gas production has averaged over 9 Bcfd in Alaska. However, more than 80 percent of this production is re-injected due to the lack of the necessary infrastructure to move the gas to the Lower-48 and also to promote oil production. As a result, on a marketed basis, Alaska is only the eighth largest producing state. Marketed gas production in Alaska has averaged about 1.2 Bcfd (430 Bcf annually) since 1995. More than half of this marketed gas production is used as lease and plant fuel, and more than a quarter is used for LNG or ammonia manufacture for export. Less than 20 percent is used for “domestic” energy consumption in Alaska, and this market has shown almost no growth in the last 15 years.

Exhibit XII-1



Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources*.

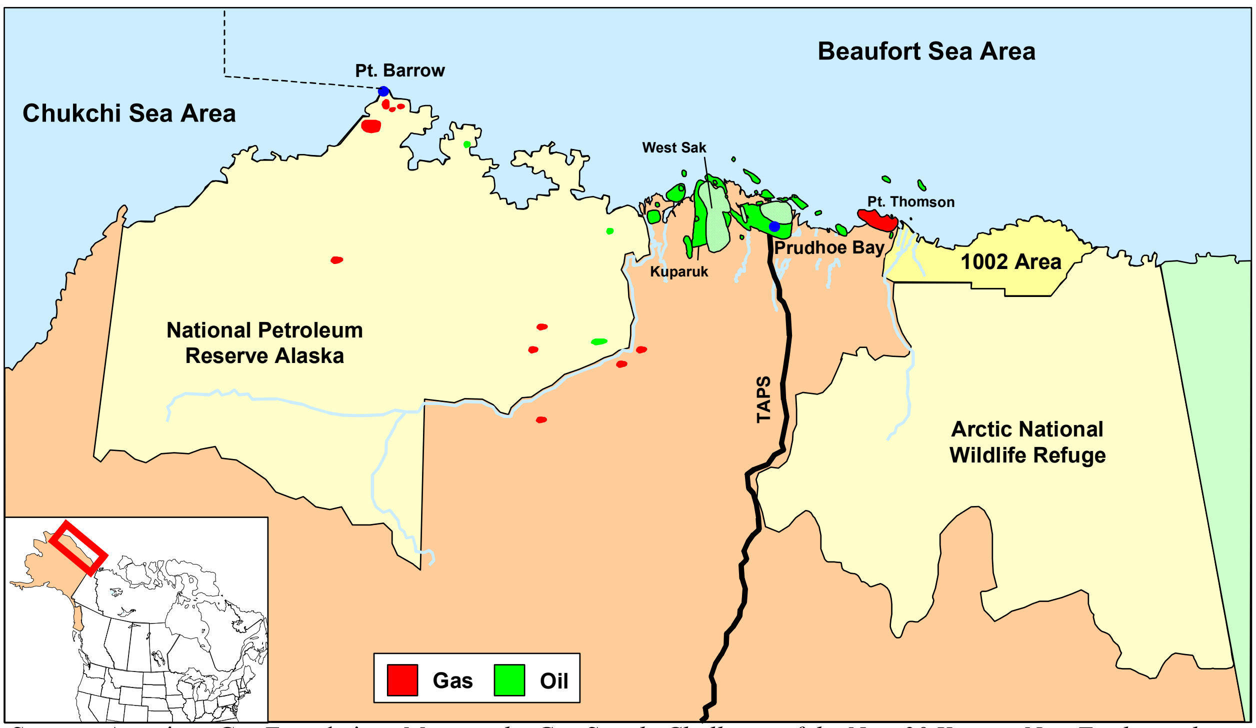
Alaskan gas production and markets are at a transition point. In the Cook Inlet area new supplies will be needed in the near-term to meet gas demand. The critical issue for the Cook Inlet markets is whether these new supplies will be obtained from new discoveries in South Alaska or by delivering gas from North Alaska. On the North Slope, the relative economics of gas production for delivery to a market is becoming more attractive relative to continued re-injection.

Unlike Cook Inlet, North Alaska gas production increased between 1980 and 2002, although most of that growth occurred by 1995. North Alaska gas production has grown slightly since 1995 but oil production has declined almost one third. Currently, almost two thirds of the Btu content of North Slope hydrocarbon production is in the gas stream, compared to only 50 percent in 1995 and 29 percent in 1988, when North Slope oil production peaked. In Prudhoe Bay, the gas share of the hydrocarbon stream is larger, currently accounting for about three fourths of the Btu content. The Prudhoe Bay reservoir is at an operational point where marketing of the produced gas may be very attractive to the owners if it is economically possible to deliver that gas to a market.

North Slope natural gas reserves are only the *tip of the iceberg* when examining the total natural gas resource potential in Alaska. When a pipeline connecting Alaskan gas to the Lower-48 states is mentioned, most often the 40 Tcf of known reserves associated with North Slope oil production is cited as the foundation for the pipeline supply. The fact is that those reserves are only a small portion of total Alaskan gas potential. The Potential Gas Committee estimates a resource potential of 251 Tcf in Alaska, including gas from coal seams and offshore. However, much of that resource potential is considered speculative because it has not yet been fully explored.

Exhibit XII-2

NORTH ALASKA DISCOVERIES AND PROSPECTIVE AREAS



Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources*.

Most of the press surrounding Alaska production issues centers on the Arctic National Wildlife Refuge (ANWR) and the National Petroleum Reserve Alaska (NPRA), outlined on the map above. However, there are large tracts of lands managed by the state of Alaska, as well as native lands that offer significant gas production potential and that are not hostage to the national debate on the environmental impacts of petroleum drilling. These properties are proximal to the proposed pipeline route and are far more likely to be gas-prone than oil-prone based on the geologic thermal history of the sediments in place. What they need for development is the transportation infrastructure that a gas pipeline would offer.

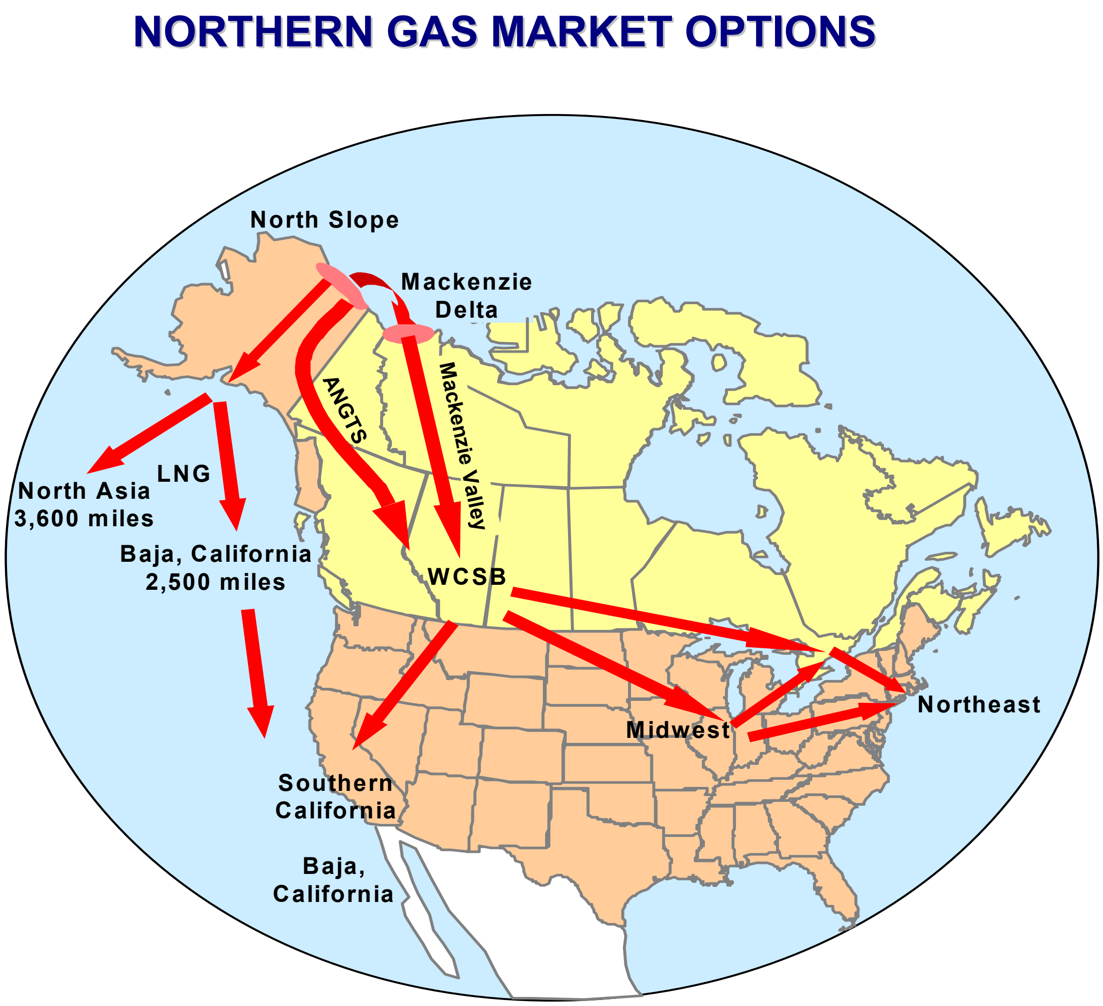
Constructing a transportation system to move Alaskan gas to the Lower-48 is likely a $20 billion proposition. The fundamental issues that impede all of the options described below to transport Alaskan gas to the Lower-48 states are quite simple – time and money. For example, the pipeline options entail roughly 10 years to construct with a price tag of some $20 billion. Combining that much time and money in an uncertain gas market, including the unknown potential market impacts of a burgeoning LNG trade, present great risk to project sponsors. It is unlikely that any project will move forward without the enactment of some measures to reduce that risk. That is, there must be no question that, once constructed, the pipeline will operate competitively at full load, 365 days per year.

The figure below shows the market options for North Alaska gas relative to its nearest large markets in North America and North Asia. From the North Slope to Southern California via the Alaskan Natural Gas Transportation System (ANGTS) route, gas would move 3,600 miles. The distance to the Midwest market is about the same as Southern California, and continuing gas movement to the Northeast would add 900 miles or more. If LNG were ever developed to move North Slope gas to Southern California, gas would move about 3,400 miles, 900 miles would be by pipeline (800 miles in Alaska and 100 miles from Baja to Southern California) and 2,500 miles by ship as LNG. No matter how you do it, moving gas from the Alaska North Slope to the Lower-48 is a long-distance proposition.

Having said that, there are three principal pipeline options to move North Alaska gas to market. Two are gas pipelines to connect North Alaska gas to the North American gas transmission grid in Western Canada. A third is a gas pipeline to South Alaska, where the gas would be liquefied for transport by ship to Pacific gas markets in North America or North Asia.

The two pipeline options that would deliver gas to Western Canada are the Alaska Highway Corridor and the "Over the Top" Corridor, which would move gas from North Alaska to the Mackenzie Delta via an offshore pipeline and then down the Mackenzie Valley to Western Canada. For delivery of Northern gas to Pacific Coast gas markets, the nominal delivery point would be the Foothills Pre-Build pipeline at Caroline, Alberta. Deliveries to the Midwest may entail linkage to the Foothills Pre-Build and Alliance pipelines.

Exhibit XII-3



Source: American Gas Foundation, *Meeting the Gas Supply Challenge of the Next 20 Years – Non-Traditional Gas Sources*.

The Alaska Highway corridor is the site of the proposed ANGTS project that was proposed in the late 1970s. A pipeline in the Alaska Highway corridor will run about 2,000 miles from the North Slope of Alaska producing areas to the high-volume North American gas transmission network in Alberta. To keep gas transportation charges competitive for this option, volumes for proposed projects have been about 4 Bcfd, with some discussion of volumes approaching 6 Bcfd.

The over-the-top option that would move gas from Prudhoe Bay to the Mackenzie Delta is shorter than the Alaskan Highway route, but it would be an unlikely winner in the pipeline construction derby primarily due to environmental opposition, opposition by the state of Alaska and the fact that the produced and transported gas would then miss the Alaska population centers along the interior pipeline route.

The shortest route, of course, would be to move gas to the south of Alaska near Valdez and then make it available for transport via LNG. At least insofar as the Lower-48 states are concerned this may be a non-starter simply because it is difficult to conceive of a LNG receiving terminal being built on the U.S. west coast due to citizen opposition. Even LNG projects in Mexico that could supply gas to the U.S. have met resistance.

XIII. NATURAL GAS TRADE WITH MEXICO WILL HAVE A LIMITED OVERALL IMPACT ON THE U.S. MARKET

Mexico is expected to remain a net importer of natural gas from the U.S, although the import levels are likely to decline. Natural gas production in Mexico is about 1.8 Tcf annually from a resource base that likely exceeds 120 Tcf. More specifically, proved reserves are estimated by PEMEX to be 28.1 Tcf. In terms of gas-driven exploration activity, the country is lightly explored.

Under all scenarios examined in this report, natural gas trade between the United States and Mexico remains a net negative to the U.S. supply balance throughout the period 2005-2020. Net exports of natural gas from the U.S. to Mexico are projected to increase from 340 Tbtu in 2003 to 526 TBtu in 2005, decreasing to a net of 176 TBtu by 2020. There are numerous reasons why Mexico is not expected to be a net supplier of gas to the U.S., including the lack of sufficient transportation infrastructure, but perhaps even more important, there is a growing demand for gas in Mexico.

Primary energy consumption and natural gas consumption in Mexico are growing. Primary energy consumption in Mexico grew 23 percent between 1991 and 2000. Most of that growth occurred after 1995, when the Mexican economy came out of its early 1990s doldrums. Gas consumption, specifically, grew more rapidly during the 1990s than total primary energy consumption. As a result, the gas share of Mexico's primary energy consumption grew from 21 percent in 1991 to almost 24 percent in 2000. Most of the increased share occurred after 1995.

Additionally, electricity consumption in Mexico grew more than twice as fast as growth in primary energy consumption during the 1990s. Although most Mexican electricity is generated by oil, most proposed new electricity generation capacity is gas-fired and a significant amount of existing oil-fired generation capacity may be converted to gas. As a result, the demand for gas in Mexico should surge as new gas-fired generation comes on line. The American Gas Foundation report, *Meeting the Gas Supply Challenge of the Next 20 Years – Non Traditional Gas Sources (December 2002),* estimates that natural gas consumed for electricity generation could grow from less than 30 percent of the country's gas consumption to as much as 59 percent by 2020. Similar to the situation in the U.S., it is likely that growing gas demand for electricity generation in Mexico may result in higher gas consumption for this sector than for all industrial uses by 2020.

Mexico's gas supply outlook is not as robust as the demand outlook. Between 1995 and 2001 Mexican gas consumption increased about 300 Bcf, and one fourth of the increased Mexican gas supply came from the United States. In 2001, 10 percent of Mexican gas came from the United States.

Pipeline imports from the U.S. and/or LNG from other sources will play a growing role in Mexican gas supply. While all gas imports currently come from the United States, LNG is likely to become a significant factor in Mexican gas imports. In fact, in the most bullish of scenarios LNG could replace all U.S. gas supply in the Mexican market. Until significant LNG imports begin, the United States will supply any increased demand for gas imports by Mexico.

In summary, because of a need to supply growing electricity demand in Mexico, Mexican gas demand is likely to grow. Unless a world-scale gas field, play, or basin beyond current expectations is discovered in Mexico, this rapid growth in Mexican gas demand will need growing gas deliveries from outside Mexico.

In the near term, the increased demand for imports likely will be met by increased deliveries from U.S. gas supply sources. By 2005, U.S. gas exports to Mexico are likely to exceed 1.4 Bcfd. If U.S. gas supplies remain tight in the near-term, this increased gas demand from Mexico would contribute to upward pressures on gas prices.

Should LNG terminals be developed in Mexico after 2005, Mexican demand for U.S. gas supply may begin to decline. The pace at which U.S. gas exports to Mexico tail off after 2010 will depend on the number and timing of additional LNG terminals in Mexico.

XIV. DRAMATIC MOVEMENT IS NOT ANTICIPATED FOR ANNUAL NATURAL GAS PRICES – UPWARD OR DOWNWARD

Average annual natural gas prices are projected to remain in the $5 to $6 range throughout most of the forecast period. Natural gas prices moved dramatically higher relative to historic normal levels late in the year 2000. Record cold temperatures late in 2000 pushed demand – and prices – upward, with an annual average price of $4.29 per MMBtu set at the Henry Hub. In contrast, prices for most of the 1990s were in the low $2.00 per MMBtu range. Prices averaged $4.00 per MMBtu in 2001, fell back to $3.37 per MMBtu in 2002, but rebounded to $5.49 per MMBtu in 2003. The average price in 2004 is expected to be in the mid $5.00 per MMBtu range. In addition to markedly higher price levels experienced since 2000, gas markets have exhibited far more short-term volatility than in past years. Spikes of $7 to $10 per MMBtu have been experienced in three of the past four years. In a study prepared for the American Gas Foundation,[1] natural gas prices were found to be more volatile than were the prices of all other commodities analyzed, with the exception of electricity.

Gas prices projected under the Expected Policies scenario average $6.72 per MMBtu throughout the forecast period. The average for the five-year period 2001-2005 is $5.26 per MMBtu, jumping to an average of $6.72 per MMBtu for 2006-2010. Supply-side relief, primarily in the form of LNG, produces a reduction to $6.31 per MMBtu in the 2011 to 2015 period. Market pressures push prices upward to $7.14 per MMBtu in the final five-year period of the forecast, peaking at $8.15 per MMBtu in 2020.

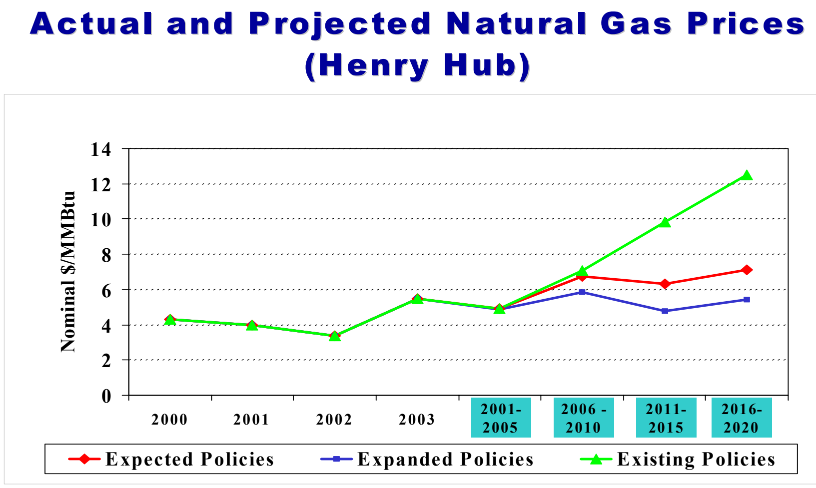
Prices projected under the Expanded Policies scenario move in a pattern similar to, but lower than, those projected in the Expected Policies scenario. Prices under this scenario average $5.86 per MMBtu for 2006-2010, $4.77 per MMBtu for 20011-2015, and $5.41 per MMBtu for 2016-2020. The peak of $5.47 in 2020 is 33 percent less than the Expected Policies final year price.

Prices in the Existing Policies scenario move upward earlier and far more sharply than in either of the other scenarios. The five-year average prices under this scenario are $7.08, $9.81 and $12.50 per MMBtu, with a peak of $13.76 per MMBtu in 2020. The peak price under this scenario is nearly 70 percent higher than the Expected Policies peak. The failure to construct new LNG receiving terminals pushes prices sharply upward as early as 2008 under this scenario.

Natural gas prices, when adjusted for inflation, are projected to decline modestly. As stated above, projected gas prices remain in a $5-$6 range for most of the 17-year forecast. Recognizing that this level is two to three times higher than the prevailing level of the 1990s, the projected prices actually fall when adjusted for inflation ("real" prices, stated in 2003 dollars). The Expected Policies real price in 2020 is $5.35 per MMBtu, 3 percent below the price of $5.49 per MMBtu set in 2003. The 2020 real price under the Expanded Policies scenario is $3.59 per MMBtu – a 35 percent decline-while the Existing Policies real price of $9.03 per MMBtu in 2020 is 64 percent higher than the actual 2003 price.

Projected prices in the Expanded Policies scenario are 33 percent lower than those of the Expected Policies scenario, but they are 70 percent higher in the Existing Policies scenario. The price trajectory of the Expected Policies scenario is not the midpoint of the two alternative scenarios. It is much closer to the Expanded Policies scenario than it is to the Existing Policies scenario. Clearly, the actions of the Expanded Policies scenario can help to ease upward pressure on gas prices. However, the implication of the alternative scenario analysis is that a lack of action, as assumed in the Existing Policies scenario, will have a more dramatic impact on gas prices than will the positive actions of the Expanded Policies scenario– but in an upward direction.

Exhibit XIV-1



Forecasted prices are in 5 year averages.

Although price fluctuations are not expected to be extreme on an annual basis, short-term price volatility likely will persist. The nature of supply and demand in the natural gas market makes it vulnerable to price volatility. The demand for natural gas is capable of severe fluctuations over very short time intervals. Residential and commercial demand are largely determined by the weather, which drives the need for heating. Electricity generation gas demand is also driven by weather – hot weather in the summer that increases the need for air conditioning, and, to a lesser extent, cold weather in the winter that increases the need for electric heating. Industrial gas demand is driven by the level of economic activity, which can also fluctuate over short time intervals, although certainly not to the same extent as weather. Conversely, the supply side of the gas market is largely fixed in the short run. Wells and pipelines cannot be added and subtracted quickly as the temperature or GDP move up and down. The relatively fixed nature of supply coupled with extremely variable demand is conducive to price volatility. Demand moving quickly upward with a relatively fixed supply can push prices sharply upward, while an evaporation of demand with that same fixed supply pushes prices sharply downward.

The natural gas market was not as susceptible to price volatility in the 1980s and 1990s as it is today because the system was, in essence, overbuilt. There was surplus production and delivery capability on a national basis and changes in demand could usually be accommodated without placing undue strain on the system. Therefore the price response was limited. That surplus capability on the supply side has been eliminated. Since late 2000, spikes in demand have generally resulted in spikes in prices. It is unlikely that this situation will change in the near future. Investments will not be made in drilling rigs, pipelines and storage fields if these assets are not to be fully utilized. Utility regulators and investors will not allow it. Because the system is unlikely to be "overbuilt" in a physical sense, a reduction in price volatility may depend on other mechanisms, such as financial hedging and the use of long-term fixed price contracts.

Failure to complete large-scale supply projects would have a severe impact on natural gas consumers. The model employed for this study foresees a tight and tenuous natural gas market. Demand, driven primarily by electricity generation customers, continues to move upward. Supply can meet that demand, but it is pressed to do so and a return to pre-2000 price levels is not deemed plausible. The completion of large-scale supply projects, notably LNG receiving terminals and the Alaskan gas pipeline, as well as increased access for Lower-48 production, can take some of the pressure off domestic production in traditional areas. However, a failure to move forward with these options quickly would have severe consequences. As illustrated by the Existing Policies scenario, natural gas prices will move to levels never before experienced if new sources of supply are not introduced into the mix. Actions must be taken today to avoid these consequences in the very near future.

---

[1] American Gas Foundation for Oak Ridge National Laboratories, *Natural Gas and Energy Price Volatility*, October 2003.

APPENDIX I

EXPECTED POLICIES SCENARIO

Expected Policies Scenario

	Regional Natural Gas Consumption (Bcf)														1999-2010	
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Change	Annual % Change
United States																
Total Consumption	21,990	21,363	22,359	23,270	21,548	22,419	21,497	21,996	22,079	21,947	22,453	23,154	23,632	24,247	1888	0.74%
Residential	4,983	4,393	4,651	4,958	4,688	4,810	5,037	5,038	5,091	5,105	5,144	5,233	5,277	5,371	720	1.32%
Commercial	3,222	2,928	3,070	3,240	3,067	3,123	3,191	3,153	3,170	3,140	3,151	3,204	3,240	3,325	255	0.73%
Industrial	8,904	8,828	8,944	8,828	7,496	7.995	7.196	7;253	7;027	6,526	6,621	6,762	6,834	6,891	-2052	-2.34%
Cogeneration/1	1,481	1,474	1,492	1,471	1,179	1,249	1,116	1,124	1,091	993	1,000	1,021	1,028	1,034	-459	-3.28%
Power Generation	2,963	3,340	3,766	4,288	4,315	4,543	4,107	4,597	4,856	5,229	5,565	5,957	6,278	6,619	2853	5.26%
Cogeneration/1	0	0	24	120	280	466	525	600	655	748	818	889	955	1,019	995	40.77%
Pipeline Fuel	697	662	708	726	737	729	754	747	729	739	757	776	780	814	106	1.27%
Lease & Plant	1,221	1,212	1,220	1,230	1,246	1,220	1,211	1,207	1,206	1,208	1,214	1,222	1,222	1,227	7	0.05%
Cogeneration Total	1,481	1,474	1,516	1,591	1,459	1,714	1,641	1,725	1,746	1,742	1,818	1,909	1,983	2,053	537	2.79%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL01

11-1e-zoos s:zs

Expected Policies Scenario

	Regional Natural Gas Consumption (Bcf)										2010-2020		1999-2020	
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Annual % Change	Change	Annual % Change
United States														
Total Consumption	24,812	25,469	26,088	26,761	27,859	28,008	28,522	28,987	29,325	29,572	5326	2.01%	7213	1.34%
Residential	5,463	5,566	5,607	5,678	5,749	5,863	5,898	5,977	6,054	6,142	771	1.35%	1491	1.33%
Commercial	3,405	3,472	3,503	3,548	3,592	3,669	3,687	3,739	3,785	3,829	504	1.42%	759	1.06%
Industrial	6,928	6;928	7,027	7,084	7,315	7;238	7;316	7,517	7,557	7 ,';IA	622	n.A70/.	-1430	-O. 83%
Cogeneration/1	1,040	1,042	1,055	1,064	1,098	1,093	1,097	1,130	1,133	1,129	95	0.88%	-364	-1.32%
Power Generation	6,999	7,463	7,899	8,371	9,069	9,106	9,473	9,577	9,747	9,906	3287	4.11%	6141	4.71%
Cogeneration/1	1,092	1,185	1,276	1,368	1,502	1,527	1,595	1,617	1,656	1,694	675	5.22%	1671	22.55%
Pipeline Fuel	787	801	812	840	899	906	924	956	964	964	150	1.70%	256	1.48%
Lease & Plant	1,231	1,239	1,241	1,239	1,235	1,227	1,224	1,221	1,217	1,218	-9	-0.08%	-3	-0.01%
Cogeneration Total	2,132	2,227	2,331	2,433	2,600	2,619	2,692	2,747	2,789	2,823	770	3.24%	1307	3.00%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL01 11-18-2004 9:26

Expected Policies Scenario

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	2001-2010 Annual %Change
	Regional Industrial Natural Gas Consumption (Bcf)											
Total of All Industrial												
Total of All End Uses	7,545	8,005	7,197	7,255	7,027	6,526	6,621	6,764	6,836	6,895	-649	-0.99%
Boilers	2,479	2,573	2,424	2,501	2,462	2,430	2,506	2,558	2,601	2,632	153	0.67%
Process Heat	2,635	2,825	2,528	2,558	2,473	2,188	2,194	2,249	2,262	2,274	-361	-1.62%
Other Uses	1,752	1,850	1,661	1,672	1,629	1,478	1,488	1,519	1,530	1,540	-211	-1.42%
Cogen Gas Use /1	1,179	1,249	1,116	1,124	1,091	993	1,000	1,021	1,028	1,034	-145	-1.45%
Ammonia Feedstock	370	426	319	280	235	212	211	211	211	211	-159	-6.07%
Methanol Feedstock	157	173	102	78	56	41	39	39	39	39	-118	-14.38%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Food												
Total of All End Uses	599	623	586	585	581	538	542	552	557	564	-36	-0.68%
Boilers	223	229	226	229	231	229	233	237	239	241	18	0.85%
Process Heat	226	237	214	211	207	183	183	187	189	192	-35	-1.83%
Other Uses	150	158	146	145	142	126	126	128	129	131	-19	-1.48%
Paper												
Total of All End Uses	590	595	595	602	604	5135	584	583	5713	574	-16	-0.31%
Boilers	410	413	414	418	418	412	416	418	418	418	8	0.21%
Process Heat	55	55	55	56	56	52	51	50	49	47	-7	-1.60%
Other Uses	125	126	126	129	130	121	117	115	112	108	-17	-1.58%
Petroleum Refining												
Total of All End Uses	1,351	1,414	1,308	1,274	1,232	1,089	1,084	1,101	1,107	1,115	-236	-2.11%
Boilers	354	358	357	362	363	361	365	368	369	371	16	0.50%
Process Heat	797	846	759	727	691	579	572	583	587	592	-206	-3.26%
Other Uses	199	211	192	185	178	150	148	151	152	153	-47	-2.92%

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	Annual %Change
Total of All												
Total of All End Uses	6,931	6,932	7,032	7,087	7,319	7,249	7,323	7,520	7,559	7,516	-28	-0.02%
Boilers	2,649	2,654	2,700	2,713	2,804	2,752	2,818	2,855	2,883	2,867	389	0.77%
Process Heat	2,282	2,276	2,305	2,329	2,410	2,394	2,394	2,489	2,491	2,466	-169	-0.35%
Other Uses	1,549	1,551	1,572	1,587	1,641	1,638	1,641	1,698	1,701	1,693	-59	-0.18%
Cogen Gas Use /1	1,040	1,042	1,055	1,064	1,098	1,093	1,097	1,130	1,133	1,129	-50	-0.23%
Ammonia Feedstock	208	206	206	205	205	205	205	205	205	205	-165	-3.06%
Methanol Feedstock	37	33	31	29	28	22	20	20	20	17	-140	-11.01%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Food												
Total of All End Uses	568	572	579	586	598	603	604	621	622	623	24	0.20%
Boilers	242	244	246	248	251	252	255	258	260	262	39	0.84%
Process Heat	193	195	197	200	206	208	207	216	215	215	-12	-0.27%
Other Uses	132	133	135	137	141	142	142	146	146	147	-4	-0.13%
Paper												
Total of All End Uses	569	564	561	559	559	555	552	555	551	547	-42	-0.39%
Boilers	418	417	418	418	420	418	420	421	421	420	10	0.13%
Process Heat	46	44	43	43	42	41	40	41	39	38	-16	-1.83%
Other Uses	106	103	100	98	97	96	92	93	91	89	-36	-1.77%
Petroleum Refining												
Total of All End Uses	1,120	1,124	1,131	1,141	1,155	1,161	1,158	1,184	1,183	1,183	-168	-0.70%
Boilers	372	372	375	376	378	378	381	383	385	385	31	0.44%
Process Heat	595	597	602	608	618	622	618	637	635	634	-163	-1.20%
Other Uses	153	154	155	156	159	160	159	163	163	163	-36	-1.04%

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.
AGAOIL01 11-16-2004 9:26

Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	Annual %Change
Chemicals												
Total of All End Uses	2,602	2,986	2,470	2,510	2,341	2,219	2,310	2,394	2,447	2,478	-124	-0.54%
Boilers	822	910	781	828	780	763	815	848	879	899	77	1.00%
Process Heat	549	676	568	605	571	528	551	579	588	592	43	0.84%
Other Uses	551	643	538	552	528	498	513	530	536	538	-13	-0.26%
Ammonia Feedstock	370	426	319	280	235	212	211	211	211	211	-159	-6.07%
Methanol Feedstock	157	173	102	78	56	41	39	39	39	39	-118	-14.38%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Stone, Clay and Glass												
Total of All End Uses	349	369	340	344	344	309	311	321	327	335	-14	-0.46%
Boilers	17	18	17	18	18	18	19	19	20	20	3	1.63%
Process Heat	287	303	278	282	281	251	252	261	266	272	-15	-0.61%
Other Uses	44	47	44	44	45	40	40	41	42	43	-1	-0.32%
Iron and Steel												
Total of All End Uses	318	334	338	368	368	338	329	325	316	309	-9	-0.30%
Boilers	50	53	56	60	60	59	60	61	61	61	11	2.23%
Process Heat	237	248	248	272	271	245	237	233	225	219	-18	-0.88%
Other Uses	31	33	34	36	37	33	32	31	30	30	-1	-0.52%
Primary Aluminum												
Total of All End Uses	89	85	82	82	80	71	69	70	68	66	-23	-3.23%
Boilers	11	11	11	11	11	11	11	11	11	11	0	0.23%
Process Heat	73	70	67	66	65	56	54	55	54	52	-22	-3.79%
Other Uses	5	5	5	5	5	4	4	4	4	4	-1	-3.60%
Other Primary Metals												
Total of Ali End Uses	191	169	137	137	134	117	116	117	118	119	-73	-5.18%
Boilers	5	5	4	4	4	4	4	4	4	4	-1	-2.45%
Process Heat	105	93	74	74	72	62	62	63	63	64	-42	-5.44%
Other Uses	81	72	59	58	57	50	50	50	50	51	-30	-5.05%

AGAOIL01 11-18-2004 9:26

Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	Annual %Change
Chemicals												
Total of All End Uses	2,493	2,480	2,543	2,552	2,707	2,603	2,683	2,749	2,779	2,731	130	0.26%
Boilers	907	903	934	933	1,005	949	993	1,011	1,024	998	176	1.03%
Process Heat	595	589	606	609	657	625	645	668	675	658	109	0.96%
Other Uses	541	538	549	552	582	565	575	592	595	585	34	0.32%
Ammonia Feedstock	208	206	206	205	205	205	205	205	205	205	-165	-3.06%
Methanol Feedstock	37	33	31	29	28	22	20	20	20	17	-140	-11.01%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Stone, Clay and Glass												
Total of All End Uses	340	345	352	361	373	380	380	399	402	405	56	0.79%
Boilers	20	20	21	21	22	22	22	23	23	23	6	1.66%
Process Heat	276	280	286	293	303	309	309	325	327	329	42	0.72%
Other Uses	44	45	45	47	48	49	49	52	52	53	8	0.89%
Iron and Steel												
Total of All End Uses	305	299	296	295	295	295	284	295	291	284	-34	-0.59%
Boilers	61	61	61	61	62	61	62	62	62	62	12	1.14%
Process Heat	215	209	207	206	206	206	196	205	202	195	-42	-1.01%
Other Uses	29	28	28	28	28	28	27	28	27	27	-4	-0.80%
Primary Aluminum												
Total of All End Uses	64	61	58	57	56	55	51	53	52	50	-40	-3.03%
Boilers	11	11	11	11	11	11	11	11	11	10	0	-0.08%
Process Heat	49	46	44	43	42	41	38	40	39	37	-37	-3.59%
Other Uses	4	3	3	3	3	3	3	3	3	3	-3	-3.49%
Other Primary Metals												
Total of All End Uses	119	119	120	121	123	124	122	126	125	124	-67	-2.24%
Boilers	4	4	4	4	4	4	4	4	4	4	-1	-1.08%
Process Heat	64	64	64	65	66	66	66	68	67	67	-38	-2.36%
Other Uses	51	51	51	52	53	53	52	54	53	53	-28	-2.18%

AGAOIL01 11-18-2004 9:26

Expected Policies Scenario

U.S. Total	2001	2002	Regional 2003	Industrial Natural 2004	2005	2006	Gas Consumption 2007	2008	2009	(Bcf) 2010	2001-2010 Change	Annual %Change
Other Manufacturing												
Total of All End Uses	869	837	770	765	759	708	714	727	735	746	-123	-1.68%
Boilers	358	348	334	340	342	340	346	351	355	359	1	0.03%
Process Heat	209	198	174	172	168	148	148	151	153	156	-53	-3.18%
Other Uses	303	290	261	253	249	220	220	225	228	232	-71	-2.93%
Non-Manufacturing												
Total of All End Uses	587	592	571	588	584	553	561	573	581	590	3	0.06%
Boilers	228	229	224	231	234	233	238	242	246	249	21	0.97%
Process Heat	96	98	92	93	91	84	84	87	88	90	-7	-0.80%
Other Uses	262	265	255	265	260	237	239	243	247	251	-11	-0.46%
Industrial Curtailments	**49**	**10**	**1**	**2**	**0**	**0**	**1**	**2**	**1**	**4**	**-45**	**-24.40%**

AGAOIL01
11-18-2004 9:26

Expected Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	tool-2020 Change	Annual %Change
Other												
Total of All End **Uses**	755	764	777	791	813	**826**	**836**	**865**	**876**	888	19	0.11%
Boilers	362	367	372	378	386	390	398	406	414	420	62	0.85%
Process Heat	158	160	163	166	172	175	176	185	186	188	-20	-0.54%
Other Uses	235	237	241	247	255	260	261	273	276	280	-23	-0.42%
Non-												
Total of All End Uses	598	605	615	626	640	648	652	673	677	681	94	0.79%
Boilers	252	255	258	261	265	267	272	276	279	282	54	1.12%
Process Heat	91	92	94	96	98	99	100	104	104	105	8	0.43%
Other Uses	255	258	263	269	277	281	281	294	294	295	33	0.62%
Industrial Curtailments	**3**	**4**	**5**	**3**	**4**	**11**	**7**	**3**	**2**	**3**	**-45**	**-12.83%**

AGAOIL01 11-16-2004 9:26

Expected Policies Scenario

Power Generation Capacity (GW)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1999-2010 Change	Annual % Change
LOWER-48																
TOTAL CAPACITY	723.2	727.4	736.0	763.8	799.9	865.0	920.8	927.8	935.7	951.5	956.5	961.6	965.9	972.0	236.0	2.56%
OIL/GAS CAPACITY	215.1	218.9	229.1	256.4	291.4	352.6	405.0	408.8	413.5	426.0	427.9	429.8	431.7	433.6	204.5	5.97%
CT/CC ADDITIONS	*0.0*	2.1	10.5	35.9	76.6	144.2	202.7	212.6	223.3	236.1	241.0	246.0	250.9	255.8	245.4	33.73%
COAL CAPACITY	304.5	304.5	304.5	306.4	307.2	309.6	311.9	314.3	316.7	319.0	321.4	323.7	326.4	329.1	24.6	0.71%
NUCLEAR CAPACITY	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	95.4	95.4	-1.1	-0.10%
HYDRO CAPACITY	100.0	100.2	99.0	97.7	97.7	97.9	98.3	98.6	98.8	99.0	99.0	99.0	99.0	99.0	0.0	0.00%
OTHER CAPACITY	7.2	7.3	6.8	6.9	7.2	8.4	9.0	9.6	10.2	10.9	11.7	12.5	13.3	14.9	8.1	7.35%

AGAOIL01 11•16-2004 9:26

Expected Policies Scenario

	Power Generation Capacity (GW)										2010-2020		1999-2020	
												Annual %		Annual %
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Change	Change	Change
LOWER-48														
TOTAL CAPACITY	977.0	982.2	987.7	993.5	999.6	1013.3	1027.4	1042.1	1056.6	1072.5	100.5	0.99%	336.5	1.81%
OIL/GAS CAPACITY	436.5	439.4	442.2	445.1	447.9	451.6	455.3	458.9	462.6	466.3	32.6	0.73%	237.1	3.44%
CT/CC ADDITIONS	261.8	267.7	273.5	279.4	285.3	292.1	298.8	305.5	312.1	318.9	63.0	2.23%	308.4	17.67%
COAL CAPACITY	329.5	329.8	330.2	330.6	331.0	337.7	344.5	351.2	357.3	364.0	35.0	1.01%	59.6	0.85%
NUCLEAR CAPACITY	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	0.0	0.00%	-1.1	-0.05%
HYDRO CAPACITY	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	0.0	0.00%	0.0	0.00%
OTHER CAPACITY	16.6	18.6	20.8	23.4	26.3	29.5	33.3	37.5	42.3	47.8	32.9	12.37%	40.9	9.71%

AGAOIL01 11-18-2004 9:26

Expected Policies Scenario

Power Generation Fossil Fuel Consumption (Quads)

															1999-2010	Annual %
	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Change**	**Change**
LOWER-48																
FOSSIL FUEL CONSUMPTION	22.5	23.7	23.8	24.779	24.662	24.675	24.446	24.955	25.602	26.180	26.75	27.456	28.045	28.711	4.9	1.73%
GAS DEMAND	3.0	3.4	3.8	4.393	4.449	4.652	4.196	4.701	4.965	5.348	5.694	6.098	6.425	6.777	2.9	5.31%
Gas Curtailments	0.0	0.0	0.0	0.010	0.039	0.006	0.000	0.002	0.000	0.000	0.000	0.002	0.000	0.001	0.0	13.00%
Cogen Gas Use /1	0.0	0.0	0.0	0.120	0.280	0.466	0.525	0.600	0.655	0.748	0.818	0.889	0.955	1.019	1.0	40.77%
COAL DEMAND	18.7	19.1	19.0	19.491	19.235	19.537	19.719	20.011	20.339	20.493	20.72	20.976	21.209	21.493	2.5	1.13%
OIL DEMAND	0.8	1.2	1.0	0.895	0.978	0.487	0.531	0.243	0.297	0.339	0.339	0.382	0.411	0.441	-0.5	-6.74%

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

AGAOIL01 11-19-2004 9:26

Expected Policies Scenario

	Power Generation Fossil Fuel Consumption (Quads)										2010-2020		1999-2020	
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Annual % Change	Change	Annual Change
LOWER-48														
FOSSIL FUEL CONSUMPTION	29.405	30.093	30.591	31.193	31.770	32.485	33.083	33.750	34.404	35.193	6.5	2.06%	11.417	1.88%
GAS DEMAND	7.167	7.645	8.092	8.576	9.296	9.341	9.713	9.814	9.985	10.149	3.4	4.12%	6.312	4.74%
Gas Curtailments	0.001	0.001	0.001	0.001	0.004	0.013	0.008	0.004	0.002	0.003	0.0	8.06%	0.003	10.62%
Cogen Gas Use /1	1.092	1.185	1.276	1.368	1.502	1.527	1.595	1.617	1.656	1.694	0.7	5.22%	1.671	22.55%
COAL DEMAND	21.739	21.912	21.992	22.027	22.038	22.403	22.784	23.225	23.647	24.140	2.6	1.17%	5.151	1.15%
OIL DEMAND	0.499	0.536	0.507	0.590	0.437	0.741	0.586	0.710	0.772	0.904	0.5	7.44%	-0.046	-0.24%

1. Cogeneratiion gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

AGAOIL01 11-1e-2004 9:26

Expected Policies Scenario

	Regional Natural Gas Balance (Annual Bcf)														1999-2010	
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Change	Annual % Change
United States/2,3																
Total Consumption	21,990	21,363	22,358	23,269	21,547	22,417	21,495	21,993	22,076	21,944	22,451	23,152	23,630	24,245	1,886	0.74%
+Storage Injections/1	1,886	1,993	1,656	1,533	2,380	1,637	2,406	2,045	2,097	2,313	2,294	2,234	2,265	2,231	576	2.75%
+ LNG Injections	76	58	37	56	35	42	42	42	42	42	42	42	42	42	5	1.27%
+ Pipeline Exports																
+ Exports to Canada	529	435	539	581	789	735	883	819	784	806	825	884	897	893	354	4.70%
+ Exports to Mexico	33	48	55	100	140	266	340	409	512	461	212	240	240	272	218	15.73%
=Total Demand	24,513	23,896	24,644	25,540	24,893	25,098	25,165	25,309	25,511	25,566	25,824	26,552	27,074	27,683	3,039	1.06%
Total Production	19,207	18,862	18,922	19,088	19,383	18,734	18,528	18,414	18,382	18,488	18,744	18,889	18,916	18,985	62	0.03%
+ Supplemental Fuels	103	102	98	86	79	79	79	79	79	79	79	79	79	79	-19	-1,94%
+Storage Withdrawals/1	1,919	1,470	1,797	2,380	1,231	2,080	2,211	2,328	2,393	2,051	2,027	2,194	2,188	2,273	476	2.16%
+ LNG Withdrawals	68	52	1.	5 i	35	40	40	40	40	40	40	40	40	40	3	0.80%
+ Net LNG Imports	16	20	100	160	169	164	464	807	1,047	1,487	1,578	1,984	2,235	2,782	2,682	35.32%
+ Ethane Rejection	5	39	7	0	102	0	87	5	0	27	19	2	1	3	-4	-7.54%
+ Pipeline Imports																
+ Imports from Canada	3,494	3,577	3,856	3,997	4,261	4,227	4,087	3,918	3,830	3,671	3,540	3,563	3,822	3,739	-117	-0.28%
+ Imports from Mexico	11	10	50	6	7	0	0	0	0	9	73	53	60	49	-2	-0.29%
=Total Supply	24,822	24,131	24,866	25,769	25,266	25,324	25,496	25,592	25,770	25,852	26,099	26,804	27,340	27,949	3,083	1.07%
Balancing Item	309	236	222	229	374	226	331	283	259	286	275	252	266	266	43	1.62%

1. Sum of net monthly storage injections/withdrawals.

2. Net LNG Imports line item does not include LNG imports at Baja.

3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

Expected Policies Scenario

United States/2,3	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2010-2020 Change	2010-2020 Annual % Change	1999-2020 Change	1999-2020 Annual % Change
	Regional Natural Gas Balance (Annual Bcf)													
Total Consumption	24,810	25,467	26,086	26,759	27,857	28,006	28,520	28,985	29,323	29,570	5,326	2.01%	7,212	1.34%
+Storage Injections/1	2,289	2,362	2,388	2,350	2,432	2,701	2,356	2,666	2,495	2,722	491	2.01%	1,067	2.40%
+ LNG Injections	42	42	42	42	42	42	42	42	42	42	0	0.00%	5	0.66%
+ Pipeline Exports														
+ Exports to Canada	825	855	858	1,122	2,368	2,340	2,521	3,121	3,146	3,124	2,231	13.34%	2,585	8.73%
+ Exports to Mexico	273	273	255	255	255	255_	255	255	255	255	-17	-0.65%	200	7.62%
=Total Demand	28,239	29,000	29,630	30,529	32,954	33,344	33,694	35,070	35,261	35,713	8,030	2.58%	11,069	1.78%
Total Production	19,071	19,239	19,286	19,524	20,688	20,524	20,614	21,158	21,110	21,124	2,139	1.07%	2,201	0.53%
+ Supplemental Fuels	79	79	79	79	79	79	79	79	79	79	0	0.00%	-19	-1.02%
+ Storage Withdrawals/1	2,362	2,367	2,337	2,387	2,342	2,667	2,455	2,515	2,655	2,666	393	1.61%	869	1.90%
+ LNG Withdrawals	40	40	40	40	40	40	40	40	40	40	0	0.12%	4	0.47%
+ Net LNG Imports	3,220	3,778	4,498	4,863	5,100	5,407	5,921	6,140	6,338	6,636	3,854	9.08%	6,536	22.12%
+ Ethane Rejection	5	16	8	11	9	63	14	1	0	20	17	20.84%	13	5.03%
+ Pipeline Imports														
+ Imports from Canada	3,691	3,714	3,597	3,846	4,969	4,830	4,833	5,395	5,312	5,382	1,643	3.71%	1,527	1.60%
+ Imports from Mexico	45	45	83	83	83	83	83	83	83	83	34	5.45%	33	2.40%
=Total Supply	28,512	29,278	29,927	30,832	33,310	33,692	34,038	35,412	35,616	36,029	8,080	2.57%	11,163	1.78%
Balancing Item	274	278	297	303	356	348	344	342	354	316	50	1.74%	93	1.68%

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

Expected Policies Scenario

Gas Prices (Nominal $/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
Henry Hub														
1997	3.37	2.21	1.91	2.04	2.24	2.21	2.19	2.49	2.87	3.04	2.98	2.33	2.49	0.44
1998	2.11	2.22	2.23	2.44	2.13	2.16	2.20	1.85	1.99	1.89	2.09	1.68	2.08	0.19
1999	1.84	1.77	1.80	2.13	2.26	2.30	2.29	2.79	2.57	2.70	2.31	2.36	2.26	0.32
2000	2.41	2.66	2.78	3.02	3.58	4.30	4.05	4.39	5.02	5.03	5.49	8.69	4.29	1.65
2001	8.48	5.65	5.15	5.20	4.21	3.74	3.07	3.02	2.20	2.44	2.37	2.37	3.99	1.79
2002	2.32	2.28	3.02	3.39	3.52	3.22	3.04	3.13	3.55	4.13	4.06	4.74	3.37	0.68
2003	5.71	7.09	6.39	5.27	5.76	5.80	5.04	4.98	4.69	4.66	4.43	6.12	5.49	0.76
2004	6.05	5.40	5.38	4.42	5.62	5.73	7.08	6.38	5.68	4.95	5.75	5.85	5.69	0.64
2005	7.03	7.29	6.87	8.94	9.21	7.67	7.55	7.14	8.05	7.55	7.72	7.91	7.74	0.69
2006	8.98	9.08	8.27	7.40	9.13	7.91	7.84	7.57	8.71	7.76	8.04	8.17	8.24	0.58
2007	8.81	8.62	8.02	6.54	6.62	6.15	6.63	6.58	6.60	4.90	6.08	6.18	6.81	1.08
2008	6.70	6.62	6.08	6.68	7.04	6.44	7.09	6.96	6.46	5.54	6.37	6.48	6.54	0.41
2009	6.95	6.77	6.33	5.76	5.53	5.59	6.33	6.15	5.88	5.14	5.83	5.89	6.01	0.50
2010	6.34	6.16	5.74	6.63	6.99	5.96	5.79	5.93	6.27	4.82	5.67	5.82	6.01	0.52
2011	6.45	6.35	5.75	7.24	6.72	5.94	6.14	6.05	6.60	5.47	6.11	6.22	6.25	0.45
2012	6.97	7.01	6.19	5.58	6.72	6.97	7.84	7.53	7.00	5.96	6.82	6.98	6.80	0.60
2013	7.60	7.47	6.83	6.47	6.24	5.77	5.76	5.87	6.34	4.79	5.64	5.82	6.22	0.77
2014	6.52	6.52	5.91	7.48	7.87	6.68	6.78	6.82	7.71	7.27	6.81	7.42	6.98	0.55
2015	7.96	7.84	7.26	4.42	3.67	4.11	5.74	5.59	4.04	3.66	4.43	4.59	5.28	1.53
2016	5.42	5.78	5.08	11.23	9.98	9.15	8.62	8.25	8.78	6.53	7.83	8.01	7.89	1.80
2017	8.52	8.47	7.86	5.85	5.53	5.19	6.05	5.69	5.60	5.19	5.54	5.65	6.26	1.20
2018	6.42	6.47	5.78	6.63	7.98	7.11	7.43	6.77	6.73	6.22	6.53	6.72	6.73	0.55
2019	7.35	7.43	6.75	7.08	7.12	6.51	7.03	6.45	6.47	5.52	6.19	6.32	6.68	0.53
2020	7.21	7.49	6.69	9.09	9.79	8.50	8.60	7.72	8.58	7.83	8.05	8.21	8.15	0.81

AGAGIL01 11-18-2004 9:26

Expected Policies Scenario

Gas Prices (2003$/MMBtu)

Henry Hub	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
1997	3.81	2.50	2.15	2.30	2.52	2.48	2.46	2.79	3.21	3.40	3.33	2.60	2.80	0.49
1998	2.35	2.47	2.48	2.72	2.36	2.40	2.44	2.04	2.20	2.09	2.31	1.86	2.31	0.22
1999	2.03	1.94	1.98	2.33	2.48	2.51	2.51	3.04	2.81	2.94	2.51	2.56	2.47	0.34
2000	2.61	2.87	3.00	3.24	3.83	4.60	4.33	4.69	5.35	5.35	5.84	9.21	4.58	1.73
2001	8.97	5.97	5.43	5.47	4.42	3.92	3.22	3.16	2.29	2.54	2.46	2.46	4.19	1.91
2002	2.40	2.36	3.12	3.48	3.62	3.30	3.11	3,19	3.62	4.20	4.12	4.80	3.44	0.68
2003	5.77	7.14	6.43	5.29	5.78	5.80	5.02	4.95	4.66	4.62	4.38	6.05	5.49	0.78
2004	5.96	5.31	5.28	4.33	5.49	5.59	6.89	6.20	5.51	4.79	5.55	5.64	5.55	0.62
2005	6.76	7.00	6.58	8.55	8.78	7.30	7.17	6.76	7.62	7.13	7.27	7.43	7.36	0.65
2006	8.43	8.51	7.73	6.90	8.49	7.34	7.27	7.00	8.04	7.15	7.39	7.50	7.65	0.56
2007	8.06	7.87	7.31	5.95	6.01	5.57	6.00	5.94	5.95	4.40	5.45	5.53	6.17	1.02
2008	5.98	5.90	5.41	5.92	6.24	5.69	6.25	6.13	5.67	4.85	5.57	5.65	5.77	0.38
2009	6.05	5.88	5.49	4.99	4.77	4.82	5.45	5.29	5.04	4.40	4.98	5.01	5.18	0.45
2010	5.39	5.22	4.86	5.60	5.89	5.02	4.86	4.97	5.24	4.02	4.72	4.84	5.05	0.46
2011	5.34	5.26	4.74	5.96	5.53	4.87	5.03	4.95	5.38	4.45	4.96	5.04	5.13	0.38
2012	5.64	5.66	4.99	4.48	5.39	5.58	6.26	6.00	5.57	4.74	5.40	5.52	5.44	0.48
2013	6.00	5.89	5.37	5.08	4.88	4.51	4.49	4.56	4.92	3.71	4.36	4.49	4.86	0.63
2014	5.02	5.01	4.53	5.72	6.01	5.09	5.16	5.18	5.84	5.50	5.13	5.59	5.32	0.40
2015	5.98	5.88	5.43	3.30	2.73	3.05	4.26	4.14	2.99	2.70	3.26	3.37	3.92	1.16
7AdC	n n~	4.22	3.71	8.18	7.26	6.64	6.24	5.96	6.33	4.70	5.62	5.74	5.71	1.30
2017	6.09	6.04	5.60	4.16	3.92	3.67	4.27	4.01	3.94	3.65	3.88	3.95	4.43	0.88
2018	4.48	4.50	4.01	4.60	5.52	4.91	5.12	4.66	4.62	4.26	4.46	4.58	4.64	0.38
2019	5.01	5.04	4.58	4.79	4.81	4.39	4.73	4.33	4.33	3.69	4.13	4.20	4.50	0.38
2020	4.79	4.96	4.42	6.00	6.45	5.59	5.64	5.05	5.61	5.10	5.24	5.33	5.35	0.53

AGAOIL01 11•18-2004 9:20

APPENDIX II

EXPANDED POLICIES SCENARIO

Expanded Policies Scenario

Regional NaturalGas Consumption (Bcf)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1999-2010 Change	Annual % Change
United States																
Total Consumption	21,990	21,363	22,359	23,270	21,548	22,419	21,497	21,988	22,069	22,026	22,540	23,260	24,145	24,638	2279	0.89%
Residential	4,983	4,393	4,651	4,958	4,688	4,810	5,037	5,038	5,092	5,110	5,155	5,250	5,305	5,419	767	1.40%
Commercial	3,222	2,928	3,070	3,240	3,067	3,123	3,191	3,153	3,172	3,147	3,166	3,227	3,280	3,393	323	0.91%
Industrial	8,904.	8,828	8,944	8,828	7,496	7,995	7,196	7,225	7,058	6,669	6,811	6,987	7,238	7,315	-1629	-1.81%
Cogeneration/1	1,481	1,474	1,492	1,471	1,179	1,249	1,116	1,125	1,096	1,018	1,036	1,062	1,102	1,119	-374	-2.59%
Power Generation	2,963	3,340	3,766	4,288	4,315	4,542	4,107	4,588	4,812	5,149	5,432	5,790	6,287	6,481	2716	5.06%
Cogeneration /1	0	0	24	120	280	466	525	599	647	734	793	858	948	993	969	40.44%
Pipeline Fuel	697	662	708	726	737	729	754	746	729	741	758	780	809	804	96	1.16%
Lease & Plant	1,221	1,212	1,220	1,230	1,246	1,220	1,211	1,207	1,206	1,210	1,217	1,226	1,226	1,226	6	0.04%
Cogeneration Total	1,481	1,474	1,516	1,591	1,459	1,714	1,641	1,723	1,743	1,751	1,829	1,920	2,050	2,112	595	3.06%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity onstructed from 1999 forward is reported in the Power Generation sector.

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

	Regional Natural Gas Consumption (Bcf)										2010-2020		1999-2020	
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Annual % Change	Change	Annual % Change
United States														
Total Consumption	25,617	25,594	26,031	26,414	27,383	27,521	27,668	28,762	28,969	29,584	4947	1.85%	7225	1.34%
Residential	5,529	5,660	5,695	5,764	5,831	5,947	5,993	6,066	6,158	6,230	812	1.41%	1579	1.40%
Commercial	3,500	3,609	3,629	3,673	3,711	3,791	3,824	3,867	3,936	3,955	562	1.55%	885	1.21%
Industrial	7,511	7,336	7,335	7,476	7,761	7,711	7,613	7,971	7,963	8,027	712	0.93%	-917	-0.51%
Cogeneration /1	1,145	1,123	1,113	1,143	1,182	1,181	1,157	1,218	1,220	1,227	109	0.93%	-265	-0.93%
Power Generation	7,036	6,980	7,346	7,461	7,996	8,009	8,173	8,734	8,813	9,248	2767	3.62%	5483	4.37%
Cogeneration/1	1,088	1,089	1,158	1,184	1,282	1,288	1,341	1,425	1,447	1,521	528	4.35%	1497	21.92%
Pipeline Fuel	807	791	800	822	875	875	881	934	927	948	143	1.65%	239	1.39%
Lease & Plant	1,234	1,218	1,227	1,218	1,209	1,188	1,183	1,188	1,173	1,176	-50	-0.42%	-44	-0.18%
CogenerationTotal	2,233	2,212	2,270	2,328	2,464	2,469	2,498	2,643	2,667	2,748	637	2.67%	1232	2.87%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	2001-2010 Annual %Change
	Regional Industrial Natural Gas Consumption (Bcf)											
Total of All Industrial Sectors												
Total *of* All End Uses	7,545	8,005	7,197	7,258	7,058	6,669	6,811	6,989	7,241	7,320	-225	-0.34%
Boilers	2,479	2,573	2,424	2,501	2,467	2,458	2,528	2,583	2,681	2,699	220	0.95%
Process Heat	2,635	2,825	2,528	2,558	2,488	2,259	2,300	2,374	2,463	2,491	-144	-0.62%
Other Uses	1,752	1,850	1,661	1,673	1,638	1,513	1,541	1,585	1,645	1,673	-79	-0.51%
Cogen Gas Use /1	1,179	1,249	1,116	1,125	1,096	1,018	1,036	1,062	1,102	1,119	-60	-0.58%
Ammonia Feedstock	370	426	320	281	237	217	216	216	216	215	-155	-5.84%
Methanol Feedstock	157	173	102	78	57	44	44	44	44	43	-115	-13.47%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Food												
Total *of* All End Uses	599	623	586	585	583	549	557	571	583	592	-7	-0.13%
Boilers	223	229	226	229	232	231	234	237	240	242	19	0.90%
Process Heat	226	237	214	211	209	189	192	198	204	208	-18	-0.93%
Other Uses	150	158	146	145	143	129	131	136	139	142	-8	-0.58%
Paper												
Total of All End Uses	590	595	595	602	604	588	586	587	585	583	-7	-0.13%
Boilers	410	413	414	418	418	414	417	419	420	420	10	0.27%
Process Heat	55	55	55	56	56	53	51	51	50	49	-6	-1.19%
Other Uses	125	126	126		130	121	118	117	115	114	-11	-1.05%
Petroleum Refining												
Total *of* All End Uses	1,351	1,414	1,309	1,274	1,240	1,130	1,144	1,163	1,179	1,192	-159	-1.38%
Boilers	354	358	357	362	364	363	366	368	370	371	17	0.52%
Process Heat	797	846	759	727	698	610	619	633	644	652	-145	-2.21%
Other Uses	199	211	192	185	179	157	159	162	165	169	-31	-1.84%

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL02 11-19-2004 »:19

Expanded Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	Annual % Change
Total of All Industrial Sectors												
Total of All End Uses	7,517	7,341	7,341	7,480	7,767	7,713	7,616	7,975	7,965	8,031	487	0.33%
Boilers	2,791	2,712	2,767	2,778	2,917	2,866	2,848	2,976	2,954	2,977	498	0.97%
Process Heat	2,552	2,497	2,464	2,537	2,624	2,613	2,568	2,698	2,698	2,722	87	0.17%
Other Uses	1,711	1,681	1,660	1,713	1,768	1,772	1,735	1,828	1,833	1,846	95	0.28%
Cogen Gas Use /1	1,145	1,123	1,113	1,143	1,182	1,181	1,157	1,218	1,220	1,227	48	0.21%
Ammonia Feedstock	215	210	207	205	205	205	205	205	205	205	-165	-3.06%
Methanol Feedstock	42	30	25	23	22	20	15	15	15	14	-144	-12.08%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Food												
Total of All End Uses	598	602	599	616	621	630	628	642	649	655	56	0.47%
Boilers	244	245	247	250	252	254	256	259	261	263	40	0.87%
Process Heat	210	212	209	218	219	223	221	228	230	233	6	0.15%
Other Uses	144	145	143	149	150	153	151	156	158	159	9	0.32%
Paper												
Total of All End Uses	579	574	565	568	564	565	557	560	559	556	-34	-0.31%
Boilers	421	419	419	420	422	422	421	422	422	423	13	0.16%
Process Heat	48	47	44	44	43	43	41	42	41	40	-15	-1.61%
Other Uses	111	108	102		100	100	95	96	95	93	-32	-1.54%
Petroleum Refining												
Total of All End Uses	1,199	1,203	1,195	1,219	1,224	1,235	1,232	1,249	1,257	1,264	-86	-0.35%
Boilers	372	374	375	377	379	380	382	383	385	386	32	0.46%
Process Heat	657	659	653	669	672	679	677	688	693	698	-99	-0.70%
Other Uses	169	170	168	173	173	175	173	177	179	180	-19	-0.53%

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

Expanded Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	2001-2010 Annual %Change
Chemicals												
Total of All End Uses	2,602	2,986	2,470	2,512	2,354	2,272	2,371	2,462	2,644	2,665	64	0.27%
Boilers	822	910	781	828	783	780	831	869	951	959	136	1.72%
Process Heat	549	676	569	606	574	545	573	602	658	662	113	2.10%
Other Uses	551	643	538	552	530	508	526	544	582	588	36	0.71%
Ammonia Feedstock	370	426	320	281	237	217	216	216	216	215	-155	-5.84%
Methanol Feedstock	157	173	102	78	57	44	44	44	44	43	-115	-13.47%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Stone, Clay and Glass												
Total of All End Uses	349	369	340	344	345	316	323	337	348	359	10	0.31
Boilers	17	18	17	18	18	18	19	19	20	20	3	1.70%
Process Heat	287	303	278	282	282	257	263	274	284	292	5	0.19%
Other Uses	44	47	44	44	45	41	42	43	45	47	2	0.53%
Iron and Steel												
Total of All End Uses	318	334	338	369	369	339	332	333	332	330	12	0.41%
Boilers	50	53	56	60	61	60	60	61	61	61	11	2.31
Process Heat	237	248	248	272	272	246	240	240	239	236	0	-0.02%
Other Uses	31	33	34	36	37	33	32	32	32	32	1	0.34%
Primary Aluminum												
Total of All End Uses	89	85	82		81	72	71	73	73	74	-16	-2.10%
Boilers	11	11	11	11	11	11	11	11	11	11	0	0.24%
Process Heat	73	70	67	66	65	57	56	58	58	59	-15	-2.47%
Other Uses	5	5	5	5	5	4	4	4	4	4	-1	-2.17%
Other Primary Metals												
Total of All End Uses	191	169	137	137	134	120	120	123	126	128	-63	-4.35%
Boilers	5	5	4	4	4	4	4	4	4	4	-1	-2.38%
Process Heat	105	93	74	74	72	64	65	66	68	69	-36	-4.60%
Other Uses	81	72	59	58	58	51	52	53	54	55	-26	-4.18%

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

	Regional Industrial Natural Gas Consumption (Bcf)										2001-2020	
U.S. Total	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Change**	**Annual %Change**
Chemicals												
Total of All End Uses	2,830	2,638	2,687	2,700	2,962	2,842	2,773	3,023	2,959	2,982	380	0.72%
Boilers	1,037	952	996	989	1,112	1,047	1,019	1,126	1,089	1,096	274	1.52%
Process Heat	711	651	659	666	749	709	687	767	744	752	203	1.67%
Other Uses	619	583	583	592	643	624	602	658	646	648	96	0.85%
Ammonia Feedstock	215	210	207	205	205	205	205	205	205	205	-165	-3.06%
Methanol Feedstock	42	30	25	23	22	20	15	15	15	14	-144	-12.08%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Stone, Clay and Glass												
Total of All End Uses	365	371	369	387	393	402	403	418	427	435	86	1.17%
Boilers	20	21	21	21	22	22	22	23	23	24	7	1.71%
Process Heat	298	302	301	315	320	328	328	341	348	355	67	1.12%
Other Uses	47	48	48	50	51	52	52	54	56	57	12	1.30%
Iron and Steel												
Total of All End Uses	327	323	304	316	309	314	298	306	309	307	-11	-0.19%
Boilers	62	61	61	62	62	62	62	63	63	63	13	1.20%
Process Heat	234	230	214	224	218	222	208	215	217	215	-22	-0.51%
Other Uses	31	31	29	30	29	30	28	29	29	29	-2	-0.32%
Primary Aluminum												
Total of All End Uses	72	69	61		60	61	56	57	57	55	-34	-2.48%
Boilers	11	11	11	11	11	11	11	11	11	10	0	-0.07%
Process Heat	57	55	47	49	46	47	42	43	43	42	-32	-2.92%
Other Uses	4	4	3	4	3	3	3	3	3	3	-2	-2.79%
Other Primary Metals												
Total of All End Uses	129	129	126	131	130	132	130	133	134	134	-57	-1.85%
Boilers	4	4	4	4	4	4	4	4	4	4	-1	-1.03%
Process Heat	69	69	68	70	70	71	70	71	72	72	-33	-1.96%
Other Uses	55	55	54	56	56	57	55	57	58	58	-23	-1.76%

AGADIL02 11-19-2004 11:19

Expanded Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	2001-2010 Annual %Change
Other Manufacturing												
Total of All End Uses	869	837	770	766	762	721	733	750	767	782	-87	-1.17%
Boilers	358	348	334	340	342	342	347	352	357	361	3	0.10%
Process Heat	209	198	174	172	169	152	155	161	166	170	-39	-2.27%
Other Uses	303	290	262	253	250	226	231	238	244	251	-51	-2.04%
Non-Manufacturing												
Total of All End Uses	587	592	571	588	586	562	573	589	603	616	29	0.54%
Boilers	228	229	224	231	234	235	239	243	247	250	22	1.01%
Process Heat	96	98	92	93	91	86	88	91	93	95	-2	-0.20%
Other Uses	262	265	255	265	261	241	246	256	264	271	9	0.38%
Industrial Curtailments	**49**	**10**	**1**	**2**	**0**	**0**	**0**	**2**	**3**	**5**	**-44**	**-22.46%**

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	2001-2020 Annual %Change
	Regional Industrial Natural Gas Consumption (Bcf)											
Other Manufacturing												
Total of All End Uses	794	801	802	829	843	862	866	895	914	932	63	0.37%
Boilers	366	369	374	381	388	394	400	409	416	424	66	0.90%
Process Heat	172	174	173	181	184	188	188	196	200	205	-4	-0.10%
Other Uses	255	258	255	268	271	279	278	290	297	303	0	0.00%
Non-Manufacturing												
Total of All End Uses	625	631	631	652	660	671	674	691	701	711	124	1.02%
Boilers	253	256	259	262	266	269	272	276	280	283	55	1.15%
Process Heat	96	97	97	101	102	104	104	107	109	111	14	0.73%
Other Uses	275	278	275	288	292	298	297	307	312	317	55	1.01%
Industrial Curtailments	**6**	**5**	**6**	**4**	**6**	**2**	**3**	**3**	**2**	**4**	**-43**	**-10.41%**

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

																1999-2010
																Annual %
	Power Generation Capacity (GW)															
	1997	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Change**	**Change**
LOWER-48																
TOTAL	723.2	727.4	736.0	763.8	799.9	865.1	920.9	928.4	937.6	954.8	960.8	966.5	971.9	979.2	243.2	2.63%
OiL/GAS CAPACITY	215.1	218.9	229.1	256.4	291.4	352.6	405.0	408.8	413.5	426.0	427.9	429.8	431.7	433.6	204.5	5.97%
CT/CC ADDITIONS	*0.0*	2.1	10.5	35.9	76.6	144.2	202.7	212.6	223.3	236.1	241.0	246.0	250.9	255.8	245.4	33.73%
COAL CAPACITY	304.5	304.5	304.5	306.4	307.2	309.6	311.9	314.3	316.7	319.0	321.4	323.7	326.4	329.1	24.6	0.71%
NUCLEAR CAPACITY	96.5	96.5	96.5	96.5	96.5	96.6	96.6	97.1	98.5	99.8	100.8	101.5	101.4	102.0	5.5	0.51%
HYDRO CAPACITY	100.0	100.2	99.0	97.7	97.7	97.9	98.3	98.6	98.8	99.0	99.0	99.0	99.0	99.0	0.0	0.00%
OTHER CAPACITY	7.2	7.3	6.8	6.9	7.2	8.4	9.0	9.6	10.2	10.9	11.7	12.5	13.3	15.4	8.6	7.70%

AGAOIL02 11-132004 11:19

Expanded Policies Scenario

Power Generation Capacity (GW)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2010-2020 *Change*	2010-2020 *Annual % Change*	1999-2020 *Change*	1999-2020 *Annual % Change*
LOWER-48														
TOTAL CAPACITY	987.5	996.6	1006.8	1018.6	1029.3	1039.4	1048.8	1057.2	1065.9	1074.8	95.7	0.94%	338.9	1.82%
OIL/GAS CAPACITY	433.8	434.0	434.1	434.3	434.5	434.8	435.1	435.4	435.8	436.1	2.5	0.06%	206.9	3.11%
CT/CC ADDITIONS	259.1	262.3	265.5	268.7	271.9	275.3	278.6	282.0	285.3	288.7	32.8	1.21%	278.2	17.12%
COAL CAPACITY	333.4	337.8	342.2	346.6	350.9	355.5	360.2	364.8	369.4	374.0	45.0	1.29%	69.6	0.98%
NUCLEAR CAPACITY	102.3	102.8	103.5	104.5	105.0	106.5	107.8	107.9	107.9	107.9	5.9	0.56%	11.4	0.53%
HYDRO CAPACITY	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	0.0	0.00%	0.0	0.00%
OTHER CAPACITY	18.9	22.9	27.9	34.2	39.9	43.6	46.7	50.1	53.7	57.8	42.4	14.12%	51.0	10.71%

Expanded Policies Scenario

Power Generation Fossil Fuel Consumption (Quads) **1999-2010**

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Change	Annual % Change
LOWER-48																
FOSSIL FUEL CONSUMPTION	22.5	23.7	23.8	24.779	24.662	24.674	24.441	24.934	25.502	25.968	26.473	27.106	27.625	28.228	4.5	1.57%
GAS DEMAND	3.0	3.4	3.8	4.393	4.449	4.651	4.196	4.692	4.920	5.266	5.556	5.925	6.436	6.636	2.8	5.11%
Gas Curtailments	*0.0*	*0.0*	*0.0*	*0.010*	*0.039*	*0.006*	*0.000*	*0.002*	*0.000*	*0.000*	*0.000*	*0.002*	*0.002*	*0.002*	*0.0*	16.94%
Cogen Gas Use /1	*0.0*	*0.0*	*0.0*	*0.120*	*0.280*	*0.466*	*0.525*	*0.599*	*0.647*	*0.734*	*0.793*	*0.858*	*0.948*	*0.993*	*1.0*	40.44%
COAL DEMAND	18.7	19.1	19.0	19.491	19.235	19.536	19.714	20.002	20.295	20.393	20.614	20.851	20.967	21.322	2.3	1.06%
OIL DEMAND	0.8	1.2	1.0	0.895	0.978	0.487	0.531	0.240	0.287	0.310	0.302	0.330	0.221	0.270	-0.7	-10.80%

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

AGADIL02 11-19-2004 11:19

Expanded Policies Scenario

	Power Generation Fossil Fuel Consumption (Quads)										2010-2020		1999-2020	
												Annual %		*Annual %*
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	*Change*	*Change*	*Change*	*Change*
LOWER-48														
FOSSIL FUEL CONSUMPTION	28.854	29.624	30.111	30.676	31.225	31.890	32.388	33.038	33.704	34.516	6.3	2.03%	10.739	1.79%
GAS DEMAND	7.207	7.147	7.523	7.639	8.193	8.202	8.369	8.947	9.024	9.474	2.8	3.62%	5.637	4.40%
Gas Curtailments	0.002	0.002	0.001	0.002	0.007	0.003	0.003	0.005	0.002	0.006	0.0	10.30%	0.005	13.73%
Cogen Gas Use /1	1.088	1.089	1.158	1.184	1.282	1.288	1.341	1.425	1.447	1.521	0.5	4.35%	1.497	21.92%
COAL DEMAND	21.435	22.040	22.287	22.599	22.754	23.251	23.543	23.767	24.175	24.536	3.2	1.41%	5.546	1.23%
OIL DEMAND	0.213	0.437	0.301	0.438	0.278	0.438	0.476	0.324	0.504	0.506	0.2	6.47%	-0.444	-2.96%

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

AGAOIL02 11-19-2004 11:19

Energy and Environmental Analysis Inc.

Expanded Policies Scenario

Regional Natural Gas Balance (Annual Bcf)

United States/2,3	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1999-2010 Change	Annual Change
Total Consumption	21,990	21,363	22,358	23,269	21,547	22,417	21,495	21,986	22,066	22,023	22,538	23,258	24,143	24,636	2,277	0.89%
+Storage Injections/1	1,886	1,993	1,656	1,533	2,380	1,637	2,406	2,048	2,106	2,328	2,293	2,252	2,259	2,343	687	3.21%
+ LNG Injections	76	58	37	56	35	42	42	42	42	42	42	42	42	42	5	1.27%
+ Pipeline Exports																
+ Exports to Canada	529	435	539	581	789	735	882	819	784	814	829	874	920	905	366	4.83%
+ Exports to Mexico	33	48	55	100	140	266	340	409	512	461	212	240	240	272	218	15.73%
=Total Demand	24,513	23,896	24,644	25,540	24,893	25,097	25,165	25,304	25,510	25,668	25,915	26,666	27,604	28,198	3,554	1.23%
Total Production	19,207	18,862	18,922	19,088	19,383	18,734	18,528	18,414	18,415	18,622	18,815	19,010	19,048	19,020	97	0.05%
+ Supplemental Fuels	103	102	98	86	79	79	79	79	79	79	79	79	79	79	-19	-1.94%
+Storage Withdrawals/1	1,919	1,470	1,797	2,380	1,231	2,080	2,211	2,325	2,370	2,053	2,073	2,228	2,179	2,332	535	2.40%
+ LNG Withdrawals	68	52	36	51	35	40	40	40	40	40	40	40	40	40	3	0.80%
+ Net LNG Imports	16	20	100	160	169	164	464	807	1,047	1,487	1,578	1,984	2,673	3,293	3,193	37.41%
+ Ethane Rejection	5	39	7	0	102	0	87	5	0	11	6	0	0	0	-7	-100.00%
+ Pipeline Imports																
+ Imports from Canada	3,494	3,577	3,856	3,997	4,261	4,227	4,087	3,916	3,821	3,640	3,520	3,524	3,777	3,649	-207	-0.50%
+ Imports from Mexico	11	10	50			0	0	0	0	9	73	53	60	49	-2	-0.29%
=Total Supply	24,822	24,131	24,866	25,[illegible]	[illegible]	25,324	25,496	25,587	25,772	25,940	26,183	26,919	27,856	28,461	3,595	1.24%
Balancing Item	309	236	222	229	374	226	330	283	262	272	268	253	252	263	41	1.54%

1. Sum of net monthly storage injections/withdrawals.

2. Net LNG Imports line item does not include LNG imports at Baja.

3. Imports from Mexico line item includes LNG gas delivered to Baia that is export to the U.S.

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

Regional Natural Gas Balance (Annual Bcf)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2010-2020 Change	2010-2020 Annual % Change	1999-2020 Change	1999-2020 Annual % Change
United States/2,3														
Total Consumption	25,615	25,592	26,029	26,412	27,380	27,519	27,666	28,760	28,967	29,582	4,946	1.85%	7,224	1.34%
+Storage Injections/1	2,287	2,430	2,415	2,446	2,428	2,591	2,493	2,687	2,626	2,663	320	1.29%	1,008	2.29%
+ LNG Injections	42	42	42	42	42	42	42	42	42	42	0	0.00%	5	0.66%
+ Pipeline Exports														
+ Exports to Canada	864	855	865	1,132	2,320	2,343	2,470	3,091	3,103	3,114	2,208	13.15%	2,575	8.71%
+ Exports to Mexico	273	273	255	255	255	255	255	255	255	255	-17	-0.65%	200	7.62%
=Total Demand	29,080	29,192	29,607	30,288	32,426	32,750	32,925	34,834	34,993	35,656	7,458	2.37%	11,012	1.77%
Total Production	19,212	18,857	19,084	19,172	20,290	19,837	19,903	20,649	20,348	20,477	1,457	0.74%	1,555	0.38%
+ Supplemental Fuels	79	79	79	79	79	79	79	79	79	79	0	0.00%	-19	-1.02%
+Storage Withdrawals/1	2,357	2,573	2,289	2,464	2,303	2,705	2,516	2,513	2,765	2,640	307	1.25%	843	1.85%
+ LNG Withdrawals	40	40	40	40	40	40	40	40	40	40	0	0.12%	4	0.47%
+ Net LNG Imports	4,060	4,437	5,045	5,410	5,593	6,242	6,596	7,290	7,670	8,319	5,026	9.71%	8,220	23.44%
+ Ethane Rejection	0	16	13	0	0	1	3	0	0	0	0	NA	-7	-100.00%
+ Pipeline Imports														
+ Imports from Canada	3,531	3,423	3,245	3,331	4,369	4,058	4,011	4,515	4,334	4,343	695	1.76%	488	0.57%
+ Imports from Mexico	45	45	83	83	83	83	83	83	83	83	34	5.45%	33	2.40%
--Total Supply	29,323	29,469	29,877	30,579	32,756	33,045	33,231	35,169	35,319	35,981	7,520	2.37%	11,115	1.78%
Balancing Item	243	277	270	292	331	295	305	335	327	326	62	2.15%	103	1.83%

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports f[illegible]e item includes LNG gas delivered to Baja that is export to the U.S.

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

Gas Prices (Nominal $/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
Henry Hub														
1997	3.37	2.21	1.91	2.04	2.24	2.21	2.19	2.49	2.87	3.04	2.98	2.33	2.49	0.44
1998	2.11	2.22	2.23	2.44	2.13	2.16	2.20	1.85	1.99	1.89	2.09	1.68	2.08	0.19
1999	1.84	1.77	1.80	2.13	2.26	2.30	2.29	2.79	2.57	2.70	2.31	2.36	2.26	0.32
2000	2.41	2.66	2.78	3.02	3.58	4.30	4.05	4.39	5.02	5.03	5.49	8.69	4.29	1.65
2001	8.48	5.65	5.15	5.20	4.21	3.74	3.07	3.02	2.20	2.44	2.37	2.37	3.99	1.79
2002	2.32	2.28	3.02	3.39	3.52	3.22	3.04	3.13	3.55	4.13	4.06	4.74	3.37	0.68
2003	5.71	7.09	6.39	5.27	5.76	5.80	5.04	4.98	4.69	4.66	4.43	6.12	5.49	0.76
2004	6.05	5.40	5.38	4.41	5.61	5.71	7.07	6.38	5.64	4.92	5.72	5.82	5.68	0.64
2005	6.98	7.23	6.79	8.85	9.12	7.52	7.39	6.97	7.86	7.38	7.52	7.68	7.61	0.68
2006	8.69	8.70	7.86	6.92	8.47	7.10	7.11	6.85	8.03	7.23	7.40	7.53	7.66	0.65
2007	8.15	7.96	7.38	6.53	6.57	5.80	6.23	6.10	6.07	4.54	5.61	5.72	6.39	0.98
2008	6.22	6.15	5.63	6.31	6.77	5.86	6.43	6.18	5.79	5.08	5.72	5.84	6.00	0.42
2009	6.18	5.99	5.67	3.85	3.38	3.65	4.68	4.51	3.44	3.08	3.70	3.83	4.33	1.03
2010	4.35	4.19	3.71	6.01	6.41	5.21	4.84	4.97	5.30	4.08	4.88	4.95	4.91	0.75
2011	5.43	5.22	4.78	4.26	3.17	2.74	2.99	2.87	2.74	2.49	2.83	2.99	3.54	1.02
2012	3.89	4.16	3.60	6.08	7.50	7.17	7.40	6.93	7.51	6.67	7.11	7.22	6.27	1.43
2013	7.92	7.71	7.02	4.32	3.57	3.70	4.20	3.99	3.78	3.01	3.69	3.79	4.73	1.67
2014	4.77	4.83	4.28	6.50	6.77	6.14	6.29	5.80	6.30	5.87	6.02	6.15	5.81	0.74
2015	6.83	6.64	5.97	3[illegible]	[illegible]4	2.27	2.57	2. 63	2. 31	2.18	2.34	2.53	3.49	1.75
2016	3.43	3.58	2.93	5[illegible]	[illegible]7	6.79	7.71	7.30	6.92	5.82	6.77	6.91	5.82	1.58
2017	7.78	7.83	6.95	6.35	5.90	4.93	5.00	4.85	5.58	5.21	5.29	5.39	5.92	1.03
2018	6.08	5.98	5.28	3.68	3.31	3.28	4.27	4.12	3.15	3.63	3.63	3.80	4.18	0.99
2019	4.67	4.84	4.15	6.19	6.31	6.10	6.38	5.95	6.24	5.10	5.85	6.03	5.65	0.72
2020	6.74	6.76	6.04	5.62	5.87	5.24	5.50	5.09	4.68	4.34	4.77	4.98	5.47	0.74

AGAOIL02 11-19-2004 11:19

Expanded Policies Scenario

Gas Prices (2003$/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
Henry Hub														
1997	3.81	2.50	2.15	2.30	2.52	2.48	2.46	2.79	3.21	3.40	3.33	2.60	2.80	0.49
1998	2.35	2.47	2.48	2.72	2.36	2.40	2.44	2.04	2.20	2.09	2.31	1.86	2.31	0.22
1999	2.03	1.94	1.98	2.33	2.48	2.51	2.51	3.04	2.81	2.94	2.51	2.56	2.47	0.34
2000	2.61	2.87	3.00	3.24	3.83	4.60	4.33	4.69	5.35	5.35	5.84	9.21	4.58	1.73
2001	8.97	5.97	5.43	5.47	4.42	3.92	3.22	3.16	2.29	2.54	2.46	2.46	4.19	1.91
2002	2.40	2.36	3.12	3.48	3.62	3.30	3.11	3.19	3.62	4.20	4.12	4.80	3.44	0.68
2003	5.77	7.14	6.43	5.29	5.78	5.80	5.02	4.95	4.66	4.62	4.38	6.05	5.49	0.78
2004	5.96	5.31	5.28	4.32	5.48	5.57	6.88	6.20	5.47	4.76	5.53	5.61	5.53	0.62
2005	6.71	6.94	6.50	8.46	8.70	7.16	7.02	6.61	7.44	6.97	7.08	7.22	7.23	0.65
2006	8.15	8.14	7.34	6.45	7.88	6.59	6.59	6.33	7.41	6.66	6.80	6.91	7.11	0.63
2007	7.46	7.27	6.73	5.94	5.96	5.26	5.64	5.51	5.47	4.08	5.03	5.12	5.79	0.93
2008	5.56	5.48	5.00	5.60	5.99	5.18	5.67	5.44	5.09	4.45	5.00	5.10	5.30	0.39
2009	5.38	5.21	4.92	3.33	2.92	3.14	4.03	3.87	2.95	2.63	3.16	3.26	3.73	0.91
2010	3.70	3.56	3.14	5.08	5.40	4.38	4.06	4.16	4.43	3.41	4.06	4.11	4.12	0.63
2011	4.51	4.32	3.95	3.51	2.61	2.25	2.45	2.35	2.24	2.03	2.30	2.42	2.91	0.86
2012	3.14	3.36	2.90	4.89	6.02	5.74	5.92	5.53	5.98	5.30	5.63	5.71	5.01	1.13
2013	6.25	6.08	5.52	3.39	2.79	2.89	3.27	3.10	2.93	2.33	2.86	2.92	3.70	1.33
2014	3.67	3.71	3.29	4.97	5.17	4.68	4.79	4.40	4.77	4.43	4.54	4.63	4.42	0.55
2015	5.13	4.98	4_47	2.42	1.81	1.69	1.91	1.95	1.70	1.61	1.73	1.86	2.60	1.32
2016	2.51	2.62	2.14	3.83	4.70	4.93	5.58	5.27	4.99	4.19	4.86	4.95	4.21	1.12
2017	5.57	5.59	4.95	4.51	4.18	3.49	3.53	3.42	3.92	3.66	3.71	3.77	4.19	0.75
2018	4.24	4.17	3.66	2.5		2.27	2.94	2.83	2.16	2.49	2.48	2.59	2.89	0.70
2019	3.18	3.29	2.81	4.1		4.11	4.29	3.99	4.18	3.40	3.90	4.01	3.80	0.48
2020	4.47	4.48	3.99	3.71	3.86	3.44	3.61	3.33	3.06	2.83	3.10	3.23	3.59	0.51

AGADIL02 11-19-2004 11:19

APPENDIX III

EXISTING POLICIES SCENARIO

Existing Policies Scenario

	Regional Natural Gas Consumption (Bcf)															1999-2010
	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Change	Annual % Change
United States																
Total Consumption	21,990	21,363	22,359	23,270	21,548	22,419	21,497	21,996	22,094	21,978	22,540	23,170	23,577	23,961	1602	0.63%
Residential	4,983	4,393	4,651	4,958	4,688	4,810	5,037	5,038	5,091	5,106	5,147	5,238	5,278	5,363	711	1.30%
Commercial	3,222	2,928	3,070	3,240	3,067	3,123	3,191	3,153	3,170	3,142	3,154	3,210	3,241	3,312	243	0.69%
Industrial	8,904	8,828	8,944	8,828	7,496	7,995	7,196	7,253	7,033	6,548	6,670	6,775	6,795	6,713	-2231	-2.58%
Cogeneration/1	*1,481*	*1,474*	*1,492*	*1,471*	*1,179*	*1,249*	*1,116*	*1,124*	*1,092*	*997*	*1,009*	*1,025*	*1,024*	*1,011*	*-481*	*-3.48%*
Power Generation	2,963	3,340	3,766	4,288	4,315	4,543	4,107	4,597	4,858	5,232	5,588	5,943	6,251	6,529	2763	5.13%
Cogeneration/1	*0*	*0*	*24*	*120*	*280*	*466*	*525*	*600*	*655*	*749*	*821*	*887*	*951*	*1,017*	*993*	*40.75%*
Pipeline Fuel	697	662	708	726	737	729	754	747	735	740	764	779	784	807	99	1.20%
Lease & Plant	1,221	1,212	1,220	1,230	1,246	1,220	1,211	1,207	1,206	1,209	1,217	1,226	1,229	1,237	17	0.13%
Cogeneration Total	1,481	1,474	1,516	1,591	1,459	1,714	1,641	1,725	1,748	1,746	1,830	1,911	1,975	2,028	512	2.68%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL4b 11-30.2004 11:37

Existing Policies Scenario

	Regional Natural Gas Consumption (Bcf										2010-2020		1999-2020	
												Annual %		Annual %
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Change	Change	Change
United States														
Total Consumption	24,356	24,614	24,879	25,230	25,192	25,585	25,610	25,805	25,884	26,113	2152	0.86%	3754	0.74%
Residential	5,431	5,503	5,514	5,553	5,598	5,675	5,703	5,758	5,816	5,899	537	0.96%	1248	1.14%
Commercial	3,358	3,383	3,371	3,374	3,385	3,414	3,423	3,443	3,467	3,506	193	0.57%	436	0.63%
Industrial	6,627	6,585	6,535	6,549	6,464	6,464	6,512	6,543	6,534	6,522	-190	-0.29%	-2421	-1.49%
Cogeneration /1	*998*	*993*	*982*	*982*	*961*	*956*	*962*	*965*	*962*	*956*	*-55*	*-0.56%*	*-536*	*-2.10%*
Power Generation	6,882	7,057	7,352	7,621	7,601	7,861	7,799	7,874	7,882	7,986	1456	2.03%	4220	3.64%
Cogeneration/1	*1,096*	*1,149*	*1,214*	*1,270*	*1,279*	*1,329*	*1,332*	*1,351*	*1,364*	*1,388*	*371*	*3.16%*	*1365*	*21.39%*
Pipeline Fuel	811	825	838	856	864	884	886	896	892	903	96	1.13%	195	1.16%
Lease & Plant	1,247	1,262	1,270	1,277	1,281	1,287	1,287	1,290	1,292	1,297	60	0.47%	77	0.29%
Cogeneration Total	2,094	2,142	2,196	2,253	Z240	Z284	Z294	Z317	Z326	Z345	316	1.46%	828	2.10%

1. Cogeneration gas use is a part of both Industrial and Power Generation gas consumption. Cogeneration gas use for capacity constructed prior to 1999 is reported in the Industrial sector; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIL4b 11-30-2004 11:37

Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	Annual % Change
Total of All Industrial Sectors												
Total of All End Uses	7,545	8,005	7,197	7,255	7,035	6,549	6,672	6,777	6,796	6,715	-829	-1.29%
Boilers	2,479	2,573	2,424	2,501	2,463	2,434	2,518	2,550	2,582	2,560	81	0.36%
Process Heat	2,635	2,825	2,528	2,558	2,477	2,199	2,219	2,262	2,246	2,208	-427	-1.95%
Other Uses	1,752	1,850	1,661	1,672	1,631	1,484	1,501	1,526	1,523	1,507	-245	-1.66%
CogenGasUse/1	1,179	1,249	1,116	1,124	1,092	997	1,009	1,025	1,024	1,011	-168	-1.69%
Ammonia Feedstock	370	426	319	280	235	213	211	21 1	21 1	2W	-16-"	6.28%
Methanol Feedstock	157	173	102	78	56	41	40	40	40	35	-122	-15.36%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Food												
Total of All End Uses	599	623	586	585	581	540	545	554	557	559	-40	-0.76%
Boilers	223	229	226	229	231	229	234	236	238	238	15	0.72%
Process Heat	226	237	214	211	208	184	185	189	189	191	-35	-1.88%
Other Uses	150	158	146	145	142	126	127	129	130	131	-19	-1.53%
Paper												
Total of All End Uses	590	595	595	602	604	585	585	583	576	567	-23	-0.43%
Boilers	410	413		418	418	413	416	417	417	414	4	0.10%
Process Heat	55	55	[illegible]	56	56	52	51	50	48	46	-9	-1.86%
Other Uses	125	126	126	129	130	121	118	116	111	107	-18	-1.71%
Petroleum Refining												
Total of All End Uses	1,351	1,414	1,308	1,274	1,234	1,096	1,095	1,110	1,112	1,109	-242	-2.17%
Boilers	354	358	357	362	363	361	365	367	369	367	13	0.39%
Process Heat	797	846	759	727	693	584	580	590	591	589	-208	-3.31%
Other Uses	199	211	192	185	178	151	150	152	153	153	-47	-2.92%

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

Existing Policies Scenario

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	Annual %Change
Total of All Industrial Sectors												
Total of All End Uses	6,631	6,590	6,541	6,554	6,467	6,468	6,516	6,547	6,545	6,543	-1,002	-0.75%
Boilers	2,541	2,540	2,555	2,571	2,580	2,603	2,623	2,645	2,660	2,681	202	0.41%
Process Heat	2,160	2,130	2,079	2,072	2,003	1,982	1,994	1,993	1,975	1,953	-682	-1.56%
Other Uses	1,490	1,481	1,462	1,463	1,430	1,423	1,432	1,436	1,430	1,421	-330	-1.09%
Cogen Gas Use /1	998	993	982	982	961	956	962	965	962	956	-223	-1.10%
Ammonia Feedstock	200	205	205	205	205	205	205	205	205	205	-165.	3.06%
Methanol Feedstock	28	24	21	20	18	17	17	16	16	15	-142	-11.64%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Food												
Total of All End Uses	561	562	555	557	549	546	550	551	550	547	-52	-0.48%
Boilers	237	239	241	242	245	246	248	251	252	255	32	0.70%
Process Heat	192	192	186	186	180	178	179	179	176	174	-53	-1.38%
Other Uses	132	131	128	128	124	122	123	122	121	119	-31	-1.21%
Paper												
Total of All End Uses	558	554	550	546	543	541	539	538	536	534	-56	-0.52%
Boilers	411	411		[illegible]	411	411	412	412	412	412	2	0.03%
Process Heat	44	43		[illegible]	40	39	38	38	37	37	-18	-2.08%
Other Uses	103	100	97	95	92	91	89	88	87	85	-40	-1.99%
Petroleum Refining												
Total of All End Uses	1,102	1,104	1,079	1,075	1,038	1,020	1,025	1,025	1,015	1,001	-350	-1.57%
Boilers	366	367	369	370	372	373	375	376	377	379	25	0.36%
Process Heat	584	585	564	560	530	514	517	515	506	493	-304	-2.50%
Other Uses	151	151	146	145	137	133	134	134	132	129	-70	-2.26%

Regional Industrial Natural Gas Consumption (Bcf)

1. Cogeneration gas use is a part of Other Uses. Cogeneration gas use reported here is only for cogen capacity constructed prior to 1999; gas consumption from capacity constructed from 1999 forward is reported in the Power Generation sector.

AGAOIUb

Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2001-2010 Change	2001-2010 %Change
Chemicals												
Total of All End Uses	2,602	2,986	2,470	2,510	2,344	2,227	2,337	2,387	2,410	2,337	-264	-1.18%
Boilers	822	910	781	828	781	765	824	842	865	845	23	0.31%
Process Heat	549	676	568	605	572	531	560	577	573	543	-6	-0.13%
Other Uses	551	643	538	552	529	500	519	529	527	509	-42	-0.88%
Ammonia Feedstock	370	426	319	280	235	213	211	211	211	206	-164	-6.28%
Methanol Feedstock	157	173	102	78	56	41	40	40	40	35	-122	-15.36%
Hydrogen Feedstock	152	157	162	167	172	177	182	188	193	199	47	3.05%
Stone, Clay and Glass												
Total of All End Uses	349	369	340	344	344	310	313	324	327	332	-16	-0.54%
Boilers	17	18	17	18	18	18	19	19	19	20	2	1.51%
Process Heat	287	303	278	282	281	252	254	263	266	270	-17	-0.70%
Other Uses	44	47	44	44	45	40	40	42	42	43	-1	-0.37%
Iron and Steel												
Total of All End Uses	318	334	338	368	368	338	330	326	314	303	-15	-0.54%
Boilers	50	53	56	60	60	59	60	61	61	60	10	2.05%
Process Heat	237	248	248	272	271	245	238	234	223	214	-23	-1.14%
Other Uses	31	33	34	36	37	33	32	32	30	29	-2	-0.73%
Primary Aluminum												
Total of All End Uses	89	85	82		80	71	70	71	67	63	-26	-3.81%
Boilers	11	11	11	11	11	11	11	11	11	11	0	0.11%
Process Heat	73	70	67	66	65	56	55	56	52	49	-25	-4.47%
Other Uses	5	5	5	5	5	4	4	4	4	4	-2	-4.26%
Other Primary Metals												
Total of All End Uses	191	169	137	137	134	117	116	118	118	118	-73	-5.21%
Boilers	5	5	4	4	4	4	4	4	4	4	-1	-2.57%
Process Heat	105	93	74	74	72	63	62	63	63	63	-42	-5.49%
Other Uses	81	72	59	58	57	50	50	51	51	51	-30	-5.05%

AGAGIUb 1130-2004 11:37

Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Annual Change	2001-2020 Annual %Change
Chemicals												
Total of All End Uses	2,278	2,248	2,252	2,261	2,249	2,275	2,297	2,320	2,333	2,351	-250	-0.53%
Boilers	829	818	822	825	820	831	837	844	845	849	27	0.17%
Process Heat	517	504	502	503	495	501	507	512	515	519	-30	-0.30%
Other Uses	493	486	484	484	480	483	487	491	493	495	-56	-0.56%
Ammonia Feedstock	205	205	205	205	205	205	205	205	205	205	-165	-3.06%
Methanol Feedstock	28	24	21	20	18	17	17	16	16	15	-142	-11.64%
Hydrogen Feedstock	205	211	218	224	231	238	245	252	260	268	116	3.02%
Stone, Clay and Glass												
Total of All End Uses	327	319	312	314	307	307	312	313	313	312	-36	-0.58%
Boilers	20	20	20	21	21	22	22	22	23	23	6	1.56%
Process Heat	265	257	251	252	247	246	250	251	250	249	-38	-0.74%
Other Uses	42	41	40	40	40	40	40	40	40	40	-4	-0.54%
Iron and Steel												
Total of All End Uses	294	287	280	276	269	265	263	259	256	252	-66	-1.22%
Boilers	60	60	60	60	60	60	60	60	60	61	11	1.02%
Process Heat	206	200	194	190	184	181	178	175	172	168	-69	-1.78%
Other Uses	28	27	26		25	25	24	24	23	23	-8	-1.56%
Primary Aluminum												
Total of All End Uses	58	54	51	49	46	44	43	42	41	40	-50	-4.19%
Boilers	11	11	11	11	10	10	10	10	10	10	0	-0.17%
Process Heat	44	40	38	36	33	32	31	30	29	27	-46	-5.08%
Other Uses	3	3	3	3	2	2	2	2	2	2	-3	-4.95%
Other Primary Metals												
Total of All End Uses	116	110	104	103	97	95	94	91	89	86	-106	-4.15%
Boilers	4	4	4	4	4	4	4	4	4	4	-1	-1.17%
Process Heat	62	59	55	54	51	50	49	48	47	45	-60	-4.39%
Other Uses	50	47	45	44	42	40	40	39	38	36	-44	-4.11%

AGAOIL4b 11•30•2004 11:37

Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)											2001-2010	
											Annual	
U.S. Total	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Change**	**%Change**
Other Manufacturing												
Total of All End Uses	869	837	770	765	760	710	718	730	735	741	-128	-1.76%
Boilers	358	348	334	340	342	340	346	350	354	355	-3	-0.10%
Process Heat	209	198	174	172	168	149	149	153	153	155	-53	-3.23%
Other Uses	303	290	261	253	249	221	222	227	228	231	-72	-2.96%
Non-Manufacturing												
Total of All End Uses	587	592	571	588	585	555	563	575	581	586	-1	-0.02%
Boilers	228	229	224	231	234	233	238	242	245	246	18	0.85%
Process Heat	96	98	92	93	91	64	85	87	88	89	-8	-0.94%
Other Uses	262	265	255	265	260	237	240	245	247	251	-11	-0.48%
Industrial Curtailments	49	10	1	2	1	0	1	2	1	3	-46	-26.92%

AGAOIL4b 11•30-2004 11:37

Existing Policies Scenario

Regional Industrial Natural Gas Consumption (Bcf)

U.S. Total	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2001-2020 Change	Annual %Change
Other Manufacturing												
Total of All End Uses	747	756	753	761	755	758	769	776	779	783	-86	-0.55%
Boilers	357	361	366	371	377	383	390	397	404	412	54	0.75%
Process Heat	157	159	156	157	152	150	152	152	151	149	-60	-1.77%
Other Uses	233	236	231	233	227	224	227	227	225	222	-80	-1.61%
Non-Manufacturing												
Total of All End Uses	590	597	606	613	613	615	623	630	634	637	50	0.43%
Boilers	247	249	252	255	259	262	265	268	272	275	47	0.99%
Process Heat	89	90	91	93	92	91	92	93	93	93	-4	-0.22%
Other Uses	254	258	262	265	263	262	266	269	270	269	7	0.14%
Industrial Curtailments	4	5	6	5	3	3	3	4	12	20	-46	-13.18%

AGAOIL4b 11-30-2004 11:37

Existing Policies Scenario

Power Generation Capacity (GW)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Change	1999-2010 Annual % Change
LOWER-48																
TOTAL CAPACITY	723.2	727.4	736.0	763.8	799.9	865.0	920.8	927.8	935.7	951.5	956.5	961.6	965.9	972.0	236.0	2.56%
OIL/GAS CAPACITY	215.1	218.9	229.1	256.4	291.4	352.6	405.0	408.8	413.5	426.0	427.9	429.8	431.7	433.6	204.5	5.97%
CT/CC ADDITIONS	0.0	2.1	10.5	35.9	76.6	144.2	202.7	212.6	223.3	236.1	241.0	246.0	250.9	255.8	245.4	33.73%
COAL CAPACITY	304.5	304.5	304.5	306.4	307.2	309.6	311.9	314.3	316.7	319.0	321.4	323.7	326.4	329.1	24.6	0.71%
NUCLEAR CAPACITY	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	96.5	95.4	95.4	-1.1	-0.10%
HYDRO CAPACITY	100.0	100.2	99.0	97.7	97.7	97.9	98.3	98.6	98.8	99.0	99.0	99.0	99.0	99.0	0.0	0.00%
OTHER CAPACITY	7.2	7.3	6.8	6.9	7.2	8.4	9.0	9.6	10.2	10.9	11.7	12.5	13.3	14.9	8.1	7.35%

AGAOIL4b 11-30.2004 11:37

Existing Policies Scenario

	Power Generation Capacity (GW)										2010-2020		1999-2020	
												Annual %		Annual %
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Change	Change	Change
LOWER-48														
TOTAL CAPACITY	977.0	982.2	987.7	993.5	999.6	1013.3	1027.4	1042.1	1056.6	1072.5	100.5	0.99%	336.5	1.81
OIL/GAS CAPACITY	436.5	439.4	442.2	445.1	447.9	451.6	455.3	458.9	462.6	466.3	32.6	0.73%	237.1	3.44%
CT/CC ADDITIONS	*261.8*	*267.7*	*273.5*	*279.4*	*285.3*	*292.1*	*298.8*	*305.5*	*312.1*	*318.9*	*63.0*	*2.23%*	*308.4*	*17.67%*
COAL CAPACITY	329.5	329.8	330.2	330.6	331.0	337.7	344.5	351.2	357.3	364.0	35.0	1.01%	59.6	0.85%
NUCLEAR CAPACITY	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	0.0	0.00%	-1.1	-0.05%
HYDRO CAPACITY	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	99.0	0.0	0.00%	0.0	0.00%
OTHER CAPACITY	16.6	18.6	20.8	23.4	26.3	29.5	33.3	37.5	42.3	47.8	32.9	12.37%	40.9	9.71%

AGAOIL4b 1130-2004 11:37

Existing Policies Scenario

Power Generation Fossil Fuel Consumption (Quads)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1999-2010 Change	Annual % Change
LOWER-48																
FOSSIL FUEL CONSUMPTION	22.5	23.7	23.8	24.779	24.662	24.675	24.446	24.955	25.602	26.180	26.754	27.458	28.049	28.700	4.9	1.73%
GAS DEMAND	3.0	3.4	3.8	4.393	4.449	4.652	4.196	4.701	4.967	5.351	5.717	6.083	6.397	6.684	2.8	5.18%
Gas Curtailments	0.0	0.0	0.0	0.010	0.039	0.006	0.000	0.002	0.001	0.000	0.001	0.002	0.000	0.001	0.0	12.04%
Cogen Gas Use /1	0.0	0.0	0.0	0.120	0.280	0.466	0.525	0.600	0.655	0.749	0.821	0.887	0.951	1.017	1.0	40.75%
COAL DEMAND	18.7	19.1	19.0	19.491	19.235	19.537	19.719	20.011	20.339	20.492	20.714	20.982	21.219	21.496	2.5	1.13%
OIL DEMAND	0.8	1.2	1.0	0.895	0.978	0.487	0.531	0.243	0.296	0.336	0.323	0.393	0.432	0.519	-0.4	-5.35%

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.

AGAOIL4b 11-30.2004 11:37

Existing Policies Scenario

	Power Generation Fossil Fuel Consumption (Quads)										2010-2020		1999-2020	
												Annual %		Annual %
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	Change	Change	Change
LOWER-48														
FOSSIL FUEL CONSUMPTION	29.375	30.018	30.516	31.093	31.669	32.386	32.963	33.630	34.278	35.059	6.4	2.02%	11.283	1.87%
GAS DEMAND	7.048	7.229	7.533	7.809	7.783	8.049	7.984	8.060	8.076	8.192	1.5	2.05%	4.355	3.68%
Gas Curtailments	0.002	0.005	0.006	0.006	0.003	0.003	0.003	0.003	0.013	0.023	0.0	33.09%	0.023	21.61%
Cogen Gas Use /1	1.096	1.149	1.214	1.270	1.279	1.329	1.332	1.351	1.364	1.388	0.4	3.16%	1.365	21.39%
COAL DEMAND	21.728	21.858	21.950	21.960	22.037	22.351	22.727	23.162	23.575	24.067	2.6	1.14%	5.077	1.13%
OIL DEMAND	0.600	0.931	1.032	1.324	1.848	1.986	2.253	2.407	2.627	2.801	2.3	18.36%	1.851	5.28%

1. Cogeneration gas use is a part of total Gas Demand. Cogeneration gas use reported here is only for cogen capacity constructed in 1999 and thereafter; gas consumption from capacity constructed prior to 1999 is reported in the Industrial sector.
AGAOIL4b 11•30.2004 11:37

Existing Policies Scenario

Regional Natural Gas Balance (Annual Bcf)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1999-2010 Change	Annual % Change
United States/2,3																
Total Consumption	21,990	21,363	22,358	23,269	21,547	22,417	21,495	21,993	22,091	21,975	22,538	23,168	23,575	23,959	1,601	0.63%
+Storage Injections/1	1,886	1,993	1,656	1,533	2,380	1,637	2,406	2,045	2,102	2,318	2,291	2,244	2,287	2,241	586	2.79%
+ LNG Injections	76	58	37	56	35	42	42	42	42	42	42	42	42	42	5	1.27%
+ Pipeline Exports																
+ Exports to Canada	529	435	539	581	789	735	883	819	784	810	832	872	892	910	371	4.87%
+ Exports to Mexico	33	48	55	100	140	266	340	409	512	461	212	240	240	272	218	15.73%
=Total Demand	24,513	23,896	24,644	25,540	24,893	25,098	25,165	25,309	25,531	25,605	25,915	26,567	27,035	27,424	2,781	0.98%
Total Production	19,207	18,862	18,922	19,088	19,383	18,734	18,528	18,415	18,389	18,512	18,795	18,969	19,052	19,201	279	0.13%
+ Supplemental Fuels	103	102	98	86	79	79	79	79	79	79	79	79	79	79	-19	-1.94%
+ Storage Withdrawals/1	1,919	1,470	1,797	2,380	1,231	2,080	2,211	2,328	2,391	2,047	2,025	2,249	2,203	2,325	528	2.37%
+LNGWithdrawals	68	52	36	51	35	40	40	40	40	40	40	40	40	40	3	0.80%
+ Net LNG Imports	16	20	100	160	169	164	464	807	1,047	1,487	1,578	1,765	1,870	1,870	1,770	30.52%
+ Ethane Rejection	5	39	7	0	102	0	87	5	0	23	17	11	6	62	55	21.93%
+ Pipeline Imports																
+ Imports from Canada	3,494	3,577	3,856	3,997	4,261	4,227	4,087	3,918	3,835	3,692	3,580	3,661	3,996	4,086	230	0.53%
+ Imports from Mexico	11	10	50	6	7	0	0	0	0	9	73	53	60	49	-2	-0.29%
=Total Supply	24,822	24,131	24,866	25,769	25,266	25,324	25,496	25,592	25,781	25,889	26,186	26,827	27,306	27,711	2,844	0.99%
Balancing Item	309	236	222	229	374	226	331	283	249	283	270	260	271	286	64	2.32%

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

AGAOM4 11-30-2004 11:37

Existing Policies Scenario

Regional Natural Gas Balance (Annual Bcf)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Change	2010-2020 Annual % Change	Change	1999-2020 Annual % Change
United States/2,3														
Total Consumption	24,354	24,612	24,877	25,228	25,190	25,583	25,608	25,803	25,882	26,111	2,152	0.86%	3,753	0.74%
+ Storage Injections/1	2,233	2,371	2,278	2,307	2,400	2,339	2,402	2,368	2,429	2,434	193	0.83%	779	1.85%
+ LNG Injections	42	42	42	42	42	42	42	42	42	42	0	0.00%	5	0.66%
+ Pipeline Exports														
+ Exports to Canada	903	895	913	920	918	923	928	948	926	925	16	0.17%	386	2.61%
+ Exports to Mexico	273	273	255	255	255	255	255	255	255	255	-17	-0.65%	200	7.62%
=Total Demand	27,805	28,194	28,366	28,752	28,805	29,142	29,236	29,415	29,533	29,768	2,343	0.82%	5,124	0.90%
Total Production	19,414	19,717	19,882	20,049	20,152	20,271	20,294	20,366	20,418	20,528	1,327	0.67%	1,606	0.39%
+ Supplemental Fuels	79	79	79	79	79	79	79	79	79	79	0	0.00%	-19	-1.02%
+ Storage Withdrawals/1	2,356	2,311	2,282	2,323	2,297	2,333	2,360	2,372	2,435	2,497	172	0.72%	700	1.58%
+ LNG Withdrawals	40	40	40	40	40	40	40	40	40	40	0	0.12%	4	0.47%
+ Net LNG Imports	1,870	1,875	1,870	1,870	1,870	1,875	1,870	1,870	1,870	1,875	5	0.03%	1,775	14.99%
+ Ethane Rejection	109	170	187	214	270	270	291	309	347	372	310	19.67%	365	20.85%
+ Pipeline Imports														
+ Imports from Canada	4,207	4,324	4,346	4,512	4,534	4,663	4,713	4,787	4,805	4,869	783	1.77%	1,013	1.12%
+ Imports from Mexico	45	45	83	83	83	83	83	83	83	83	34	5.45%	33	2.40%
=Total Supply	28,119	28,560	28,768	29,169	29,324	29,615	29,730	29,906	30,076	30,343	2,632	0.91%	5,476	0.95%
Balancing Item	314	366	403	417	519	473	495	491	543	575	289	7.23%	353	4.63%

1. Sum of net monthly storage injections/withdrawals.
2. Net LNG Imports line item does not include LNG imports at Baja.
3. Imports from Mexico line item includes LNG gas delivered to Baja that is export to the U.S.

AGAOIL4b 11-30-2004 11:37

Existing Policies Scenario

Gas Prices (Nominal $/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
Henry Hub														
1997	3.37	2.21	1.91	2.04	2.24	2.21	2.19	2.49	2.87	3.04	2.98	2.33	2.49	0.44
1998	2.11	2.22	2.23	2.44	2.13	2.16	2.20	1.85	1.99	1.89	2.09	1.68	2.08	0.19
1999	1.84	1.77	1.80	2.13	2.26	2.30	2.29	2.79	2.57	2.70	2.31	2.36	2.26	0.32
2000	2.41	2.66	2.78	3.02	3.58	4.30	4.05	4.39	5.02	5.03	5.49	8.69	4.29	1.65
2001	8.48	5.65	5.15	5.20	4.21	3.74	3.07	3.02	2.20	2.44	2.37	2.37	3.99	1.79
2002	2.32	2.28	3.02	3.39	3.52	3.22	3.04	3.13	3.55	4.13	4.06	4.74	3.37	0.68
2003	5.71	7.09	6.39	5.27	5.76	5.80	5.04	4.98	4.69	4.66	4.43	6.12	5.49	0.76
2004	6.05	5.40	5.38	4.42	5.62	5.73	7.08	6.38	5.68	4.95	5.75	5.85	5.69	0.64
2005	7.02	7.29	6.86	8.92	9.16	7.62	7.48	7.07	8.02	7.52	7.67	7.86	7.71	0.68
2006	8.93	9.02	8.20	7.34	9.04	7.81	7.76	7.48	8.59	7.66	7.93	8.07	8.15	0.58
2007	8.69	8.48	7.92	6.30	6.28	5.88	6.36	6.29	6.14	4.51	5.70	5.80	6.53	1.17
2008	6.38	6.34	5.78	7.15	7.65	6.97	7.48	7.23	6.97	5.85	6.72	6.84	6.78	0.57
2009	7.38	7.20	6.70	6.12	5.94	5.94	6.60	6.44	6.38	5.40	6.14	6.23	6.37	0.52
2010	6.83	6.69	6.15	8.29	9.01	7.96	7.70	7.75	8.42	6.59	7.49	7.74	7.55	0.81
2011	8.40	8.33	7.71	8.75	8.73	8.10	8.50	8.24	8.76	7.51	8.24	8.35	8.30	0.37
2012	9.14	9.23	8.54	8.61	9.92	9.71	9.81	9.66	9.83	9.29	9.61	9.74	9.43	0.45
2013	10.32	10.23	9.64	9.49	9.74	9.75	9.92	9.84	9.86	8.50	9.41	9.58	9.69	0.44
2014	10.19	10.17	9.69	10.41	10.91	10.21	10.24	10.25	10.58	10.31	10.37	10.54	10.32	0.28
2015	11.15	11.21	10.60	11.15	12.00	11.47	11.58	11.32	11.83	10.83	11.11	11.47	11.31	0.38
2016	11.86	11.95	11.35	11.17	11.79	11.36	11.54	11.28	11.25	10.53	11.04	11.18	11.36	0.38
2017	11.77	11.78	11.16	[illegible]	2.95	12.01	12.22	11.77	12.17	11.19	11.71	11.84	11.91	0.47
2018	12.38	12.40	11.79	[illegible]	3.32	12.61	13.11	12.18	12.35	11.67	12.07	12.20	12.32	0.49
2019	12.81	12.87	12.25	[illegible]	4.29	13.64	13.65	12.70	13.71	12.08	12.86	12.98	13.15	0.66
2020	13.61	13.76	13.11	14.09	15.02	14.07	14.29	13.15	14.10	12.96	13.41	13.57	13.76	0.56

AGAOIL4b 11-30-2004 11:37

Existing Policies Scenario

Gas Prices (2003$/MMBtu)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	AVG	Std Dev
Henry Hub														
1997	3.81	2.50	2.15	2.30	2.52	2.48	2.46	2.79	3.21	3.40	3.33	2.60	2.80	0.49
1998	2.35	2.47	2.48	2.72	2.36	2.40	2.44	2.04	2.20	2.09	2.31	1.86	2.31	0.22
1999	2.03	1.94	1.98	2.33	2.48	2.51	2.51	3.04	2.81	2.94	2.51	2.56	2.47	0.34
2000	2.61	2.87	3.00	3.24	3.83	4.60	4.33	4.69	5.35	5.35	5.84	9.21	4.58	1.73
2001	8.97	5.97	5.43	5.47	4.42	3.92	3.22	3.16	2.29	2.54	2.46	2.46	4.19	1.91
2002	2.40	2.36	3.12	3.48	3.62	3.30	3.11	3.19	3.62	4.20	4.12	4.80	3.44	0.68
2003	5.77	7.14	6.43	5.29	5.78	5.80	5.02	4.95	4.66	4.62	4.38	6.05	5.49	0.78
2004	5.96	5.31	5.28	4.33	5.49	5.59	6.89	6.20	5.51	4.79	5.55	5.64	5.55	0.62
2005	6.75	6.99	6.57	8.52	8.74	7.25	7.10	6.71	7.59	7.10	7.23	7.39	7.33	0.65
2006	8.37	8.44	7.67	6.84	8.41	7.26	7.19	6.91	7.93	7.06	7.29	7.40	7.56	0.56
2007	7.95	7.75	7.22	5.73	5.70	5.33	5.75	5.67	5.53	4.05	5.11	5.19	5.92	1.10
2008	5.70	5.65	5.14	6.34	6.77	6.16	6.60	6.36	6.13	5.13	5.88	5.98	5.99	0.50
2009	6.43	6.26	5.81	5.30	5.14	5.12	5.68	5.53	5.46	4.62	5.24	5.31	5.49	0.48
2010	5.81	5.67	5.21	7.00	7.59	6.70	6.46	6.49	7.04	5.50	6.24	6.43	6.34	0.67
2011	6.96	6.90	6.37	7.21	7.18	6.65	6.97	6.74	7.14	6.11	6.70	6.77	6.81	0.32
2012	7.39	7.45	6.88	6.93	7.96	7.78	7.84	7.70	7.82	7.38	7.62	7.71	7.54	0.33
2013	8.15	8.06	7.58	7.45	7.62	7.62	7.73	7.66	7.66	6.59	7.27	7.39	7.56	0.38
2014	7.85	7.81	7.43	7.96	8.33	7.78	7.79	7.78	8.01	7.79	7.82	7.93	7.86	0.20
2015	8.38	8.40	7.93	8.33		8.53	8.59	8.38	8.74	7.98	8.17	8.43	8.40	0.28
2016	8.69	8.74	8.29	8.14		8.24	8.36	8.15	8.11	7.58	7.93	8.01	8.23	0.32
2017	8.41	8.41	7.95	8.78	9.19	8.50	8.63	8.30	8.56	7.86	8.20	8.28	8.42	0.34
2018	8.64	8.63	8.19	8.16	9.22	8.71	9.04	8.37	8.48	7.99	8.25	8.32	8.50	0.35
2019	8.72	8.74	8.30	9.43	9.64	9.19	9.17	8.52	9.18	8.07	8.58	8.64	8.85	0.45
2020	9.04	9.12	8.67	9.29	9.89	9.24	9.37	8.61	9.21	8.45	8.72	8.81	9.03	0.39

AGAOIL4b 11-30-2004 1137

EA 2000-01 **February 11, 2000**

PATTERNS IN RESIDENTIAL NATURAL GAS CONSUMPTION SINCE 1980

I. Introduction

Nationally, natural gas use per residential customer dropped 16 percent from 1980 to 1997 from 106 thousand cubic feet (Mcf)/year to 89 Mcf/year (numbers adjusted to reflect normal weather). The purpose of this analysis is to quantify the primary factors contributing to this decline on both a national and a regional basis. This analysis also provides a starting point for a separate AGA-funded study on methods for local gas utilities to counteract this declining use trend – a trend likely to continue for the foreseeable future. Residential use per customer is likely to fall at least another five percent over the next ten to 15 years.

II. Executive Summary

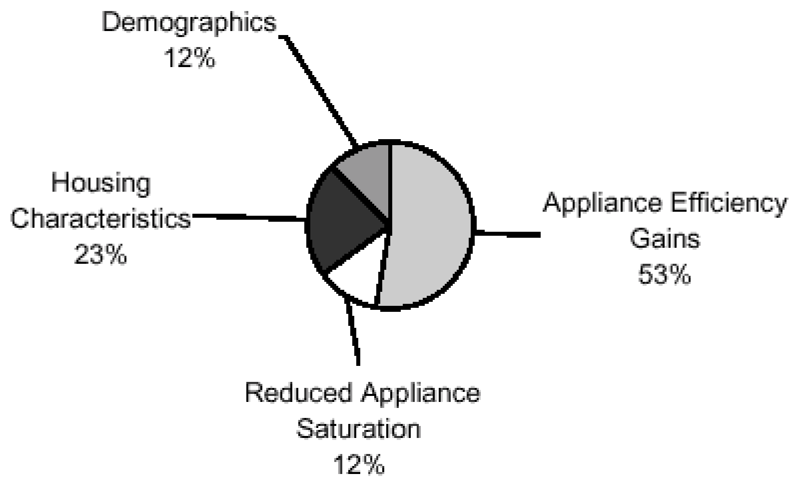
The primary cause of the declining use trend was increasing efficiency of gas appliances, primarily space heaters. Other factors include a reduction in the number of gas appliances in homes served with gas and tighter, more energy efficient homes. Chart 1 shows the estimated proportional impact of the various factors contributing to this decline on a national basis.

- Significant regional variation was observed. There was a decline in the use per customer in all regions of the country except for the Northeast, which gained 0.6 Mcf/year comparing 1997 to 1980. The South lost 15.0 Mcf/year, the West 19.2 Mcf/year, and the Midwest 25.4 Mcf/year (Table 1). Graphical representation of some of the factors contributing to these trends can be seen in Chart 2.

Chart 1

Factors Contributing to Declining Natural Gas Use per Residential Customer

(Estimate of Proportional Impacts Based on U.S. Average for 1980-1997)



- **Space heating efficiency gains** contributed almost half of the residential load loss. In 1980, the average furnace efficiency was slightly higher than 65 percent. Since then, federal regulations set the minimum gas space heating efficiency at 78 percent, and consumers can purchase units with efficiency ratings up to the mid-90s. The current weighted average gas space heating appliance efficiency for all units in place is estimated at roughly 74 percent.

- **Water heating efficiency gains** contributed about seven percent of the average residential load loss. During the 1980's, the typical water heater energy factor (EF) was 0.50. Federal water heater standards took effect in 1990, setting the minimum gas water heater EF at 0.54. In addition, consumers are purchasing units with EF ratings higher than 0.54. The current weighted average gas water heating EF is estimated to be slightly less than 0.53.

- **Space heating market share loss** accounted for about six percent of the overall decrease in gas use per residential customer. The proportion of homes with gas service increased slightly since 1980, but the percentage of those homes with gas space heat declined four percent. Thus the relative heating base of gas utilities declined.

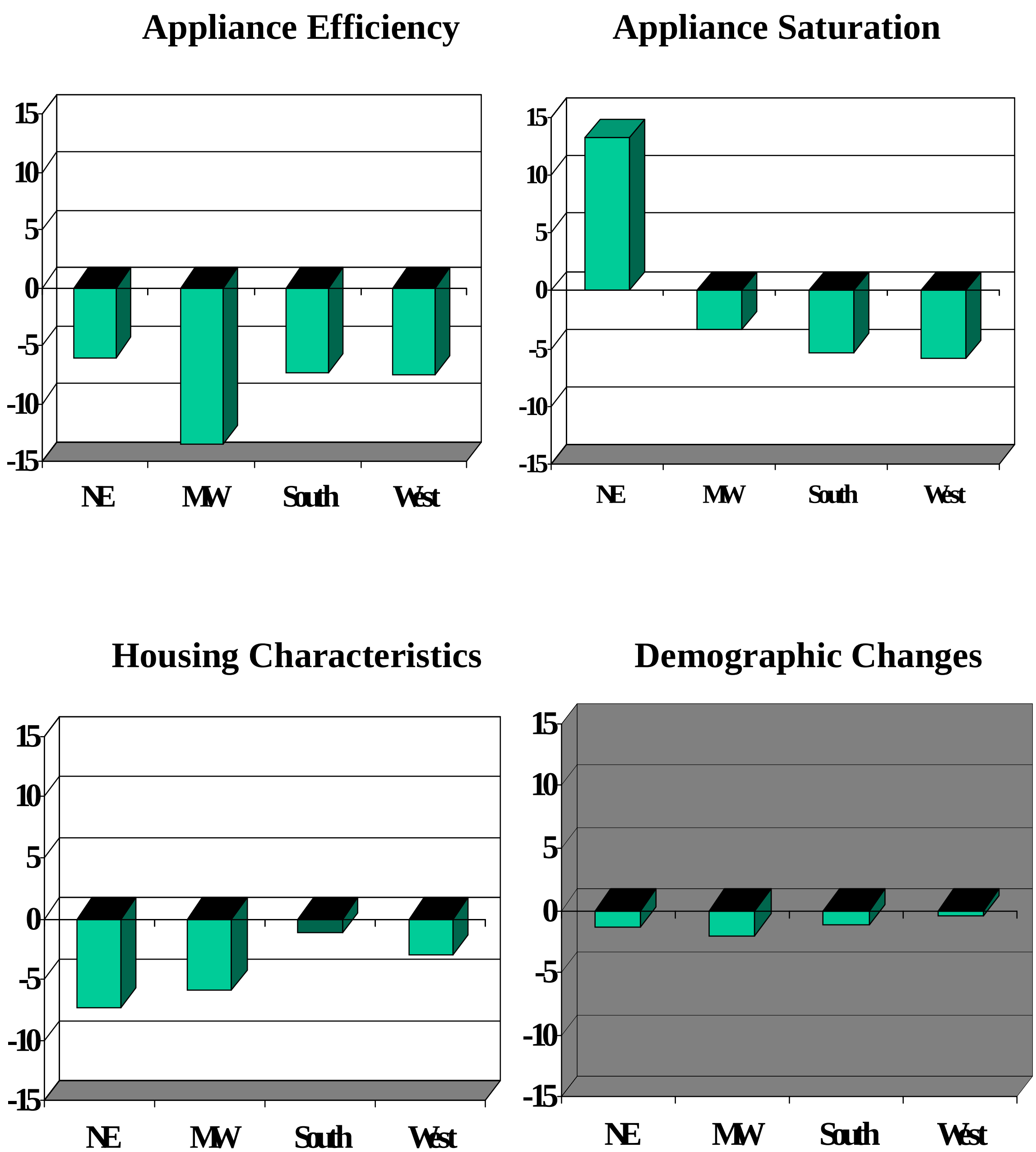
    - The market share loss in the South and West was three to five times as great as the national average. In the Northeast, however, there was a significant <u>increase</u> in use per customer as homes heated primarily with oil converted to natural gas (see Chart 2).

- **Baseload appliance market share loss** accounted for about six percent of the residential load loss since 1980. Overall, the number of gas appliances per customer has declined. The market share loss for water heaters, cooking appliances, and gas lights contributed about the same toward the overall decline. Saturation of natural gas clothes dryers increased a bit, slightly offsetting this decline.

Chart 2

Regional Impact of Major Factors

(Change in Mcf/year per residential customer, 1980 - 1997)



Note: Contributing factors are calculated independently and may not total to actual change

- **Improved home energy efficiency** was responsible for about 23 percent of the decline. Newer homes with improved thermal envelope characteristics, as well as older homes adding insulation and storm windows/doors, reduced the typical amount of gas needed for space heating. This caused overall use to fall by about 18 percent. In addition, the amount of heated floor space per residence declined, reducing overall demand by about five percent.

- **Demographic changes** contributed about 12 percent of the decline in typical residential gas use. Population shifts of gas customers to warmer climates since 1980 contributed about six percent of the residential load loss when viewed from a national perspective. The average number of people per residence fell slightly, causing a three percent decline in consumption. In addition, the number of households setting back their thermostats at night increased, contributing about three percent of the overall loss.

Reduction in the average gas use per residential customer will continue into the foreseeable future.

- **Space heating efficiency gains** will reduce average gas demand by at least an additional four percent over the next ten to 15 years as older furnaces are replaced with units that at least meet federal minimum standards.

- **Gas water heater efficiency gains** will cause residential demand to fall about one percent as older units are replaced.

- **Residential thermal efficiency** will continue to improve as newer, better-insulated residences replace older, less efficient homes. Currently, about 40 percent of existing residences were built before 1960.

This reduction in natural gas demand per customer has impacted gas utility companies.

- This trend has created a financial challenge to utilities. Utilities have responded by increasing their operational and managerial efficiencies, leading to a decline in real terms (adjusted for inflation) in the transmission and distribution cost per unit of gas sold for the past 14 years.

- Utilities find it more difficult to economically add new residential customers when demand per customer is declining. Most utilities have financial tests to determine the feasibility of adding customers based on expected gas demand and cost to hook up that customer. Utilities have responded to this challenge by seeking to lower their construction costs per customer hook up.

III. Purpose and Data Limitations

This report attempts to provide a broad-based identification and quantification of factors that impacted the average annual natural gas use per residential customer from 1980 to 1997. Most natural gas distribution utilities experienced a much slower growth rate in residential demand compared to the growth rate in the number of residential customers during that time period. This trend makes it more difficult for gas companies to achieve expected revenues and to connect new customers economically. This analysis is intended to help companies understand the driving forces behind the declining use trend and to estimate future trends.

The results herein estimate the overall impacts of several contributing factors based on national and regional data. Analysis of utility-specific factors could result in conclusions different from those in this report. Individual companies should use this report as a guide in calculating their specific impacts, and they should include factors and influences pertinent to their systems that may not be considered and/or quantified here.

These contributing factors were examined separately. Some of them may have synergistic properties that compound or offset impacts when considered together.

The quantification of these factors is not an attempt to determine absolute values for each influence, but rather to indicate the proportional impact that they have on residential use per customer.

Much of the data used in this analysis come from government and AGA surveys. While this information is the best available for national and regional analysis, survey sampling, structure, and/or extrapolation techniques can be flawed, particularly when ascribing results to smaller populations such as regions and states.

IV. Historical Trends

National/Regional Averages

From 1962 to 1972, natural gas demand in the residential sector averaged an annual growth rate of 3.8 percent.[1] Utilities were expanding their pipeline systems to reach more customers, prices were kept artificially low by government regulation, and gas appliances offered superior performance, cost, and efficiency compared to competing fuel technologies.

During the mid to late 1970's, three factors led consumers to start conserving energy. First, foreign oil embargoes led to fears regarding long-term energy supplies. Second, heightened environmental awareness and energy's impact on the environment led to a reexamination of energy use practices. Finally, the federal government deregulated energy prices, which led to a significant short-term price increase, particularly for natural gas.

Efforts to reduce energy consumption are clearly reflected in gas use per customer. On a national average basis, natural gas use per residential customer dropped 16 percent from 1980 to 1997 from 106 Mcf/year to 89 Mcf/year. On a regional basis, these impacts varied. For the Northeast, the average gas use per customer actually increased about one percent. Residential gas use per customer dropped 18 percent for the Midwest and South regions of the country, while the West showed a decline of 22 percent.

[1] Gas Facts, 1975 Data, American Gas Association, Arlington, VA, 1976.

Table 1
Trends in Residential Natural Gas Use
(Weather Normalized Mcf/Customer/Year)

	1980	**1990**	**1997**	**Change, 1980-1997**
United States	105.6	95.8	89.2	-16.4
Northeast	96.5	101.2	97.1	0.6
Midwest	141.8	125.5	116.4	-25.4
South	85.2	79.6	70.2	-15.0
West	87.5	68.4	68.3	-19.2

Residential gas use can be classified as space heating and non-heating. On average, space heating demand accounts for three-quarters of typical gas consumption by residential customers. This demand is very weather sensitive, with use per customer higher in the colder climates than in the warmer regions.

Residential non-heating use of gas is also known as baseload use. This use is typically not weather sensitive. The primary residential baseload use is for water heating, which accounts for about 86 percent of non-heating demand, based on national averages. The other two primary residential gas appliances are cooking equipment and clothes dryers. Natural gas logs/fireplaces are increasing their market share, and can be used for heating or decorative purposes. Appliances that could also be considered baseload, but have a much lower market penetration, are gas lights, pool heaters, and grills.

V. Contributing Factors

Appliance Efficiency

In response to the energy disruptions of the 1970s, Congress passed the Energy Policy and Conservation Act (EPCA) of 1975. EPCA established an energy conservation program for major household appliances including furnaces, water heaters, refrigerators and freezers, central air conditioners and central air conditioning heat pumps, room air conditioners, dishwashers, clothes washers, clothes dryers, direct heating equipment, pool heaters, kitchen ranges and ovens, fluorescent lamp ballasts, and television sets. The Energy Policy and Conservation Act (EPACT) of 1978 expanded the coverage of EPCA to include commercial building heating and air conditioning equipment, water heaters, certain incandescent and fluorescent lamps, distribution transformers, and electric motors. In 1987, the National Appliance Energy Conservation Act (NAECA), which also incorporates EPCA and EPACT, authorizes the U. S. Department of Energy (DOE) to set energy efficiency standards for major home appliances according to a statutory time schedule stretching into the next century.

DOE's Office of Codes and Standards sets the minimum efficiency ratings of many residential appliances. DOE has set standards for such natural gas appliances as space heaters, water heaters, ovens, and ranges.

Furnaces

During the 1970's natural gas furnaces averaged about 65 percent annual fuel utilization efficiency (AFUE). As interest in more energy efficient appliances increased, the average AFUE for new furnaces increased. DOE, through authority granted by NAECA, set 78 percent AFUE as a minimum for gas furnaces manufactured after January 1, 1992. Furnaces with AFUE ratings up to the mid-90's are available to consumers, and the average AFUE of new residential furnace shipments is currently in the mid-eighties. As the higher efficiency furnaces have worked their way into the residential market in new homes and replacement units, the average AFUE for all residential natural gas furnaces has increased from 65 percent in 1980 to 74 percent in 1997.

Table 2
Residential Natural Gas Furnace Average AFUE
(Percent)

	1980	**1990**	**1997**
New Furnace Shipments	66%	76%	85%
All Furnaces In Place	65%	68%	74%

Source for shipment information: Gas Appliance Manufacturers Association

Since the average improvement in overall furnace efficiency was roughly 14 percent, this caused gas space heating use per customer to fall 14 percent. However, the impact in terms of sales volume varied by region due to the weather differences. Overall, use per residential customer dropped about 7.7 thousand cubic feet (Mcf) per year from 1980 to 1997, with regional impacts ranging from 5.0 Mcf in the Northeast to 12.3 Mcf in the Midwest, due to the improved furnace efficiency. Most of the decline occurred between 1990 and 1997, when a greater number of higher efficiency gas furnaces were sold.

Table 3
Impact of Gas Space Heating Efficiency Gains on Use per Customer
(Weather-normalized Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer	
	1980	**1990**	**1997**
United States	65.2	2.6	7.7
Northeast	42.5	1.7	5.0
Midwest	105.0	4.3	12.3
South	52.8	2.1	6.2
West	52.8	2.1	6.2

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance
Note: Assumes national average furnace efficiency for all regions.

Water Heaters

DOE set the minimum efficiency of natural gas water heater at 0.54 energy factor (EF) for units manufactured after 1989. Previously, water heaters averaged about 0.5 EF. Industry analysts estimated that the availability of even higher efficiency units raised the average EF of new units sold to 0.56 by the mid-90s. Based on shipment data and typical retirement rates, the average EF of water heaters went from 0.5 in both 1980 and 1990 to 0.53 in 1997.

Table 4
Residential Natural Gas Water Heater Average EF
(Percent)

	1980	1990	1997
New Water Heater Shipments	50%	54%	56%
All Furnaces In Place	50%	50%	53%

Since the average water heater EF improved slightly less than six percent from 1980 (and 1990), the typical consumption by residential customers that have water heaters declined in the same proportion. The average decline was 1.2 Mcf per customer, with regions not varying much from that average.

Table 5
Impact of Gas Space Water Heating Efficiency Gains on Use per Customer
(Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1980	**1997**
United States	22.2	1.2
Northeast	17.5	0.9
Midwest	24.0	1.3
South	22.0	1.2
West	24.8	1.3

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Other

Natural gas cooking equipment and clothes dryers have not yet been affected significantly from efficiency standards. Improvements in efficiency have occurred due to marketplace demand, most of which stemming from the development of electronic ignition devices for these appliances. While electronic ignitions can reduce annual demand for gas from these appliances by almost half, penetration of these devices into the residential market could not be determined. Therefore, no estimate of the improved efficiency impacts for these appliances is provided.

Appliance Saturation

The most common natural gas appliances found in homes are space heaters, water heaters, cooking equipment, clothes dryers, and, to a lesser extent, outdoor lights. All of these applications face competition from other energy forms, particularly electricity. Since 1980, the average number of gas appliances found in homes has dropped. This trend, discussed below, contributes to the decline in gas use per residential customer.

Space Heaters

The percentage of gas customers that use natural gas as their main space heating fuel declined by 1.7 percentage points over the 17-year period. Regionally, the

Northeast sector saw a significant increase in this market penetration among its customers, due mainly to conversions from fuel oil-based heating. The Midwest basically maintained their high market penetration for gas heating over the period. The South and the West regions exhibited significant declines in the proportion of their customers that use gas for their main space heating fuel. A primary contributing factor to this decline is the increasing popularity of the heat pump during this time. Not only did heat pumps make significant inroads into new construction (particularly in multi-family housing), electric utilities encouraged existing gas customers to add on heat pumps and use their gas furnaces as back-up systems.

Table 6
Natural Gas Space Heating Appliance Market Penetration
(Percent of all gas customers)

	1980	**1990**	**1997**
United States	87.5%	89.6%	85.8%
Northeast	62.3%	73.9%	77.3%
Midwest	97.4%	97.6%	96.2%
South	89.4%	92.2%	82.6%
West	94.9%	90.5%	83.3%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Since the overall change for gas space heating market penetration was not substantial, it caused a decrease in heating use of less than two percent for the average U.S. gas customer. This was also true for the typical Midwest gas customer. The Northeast gas utilities experienced a gain of more than 25 percent in heating use per customer due to increased market penetration for space heating. The South and West regions experienced falling space heating demand per customer ranging from six to nine percent due to the decline in market penetration.

Table 7
Impact of Gas Space Heating Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Space Heating Use per Customer	Change in Weighted Average Space Heating Use per Customer	
	1980	**1990**	**1997**
United States	65.2	+1.5	-1.0
Northeast	42.5	+8.2	+11.0
Midwest	105.0	+0.2	-1.1
South	52.8	+1.5	-3.1
West	52.8	-1.7	-4.8

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Information regarding natural gas use as a secondary heating fuel is limited. Overall, this use increased slightly over time for all households. Since it is not known what equipment was used as a secondary source nor whether gas was used as the main heat source, an estimate of any impact from these units is not possible. In addition, information regarding use of secondary heat from other fuels by gas customers is not available.

Table 8
Natural Gas Used as Secondary Space Heating Source
(Percent of all customers)

	1980	1997
United States	6.5%	7.3%
Northeast	4.7%	3.4%
Midwest	5.2%	7.1%
South	9.8%	12.6%
West	6.8%	4.7%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Water Heaters

Water heaters contribute significantly to a utility's load profile. Demand by these appliances are relatively non-weather sensitive, allowing for optimal utilization of utility investment. Also, these appliances can use as much gas as a furnace in some regions. Therefore, any loss in market penetration or improvements in efficiency will impact noticeably on average use per customer.

In most areas, market penetration of gas water heaters has declined. In 1980 natural gas water heaters were in about 87 percent of U. S. homes with natural gas service. By 1997 this market penetration had dropped to about 85 percent. Regionally, the Northeast's market penetration increased, with the other regions showing significant declines.

Table 9
Natural Gas Water Heater Market Penetration
(Percent of all gas customers)

	1980	1990	1997
United States	86.5%	86.1%	84.5%
Northeast	67.9%	79.0%	77.3%
Midwest	93.5%	87.0%	87.0%
South	85.6%	83.0%	80.2%
West	96.6%	94.2%	92.0%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

When the proportion of gas customers with gas water heaters declines, the weighted average gas use per customer declines. For example, the national average penetration of water heaters fell about two percentage points from 1980 to 1997, resulting in a decline in overall gas use per customer of 0.5 Mcf/year. The Midwest, South, and West regions' losses ranged from 1.1 to 1.6 Mcf/year. The Northeast region saw proportionally more gas customers using gas water heaters during that time frame, so this increase in burnertips added more than two Mcf/year to average residential customer use.

Table 10
Impact of Gas Water Heater Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Water Heating Use per Customer	Change in Weighted Average Water Heating Use per Customer	
	1980	**1990**	**1997**
United States	22.2	-0.1	-0.5
Northeast	17.5	+2.8	+2.3
Midwest	24.0	-1.7	-1.6
South	22.0	-0.7	-1.3
West	24.8	-0.6	-1.1

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Cooking

The percentage of gas customers that cook with gas declined in all regions of the country, due to electric products dominating the new home market, even those homes with gas service, as well as replacing old gas units. Nationally, cooking market penetration for gas customers fell 12 percent, with the Northeast falling ten percent, the Midwest nine percent, the South 21 percent, and the West five percent.

Table 11
Natural Gas Cooking Appliance Market Penetration
(Percent of all gas customers)

	1980	**1990**	**1997**
United States	62.0%	57.2%	54.4%
Northeast	82.1%	73.9%	73.9%
Midwest	55.8%	53.3%	50.0%
South	59.8%	51.6%	47.3%
West	54.7%	53.3%	52.0%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Despite the significance of the decline for gas cooking penetration, the resulting impact is relatively small. This is due to the smaller proportion of gas customers with this appliance combined with the modest annual energy consumption from these units. For all regions, the decline amounted to less than one half Mcf annually.

Table 12
Impact of Gas Cooking Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Cooking Use per Customer	Change in Weighted Average Cooking Use per Customer	
	1980	**1990**	**1997**
United States	2.6	-0.2	-0.3
Northeast	3.4	-0.3	-0.3
Midwest	2.3	-0.1	-0.2
South	2.5	-0.3	-0.4
West	2.3	-0.1	-0.1

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Clothes Dryers

Penetration of gas dryers increased slightly in all regions from 1980 to 1997, ranging from three percent in the South to 20 percent in the Northeast.

Table 13
Natural Gas Clothes Dryer Market Penetration
(Percent of all gas customers)

	1980	**1990**	**1997**
United States	23.1%	25.1%	25.2%
Northeast	24.5%	25.2%	29.4%
Midwest	30.5%	29.0%	31.5%
South	15.2%	18.3%	15.6%
West	20.5%	27.7%	24.0%

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

This increase in penetration for gas clothes dryers resulted in modest increases in typical use per customer, from negligible in the Midwest and South to less than one-quarter Mcf in the other regions.

Table 14
Impact of Gas Drying Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Drying Use per Customer	Change in Weighted Average Drying Use per Customer	
	1980	**1990**	**1997**
United States	1.0	+0.1	+0.1
Northeast	1.1	-0.0	+0.2
Midwest	1.3	-0.1	0.0
South	0.7	+0.1	0.0
West	0.9	+0.3	+0.1

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Outdoor Gas Lights

Natural gas lights were somewhat popular with customers the through mid-1970s. During the turmoil in the energy markets in the late-70s, President Carter encouraged people to turn their gas lights off or convert them to electricity. Since that time, their market share for gas customers fell more than 50 percent. Assuming typical gas light usage of 19 Mcf per year, the decline in market share caused the weighted average gas use per residential customer to decline about one-third Mcf per year on a national average. The decline was about one-half Mcf for the Midwest and South, while 1997 data were unavailable for the Northeast and West.

Table 15
Outdoor Gas Light Market Share Decline and Resulting Impact

	Gas Customer Market Penetration		Wgtd. Avg. Change (Mcf/year)
	1980	1997	
United States	3.1%	1.5%	-0.31
Northeast	0.9%	N/A	N/A
Midwest	4.5%	1.6%	-0.54
South	4.5%	1.8%	-0.51
West	1.7%	N/A	N/A

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years. Note: Data not available for NE and West regions for 1997.

Housing Characteristics

Thermal Efficiency

Homes across the country have become more energy efficient due, in part, to the improved thermal efficiency of the building envelope. New homes, which must meet local regulations implemented over the last two decades regarding thermal efficiency, account for most of this improvement. In addition, many homeowners have retrofitted older residences in order to cut their energy bills.

In all regions, the percent of homes that have wall and roof insulation has increased since 1980. The same is true for homes with storm doors and windows.

Table 16
Trends in Residential Thermal Characteristics

	United States			Northeast			Midwest			South			West		
	1980	1990	1993	1980	1990	1993	1980	1990	1993	1980	1990	1993	1980	1990	1993
Have Wall Insulation	64%	67%	70%	72%	69%	75%	74%	77%	77%	61%	64%	68%	49%	56%	62%
Have Roof Insulation	77%	80%	81%	78%	79%	83%	82%	84%	84%	74%	80%	80%	72%	76%	78%
Have Storm Windows	48%	58%	N/A	68%	81%	N/A	78%	84%	N/A	33%	45%	N/A	14%	26%	N/A
Have Storm Doors	43%	47%	N/A	53%	58%	N/A	67%	68%	N/A	35%	39%	N/A	13%	39%	N/A

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years. NOTE: 1997 data not available; 1993 data not available for homes with storm windows and doors.

This improvement in thermal efficiency has significantly reduced the heating demand from the residential sector. Overall, typical consumption decreased by about three Mcf nationally. Regionally, the decrease in weighted average gas use per customer ranged from about two Mcf in the Midwest to over four Mcf in the West.

Table 17
Impact of Improving Home Thermal Efficiency on Gas Demand
(Decrease in Mcf per Residential Customer per Year)

United States	3.0
Northeast	3.4
Midwest	2.1
South	2.8
West	4.3

Square Footage

According to the Energy Information Administration, the amount of heated floorspace per residence decreased about three percent, on a national average, since 1980. The Northeast and Midwest regions exhibited decreases in heated floorspace per residence of 13 percent and 10 percent, respectively, while the South and West regions showed increases of less than 10 percent. Two factors are counteracting each other here: the number of townhomes and condominiums have increased since 1980, bringing down the average amount of heated floorspace, while the size of new single family homes has been increasing, particularly in the 1990s.

Table 18
Average Heated Floorspace Per Residence
(Square feet)

US		NE		MW		South		West	
1980	**1997**	**1980**	**1997**	**1980**	**1997**	**1980**	**1997**	**1980**	**1997**
1,524	1,477	1,636	1,420	1,678	1,505	1,411	1,540	1,395	1,504

Source: RECS: Housing Characteristics, Energy Information Administration, U.S. Dept. of Energy, various years.

Any change in the average amount of heated floorspace will impact the amount of gas consumed for space heating. On a national average, the decrease in heated floorspace caused the weighted average gas use per residential customer to decline about one Mcf per year. For the Northeast and Midwest, where heating loads are most significant, the decreases in heated floorspace resulted in an almost four Mcf per year decline. The increase in average floorspace in the South and West regions caused increases in typical gas demand ranging from 1.3 Mcf to 1.7 Mcf per year.

Table 19
Weighted Average Impact of Changing Amount of Heated Floorspace on Gas Demand
(Change in Mcf per Residential Customer per Year)

United States	-0.8
Northeast	-3.9
Midwest	-3.7
South	+1.7
West	+1.3

Temperature Setting/Control

Overall, the average temperature setting during the heating season for homes has not changed significantly since the mid-1980s. Therefore, this factor should not have had an impact on residential gas demand.

Table 20
Average Temperature in U.S. Residences During Heating Season
(Degrees Fahrenheit)

	1984	**1990**	**1997**
Daytime	69.3	70.0	69.8
Nighttime	69.3	71.7	68.0

Source: <u>RECS: Housing Characteristics</u>, Energy Information Administration, U.S. Dept. of Energy, various years. Note: 1980 data not available.

The number of households that turned the thermostat back at night increased since the 1980s, due in part to the increased popularity of programmable thermostats. For the U.S. as a whole, almost 40 percent more households were setting the thermostat lower at night in 1997 compared to 1984. Regionally, the increase ranged from 35 percent for the Northeast to 57 percent for the South.

Table 21
Residential Trends in Thermostat Setback
(Percent turning temperature back)

	Nighttime – Sleeping Hours		
	1984	**1990**	**1997**
US	38%	47%	53%
NE	43%	59%	58%
MW	44%	49%	60%
South	35%	41%	55%
West	30%	43%	40%

Source: <u>RECS: Housing Characteristics</u>, Energy Information Administration, U.S. Dept. of Energy, various years.
Note: 1980 data not available

Assuming the average temperature setback was less than five degrees Fahrenheit, the impact of increasing use of thermostat setback would be less than one

Mcf on an annual basis for the average customer. Regionally, the impact ranged from one-third Mcf (West) to one Mcf (Midwest).

Table 22
Weighted Average Impact of Increase Use of Thermostat Setback on Gas Demand
(Change in Mcf per Residential Customer per Year)

United States	-0.7
Northeast	-0.8
Midwest	-1.0
South	-0.6
West	-0.3

<u>Other</u>

Geographic Population Shifts

From 1980 to 1997, population growth, and subsequently gas customer growth, was greater in the warmer regions (South and West) than in the colder regions (Northeast and Midwest). About 51 percent of the residential gas customers were in the warmer Southern and Western sections of the country in 1997, compared to 48 percent in 1980. With more of the households in warmer climates, the average heating demand, on a national basis, declined. This larger percentage of gas customers in warmer climates resulted in overall use per gas customer falling about one Mcf on a national basis. This factor does not impact typical regional use per gas customer.

Table 23
Regional Natural Gas Customer Population Trends
(Percent of all gas customers)

	1980	**1997**
United States	100.0%	100.0%
Northeast	21.4%	19.2%
Midwest	31.0%	29.7%
South	24.9%	26.9%
West	22.7%	24.2%

Source: <u>RECS: Housing Characteristics</u>, Energy Information Administration, U.S. Dept. of Energy, various years.

Household Size

The average number of persons in a residence can impact the amount of gas consumed (hot water for showers, laundry, & dishwasher, cooking for meals, drying for laundry). On average, the number of persons per household declined five percent, with regional numbers ranging from less than two percent for the West to about eight percent for the Midwest.

Table 24
Average Number of Persons per Household

	1980	1990	1997
US	2.56	2.41	2.43
NE	2.55	2.44	2.39
MW	2.64	2.36	2.41
South	2.54	2.42	2.43
West	2.51	2.47	2.48

The impact of the declining number of people per household, overall, reduced annual gas demand by about half an Mcf. Regionally, the impact ranged from one-tenth an Mcf for the West to one Mcf for the Midwest.

Table 25
Weighted Average Impact of Declining Number of People per Residence on Gas Demand
(Change in Mcf per Residential Customer per Year)

United States	-0.5
Northeast	-0.5
Midwest	-1.0
South	-0.5
West	-0.1

Other Factors Not Quantified

Other factors could have an impact on residential natural gas use, but were not quantified here, primarily due to lack of data. For the most part, these should have impacts less than most of those factors listed above. Some of these factors are listed below:

Water Conservation – Low flow showerheads and increasingly efficient dishwashers and washing machines have decreased the amount of hot water needed per residence.
Economic Influences – Changes in the price of natural gas and in the general economic condition of the general population may influence consumption.
Environmental Regulations – Restrictions on certain combustion practices, such as wood fireplaces, may impact consumer purchases of gas products.
Gas Hearth Products – Gas fireplace/logs have become more popular over the past 17 years, but it is not clear whether these units actually add to load. Some units could displace gas furnace requirements.

VI. National & Regional Summaries

Table 26 summarizes the factors contributing to the decline in use per residential customer. For the most part, the sum of the estimated factors closely approximates the observed decline for most of the regions. Keep in mind that this report provides a broad-based assessment to the factors contributing to the decline in order to provide an understanding of the relative impact from each of these factors. This report does not attempt to provide precise measures of these factors due to limitations in the data.

Table 26
Summary of Factor Quantification and Comparison to Actual Decline
(Change in use per residential customer, 1980-1997, Mcf/year)

	U.S	NE	MW	South	West
Space Heating Efficiency	-7.7	-5.0	-12.3	-6.2	-6.2
Baseload Appliance Efficiency	-1.2	-1.0	-1.3	-1.2	-1.4
Space Heating Market Penetration	-1.0	+11.0	-1.1	-3.1	-4.8
Baseload Appliance Market Penetration	-1.0	+2.2	-2.3	-2.3	-1.1
Thermal Efficiency Gains	-3.0	-3.4	-2.1	-2.8	-4.3
Other Residence Characteristics*	-2.0	-5.2	-5.7	+0.6	+0.9
Population Trends	-0.9	N/A	N/A	N/A	N/A
Total	-16.8	-1.4	-24.8	-15.0	-16.9
Actual Change	-16.4	+0.6	-24.8	-15.0	-19.2
Difference**	-0.4	-2.0	0.0	0.0	+2.3

** Includes changes in heated floorspace, thermostat setback, and number of people per residence*
*** Can be due to a variety of factors, including data error, omission of other factors, and imprecise methodology*

United States
- Space heating efficiency gains account for about 47 percent of decline
- Water heating efficiency gains - about seven percent
- Space heating market share loss – about six percent
- Baseload market share loss – about six percent
- Improved home thermal efficiency – about 18 percent
- Change in average amount of heated floorspace – about five percent
- Increased use of thermostat setback – about four percent
- Population shift to warmer climates – about six percent
- Decrease in number of people per home – about three percent

Northeast
- Appliance efficiency gains result in substantial decrease in use per customer
- Increased market penetration of space and water heaters more than offset other declining factors
- Improved home thermal efficiency and decreased average heated floorspace each account for almost a much decline as increased space heating efficiency
- Other factors have minor impact on use per residential customer

Midwest
- Space heating efficiency gains account for about 47 percent of decline
- Water heating efficiency gains - about five percent
- Space heating market share loss – about four percent
- Baseload market share loss – about nine percent
- Improved home thermal efficiency – about eight percent
- Change in average amount of heated floorspace – about fourteen percent
- Increased use of thermostat setback – about four percent

- Decrease in number of people per home – about four percent

South

- Space heating efficiency gains account for about 41 percent of decline
- Water heating efficiency gains - about five percent
- Space heating market share loss – about 21 percent
- Baseload market share loss – about 16 percent
- Improved home thermal efficiency – about 19 percent
- Change in average amount of heated floorspace – substantial offset to decline
- Increased use of thermostat setback – about four percent
- Decrease in number of people per home – about three percent

West

- Space heating efficiency gains account for about 32 percent of decline
- Water heating efficiency gains - about seven percent
- Space heating market share loss – about 25 percent
- Baseload market share loss – about six percent
- Improved home thermal efficiency – about 22 percent
- Change in average amount of heated floorspace – increase helped offset decline
- Increased use of thermostat setback – about two percent
- Decrease in number of people per home – about one percent

VII. Estimate of Future Impacts

<u>Appliance Efficiency</u>

Today, most of the space heating and water heating appliances in place were purchased before government-mandated minimum efficiency ratings were imposed on this equipment. Therefore, the average efficiency for these appliances is lower than the regulatory minimum. As the older, less efficient appliances are replaced through normal attrition, gas utilities will continue to experience declining residential demand per customer.

Based on equipment sales data and typical appliance lifetimes, the average efficiency for residential furnaces was 74 percent in 1997, below the 78 percent regulatory minimum. Consumer demand for high efficiency gas furnaces has driven the average efficiency of units sold to over 85 percent by 1997. As the older units are replaced over the next ten years, the national average residential demand for gas could decline another 3.2 Mcf/year (AFUE = 78 percent) to 8.2 Mcf/year (AFUE = 85.6 percent). Regional impacts vary depending on the typical heating load and the market penetration of gas heat.

Table 27
Future Impact of Increasing Space Heating Efficiency
(Mcf/year)

	Weighted Average AFUE=78.0%*	Weighted Average AFUE=85.6%**
US	-3.2	-8.2
NE	-2.1	-5.4
MW	-5.2	-13.3
South	-2.4	-6.7
West	-2.4	-6.7

* Current regulatory minimum
** Current average efficiency of units sold

Gas water heating appliances are becoming increasingly efficient as well. Based on industry estimates and shipment data, the average water heater EF in residences is about 0.53, slightly below the current mandate of 0.54, again due to the number of appliances purchased before the mandate became effective. Based on the availability of even higher efficient gas water heaters, the weighted EF for current shipments is probably 0.56 or higher. Assuming typical replacement rates, gas utilities could experience declines in residential demand due to increasing water heater efficiencies averaging from 0.4 Mcf/year (EF = 0.54) to 1.2 Mcf/year (EF = 0.56). Regional impacts will probably vary from this average.

Table 28
Future Impact of Increasing Water Heating Efficiency
(Mcf/year)

	Weighted Average EF=0.54	Weighted Average EF=0.56
US	-0.4	-1.2
NE	-0.4	-1.0
MW	-0.5	-1.3
South	-0.4	-1.2
West	-0.5	-1.4

DOE, by law, periodically reviews the feasibility of increasing the minimum efficiencies of these and other appliances. Any further rulemakings from DOE on appliance efficiency will impact residential gas demand.

Housing Characteristics

By 1997, 40 percent of existing homes were built before 1960. These residences, on average, are less thermally efficient than new homes. While some have been renovated to improve their thermal efficiency (wall and ceiling insulation, storm windows and doors), the addition of new homes and the removal of older stock will increase the average efficiency of a gas utility's residential base. This, in turn, will cause typical residential demand to decline.

Other

No attempt is made here to estimate the future trends of gas appliance penetration or demographic changes. Other factors that may have a future impact include new products and technologies.

VIII. Impacts on Utilities

Marketing

Changes in residential gas use impacts utilities' ability to connect new customers. Allowed investments for connecting customers are based on the expected sales to those customers. Declining use per residential customer, particularly for new customers with energy efficient homes and appliances, makes connecting these customers on an economic basis more difficult. Some new housing developments may not qualify for gas service based on their relatively lower gas use. This may cause the utility to forgo sales not only from that neighborhood but possibly from later developments that could have been served off lines that would have been in place had the original neighborhood been connected.

Utilities have made adjustments to try and compensate for this decline through improved construction techniques and technologies. Innovations such as plastic pipe, 2-PSI systems, and common trenching have lowered the cost of connecting new homes to the gas system.

Profitability

While the number of homes in a utility's customer base is increasing, overall sales have remained relatively flat. Utilities have difficulty achieving allowed returns when investment increases but sales revenues stagnate. Since government regulation and competition from other energy sources limit a utility's ability to increase revenues through price increases, many utilities have been cutting costs to maintain profitability. Over the past 15 years, the margin (price less cost of gas) utilities charge the residential customer fell, in real terms, by nine percent, reflecting the efficiency gains by these companies.

IX. Methodology

Normalized Use Per Customer

- Calculate actual use per residential customer from EIA data[2]
- Determine heating portion of use based on AGA survey data[3]
- Determine weather normalization factor by dividing the 30-year (1961-1990) normal heating degree days into the actual degree days, based on NOAA data[4]
- Divide heating portion by weather normalization factor, and add back in non-heating load

[2] Natural Gas Annual, various years, Energy Information Administration, U.S. Department of Energy, Washington, DC.
[3] Residential Natural Gas Market Survey, various years, American Gas Association, Washington, DC.
[4] State, Regional, and National Monthly and Seasonal Heating Degree Days, various years, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Washington, DC.

Average Space Heating AFUE

- Assume 65% AFUE as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas space heating customers from current year's, based on trend analysis of EIA RECS data[5]
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data[6]
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace AFUE for all existing units based on average AFUE of shipments as provided by GAMA

Space Heating Efficiency Impact

- Calculate average use per customer by multiplying the normalized heating load by the percent of gas customers with gas space heating (based on EIA RECS data)
- Calculate change in average furnace AFUE by dividing 1980 AFUE value into the selected year's AFUE value
- Calculate the efficiency-adjusted demand by dividing the 1980 average use per customer by the change in average furnace AFUE for the selected year
- Subtract the efficiency-adjusted demand from the 1980 average use per customer to determine impact

Average Water Heating EF

- Assume 0.50 EF as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas water heating customers from current year's, based on trend analysis of EIA RECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace EF for all existing units based on average EF of shipments estimated at 0.54 EF to 0.56 EF

Water Heating Efficiency Impact

- Calculate average use per customer by multiplying the water heating load (based on AGA survey data) by the percent of gas customers with gas water heating (based on EIA RECS data)
- Calculate change in average EF by dividing 1980 EF value into the selected year's EF value
- Calculate the efficiency-adjusted demand by dividing the 1980 average use per customer by the change in average water heater EF for the selected year
- Subtract the efficiency-adjusted demand from the 1980 average use per customer to determine impact

[5] RECS: Housing Characteristics, various years, Energy Information Administration, U. S. Department of Energy, Washington, DC.
[6] GAMA News, various years, Gas Appliance Manufacturers Association, Arlington, VA.

Appliance Market Penetration Impact

- Calculate appliance penetration by dividing the number of residences with gas service by the number of customers with that appliance, based on EIA RECS data
- Subtract the impact year penetration from the 1980 penetration to determine the change in market penetration
- Calculate the weighted average gas use per customer for that appliance by multiplying the penetration value times the typical gas use for that appliance
- Multiply the change in market penetration by the 1980 weighted average use of that appliance to determine the reduction in weighted average use per customer for that appliance

Thermal Efficiency Impact

- Determine the percent difference in heating load for a typical residence with and without insulation, storm doors, and storm windows, based on EnergyHelp for the Home software package[7]
- Calculate the percent increase in homes with those thermal efficiency enhancements from EIA RECS data
- Multiply the thermal efficiency percent increase by the percent difference in heating load and by the percent of gas homes with gas space heating to determine the thermal efficiency impacts

Change in Average Heated Floorspace Impact

- Determine the percent difference in heating load for a typical residence based on various amounts of heated floorspace, based on EnergyHelp for the Home software package
- Calculate the percent change in average heated floorspace in homes from EIA RECS data
- Multiply the change in average heated floorspace by the percent difference in heating load and by the percent of gas homes with gas space heating to determine impacts

Increase in Use of Thermostat Setback Impact

- Determine the percent difference in heating load for a typical residence based thermostat setback of less than five degrees for eight hours, based on EnergyHelp for the Home software package
- Calculate the percent change in households setting back thermostats at night from EIA RECS data
- Multiply the change heating demand from thermostat setback by the percent difference in heating load and by the percent of gas homes with gas space heating to determine impacts

Population Shift Impact

- Determine the percent of gas customers by region for 1980 and 1997 from EIA RECS data
- Determine the normalized heating demand for those regions in 1980 based on AGA survey data

---

[7] *EnergyHelp For The Home* computer program distributed by Columbia Energy, Virginia, 1998

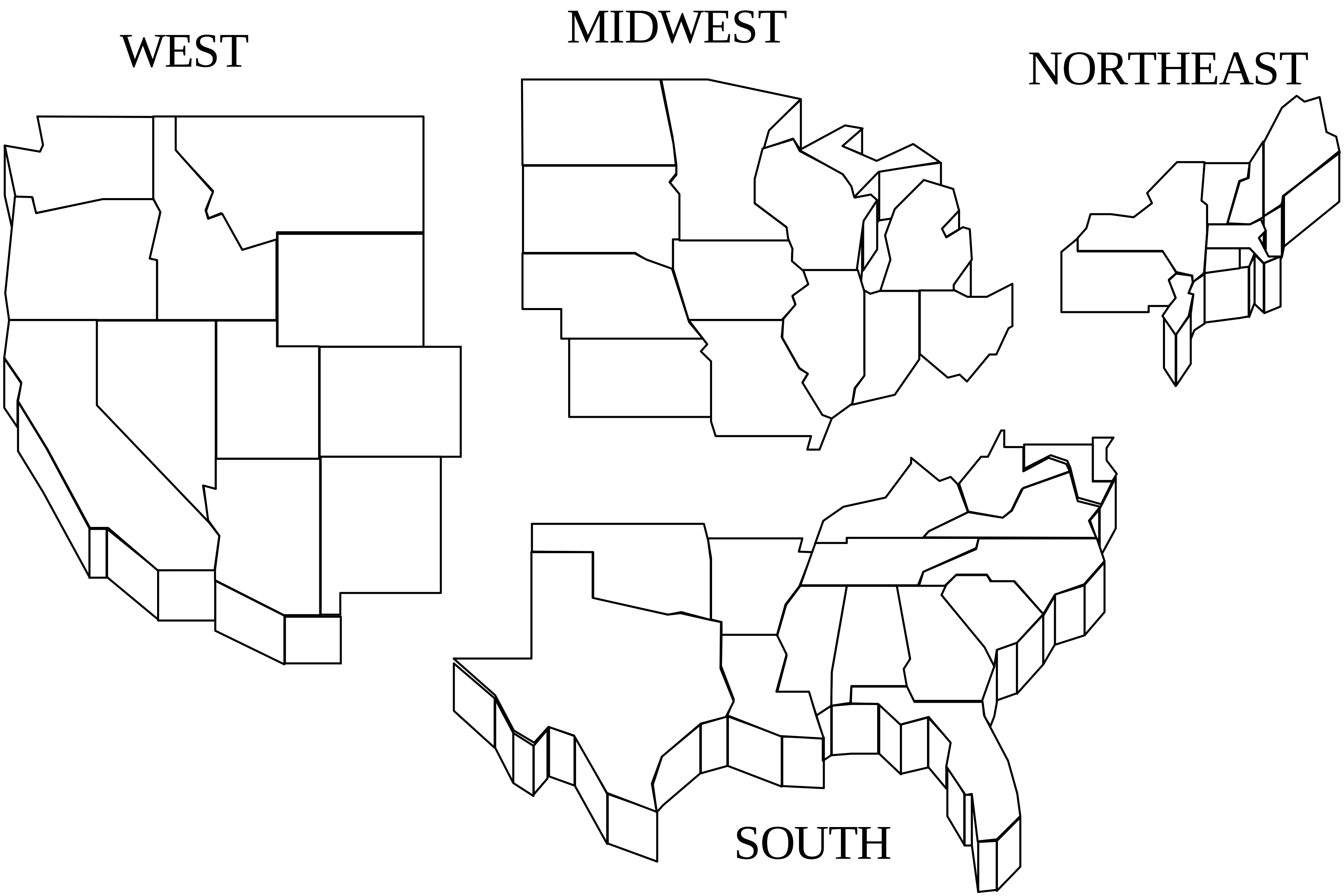
- Apply those same regional demand figures to the 1997 regional population distribution, calculate the weighted average national numbers for both, and compare the two numbers

Average Number of Persons per Household Impact

- Calculate the difference in average number of persons per household from EIA RECS data
- Determine the percent difference in heating load for a typical residence based on that same reduction in number of people per home, based on EnergyHelp for the Home software package
- Multiply the change heating load by the percent of gas homes with gas space heating to determine impacts

Appendix

US Census Regions



Attachment 42.2

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 43.0

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 44.2

Green makeovers all the rage in an ugly market; The iconic black towers of Toronto's TD Centre are among downtown properties undergoing refits to gain a competitive advantage

The Globe And Mail
Tue Jul 21 2009
Page: B5
Section: Report On Business: Canadian
Byline: Angela Kryhul
Source: Special to The Globe and Mail

The Toronto-Dominion Centre is undergoing a makeover, but there's more to it than renovated foyers and a spruced-up outdoor courtyard.

The real story is behind the walls of the iconic black towers, where owner Cadillac Fairview Corp. is investing in systems that will help to reduce energy consumption and operating costs - and make the six-building office complex in downtown Toronto more attractive to tenants.

Cadillac Fairview is typical of Toronto landlords who are investing in green retrofits, hoping that upgrades to older buildings will make them more competitive in a market where the office vacancy rate is rising and millions of square feet of newly constructed, LEED-certified space will be delivered over the next several months.

There is more retrofitting going on in Toronto than in other parts of Canada because of the huge amount of older office space that will open up as tenants jump from these buildings into five new towers going up in the downtown core, says Robert Armstrong, managing director of leasing services for commercial property broker Avison Young in Toronto.

Tenants are working with tight budgets and they're looking everywhere for savings. "What they're asking for right now is how to reduce costs, whether it's getting into a building that is more efficient than the one they're in, or how to make the space they're occupying more efficient," Mr. Armstrong says.

While the economy has put the kibosh on new commercial construction, the retrofitting trend is taking hold.

A report by Pike Research, a market research firm based in Colorado, predicts the retrofit market will experience strong growth through 2013 and beyond.

"Compared to conventional space, high-performance green building space is vacant less often," notes the report, called Energy Efficiency Retrofits for Commercial and Public Buildings. "Owners of empty commercial buildings are adopting green retrofits as a market differentiator."

Tenants are starting to pay more attention to such things as energy efficiency and certification in the Leadership in Energy and Environmental Design (LEED) green-building rating system when scouting for new premises, says Dermot Sweeny, principal of Sweeny Sterling Finlayson & Co. Architects in Toronto.

"I think we're seeing a tremendous change in how tenants are going to the market," Mr. Sweeny says. "As tenants become more sophisticated, the smart landlords out there are saying, 'We've got to be ahead of this curve.' When tenants walk in and say, 'What are you doing for the environment' or 'What are you doing to save me money, Mr. Landlord,' they can answer with seven or eight specific, highly desirable changes and retrofits they are doing to the building. "

Steven Sorensen, vice-president and divisional manager for Cadillac Fairview's Toronto office portfolio, says the upgrades at the TD Centre - the buildings range in age from 18 to 42 years and provide office and retail space for 21,000 people - benefit the environment and will make the space more competitive.

"Most environmental initiatives are based on reducing utility consumption. It's to the mutual advantage of the tenant and the landlord because, if we can reduce our operating costs, we become more competitive and, hence, can attract more tenancy," Mr. Sorensen says.

Cadillac Fairview is spending more than $15-million on energy-efficiency initiatives such as re-commissioning all of the mechanical systems, Mr. Sorensen says.

Millions more are being spent on a new fibre-optic building automation control system that will improve the management of heating, ventilation and air- conditioning systems, he says.

This includes installing meters for each tenant so that they can monitor their own energy use. "We felt the most effective way to get [tenants] engaged is to give them the information to help them understand their consumption and usage patterns," Mr. Sorensen says.

Other improvements include outfitting washrooms with low-flush toilets and automated taps, and sourcing recycled paper products. Lighting will be put on auto sensors.

The TD Centre will eventually apply for a new LEED certification meant specifically for retrofits, Mr. Sorenson says. It's called the LEED Canada for Existing Buildings: Operations and Maintenance (LEED EBOM), and will be introduced this summer by the Vancouver-based Canada Green Building Council, which oversees the LEED program.

The new certification, already available in the United States, will give older, upgraded buildings the chance to tout LEED certification, a status until now largely awarded to new, energy-efficient buildings.

The TD Centre isn't the only downtown property that is now renovating, Mr. Armstrong says. Most of the major landlords are improving their properties as the market becomes more competitive.

Toronto's overall vacancy rate rose to 8.4 per cent during the second quarter of 2009, from 6.7 per cent for the same period last year, according to CB Richard Ellis. And the city will see about 3.9 million square feet of new office space hit the market as five office towers are completed over the next few months - the RBC Centre, the Telus Tower, the Bay-Adelaide Centre and Maple Leaf Square - as well as 18 York St., to be completed by 2012.

As they move into the new towers, tenants will leave behind about three million square feet of older space, Mr. Armstrong says.

Mr. Sweeny's firm worked on the RBC Centre, which will apply for LEED gold certification when it is completed this summer. He describes the project as an "epiphany" for the Toronto market because it's an example of how a powerful tenant went to the developer community with a very specific set of requirements for an energy-efficient building. It's a fairly rare example, he says, where "a tenant absolutely drives the result."

Mr. Armstrong says that, in the past six months, landlords have made more of an effort to help tenants find ways to cut costs and increase efficiencies.

This atmosphere of co-operation is quite refreshing, Mr. Armstrong says.

"Sure, there are negotiations, and you're always pushing and pulling to get the best deal, but landlords are definitely coming to the table to try and meet the needs of the tenants out there. It's actually a very good environment to work in right now."

Length: 996 words
Idnumber: 200907210079

Tone: Positive
Ad Value: $30,537.38
Circulation: 326,228

Attachment 45.2

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 49.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 50.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 64.3

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 79.2

AGREEMENT

between:

TERASEN GAS INC.

and

CANADIAN OFFICE AND PROFESSIONAL
EMPLOYEES' UNION LOCAL 378

Relating to

WAGES AND WORKING CONDITIONS

Effective Date: April 1, 2007

Expiry Date: March 31, 2012

TABLE OF CONTENTS

LETTERS OF UNDERSTANDING

NOTE: **Underlining in the text of an Article indicates new language.**

THIS AGREEMENT made

Between:

TERASEN GAS INC.

(hereinafter called the "Company")

and

CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES' UNION LOCAL 378

representing the employees of **TERASEN GAS INC.**

affected by this Agreement

(hereinafter called the "Union")

PREAMBLE

WITNESSETH that the Parties agree to exclude the operation of Section 50(2) of the Labour Relations Code of British Columbia and that the following provisions shall take effect and be binding upon the Company and the Union for the period commencing April 1, 2007 and ending on March 31, 2012 and thereafter until terminated as follows:

Either party may at any time within 4 months immediately preceding the expiry date of this Agreement, give written notice of its intention to reopen or amend the Agreement on its expiry date. After the expiry date and until a revised Agreement is signed, this Agreement and all its provisions shall remain in full force and effect until such revised Agreement is signed without prejudicing the position of the revised Agreement in making any matter retroactive to any date detailed in such revised Agreement.

Notwithstanding the paragraph above, the employees may strike, and the Company may lock out after this Agreement expiry date, within the provisions of the legislation existing at the time as a part of the negotiating process in arriving at a new Agreement.

ARTICLE 1 RECOGNITION OF THE UNION

1.01 This Agreement shall apply to and be binding upon all employees of the Company described in a certificate issued to the Union by the Industrial Relations Council of British Columbia dated 3 April 1991 and which are all employees of the Company in its establishments in British Columbia, in any phase of office, clerical, technical, administrative or related work and including gas controllers, field workers employed by the employer (such as representatives, salespersons, engineering survey persons, safety inspectors, construction inspectors, who are mentioned by way of example only and not to limit the generality of the term "field workers") but excluding those field workers who are represented by the International Brotherhood of Electrical Workers, Local 213, employed by the employer in transmission, distribution, liquefaction and storage, construction and maintenance, customer service, fabrication and repair shops.

1.02 a) The Company agrees that all employees covered by this Agreement shall, within 15 days of the date hereof, or within 15 days of their employment by the Company, whichever event shall later occur, as a condition of employment, become and remain members of the Union. The Company shall deduct from each affected employee's pay the amount of any union dues and assessments, and remit same to the Union monthly, together with the information as to the persons from whose pay such deductions have been made.

b) Monthly Employee Information
The Company shall provide the Union each month with the following information in magnetic media form:

1. The names, social insurance numbers, classifications, pay groups, salaries, location and seniority dates of bargaining unit employees;
2. A list of hires, rehires and terminations in the previous month;
3. A list of all employees going on or returning from leave of absence without pay, maternity leave or long-term disability in the previous month.

1.03 The Union will provide the Company with official forms, covering Application for Membership, Initiation and Authorization for Dues Deduction.

1.04 The officers, representatives and members of the Union shall not engage in any activity of the Union on Company time or on Company premises, except by prior authority of the Company. The Union shall advise management as to who represents the Union as Union Officers, Union Stewards and Union Representatives. Union Stewards may carry out their Union duties relative to the Agreement on Company time in the town in which the Steward is located, subject to their Manager's approval.

1.05 The Company will grant leave of absence without pay to employees who are:

a) Acting as full-time officers or representatives of the Union (but excluding the Union clerical staff). Such employees will be placed on leave of absence, with the time involved considered as service with the Company. On conclusion of such leave of absence employees will return to the position they previously held with the Company.

b) Elected as representatives to attend Union meetings, conventions, or to Union business.
Reasonable notice for such leaves of absence must be given to the Company.

c) The Company will not charge the Union for salaries of employees absent from work to attend Executive Board or Executive Council meetings, where the leave of absence is 1 day or less. Time away will be by arrangement between the employee and their Manager, and such time off will not be unreasonably withheld.

d) The amount of leave granted for the purpose of attending Executive Board meetings shall not exceed 40 working days per year in total for the bargaining unit. The maximum leave granted for Executive Council meetings shall not exceed 130 working days per year in total for the bargaining unit.

e) Where a leave of absence specified in (c) above exceeds 1 day and for all other leaves of absence for Union business not specified in (c) above, the Union is responsible for the costs of the leaves, including salary and a loading factor of 17.3%.

f) The Parties agree that Article 1.05 (c) of the Collective Agreement is interpreted to mean that the Union will reimburse the Company for all time lost whenever an employee is continuously involved in Union business for more than 1 day, even if it is an Executive Board meeting, an Executive Council meeting, or a combination of the two.

1.06 Bulletin boards shall be made available to the Union for the purpose of posting Union notices relating to meetings and general Union activities. With the exception of routine notices of COPE meetings, COPE elections, job bulletins to fill vacancies in the COPE office and notices of appointment, all notices shall be submitted to the Company for approval before being posted.

1.07 The Company retains the right to manage its business and direct the working forces, provided it does not conflict with the provisions of this Agreement.

1.08 Neither the Union nor the Company, in carrying out their obligations under this Agreement, shall discriminate in matters of hiring, training, promotion, transfer, layoff, discharge or otherwise because of race, colour, ancestry, place of origin, religion, marital status, family status, physical or mental disability, age, sex, sexual orientation, or any other grounds under the BC Human Rights Code.

1.09 Duties normally performed by employees within the bargaining unit will not be assigned to or be performed by non-bargaining unit employees except to overcome immediate, short-term operational or personnel difficulties when bargaining unit employees capable of performing the work are not available.

1.10 The Company will not contract out work normally performed by bargaining unit employees if such contracting out will result in any termination or downgrading of an existing employee.

1.11 Persons referred by an employment agency will become temporary employees of the Company after accumulating 25 working days in a calendar year.

1.12 When employees covered by this Agreement are assigned away from their regular headquarters overnight to work on a construction project being done by Company employees who are members of another bargaining unit, their manager will assign them overtime on the same basis as those employee members of the other bargaining unit, provided the work is available.

1.13 The Company shall provide each employee with a copy of the Collective Agreement within 90 calendar days of a revised agreement being ratified and signed by both parties. New employees shall be provided with a copy of the Collective Agreement at the time of their hire. In addition, the Company will allow up to one-half hour of paid time <u>after</u> the Company's employee orientation sessions for a Union Representative to meet with new employees for the purpose of informing them of their rights and obligations as Union members.

1.14 a) A consultation committee shall be established in accordance with Section 53 of the Labour Relations Code.

b) At the request of either party, the parties shall meet at least once every two months until this Agreement is terminated, for the purpose of discussing issues relating to the workplace that affect the parties or any employee bound by this Agreement.

c) The purpose of the consultation committee is to promote the cooperative resolution of workplace issues, to respond and adapt to changes in the economy, to foster the development of work related skills and to promote workplace productivity.

1.15 The Company will indemnify and hold harmless Company employees from legal liabilities imposed upon them arising from their normal course of employment save in the case of gross negligence or willful misconduct by an employee.

<u>1.16</u> <u>The Company will provide service twice a week to the Union Office at 2nd Floor, 4595 Canada Way, Burnaby, B.C., V5G 1J9. The service will be rendered at a cost to be determined by the Company from time to time and shall include drop off and pick-up of mail on Tuesday and Thursday on normal working days.</u>

<u>The cost of the service will be shared 50/50 between the Company and the Union.</u>

2.01 THE JOB CLASSIFICATION SYSTEM

a) The TERASEN GAS/COPE Point-Factor Plan shall be the sole determinant of job groupings for the Classification Levels used in the Job Classification System.

b) The Company shall be responsible for maintaining the Job Family and Level definitions and evaluations to meet ongoing operational requirements.

c) The job levels for employees shall be determined by application of the Job Classification System, except as outlined in Article 2.07.

d) The parties acknowledge the practicality of determining the evaluation of a position by the use of Job Family and level definitions, particularly where a specific job is clearly defined by the Family, Sub-Family, Level Definition or Summary of a Representative Job and where there is an appropriate benchmark (or benchmarks) as a comparison. However it is also acknowledged that the evaluation of specific positions may not be so readily determined because the job is not clearly defined in the Job Family and Level definitions and/or there are no comparable benchmarks; in these cases, the position(s) will be evaluated under the Point Factor Plan. It is understood that all benchmarks will be point-factored.

e) Should there be a dispute as to whether the evaluation of a position has been properly determined pursuant to application of either the Job Family and Level definitions or the Point-Factor Plan, the matter will be referred to the appeal process set out in the remainder of this Article. If the appeal proceeds to the Standing Arbitrator, the level must be confirmed by the Point Factor Plan pursuant to Article 2.05(b).

f) The Human Resources Department (HRD) is responsible for ensuring that all Job Descriptions and Evaluations are current and that every job is reviewed at least once every three (3) years. In order to discharge this responsibility, the HRD shall plan and carry out an annual review schedule that encompasses approximately one-third (1/3) of all active, evaluated COPE jobs.

2.02 **JOB DESCRIPTIONS**

a) The Company agrees that it will provide the Union with copies of all current job descriptions covering employees for whom the Union is certified as the bargaining agent.

b) The Company shall provide the Union with descriptions of new jobs as soon as operational requirements permit. The Union will be provided with a copy of the new, evaluated job description at least 3 working days prior to the new job being bulletined.

c) A new job is defined for the purpose of this Article as:

1. A newly created job which has not previously existed, or;

2. Any job within a section, the duties of which have not been performed by an employee within that section during the previous 6 month period. Seasonal jobs, agreed training jobs and jobs which are part of a hierarchy within a section, will not be considered as new jobs under this definition.

d) When jobs are to be downgrouped the Union will be notified and given reasons in writing 30 calendar days prior to the effective date.

2.03 **SALARY TREATMENT**

a) Changes in job groupings will be treated as follows:

1. upgroupings - Article 18.01 (b)
2. downgroupings - Article 18.06 (e).

b) Those employees who were downgrouped prior to May 1, 1989 and were red circled, shall receive blue circle salary treatment.

Those employees who were downgrouped prior to May 1, 1989 and were blue circled, shall continue to receive blue circle salary treatment.

2.04 JOB DESCRIPTION AND EVALUATION PROCEDURES

a) Job Review Requests

1. The incumbent(s) or the Union may request that a job be reviewed.

2. The immediate Manager shall, within 7 calendar days of receipt of the request, either accept or reject the request. If the request is rejected, the incumbent(s) or the Union may initiate an appeal pursuant to Article 2.04(b) within 7 calendar days of notification of the rejection.

3. If the request is accepted, the Company will have 14 calendar days to prepare and issue a draft job description to the incumbent(s) and the Union. The Company will then have an additional 14 calendar days in which to issue a final evaluated job description.

4. Upon receipt of the agreed job description, the incumbent(s) or the Union may appeal the evaluation on the grounds outlined in Article 2.05(b) (1) within 28 calendar days. Such appeal shall be referred in writing to the immediate Manager, with copies to the Compensation designate, and to Labour Relations, and specify the grounds of the appeal.

b) Job Evaluation Appeal Procedure

1. Step 1

   The appeal will be jointly investigated by a COPE Job Evaluation Officer and the appropriate Compensation designate in an effort to resolve the appeal with the immediate Manager and the employee. Following completion of the investigation, the immediate Manager will consider the appeal and provide a written response to the COPE Job Evaluation Officer (with copies to the Compensation designate and Labour Relations) within 10 working days.

2. Step 2

   An appeal not settled at Step 1 may be referred in writing by the Union to the appropriate Vice President (with copies to the Compensation designate and Labour Relations)within 10 working days of the Step 1 reply. The Parties shall meet to discuss and attempt to resolve the appeal. The Company shall reply within 15 working days of the date of the written referral to Step 2. If the appeal is not settled at this step, it may be referred to Step 3 by the Union within 40 working days of receipt of the Company's reply.

3. Step 3

   If the appeal is not resolved in (2) above, then the appeal shall be referred to the Job Evaluation Appeals Committee for a final and binding decision.

2.05 **JOB EVALUATION APPEALS COMMITTEE**

a) The Job Evaluation Appeals Committee (JEAC) shall consist of 4 nominees from the Company and 4 from the COPE. In the event of the resignation of either Party's nominee(s), the nominee(s) shall be replaced within 30 calendar days. There shall also be a Standing Arbitrator appointed from time to time as required upon nomination and approval of the Parties. At any time, by 30 days written notice of 1 party upon the other, the services of the Standing Arbitrator may be terminated.

b) Authority

1. To receive and to rule on appeals from employees, or the Union regarding the interpretation and application of the Job Classification System in terms of:

    a) whether all assigned duties and responsibilities have been considered in making the job classification decision;

    b) whether the job has been assigned to the appropriate Job Family based on its assigned duties and responsibilities;

    c) whether the job has been assigned to the appropriate Classification level based on its assigned duties and responsibilities; and

    d) whether the level is confirmed by the Point Factor Plan.

2. To recommend to the Parties administrative procedures required for JEAC to effectively carry out its responsibilities.

c) Procedures

1. JEAC decisions shall be by majority vote of the voting members. Voting members, 2 from the Company and 2 from the Union shall be selected by the Parties in advance of each meeting.

2. All voting members of the committee shall cast a vote on all questions. Tied votes shall be resolved by the casting of a vote by the JEAC Standing Arbitrator.

2.06 COST APPORTIONMENT

a) JEAC STANDING ARBITRATOR

1. The costs of the Standing Arbitrator shall be shared equally by the Parties. Such costs shall include the following: Arbitrator's salary and benefits, secretary, travel and incidental expenses.

2. The shared portion shall be billed to the Union.

3. A per diem rate will be determined by the Parties and reviewed and approved by the Parties annually. Where the parties cannot agree upon the per diem rate, such matter shall be referred to arbitration under Article 3.10 of the Collective Agreement. Such per diem rate will be shared equally by the Parties.

b) JEAC Members

The salaries of the JEAC members appointed by the COPE shall be paid by the Company. Expenses of these members shall be the responsibility of the COPE.

2.07 JOB EVALUATION EXCLUSIONS

a) If either of the Parties is of the opinion that the circumstances of a job are such that its value cannot be determined solely by application of the Job Classification System, the job shall be discussed by the HRD Officer and Union Job Evaluation Officer (or delegates) to resolve the question. If they agree, they will document the reason(s) for the Job Evaluation Exclusion.

b) If they cannot agree on the exclusion, or an agreement has not been reached within 5 working days, the question shall be referred to the JEAC Standing Arbitrator who will act as a single arbitrator in determining the applicability of the Plan to the job in question. The JEAC Standing Arbitrator will provide a ruling final and binding on both Parties, except as provided for in 2.07(d), within 5 working days of receiving the question and will provide the Parties with documented reason(s) for the ruling.

c) In the event that the Parties are unable to agree on an appropriate salary for a Job Evaluation Exclusion within 10 working days of a decision under (a) or (b) above, the Company shall implement the salary they proposed for the job, subject to the Union's right to refer the matter to arbitration pursuant to Article 3.10.

2.07 d) Excluded jobs will be reviewed bi-annually by the HRD Officer and the Union Job Evaluation Officer (or delegates) to determine whether or not the reasons for exclusion still exist and whether or not the Job Evaluation Exclusion status should continue to apply. If they cannot agree, then (b) above shall apply.

e) Once a question of exclusion has been resolved under the provisions of (a), (b) and/or (d) above, the question may not again be raised for the same job(s) within the term of the Collective Agreement.

f) Salary treatment resulting from the application of the provisions of Article 2.07 shall be as per Article 2.03 (a).

2.08 **WORK LEADERSHIP RESPONSIBILITIES**

Work leadership responsibilities shall be as follows:

a) may perform duties largely similar to those whose work they direct;

b) may perform duties related to, but at a higher level than the work of the subordinates whom they direct;

c) relieves the manager of detailed supervision of routine aspects of the work by:

1. ensuring even work flow and consistency of effort;
2. allocating various phases of work to different individuals within a general framework laid down by the manager;
3. transmitting the manager's instructions to other employees;
4. performing a quality control function in respect to subordinates;
5. warning subordinates of unacceptable performance (quality or quantity of work) or conduct (observance of hours, appearance, etc.). Should a subordinate's performance or conduct fail to improve as a result of such warning then the work leader will bring the matter to the attention of the manager who will then take suitable disciplinary action;
6. assists the manager in their responsibilities by providing on-the-job detailed training to employees with respect to the performance of their job duties.

d. if the classification of a job which has Work Leadership responsibilities does not result in a group which is at least one higher than that of any subordinate COPE position, then a group one higher than that of the highest COPE subordinate shall be assigned.

ARTICLE 3 GRIEVANCE PROCEDURE AND ARBITRATION

3.01 The parties to this Agreement are agreed that it is of the utmost importance to adjust complaints and grievances as quickly as possible in accordance with the procedures as set out in this Article. For the purpose of this Article the word "employee" when used, will be interpreted to refer to any employee of the Company who is a member of the bargaining unit. The grievor shall be allowed the necessary time off with pay to attend grievance meetings with the Company, including their arbitration hearing to a maximum of 7.5 hours per day at straight time, excluding travel time, cost of transportation and cost of board and lodging.

3.02(a) In this Agreement, unless the context otherwise requires, "grievance" means any dispute or difference between the parties to this Agreement concerning the discipline, dismissal or suspension of an employee bound by the Agreement or any dispute or difference between the persons bound by the Agreement concerning its interpretation, application, operation, or any alleged violation thereof, including any questions as to whether any matter is arbitrable. All grievances or disputes arising during the life of this Agreement shall be settled without stoppage of work and without strike or lockout.

3.02(b) Deleted in 2007

3.03 **UNION OR COMPANY (POLICY) GRIEVANCES**

a) Should either the Union or the Company consider that an action or contemplated action is, or will become, a difference or dispute between the parties concerning the application, interpretation, operation or any alleged violation of this Agreement; or any questions as to whether a matter is arbitrable, then such will be considered a policy grievance and will be dealt with as follows:

b) Deleted in 1999.

c) Should a policy grievance raised by the Union remain unresolved, the Union may refer the grievance to the Vice-President of Human Resources who shall, within 15 working days of the referral, arrange for no less than two Vice-Presidents to hear the Union's grievance and render a written decision within ten working days of the meeting.

3.03 d) If the grievance remains unresolved it may be submitted to a third party pursuant to Articles 3.10 or 3.13.

3.04 **TERMINATION, SUSPENSION GRIEVANCES**

Grievances concerning termination or suspension of an employee may be submitted directly to Step 2, Article 3.08 at the option of the grieving party, within 10 working days of the termination or suspension.

3.05 **JOB SELECTION GRIEVANCES**

a) Should any applicant feel that preference has not been given under the terms of Article 6.03, or should a more senior applicant feel aggrieved as a result of a job selection under Article 6.03, the applicant or a Union Representative on their behalf, will raise the matter with the selecting Manager or nominee within 10 working days of the date the unsuccessful applicant was notified in writing.

STEP 1

b) The selecting Manager or nominee will meet with the Union Representative and the unsuccessful applicant within 10 working days of being notified that a grievance has been filed to review the selection.

c) The selecting Manager, or nominee, will reply to the Union in writing within 5 working days with their decision to support or reverse the selection, and the reasons for the decision. A copy of this letter will be sent to the grievor.

STEP 2

d) Should the employee not be satisfied with the reply from the Manager, the Union may raise the matter with the Department Head in writing (with a copy to the Labour Relations Department) within 5 working days of the reply from the selecting Manager.

e) The parties will meet within 10 working days of the referral in (d) above, and the Department Head will render their decision in writing within 5 working days of the meeting.

STEP 3

f) The Union may refer the matter to arbitration under Article 3.10 at any time within 15 working days of the reply in (e) above.

3.06 **EMPLOYEE COMPLAINT**

Should an employee have a complaint, the employee along with the Union Steward whenever possible, will normally discuss such complaint with their immediate Manager in an effort to resolve same. Such discussion will take place not later than 10 working days after the event causing the complaint or within ten 10 working days from the time the employee became aware of the event causing the complaint.

GENERAL GRIEVANCES

3.07 **STEP I**

a) Should a complaint be unresolved, the complaint may be submitted by the Union Steward/Representative to the immediate Manager in writing, with a copy to the immediate Manager, the Union, and to the Labour Relations Department, not later than 7 working days from the date the complaint was first discussed under the complaint procedure, and will be considered a Step 1 grievance.

b) The immediate Manager (or nominee) will discuss the grievance as required with the Union Steward and/or Union Representative and render a written decision to the Union Representative with copies to the Union Steward, the Vice President and Labour Relations Department within 7 working days of the date of the referral at Step 1.

3.08 **STEP 2**

a) Should a grievance be unresolved at Step 1, the Union may refer the matter to Step 2 by writing to the Department Head, with a copy to the Labour Relations Department, within 10 working days of receipt of the decision at Step 1.

b) Within 10 working days of receipt of the Union's referral to Step 2, the Department Head will discuss the grievance with representatives of the Union and render a decision in writing within 10 working days of the discussion.

3.09 **STEP 3**

a) If the parties are unable to resolve the dispute the Union may refer the matter to Step 3 within 10 working days of the Step 2 response, by writing the appropriate Vice-President and the Vice-President, Human Resources (or delegates).

b) Within 15 working days of receipt of the Union's referral to Step 3, the appropriate Vice-President and the Vice-President Human Resources (or delegates) will discuss the grievance with representatives of the Union.

GENERAL GRIEVANCES (continued)

c) Within 10 working days of the discussion of the grievance between the appropriate Vice President and the Vice-President, Human Resources and representatives of the Union, the appropriate Vice-President will render a decision to the Union in writing.

d) Within 20 working days of receipt of the written reply at Step 3, the Union may refer the grievance to arbitration as set out in Article 3.10.

3.10 ARBITRATION PROCEDURE

a) Any grievance which has been properly processed through the relevant Steps of the grievance procedure without being settled may be submitted to a single arbitrator.

At the time that either party serves notice, in writing, of its intention to proceed to arbitration, it shall at the same time notify the other party of the names of potential arbitrators. The other party shall not be obligated to agree to 1 of the names put forward. Nevertheless, the Union and the Company shall, within 5 working days of notification being received by the other party, agree on a single arbitrator.

Should the parties fail to agree on the selection of an arbitrator within the prescribed time limit, application may be made by either party to the Minister of Labour to appoint an arbitrator.

b) The arbitrator shall be requested to render a decision within a period of 1 month following their appointment. The arbitrator's decision shall be final and binding on both parties to this Agreement.

c) The arbitrator shall not be vested with the power to change, modify, or alter any part of this Collective Agreement except under the provisions of Section 89 of the Labour Relations Code of British Columbia.

d) Each party shall pay one-half of the fees and expenses of the arbitrator, including any disbursements incurred by the arbitration proceedings.

3.11 Time limits specified in Article 3 may be extended by written agreement between the two parties.

3.12 The processing of any grievance may begin with Step 2 by mutual agreement of the parties.

SECTIONS 103 AND 87

3.13 Notwithstanding all of the foregoing provisions of this Article, at any time after the commencement of Step 1, the procedure set out in Section 103 of the Labour Relations Code of British Columbia (Bill 84 - 1992) may be implemented as follows:

"Where a difference arises between the parties relating to the dismissal, discipline, or suspension of an employee, or to the interpretation, application, operation, or alleged violation of this agreement, including any question as to whether a matter is arbitrable, during the term of this collective agreement, Mr. V. Ready or a substitute agreed to by the parties, shall at the request of either party:

a) investigate the difference;

b) define the issue in the difference; and

c) make written recommendations to resolve the difference within 5 days of the date of receipt of the request; and, for those 5 days from that date, time does not run in respect of the grievance procedure."

3.14 Section 87 of the Labour Relations Code of British Columbia shall be excluded by the operation of Article 3 of this Collective Agreement unless otherwise agreed by the parties on an ad hoc basis.

ARTICLE 4 SENIORITY

4.01 a) Seniority for the purpose of this Agreement shall be established on the basis of length of service with the Company as an employee within the terms of Article 1.01, and shall date from the commencement of such service. Seniority shall accrue on a Company-wide basis with Terasen Gas or its predecessor companies.

b) A regular employee shall be deemed to have seniority after 3 months' service. After completion of 3 months' service, seniority shall accrue from the date of employment.

c) Part-time regular employees shall accumulate seniority on the basis of time worked.

d) A temporary employee shall be deemed to have seniority after a total of 6 months accrued service accumulated on the basis of time worked, provided at least 1 day is worked in each calendar month, except that an employee on maternity leave or absent due to a disability caused by an off-the-job sickness or accident shall retain his or her seniority.

4.02 The Company shall keep a record showing the date upon which each employee's service commenced and terminated. A revised seniority list shall be prepared by the Company quarterly, and an electronic copy of the revised list will be forwarded to the Union the following month. The most current seniority list shall also be published on the Intranet.

4.03 An employee cannot count for seniority purposes, time lost from the Company's service as a result of being disciplined or while on lay-off.

4.04 An employee who is granted a leave of absence from the Company's service shall not lose seniority thereby.

4.05 a) If an employee with five or more years of seniority in the COPE bargaining unit resigns or otherwise leaves the bargaining unit and subsequently is rehired into the bargaining unit after January 1, 1998, s/he may reinstate this prior seniority to be effective five years after the employee's return to the bargaining unit if:

1. the employee serves notice to the union of intent to reinstate within two years of his or her return to the bargaining unit; and
2. the employee satisfies all other terms and conditions of reinstatement as determined by the union.

b) This article does not in any way diminish the company's rights with respect to the employee's probationary period.

4.06 "Service", for the purpose of this Agreement shall be established on the basis of employment with the Company, whether or not under the terms of Article 1.01, and shall commence from the date last employed.

ARTICLE 5 EMPLOYMENT, TRANSFER AND TERMINATION

5.01 a) All new employees entering the Company in a job covered by this agreement shall be considered as probationary for a period of 120 days at work and the Company may terminate their employment for any reason, except as provided in Article 1.08.

b) The Company may elect to extend the probationary period by a further period of up to 3 months by notifying the employee and the Union in writing any time prior to the expiration of the applicable probationary period set out in Article 5.01(a) above. The letter extending the probationary period will outline the reasons for such extended probationary period.

c) Such extended probationary period will be only to allow further performance assessment, and therefore the Company may terminate the employee during this extended probationary period for reason of inadequate performance and the provisions of Article 5.04 will not apply. All other provisions of the Agreement, including the accrual of seniority, will apply.

d) A temporary employee entering a full-time or part-time regular position in a different classification from a temporary position previously held, shall be subject to a three-month performance probation. The employee may be terminated during this period solely as a result of inadequate performance. The probationary period may be extended for an additional one month by mutual agreement of the parties.

e) FTR probationary employees, pursuant to Articles 5.01(a) and (b) are not eligible to bid on temporary positions.

5.02

a) Employees may be dismissed for cause without notice. The Company shall immediately notify the Union in writing stating the reasons for the dismissal. In the event the Union is not in receipt of a copy of such written notification and the same is not a willful act on the part of the Company, then such an event shall not be a breach of the terms and conditions of this Agreement.

b) An employee who is subject to discipline or dismissal shall have the right to request the presence of a Union Steward/Representative. The employee shall be advised of this right prior to proceeding with the disciplinary meeting.

c) Terasen Gas electronic media (including Internet access and e-mail) must not be used to access deliberately, download, store, copy or transmit pornographic, racist or sexist material. The parties further agree that any such activity is considered just cause for termination without compensation. This agreement does not prejudice either party with respect to discipline for any other types of offences.

5.03 Temporary employees shall give or receive the lesser of 10 working days notice of termination of employment or one working day notice for each month worked.

5.04 a) The Company recognizes the distinction between culpability and non-culpability as they relate to employee behaviour and performance. The company emphasizes coaching and counseling to correct non-culpable behaviour and performance. Coaching is an informal process that occurs on a day-to-day basis. When the employee's manager implements the counseling stage, s/he will meet with the employee and the Union steward to develop a written action plan for improvement.

b) Where the employee, despite appropriate coaching and counseling, is unable to achieve a reasonable standard of performance or behaviour, and where the employee is not culpable, the manager will place the employee on a performance probation of not less than 3 months. During this period the manager will continue to work with the employee and the Union steward with the view to improving the employee's performance to a satisfactory level to avoid termination. The parties will also cooperate with the view to placing the employee into a more suitable position within the Company.

c) If at the end of the probationary period no suitable alternative has been agreed to, the company may discharge the employee.

5.05 a) Employees may review their own personnel files. This may be done by making a written request to a Human Resources Management Officer, with a copy to the employee's <u>Manager</u>. Arrangements will be made for the employee to sit at a desk or in an office to review the file in the presence of the Human Resources Management Officer or their designate. It is understood that the file or any of its contents may not be removed from the designated area. <u>An employee may request and shall receive a copy of any document, record or report contained in the Employee's personnel file, not previously received.</u>

<u>b)</u> <u>A representative of the Union shall have the right to read and review an Employee's personnel file at any time, upon written authorization of the Employee and upon reasonable notice and by written request to the employer. On request, the Union representative shall be provided with copies of any document, record or report contained in the Employee's personnel file</u>.

<u>c)</u> A disciplinary notation or adverse performance notation which will form part of the employee's general record with the Company must be shown to the employee prior to being placed on the employee's file. The employee may initial the notation, but this will acknowledge only awareness of its existence, and the employee may write a rebuttal which must also become part of the employee's file.

<u>d)</u> Adverse disciplinary and/or performance notations must be removed from an employee's file 2 years after having been written. It is understood that repeated offenses will continue to remain on record until a clear 2 year period has been established.

5.06 Deleted in 2002

5.07 When specific projects or new or revised processes are to be planned and/or implemented, and the company seeks COPE members to be part of the planning and/or implementation process, the parties will meet to determine:

a) the extent to which COPE members will participate in the process, if at all;

b) the manner in which recruitment for the process is conducted;

c) whether compensation is warranted for that participation;

d) if the parties are unable to agree regarding compensation, the matter will be referred to the process established under Article 2.07(b).

This Article covers only employees whose regular job duties do not involve planning or implementing change to the company's operating procedures or processes.

5.08 WORKING OUTSIDE THE BARGAINING UNIT

An Employee who accepts a temporary position to an excluded position with the Employer outside of the bargaining unit shall accrue seniority for a period not to exceed eighteen (18) consecutive months from the date of commencement of such work. Upon expiry of this time limit, and continuation in the position outside of the bargaining unit, the Employee shall lose all seniority accumulated under this Agreement. An Employee choosing to return to the bargaining unit will return to their most recently held position within the bargaining unit. An Employee shall only have the right to accrue seniority while working outside the bargaining unit one (1) time in any eighteen (18) consecutive month period. It is understood that employees will pay Union dues during this period.

6.01 For the purpose of this Article, a job vacancy occurs when the Company requests a replacement for an existing job which has become vacant because of termination, promotion, etc., or when the Company creates a new job and seeks applicants for same, except temporary summer employment jobs which have been mutually agreed upon.

6.02 a) Except as otherwise provided in this Agreement, job vacancies shall be posted on the appropriate bulletin board and shall close 5 working days from date of posting, but may be filled on a temporary basis until applications have been processed and a regular appointment is made. The posting will not be removed from the bulletin board until a successful candidate has been notified. Late applicants who have been on annual vacation or sick leave during the posting period of five 5 working days will be considered provided their application is received prior to the successful candidate being notified.

b) The Company agrees that the Manager (or their designate) responsible for making the selection to a job vacancy will conduct placement interviews with at least the 3 most senior qualified applicants for the job.

c) Applicants shall receive notification of the receipt of their application and, when a regular appointment has been made, of the name of the successful applicant. Applicants have 10 working days after being advised by the Company that they were unsuccessful in a job competition to raise a job selection grievance under Article 3. A copy of the job vacancy bulletin will be sent to the Union at the same time it is posted on bulletin boards.

d) Applications for posted vacancies received from Temporary employees prior to the Bulletin closure date on or before their termination date shall be considered as internal applications for the purposes of Article 6.03(a).

e) If a selection has not been made for a posted position within 6 months of the closing date on the job bulletin, the position will be re-bulletined unless otherwise agreed.

f) When an employee is on leave for more than five working days, s/he may chose to register a standing application with Human Resources.

6.03 a) Preference in selection for vacant jobs within the bargaining unit shall be given to applicants in the bargaining unit who have the ability and qualifications to perform the vacant job and shall include consideration of an employee's performance on their current job.

b) Should more than 1 employee within the unit meet the above requirements, then preference shall be given to the senior employee as defined under Article 4.

c) If there are no applicants within the unit who meet the qualifications then the Company may fill the vacancy by hiring outside the bargaining unit. Such outside hire must meet the qualifications for the job.

d) If there are no applicants within the bargaining unit who meet the required education and experience qualifications, the company may, at its sole discretion, offer the vacancy to any regular member(s) of the bargaining unit, whether an applicant or not. In this event, the company shall designate an appropriate rate of pay and a schedule of progression for each such employee, during which time the employee must become fully functioning in the job.

e) The progression schedule designated in 6.03(d) above shall allow the employee to achieve no less than the minimum step of the job in five years or less. In the event the employee is unsuccessful in meeting the requirements of the job within the time limit of the designated progression schedule, the company many lay off the employee to the recall list, in which case the terms of article 7.06 apply (the employee is not entitled to exercise bumping rights under article 7.02(a)).

6.04 Where an employee has attained a lateral transfer as a result of a job posting, the Company will not be required to accept an application by that employee for another lateral transfer until they have completed 1 year's service in that position. Employees in this category should contact Human Resources if they are uncertain as to whether their application will be accepted.

6.05 An applicant who has been selected to fill a posted job vacancy and whose selection is being grieved, may assume the new position, but will be advised by the Company that a selection grievance has been initiated. In the event the grievance is sustained, the selected applicant will return to the position which they previously held.

6.06

a) For the purposes of this Article, a temporary position is defined as a position with a minimum duration of one partial day and a maximum duration of 18 months unless otherwise specifically agreed by the parties.

b) Temporary jobs shall be bulletined, excluding those involving summer relief (April 15th to August 31st), those where the temporary job lasts less than 6 months (except for maternity leave in which case a 3 month period applies), or others specifically agreed by the parties.

c) For positions under 6 months that are not bulletined, preference will be given to the senior available qualified employee within the same work group where the vacancy exists, pursuant to Article 6.03 (a). For vacancies under 6 weeks, the Company will give preference to the most senior employee within the workgroup who has the ability to perform the job with no further orientation or training. If none of these employees volunteer, the least senior employee may be appointed.

d) An extension to an unbulletined temporary position beyond 6 months shall only be by consent of the Union; otherwise the position, if extended, shall be immediately posted.

e) An extension to a bulletined temporary position beyond 18 months shall only be by consent of the Union; otherwise the position will be bulletined as a regular position. In this event, if the temporary position is occupied by a temporary employee who is not the successful applicant, then they will be terminated in accordance with Article 5.03. If they are the successful applicant, they will become regular as of the date they commenced employment in the position.

f) A regular employee who is a successful applicant for a temporary job will return to their regular position when the temporary job is concluded.

g) Any vacancy created by an employee moving to fill a temporary vacancy may be filled by the Company without posting. For positions that are not bulletined, preference will be given to the senior available qualified employee within the same work group where the vacancy exists, pursuant to Article 6.03(a).

h) Temporary jobs shall be re-bulletined if they become permanent in nature, unless otherwise specifically agreed by the parties.

i) Any employees bidding into temporary positions must complete the term of the temporary position as specified on the bulletin before bidding out into another temporary position, except by agreement of their regular Manager and their current temporary Manager.

j) Employees hired as Summer Students for Summer Vacation Relief or additional summer help will not accrue seniority and will not be entitled to apply on bulletined positions.

k) Salary levels for summer students will be the minimum of the Job Group within which their classification falls, except for specific Project Work as agreed by the parties, which will be paid at the Minimum of Group 3 or as otherwise agreed by the parties.

6.07 a) Where an employee has been selected to fill another position, the manager concerned shall release the employee as expeditiously as possible after being notified of the transfer by the Human Resources Dept. Successful applicants shall normally assume their new duties within 4 weeks from the date they receive written notification of their successful application. Where operational requirements do not permit successful applicants to assume their new duties within this period, the employee will be paid as if they were in the new position. The Company will also reimburse the employee for reasonable out-of-pocket expenses incurred as a direct result of the Company delaying the transfer. In no event will a transfer be delayed for longer than 3 months under this Article.

b) Eligibility for length-of-service progression on the new job shall be determined from the starting date in the new job or 4 weeks from the date of selection, whichever date shall first occur.

6.08 a) A FTR or PTR employee in a hierarchical* classification may be promoted to a higher level in that classification, at the same location, within the same work group, without that job being bulletined, provided; there is no vacancy, the promotion goes to the senior qualified employee and the number of employees in the work group does not increase. The Union shall be notified in writing of all instances where promotions are made under this clause.

*Hierarchical classification is defined as:

Engineering Drafter	[formerly: Drafter]
Measurement Accounting Chart Analyst	
Cathodic Protection Technician	[formerly: Technician - Corrosion Control]
Technologists – Instrumentation and Communications	
Technologists – Capacity Planner	[formerly: Gas System Planner]
Operations Support Representative (OSR)	

b) For purposes of the above hierarchical classifications, "work group" is defined as that group of employees who participate on the same shift schedule or, where no shift schedule exists, on the same vacation schedule. The position of Work Leader, if it exists, is not included in the hierarchy and any vacancy must be bulletined.

6.09 The Company and the Union shall meet periodically to jointly review all Company requests to alter the status of Part-time Regular positions to Full-time Regular positions. Where the Company can demonstrate that a position that was previously posted as a PTR has existed for at least 24 months and has evolved into a FTR position, the Union shall give consideration to waiving the posting provisions of this Article, allowing the present incumbent to evolve to FTR status.

7.01(a) The Company will provide the Union with no less than 60 calendar days written notice of intention to introduce automation or new equipment or procedures which might result in displacement or reduction of personnel or in changes of job classification.

(b) If it is necessary to lay off regular employees, the Company shall meet with the Union in a timely manner and advise the Union of the proposed reduction and the positions and employees affected.

(c) Prior to laying off any regular employee to the recall list, the Company shall terminate temporary employees in the department or location affected, provided the laid off employee has the present ability to perform the temporary employee's job.

(d) Regular employees shall be laid off in inverse order of their seniority, provided that the retained employees have the present ability to perform the job.

(e) Written notice or pay in lieu of notice will be given to regular employees for layoffs in excess of 13 weeks. Notice will be one week per year of service with a minimum notice of four weeks and a maximum notice of eight weeks. A copy of such written notice will be sent to the Union.

7.02(a) A regular employee who is subject to layoff may elect any same-status (FTR or PTR) option in 7.02(a) 1 and 2: except that if there are no opportunities or options under 7.02(a) 1, 2, or 3, a FTR or PTR employee may cross-status bump (FTR to PTR or PTR to FTR) the least senior PTR or FTR employee in their current headquarters in order to retain their current headquarters:

1. To be placed into other FTR or PTR vacant positions which the employee has the present ability to satisfactorily perform; or

2. To bump the least senior FTR or PTR employee in the following categories:

   a) in the same job classification at the employee's current headquarters; or

   b) in the same job classification in the same District; or

   c) in the same job classification Company-wide; or

   d) in a job classification which the redundant employee previously permanently held[1] at the employee's current headquarters; or

   e) in a job classification which the redundant employee previously permanently held[1] in the same District; or

   f) in a job classification which the redundant employee previously permanently held[1] Company-wide.

[1]In order to qualify as a job classification "previously permanently held" the employee must have held regular status in that classification and concurrently performed work in that classification for a period not less than 100 days at work.

7.02(a) 3. If there are:

a) no placement opportunities under 7.02(a)1 and

b) no bumping options under 7.02(a)2 the employee;

c) may elect to bump to the position held by the least senior employee, first in an equal group job and secondly in the highest lower group job that the redundant employee has not previously held but which, in the opinion of the Company, the employee has the present ability to satisfactorily perform.

d) bumping under 7.02(a)3 is limited to the location in which the employee is currently regularly employed unless there is no employee to be bumped at that location, in which case this bumping option will be expanded to the District as defined in article 7.05, and, failing this, to Company-wide.

4. a) In the event there is no opportunity for lateral vacancy placement or bumping under 7.02(a) 1, 2, or 3, the provisions of article 18.10(b)2 will apply.

b) If, however, the employee bumps or chooses placement to a lower group job, other than the highest group available below their current level, the provisions of article 18.10(a) will apply, except that, if eligibility for re-location expenses is avoided, the employee will receive article 18.10(b)2 protection provided s/he accepts placement or bumps to the highest lower level position available, either currently or in a subsequent placement opportunity pursuant to articles 7.02(a)6 or 8, below.

5. In cases of vacancy placement, the Union shall waive job postings, except in the event the union intends to pursue a grievance that the layoff is not founded in good faith.

6. An employee under protection of article 18.10(b)2 will be considered an automatic applicant to all vacancies posted pursuant to article 6 on the following basis:

a) an initial screening indicates the employee may be qualified;

b) the job is in a pay group above the job the employee currently occupies;

c) the job is in a pay group not higher than the job from which the employee was displaced or at which the employee is salary protected;

d) the job is a reasonable commuting distance from the employee's residence.

e) Article 18.10(a) will apply to employees who decline a position under this provision.

7. PTR employees re-locating pursuant to article 7.02 will receive reimbursement for moving expenses in direct proportion to the number of hours worked in the previous 12 months in relation to the annual 1826 hours worked by FTR employees.

7.02(a) 8. Upon displacement an employee already under salary protection pursuant to article 18.10(b) will be offered placement and bumping options under article 7 that reflect the salary level at which the employee is protected.

(b) Any election an employee makes under this article shall be given in writing to the Company no later than five working days after the Company has given the required written notice of layoff to the employee, identifying the employee's options.

(c) Where an employee has exercised the right to bump under article 7, or where an employee is placed into a vacant job or position in another town or district, the employee will be eligible for all travelling allowances, moving expenses and living expenses in accordance with Article 17.11.

(d) Regular employees with less than 12 months of service who are laid off shall be placed on the recall list pursuant to article 7.03 for a period of six months. Regular employees with twelve months or more of service who are laid off shall be placed on the recall list pursuant to article 7.03 for a period of twelve months. These periods shall be extended by the equivalent time of any temporary employment while on the recall list.

(e) The Company shall maintain an up-to-date recall list and provide a copy to the Union upon request.

7.03(a) No new employee will be hired until employees on the recall list who have specified in writing to the Human Resources Department the locations and the types of vacancies they wish to be notified of, and who have the present ability to perform the vacant job, have been offered the position in order of seniority.

(b) A vacancy at the same or lower salary group as the position which an employee on the recall list was displaced from or is salary protected at, shall not be posted until such employees on the recall list who have the present ability to perform the vacant job have been offered the position, in order of seniority.

7.04(a) When it is necessary to increase personnel in the job classification from which employees have been laid off, laid off employees will be recalled in order of seniority. The following conditions shall apply:

(b) Employees on the recall list are responsible for notifying the Human Resources Department of any change in their postal address or telephone number. Employees who have complied with the foregoing procedure shall be notified by the Company either personally by telephone, or failing that, by registered mail at their last known address of the date on which they are to report for work.

(c) Should an employee fail to report for work within seven days of being notified personally by telephone or within 10 days of the postal registration date of the written notice, the employee shall lose the right of recall and seniority.

(d) An employee who has been laid off in accordance with the provisions of article 7 will be removed from the recall list if they have not been recalled at the conclusion of the recall period as defined in Article 7.02(d), unless the employee is unable to work due to sickness or injury at the time of recall. At the Company's request, the employee will be required to produce a medical certificate to substantiate that the sickness or injury prevented the employee from working.

7.05 **DEFINITION OF DISTRICTS**

For the purposes of this agreement, Districts shall be defined as follows:

a) Lower Mainland District covers employees employed in the Lower Mainland (Greater Vancouver to Hope);

b) Northern District covers employees employed at the company's Interior operations north of the Trans Canada Highway;

c) Southern District covers employees employed at the company's Interior operations in communities on the Trans Canada Highway or south of it.

7.06 Where an employee does not exercise bumping rights or vacancy placement pursuant to article 7, the employee may elect to terminate with severance of two weeks pay for each completed year of service, or elect layoff and placement on the recall list pursuant to this article, in which case severance pay of the amount originally accrued shall be paid at the end of the recall period, if the employee has not been permanently recalled by that time.

7.07 Return to Former Position: The active regular employee with the highest seniority who was previously displaced from a classification shall have preference to return to that classification if a position at the headquarters the employee was displaced from becomes vacant within 12 months of the effective date of displacement from that classification and the union will waive the requirement to bulletin the job. If the employee is under salary protection and chooses not to return to the classification, s/he shall lose that salary protection unless s/he has moved since the layoff due to a change of headquarters and is now living more than a reasonable commuting distance from the location of the vacancy.

7.08 **ELIGIBILITY POOL**

Where the collective agreement simultaneously entitles more than one employee to be offered, placed, or recalled to a specific vacant position, the most senior eligible employee will have precedence. For each vacancy, all eligible employees will be placed in a common "eligibility pool" and the company will place/offer/recall from that pool, in order of seniority. Each employee's options and consequences of accepting or declining the option will be determined by the specific article which makes that employee eligible for placement/offer/recall.

ARTICLE 8 TECHNOLOGICAL OR PROCEDURAL CHANGES

Merged with Article 7 in 1998.

ARTICLE 9 LEAVES OF ABSENCE

9.01 Compassionate leave of absence of up to 5 days, 3 days with pay and 2 days without pay, shall be granted an employee upon application in the event of a death of a spouse, son, daughter, mother, mother-in-law, father, father-in-law, sister, sister-in-law, brother, brother-in-law, or grandparents and for legitimate personal reasons acceptable to the Company.

9.02 One-half day shall be granted without loss of pay to attend a funeral as pallbearer or mourner, provided such absence does not interfere with the efficiency of the department.

9.03 An employee who is subpoenaed as a witness and appears, or who attends for, or serves on jury duty shall continue to receive their salary, provided such court action is not occasioned by the employee's private affairs.

9.04 **MEDICAL/DENTAL APPOINTMENTS**

a) Wherever possible, employees shall schedule medical and dental appointments outside of normal working hours. Regular employees who go for medical and dental appointments will not have any such time deducted from their sick leave or their pay where the period of absence from work is two hours or less. Medical and dental appointments requiring an absence from work beyond two hours will result in the excess over two hours being deducted from sick leave or from pay (if paid sick leave is exhausted). Managers at their discretion may grant extra time without deduction in locations where medical and dental facilities are remote.

b) The Union agrees that employees should cooperate with their Manager by providing as much notice as they can of pending medical and dental appointments; this is to facilitate replacement staff and scheduling of work. Furthermore, the Union will encourage its members to make every effort to schedule their appointments on ADO days, near the end of a working day or lunch time to help minimize the impact of medical or dental appointments.

9.05 a) Regular employees may be granted leave of absence without pay upon application to their Manager where such leave of absence does not exceed 14 calendar days, insofar as the proper operation of the service will permit. All leaves of absence must be approved by the Company.

b) Employees who have completed 5 or more years of service shall, on request, receive 10 scheduled working days leave of absence per year without pay. All days taken in any calendar year must be consecutive, (exclusive of other scheduled days off), i.e. 1 occurrence per year only. The leave of absence shall be scheduled at a time mutually agreeable between the employee and the Company and such agreement will not be unreasonably withheld.

9.05 c) It is agreed that an employee cannot request or be granted a leave of absence, for reasons other than maternity/parental leave, until all of their outstanding vacation entitlement has either been taken, or is scheduled to be taken.

d) After 10 calendar years of service an employee will be entitled to a one-time unpaid long service leave of up to 12 months. No alternative paid employment may be undertaken by an employee during this leave. This leave is subject to the terms and conditions set out in Article 20.02.

MATERNITY LEAVE

9.06 a) An employee who qualifies for maternity leave shall be entitled to a maximum of 17 weeks without pay in accordance with the Employment Standards Act of B. C. During the maternity leave of absence, the B. C. Medical Services Plan, Extended Health Benefit Plan, Life Insurance, Dental Plan and Pension Plan (as applicable) will continue in force subject to the employee paying her share, if any, of the costs.

b) Employees requesting both maternity and parental leave must apply for them both at the same time.

c) No less than thirty (30) days prior to the commencement of the leave, the employee must notify her manager (or designate) of the start date for the leave, the number of weeks leave she intends to take and provide a certificate or letter from a duly qualified medical practitioner, which will state the expected delivery date.

d) The period of leave can be shortened after commencement of the leave upon a further thirty days notice.

e) Any extension of leave beyond the total leave of 52 weeks (maternity and parental together) will be at the sole discretion of the company. There will be no annual vacation accrual during any such extension period.

9.07 **PARENTAL LEAVE**

a) To request parental leave only, an employee must notify their manager in writing no less than 30 days prior to the commencement of the leave. The notice must include the start and end dates. During parental leave, the B.C. Medical Services, Extended Health Benefit Plan, Life Insurance, Dental Plan and Pension (as applicable) will continue in force subject to the employee paying their share, if any, of the costs.

b) If this leave is in conjunction with the maternity leave, notice must have been received at the same time the maternity leave was requested.

c) An employee who qualifies for parental leave shall be entitled to leave without pay in accordance with the Employment Standards Act of B. C. as follows:

1. birth mother – up to a maximum of 35 consecutive weeks which must be taken immediately and continuously following the maternity leave;
2. birth father – up to a maximum of 37 consecutive weeks beginning after the child's birth and within 52 weeks after that event;
3. adoptive parent – up to a maximum of 37 consecutive weeks beginning within 52 weeks after the child is placed and must not commence prior to the birth or placement of the child.

Any requests for this leave must be accompanied by legal documentation of the birth or adoption.

d) To change to an earlier return date, employees must notify their immediate manager (or designate) in writing no less than 30 days prior to the desired date of return. If the employee fails to provide notice or fails to return to work on the expected return date, the vacancy may be filled on a permanent basis.

9.08 MATERNITY LEAVE DISABILITY

a) The parties agree that regular employees who are on maternity leave and who have given birth to a child shall receive a six-week EI top-up as follows:

b) Eligibility for the top-up is identical to the eligibility criteria for paid sick leave allowances on the employee's last working day prior to commencing maternity leave.

c) The top-up shall be to 70% or 100% of regular earnings (per the employee's entitlements under Article 10.02) and shall commence with the date of birth.

d) Regular earnings for purposes of this Article are defined as the employee's base rate earnings for her regular job (not necessarily the job she is in when commencing maternity leave) and do not include any premium payments.

e) The company's contributions pursuant to the foregoing shall not reduce the employee's paid sick leave allowances or any other of the employee's time-off entitlements. However, the company's contributions are limited to the equivalent of the employee's balance of paid sick leave allowances - in other words, an employee is not entitled to a greater 'sick leave' benefit under this Article than she would be for any other disability.

f) The first stage of top-up (currently the two-week EI waiting period) is subject to proof that the employee has filed an EI Maternity Claim and is serving the EI waiting period.

g) The second stage of the top-up (following the two-week EI waiting period) is subject to the employee submitting proof of receipt of EI benefits during the applicable period.

h) Employees can expect a delay of several weeks in obtaining the documentation from EI, and therefore should expect to receive some or all of the Terasen Gas top-up retroactively

i) Should the employee's birth-related disability continue beyond the six-week top-up period, the company will continue the appropriate top-up amount for so long as the birth-related disability continues, or until EI entitlements are exhausted, or until 'sick-leave-equivalent' entitlements are exhausted (per Paragraph 5), whichever first occurs.

j) The disability-related portion of the maternity leave is considered part of the term of maternity leave specified by Article 9.06.

k) Should the employee continue to be disabled as a result of complications from the childbirth at the end of the maternity leave period, the LTD provider's 15-week waiting period is deemed to run concurrently with the employee's maternity leave from the date of childbirth.

l) The Terasen Gas claims management process will be used to assess all medically-related absences except for the six-week period immediately following the date of childbirth. Absences immediately following this six-week period will **not** be subject to the normal five-day waiting period for claims management.

m) The employee is not eligible for paid sick leave allowances for a disability not related to childbirth unless the disability was pre-existing to the period of maternity leave.

ARTICLE 10 PAID SICK LEAVE ALLOWANCES

10.01 A regular employee becomes eligible for paid sick leave benefits after accumulating 3 months of service with the Company.

10.02 Employees who are unable to work as a result of a disability caused by an off-the-job sickness or accident will be eligible to receive the following paid sick leave benefits:

a) **Paid Sick Leave Allowance Per Plan Year**

Period of Service with the Company at Previous July 1	Full Regular Earnings For	Followed By 70% of Regular Earnings For
3 mos - 1 yr less 1 day	1 week	14 weeks
1 yr - 2 yrs less 1 day	2 weeks	13 weeks
2 yrs - 3 yrs less 1 day	3 weeks	12 weeks
3 yrs - 4 yrs less 1 day	4 weeks	11 weeks
4 yrs - 5 yrs less 1 day	5 weeks	10 weeks
5 yrs - 6 yrs less 1 day	6 weeks	9 weeks
6 yrs - 7 yrs less 1 day	7 weeks	8 weeks
7 yrs - 8 yrs less 1 day	8 weeks	7 weeks
8 yrs - 9 yrs less 1 day	9 weeks	6 weeks
9 yrs - 10 yrs less 1 day	10 weeks	5 weeks
10 yrs - 11 yrs less 1 day	11 weeks	4 weeks
11 yrs - 12 yrs less 1 day	12 weeks	3 weeks
12 yrs - 13 yrs less 1 day	13 weeks	2 weeks
13 yrs - 14 yrs less 1 day	14 weeks	1 week
14 yrs or more	15 weeks	0

a) **Paid Sick Leave Allowance Per Plan Year**

Effective January 1, 2011, the following shall apply:

Period of Service with the Company at Previous July 1	Full Regular Earnings For	Followed By 70% of Regular Earnings For
3 mos - 1 yr less 1 day	3 week	23 weeks
1 yr - 2 yrs less 1 day	5 weeks	21 weeks
2 yrs - 3 yrs less 1 day	7 weeks	19 weeks
3 yrs - 4 yrs less 1 day	10 weeks	16 weeks
4 yrs - 5 yrs less 1 day	13 weeks	13 weeks
5 yrs - 6 yrs less 1 day	15 weeks	11 weeks
6 yrs - 7 yrs less 1 day	17 weeks	9 weeks
7 yrs - 8 yrs less 1 day	19 weeks	7 weeks
8 yrs - 9 yrs less 1 day	21 weeks	5 weeks
9 yrs - 10 yrs less 1 day	24 weeks	2 weeks
10 yrs – and more	26 weeks	0 weeks

10.02 b) Employees who had less than 3 months service as at the previous July 1st, or who were not employed by the Company at the previous July 1st, will have their period of service determined as the period of time from the date their employment with the Company commenced until the date of their disability.

10.03 A plan year is defined as a 12 month period beginning on July 1st, and ending on June 30th.

10.04 a) For purposes of the Article "regular earnings" means the daily rate in effect at the date of disability, for the employee's normal job classification, as determined by dividing the employee's normal bi-weekly salary by ten.

b) Where an employee is in receipt of a temporary promotional increase pursuant to Article 18.08 and that promotional increase is for a specific period of time exceeding 2 weeks in length, then, the employee's "temporary earnings" will be utilized to calculate the daily rate outlined in the first paragraph above. The daily calculation will not utilize the "temporary earnings" for a longer period of time than originally specified.

10.05 When the entitlement at full regular earnings has been exhausted, employees will be eligible to receive further paid sick leave benefits of seventy percent (70%) of regular earnings for the balance of a 15 week <u>(a 26 week, effective January 1, 2011)</u> period. Note: See Article 21.04(e) for supplementary entitlement.

10.06 Any unused days of paid sick leave allowance at full regular earnings cannot be carried over from one plan year to the next. If a disability continues into a new plan year, the amount of benefits at full regular earnings for that disability in the new plan year will be the balance of what is left from the previous plan year's full regular earnings entitlement.

10.07 Employees may utilize part of the paid sick leave allowance accruing to them under Article 10.02 in the event of injury or illness to a dependent child on the following conditions:

a) a maximum of one-half of annual full regular earnings allowance may be used for this purpose; but

b) no more than a total of 5 days may be used for this purpose in any plan year; and

c) use of this provision is limited to a maximum of 4 separate occurrences per plan year; and

d) Deleted in 2007

10.08 a) If an employee has received 15 weeks <u>(26 weeks, effective January 1, 2011)</u> of paid sick leave benefits and returns to active duty, the employee will have their entitlement as at the previous July 1st, reinstated after 1 month's service in the case of a new disability, and after 3 months' service in the case of the same or a related disability.

10.08 b) If a disabled employee has exhausted their paid sick leave benefits prior to the expiry of the 15 week (26 week, effective January 1, 2011) elimination period for Long Term Disability, s/he shall be paid 70% of regular earnings for the balance of the elimination period.

10.09 Benefits under this plan will be reduced by any benefits an employee receives under any government sponsored plans, other than Employment Insurance. Income benefits from any individual disability policy which has been purchased by an employee will not be considered in determining benefit entitlement under this plan.

10.10 Employees absent from work for any of the following reasons will not be eligible for paid sick leave benefits:

a) disabilities which occur while the employee is on maternity leave,

b) disabilities covered by any Workers' Compensation Act,

c) disabilities caused by intentionally self-inflicted injuries or disease; while serving in the Armed Forces; while participating in a riot, war or civil disobedience; or while committing a criminal offence or serving a prison sentence.

10.11 When an employee is given notice of layoff and the employee subsequently becomes disabled within 2 months of the effective date of the layoff, the paid sick leave benefits will terminate on the effective date of the layoff.

10.12 Employees with health problems will be considered for severance pay providing the employee is not receiving long-term disability benefits.

10.13 (a) At the request of the Company, employees will provide a medical certificate by a licensed physician substantiating any disability extending beyond 5 working days, or to substantiate absences in excess of 4 occurrences in any calendar year. All such medical certificates are expected to meet the standards for Medical Certificates in the CPSBC Policy Manual, and the cost of such medical certificate, if any, will be borne by the company.

(b) The Company recognizes its duty to accommodate to the point of undue hardship, employees with medical disabilities. Where it is clear that an employee's absences are related to a recognized disability, the company will endeavour to work with the employee, the employee's doctor and the union, in order to accommodate the employee in preference to continually requesting medical certificates pursuant to clause 'a' above. This process does not prejudice the employee, the company or the union from implementing other process that are legally available to them.

(c) An employee may be required to submit to an examination by a licensed physician who is mutually agreeable to the employee and the Company. Should this examination result in a cost that is not borne by the Company's medical plan, the cost of such examination will be paid by the Company. In the event the parties cannot mutually agree upon a licensed physician, the B.C. College of Physicians will be requested to appoint a licensed member.

10.14 Employees who leave the Company subsequent to April 1, 1975 and are rehired will receive credit for past service in establishing paid sick leave entitlement provided the employee is rehired by the Company within 3 years.

10.15 It is understood that the plan may be altered or amended from time to time in order that the plan will continue to meet the standards of the <u>Employment Insurance</u> regulations and thereby qualify the Company for a full premium reduction.

10.16 In cases where employees are on compensation and receiving Workers' Compensation Board payments, the Company will pay the difference between such payments up to a maximum of 85% of the employee's normal 35 hour weekly straight time wages for the period the employee is paid by the Workers' Compensation Board, but in any event, the percentage of contribution by the Company shall not be greater than that which would give the employee an income, including the Workers' Compensation Board payments that s/he would have received for a normal 35 hours straight time wage after the deduction of income tax. This paragraph shall only apply to those employees who have served their probationary period and/or hold a bulletined job. Neither the time off nor the payments shall be charged to sick leave credits.

ARTICLE 11 HEALTH & SAFETY and UNIFORMS

11.01 When an employee is required to wear a uniform, the uniform will be provided by the Company at no cost to the employee. The Company will also pay the cost of reasonable periodic cleaning of such uniforms.

11.02 Where required, protective clothing such as smocks, safety hats, and, with the approval of the Manager, raingear will be provided by the Company at no cost to the employee.

11.03 When safety footwear is advisable in the performance of some or all job duties and approved by the Manager, the employee shall be reimbursed for fifty percent (50%) of the cost (to a maximum of $165.00) of one pair of protective safety footwear per calendar year. Purchase shall be limited to C.S.A. approved footwear.

11.04 Working Practices

(a) It is the intent of the Parties to this Collective Agreement to conduct a safe operation.

(b) Working practices shall be governed by the regulations of the province of British Columbia insofar as they apply.

(c) No employee shall undertake any work which the employee has reasonable grounds for believing that the work is unsafe. Such incidents must be immediately reported by the employee, and investigated by the local management.

(d) No employee shall be subject to discipline for acting in compliance with sections 3.12 of the Workers' Compensation Board Industrial Health and Safety Regulations.

(e) Safety Committee meetings shall be held as per the Workers' Compensation Board Industrial Health and Safety Regulations and the practice of the parties.

12.01 The Company's various operations have required and will continue to require shift work.

12.02 The Company will provide the Union and affected employees with 3 months' notice prior to introducing shift requirements in a work area for the first time. Thereafter the shift schedule may be varied upon 30 calendar days notice to the affected employees.

12.03 Should an employee's position become a shift position, the employee will have the option to either:

a) accept the shift position, or

b) decline the shift position. In the latter event, the shift vacancy will be filled in accordance with the provisions of Article 6.02; the employee who has declined the shift position will continue to work regular days and hours, or will be treated in accordance with the provisions of Article 7. In the event of layoff, the declined shift position is not considered a placement option or a bumping option for purposes of Article 7.02(a)3.

12.04 With the exception of employees who are covered by LOU #7 and LOU #31, and those employees who are covered under Article 15.09, full-time regular employees working shifts shall be governed by the following conditions:

a) **WORKING HOURS**

1. The hours of work shall be the equivalent of 35 hours per week. This will be done by allowing 17 days a year Accumulated Days Off (ADOs) in lieu of the 35 hour week.

2. An ADO will be earned in each of the 17 biweekly pay periods which do not contain a statutory holiday. Notwithstanding the standard defined in Article 15.08(a) or the provisions of Article 15.08(c), it is intended that ADOs will normally be scheduled to allow shift employees one full day off in each 3 week period excluding the last week of the calendar year.

b) **WORK DAY**

Any consecutive 7.5 hours of work, exclusive of lunch period, in a 24 hour period, except that a shift may not start between 1201 and 1459.

c) **WORK WEEK**

Any consecutive 5 days of work out of 7 consecutive calendar days. The remaining 2 days will be scheduled as days off in lieu of Saturdays and Sundays

12.04 d) **STATUTORY HOLIDAYS**

In recognition that statutory holidays may be scheduled work days for shift workers, employees will be scheduled off for 11 days in lieu of statutory holidays. These days off in lieu of statutory holidays shall normally be scheduled in the pay period in which the statutory holiday falls.

e) **SHIFT PREMIUMS**

Notwithstanding any other language in the collective agreement, a 12% shift premium shall be paid for all hours worked between 1500 and 0800 Monday to Friday, and all hours worked on a Saturday, Sunday or Statutory Holiday.

f) **LUNCH BREAKS**

The lunch break will be taken as close as possible to mid-shift but may be varied or staggered for different employees from one hour before to one hour after the middle of the shift according to the needs of the work in progress.

g) **WORK BREAKS**

Each employee shall receive 2 work breaks of 15 minutes in each day's work schedule. The first such break shall occur during the tour of duty prior to the lunch period and the second break shall occur during the tour of duty prior to quitting time.

h) **OVERTIME PAYMENTS**

All time worked in excess of the hours specified in Article 12.04 shall be paid for at the rate of double time. All overtime worked on scheduled days off in lieu of Saturdays, Sundays and statutory holidays shall be paid at the rate of double time. All time worked on annual vacation shall be paid for at double time plus regular salary.

i) **OVERTIME BANKING**

Any election to bank under this provision will be done in accordance with Article 16.07.

12.04 j) **SIGN-UPS**

1. A majority of any group of shift workers may elect to sign-up on a seniority basis to establish the choice of shifts, location and days off. Periods of the sign-up shall be 51 weeks or 24 weeks or more frequently by mutual agreement, provided that the period shall be a multiple of 3 weeks.

2. Shift sign-up shall be by seniority as defined in Article 4 or by criteria determined by a simple majority of the group concerned, subject to approval by the Company and the Union. Once established, the sign-up criteria may not be changed except by a two-thirds majority vote of the group concerned. The seniority list will be posted in conjunction with the sign-up.

k) **NOTICE OF RELIEF**

1. To provide relief coverage for unscheduled leaves of absence due to sickness, accidents, etc., the Company may request an employee to temporarily change their shift. When shift employees' scheduled shifts are changed, 2 calendar days notice will be provided. If less notice is given, up to the first two of the changed shifts, occurring consecutively, shall be at double time rates as follows:

   a) 48 hours notice - no penalty;

   b) 24 hours notice - 1 shift at double time;

   c) Less than 24 hours notice - 2 shifts at double time.

2. a) Shift changes requested by the employee will not be subject to overtime penalties.

   b) Designated relief employees incurring shift changes with less than a 16 hour break between the end of one shift and the beginning of their next shift will be paid one shift at double time.

ARTICLE 13 STATUTORY HOLIDAYS

13.01 The following statutory holidays shall be recognized by the Company:

New Year's Day	Labour Day
Good Friday	Thanksgiving Day
Easter Monday	Remembrance Day
Victoria Day	Christmas Day
Canada Day	Boxing Day
B.C. Day	

and any other day declared a holiday by Federal, Provincial and Civic Governments. Civic holidays shall be observed only in the area affected.

13.02 Any of the above holidays falling on a Saturday or Sunday will be observed on Friday or Monday at the Company's option.

13.03 Statutory holiday pay for part-time regular employees shall be paid in accordance with Article 19.02(g) of this Agreement.

13.04 Shift workers shall receive an equivalent number of days off. These days off in lieu of statutory holidays shall normally be scheduled in the pay period in which the statutory holiday falls.

14.01 Moved to Article 14.06 – in 2001

14.02 **YEAR-OF-HIRE VACATION ENTITLEMENT**

Vacation entitlements will be advanced in January of the calendar year it is earned, and it will be prorated for new hires based on the year of hire service.

14.03 **ANNUAL VACATION ENTITLEMENTS**

A regular employee shall EARN their annual vacation entitlement for any calendar year only when s/he reaches their anniversary, although they may TAKE their annual vacation anytime during that calendar year. Annual vacation entitlements with pay shall be as follows:

a) Employees who terminate prior to their first anniversary date will receive vacation pay at the rate of 6% of gross earnings less any pay actually received for vacation taken.

b) **Vacation Entitlements**

In the calendar year of:

1st - 9th anniversary	-	3 weeks
10th - 17th anniversary	-	4 weeks
18th - 29th anniversary	-	5 weeks
30th and later anniversary	-	6 weeks

In the calendar year of: (Effective January 1, 2011)

1st - 7th anniversary	-	3 weeks
8th - 17th anniversary	-	4 weeks
18th - 24th anniversary	-	5 weeks
25th and later anniversary	-	6 weeks

14.04 **PAYMENT OF VACATIONS**

a) Payment for vacations will be made at an employee's rate of pay at the time the vacation is taken, or depending upon their vacation entitlements, at the rate of 6%, 8%, 10% or 12% of their current year's earnings, whichever is the greater. Adjustments arising out of the percentage application will be made in the first quarter of the following year. Notwithstanding the foregoing, banked vacations will be paid at the employee's rate of pay at the time the vacation is taken.

b) Deleted in 2001

c) Deleted in 2001

d) Deleted in 2001

e) Effective 1 January 2002 upon termination of service all employees will receive final vacation pay prorated on the basis of an anniversary date of 1 January.

14.05 **BROKEN VACATIONS**

Vacations may be taken in broken periods but normally at least 2 weeks of the year's entitlement must be taken as a continuous period. Employees shall select their vacation periods in order of seniority as defined in this Agreement. However, only one vacation period shall be selected by seniority until all employees in the signing group have selected one period. Subsequently, all employees in the signing group who have chosen to take their vacation in broken periods shall select in order of seniority for a second vacation period and again for subsequent periods until all periods are chosen.

14.06 **SCHEDULING VACATIONS**

Vacation periods shall not conflict with essential departmental requirements. However, agreement to schedule time off shall not be unreasonably withheld by the Manager. Employees are encouraged to take all of their earned annual vacation before the end of the calendar year. Employees are required to take a minimum of 25 days off each year, this includes time earned for both Annual Vacation and ADOs/PDOs.

If the employee is unable to take the balance of time off in excess of 25 days, then the balance at year end will be transferred to the Cash/Time Bank.

Time off will be taken from the following banks in succession until they are depleted.

Time Banks:	Description:
1. Current AV/ADO/PDO	Current AV advanced; current ADOs/PDOs earned
2. Time Bank	Non-renewable time bank. Balance of hours in the EB Time and Permanent bank as of December 31, 2001
3. Cash/Time Bank	Banked overtime and year end rollover of current AV and ADOs./PDOs Withdrawals from this bank can be either time off or cash. This bank can exceed 18 weeks only with managerial approval.

14.07 **STATUTORY HOLIDAYS DURING VACATIONS AND LEAVE OF ABSENCE**

An employee will be granted a day in lieu with pay for each statutory or Company-observed holiday falling in their paid vacation period, or falling within any leave of absence period not exceeding 10 working days.

14.08 **RELIEVING ON HIGHER-GROUPED JOB**

a) If an employee is relieving on a higher-grouped job at the time they go on vacation, and their promotion involves salary adjustment, their annual vacation will be paid at the higher rate if it is both preceded and followed by working time on the higher job and if there is a minimum of 20 working days at the relief level.

b) However, if an employee is required to postpone their period of annual vacation in order to carry out the duties of a higher-paid position for an uninterrupted period of a temporary transfer, and must therefore take their annual vacation at some other less convenient time, they shall nevertheless qualify for the higher rate for vacations as set out in the paragraph immediately preceding.

14.09 **PRORATION OF ANNUAL VACATION ENTITLEMENT**

a) ABSENCES DUE TO SICK LEAVE, LONG-TERM DISABILITY OR WORKERS' COMPENSATION INJURY.

In any case where an accumulation of such absences exceed 6 calendar months in a calendar year, vacation entitlement for that year will be reduced by 1/6 for each full month of absence in excess of 6 months.

b) ABSENCES OTHER THAN SICK LEAVE, LONG TERM DISABILITY, WCB AND ANNUAL VACATION.

Where an accumulation of such absences exceed 3 calendar months in any calendar year, annual vacation will be reduced by 1/9 for each full month of absence in excess of 3 months.

c) It is understood that Article 14.09 will not apply to the period of maternity leave described in Article 9.06(a) of the Collective Agreement. This understanding is without prejudice to the position of the Parties in the relationship of maternity leave to other provisions of the Collective Agreement.

14.10 **INLAND/COLUMBIA VACATION ENTITLEMENT**

Former Inland/Columbia employees as at September 14, 1989 shall retain their annual vacation and supplementary vacation entitlements and horizons in accordance with Article 7.03 and 7.10 of the 1988/89 Inland/Columbia Collective Agreement.

CANCELLATION OF VACATION

14.11 An employee shall be reimbursed for any financial loss actually incurred as a result of the cancellation by the Company of a scheduled annual vacation.

PAST SERVICE CREDITS

14.12 Employees who leave the Company subsequent to April 1, 1977 will receive credit for past service in establishing vacation entitlement provided any such employee is rehired by the Company prior to the expiry of a period of not more than 3 years. Such additional vacation entitlement shall not accrue until 1 January of the year following the re-hire date.

ARTICLE 15 HOURS OF WORK AND ADOS (Standard Model)

Employees Hired – January 1, 2008 – March 31, 2012
Legacy Employees - Effective January 1, 2011 – March 31, 2012

15.00 Deleted on January 1, 2011.

15.01 The hours of work of all employees, except those otherwise specifically mentioned in this Agreement, shall be as follows:

(a) Standard hours of work are 0630 to 2000, Monday through Saturday;
(b) Core hours are 0630 to 1730, Monday through Friday.
(c) The standard start time will be a specific time between 0630 and 1200 hours inclusive.
(d) The company may vary an employee's start time and work week upon 2 weeks notice. An employee's schedule cannot be varied more often than once every 90 calendar days.
(e) The start time parameters of article 15.01(c) may be extended by mutual agreement between the manager and an employee.

15.02 **WORK WEEK**

The standard work week shall be any 5 consecutive days Monday through Saturday.

15.03 **WORK DAY**

The work day shall be any 7.5 consecutive hours of work, exclusive of lunch period, subject to the provisions of Articles 15.01 and 15.04.

15.04 Deleted on January 1, 2011.

15.05 **WORK BREAKS**

Each employee shall receive 2 work breaks of 15 minutes in each day's work schedule. The first such break shall occur during the morning tour of duty prior to the lunch period and the second break shall occur in the afternoon tour of duty prior to quitting time.

15.06 **LUNCH BREAK**

The standard lunch break shall be at or near the midpoint of the working day and shall be either one hour or 1/2 hour as determined by mutual agreement between the manager and an employee or group of employees. Failing agreement, the practice in place at that time will continue.

15.07 **NON-CORE PREMIUM**

All time worked before 0630 and after 1730, and all standard hours worked on Saturday, shall be subject to a 12% non-core-hour premium. This premium is not paid if the time worked during these hours is at the employee's request, or if it attracts a higher premium rate pursuant to Articles 13 and 16.

15.08 Deleted on January 1, 2011.

15.09 PURCHASED DAYS OFF (PDO)

a) PDOs include days off elected annually by Full-time Regular employees from their 4% Flex benefit allocation.

b) FTR Legacy employees who were FTR on December 1, 2007 may choose, annually, an additional seven (7) PDOs in lieu of the 3% Employee Savings Plan effective January 1, 2011. The seven (7) PDOs shall be pro-rated for employees who terminate during the calendar year.

c) PDOs shall be taken in the year that they are credited. If the employee is not able to take their full PDO entitlement during that year, the unused balance shall be transferred to the employee's Cash/Time Bank.

d) Scheduling of PDOs is by mutual agreement. Such agreement shall not be unreasonable denied.

15.10 FLEXIBLE HOURS OF WORK

For:	Promotions and Display Designers	(formerly Gas Sales Promotion Officer)
	Sales Assistant	
	Sales Representatives	(formerly New Residential Markets Representative and Commercial Sales Representative)
	Technologist 4 - Energy Utilization	(formerly Energy Utilization Specialist)
	Trade Relations Representatives	

a) For the purposes of this Article, the flexible work period shall be 37.5 hours consisting of a maximum of 5 consecutive days Monday through Sunday. Time worked on scheduled days off will be compensated at double time rates.

b) A work day of any consecutive 7.5 hours, exclusive of lunch period, may be scheduled between 06:00 and 22:00 at straight time rates. Time worked in excess of 7.5 hours per day or 37.5 hours in a week will be compensated at double time rates (200%).

c) The Company will provide as much advance notice as possible of a requirement to work flexible hours. Work scheduled under this clause will not interfere with scheduled annual vacation.

d) Where an employee subject to flexible hours works more than 7.5 hours per day, meal entitlements will be in accordance with Article 16.09 of this Agreement.

Employees Hired – January 1, 2008 – March 31, 2012
Legacy Employees - Effective January 1, 2011 – March 31, 2012

e) Where an employee subject to flexible hours is required to work Sundays, the employee shall be reimbursed at 1-1/2 times the regular hourly rate for each hour worked.

f) Where the majority of working hours fall outside the hours of 08:00 - 16:30, a premium will be paid as follows:

Shift	Weekdays	Saturday	Sunday	Statutory Holidays
Day	0 hrs	2 hrs	0 hrs	4 hrs
Aft.	1 hr	2 hrs	0 hrs	4 hrs
Night	2 hrs	2 hrs	0 hrs	4 hrs

g) All time worked on annual vacation shall be paid at overtime rates plus regular salary. All time worked on statutory holidays or on scheduled days off in lieu of statutory holidays will be paid at double time rates plus regular salary.

ARTICLE 15 HOURS OF WORK AND ADOS- Legacy Model
Effective April 1, 2007 – December 31, 2010 – Legacy Employees Only

15.00 The hours of work will incorporate the concept of extending the normal work day for certain employees. This will allow these employees to work a longer day and accumulate days off (ADOs). To enable the time off concept to be workable, flexibility within job assignments will have to be recognized. This will have to be done in such a manner as to provide an uninterrupted, ongoing work flow in all departments participating in the ADOs and in such a manner that will not adversely affect productivity, efficiency and service or result in an increased cost to the Company.

15.01 The hours of work of all employees, except those otherwise specifically mentioned in this Agreement, shall be as follows:

(a) Standard hours of work are 0630 to 2000, Monday through Saturday;
(b) Core hours are 0630 to 1730, Monday through Friday.
(c) The standard start time will be a specific time between 0630 and 1200 hours inclusive.
(d) The company may vary an employee's start time and work week upon 2 weeks notice. An employee's schedule cannot be varied more often than once every 90 calendar days.
(e) The start time parameters of article 15.01(c) may be extended by mutual agreement between the manager and an employee.

15.02 **WORK WEEK**

The standard work week shall be any 5 consecutive days Monday through Saturday.

15.03 **WORK DAY**

The work day shall be any 7 consecutive hours of work, exclusive of lunch period, subject to the provisions of Articles 15.01 and 15.04.

15.04 **WORKING HOURS**

The hours of work shall be the equivalent of 35 hours of work per week. This will be done by each full-time regular employee working a normal week of 5 days of 7.5 hours accruing 17 days a year Accumulated Days Off (ADO) in lieu of the 35 hour week.

15.05 **WORK BREAKS**

Each employee shall receive 2 work breaks of 15 minutes in each day's work schedule. The first such break shall occur during the morning tour of duty prior to the lunch period and the second break shall occur in the afternoon tour of duty prior to quitting time.

15.06 **LUNCH BREAK**

The standard lunch break shall be at or near the midpoint of the working day and shall be either one hour or 1/2 hour as determined by mutual agreement between the manager and an employee or group of employees. Failing agreement, the practice in place at that time will continue.

15.07 **NON-CORE PREMIUM**

All time worked before 0630 and after 1730, and all standard hours worked on Saturday, shall be subject to a 12% non-core-hour premium. This premium is not paid if the time worked during these hours is at the employee's request, or if it attracts a higher premium rate pursuant to Articles 13 and 16.

15.08 **ADO APPLICATION**

a) The standard is that ADOs will be taken in the pay period in which they are earned, but shall not conflict with essential departmental requirements.

b) The authorized variation is that earned ADOs may be taken at a future date by mutual agreement between the employee and the manager

c) Prescheduling of ADOs shall be for 12 week periods, or multiples thereof, with sign-up at least 2 weeks in advance. Sign up shall be by the method agreed to by the majority decision of a work group reporting to an individual manager. Conflicts in sign up shall be resolved by seniority.

d) ADOs will only apply to full-time regular employees. Except for newly hired employees and terminating employees, a person's ADO allowance will be earned by full-time regular employees in service during that period.

e) Employees who are hired or who terminate during a period will earn or be paid out the period's ADO allowance on the basis of 1/9 of that period's ADO allowance for each day worked during that period.

N.B. For the purpose of Clauses d and e of this Article, "period" means one of the 17 bi-weekly pay periods in a calendar year that does not contain a statutory holiday.

f) Full-time regular employees on leave of absence without pay for a pay period will not earn their ADO for that pay period.

g) Current year's earned ADOs will be combined with current entitlement for annual Vacation and reported on each employee's pay statement.

h) Deleted 30 April 1995.

i) Deleted 30 April 1995.

j) Deleted in 2001

k) Deleted 30 April 1995.

l) Employees are encouraged to take all of their earned ADOs before the end of the calendar year. Employees are required to take a minimum of 25 days off each year, this includes time earned for both Annual Vacation and ADOs. If the employee is not able to take the balance of time off in excess of 25 days the balance at year end will be transferred to the Cash/Time Bank.

Time Banks:	Description:
1. Current AV/ADO	Current AV advanced; current ADOs earned
2. Time Bank	Non-renewable time bank. Balance of hours in the EB Time and Permanent banks as of Dec 31, 2001
3. Cash/Time Bank	Banked overtime and year end rollover of current AV and ADOs. Withdrawals from this bank can be either time off or cash. This bank can exceed 18 weeks only with managerial approval.

15.10 From January 1, 2008 to December 31, 2010, employees hired to FTR status are not subject to Article 15.00, 15,03, 15.04, 15.08. These employees shall work a 7.5 hour day (37.5 hour work week) are be credited annually (prorated for part year) with 10 PDOs. Scheduling of PDOs is by mutual agreement and shall not be unreasonably denied.

15.11 Variations of the standard work day or work week, e.g. LOU #7, LOU #14, and LOU #31, shall remain in place and be modified only to the extent necessary to reflect the changes to the standard hours of work.

15.12 FLEXIBLE HOURS OF WORK

For:

Promotions and Display Designers	(formerly Gas Sales Promotion Officer)
Sales Assistant	
Sales Representatives	(formerly New Residential Markets Representative and Commercial Sales Representative)
Technologist 4 - Energy Utilization	(formerly Energy Utilization Specialist)
Trade Relations Representatives	

a) For the purposes of this Article, the flexible work period shall be 37.5 hours consisting of a maximum of 5 consecutive days Monday through Sunday. Time worked on scheduled days off will be compensated at double time rates.

b) A work day of any consecutive 7.5 hours, exclusive of lunch period, may be scheduled between 06:00 and 22:00 at straight time rates. Time worked in excess of 7.5 hours per day or 37.5 hours in a week will be compensated at double time rates (200%).

c) The Company will provide as much advance notice as possible of a requirement to work flexible hours. Work scheduled under this clause will not interfere with scheduled annual vacation.

d) Where an employee subject to flexible hours works more than 7.5 hours per day, meal entitlements will be in accordance with Article 16.09 of this Agreement.

e) Where an employee subject to flexible hours is required to work Sundays, the employee shall be reimbursed at 1-1/2 times the regular hourly rate for each hour worked.

f) Where the majority of working hours fall outside the hours of 08:00 - 16:30, a premium will be paid as follows:

Shift	Weekdays	Saturday	Sunday	Statutory Holidays
Day	0 hrs	2 hrs	0 hrs	4 hrs
Aft.	1 hr	2 hrs	0 hrs	4 hrs
Night	2 hrs	2 hrs	0 hrs	4 hrs

g) All time worked on annual vacation shall be paid at overtime rates plus regular salary. All time worked on statutory holidays or on scheduled days off in lieu of statutory holidays will be paid at double time rates plus regular salary.

ARTICLE 16 OVERTIME

16.00 This clause applies to all employees unless they are specifically exempted from its provisions by express terms elsewhere in this Agreement.

16.01 All time worked in excess of 7.5 hours in a day or 37.5 hours in a week shall be paid at the rate of double time (200%).

16.02 **MINIMUM PAID PERIODS**

If an employee is required to remain at their work place to work overtime, they will be paid for a minimum of 1/2 hour. Time worked beyond the first 1/2 hour of overtime will be recorded to the next higher 1/4 hour. The applicable clause may be invoked with respect to meal intermissions. If they are required to return to their normal work location, aside from a normal meal intermission, or if they are required to perform overtime work at another location, a 2 hour minimum will apply, plus whatever travelling time is applicable. An employee scheduled to work on their scheduled day off will be paid for a minimum of 4 hours at overtime rates, but will not be paid for time spent in travelling to and from their normal work location.

16.03 Work performed on a regularly scheduled day off will be paid for at double time.

16.04 Work performed on holidays will be paid for at double time plus pay for the holiday.

16.05 **REST PERIODS**

An employee who has worked overtime shall return to work after 8 hours rest, but only if they can do so by the mid-point of their regular shift, unless they report earlier by mutual agreement. Whether or not they report to work they shall nevertheless be paid for the regular shift following the overtime at their normal straight-time rate. However, if their overtime finished at or before 8 hours prior to the mid-point of their regular shift on the day in question, they must return to work by the mid-point of their regular shift in order to qualify for full pay for their regular shift. An employee who is called in and reports to work before the expiration of their 8 hours absence shall receive double time payment for those hours which coincide with the working hours of their normal shift, plus their regular salary for the day.

16.06 **CALL-OUTS**

a) Notwithstanding the provisions of Clause 16.05, a call-out occurring within a period of 4 hours prior to the commencement of their regular working day or shift will nevertheless require an employee to report at their regular hour and be paid at straight-time rates for their full regular shift.

b) An employee called to work during off-scheduled hours or on a normal day off shall be paid at overtime rates for a minimum of 2 hours beginning at the time they leave their residence. 1/2 hour at double time shall be allowed an employee to reach their living quarters on completion of a call-out irrespective of the amount of time actually worked. When call-outs run into a normal shift, minimum call-out shall not apply.

16.07 **OVERTIME BANKING**

a) Employees may elect to bank the hours of overtime worked at the straight-time equivalent (i.e. one hour at double time equals two hours in the overtime bank).

b) Deleted in 2001

c) Deleted in 2001

d) Time off at the employee's request must be taken at a time mutually agreed upon between the employee and the manager. Agreement to schedule time off shall not be unreasonably withheld.

e) Cash withdrawals may be made from the Cash/Time Bank by the employee at any time on 10 working days written notice to the Pay Department.

16.08 **TRAVEL TIME PAYMENTS**

a) If an employee is scheduled to work prior to their normal working hours and at their normal work location, travel time will not apply.

b) If an employee is required to work overtime beyond their normal working day at their normal headquarters, no travel time will be paid.

c) When an employee is assigned to work away from their normal headquarters, travelling time shall be paid in accordance with Article 17.03.

16.09 **MEAL PROVISIONS**

a) Where an employee is required to work less than 2 hours beyond their regular shift, a 1/2 hour unpaid meal period will be allowed.

b) An employee will be paid for a 1/2 hour meal period at double time and the Company will provide a meal or reimburse the employee for reasonable meal expenses incurred:

1. where the actual overtime worked, exclusive of any meal period is 2 hours or longer before or after the regular day or shift;

2. where an employee is called in and works 4 hours overtime;

3. where an employee is required to work 4 hours overtime beyond an overtime meal period already taken. Where this overtime follows a regular shift the first meal period regardless of when it is actually taken, will be considered to have been taken immediately after the regular shift;

4. where an employee misses a paid meal period to which they are entitled they shall nevertheless be paid at the prevailing rate for such missed meal period in addition to all time worked.

c). Where work is prescheduled for normal days off and employees have been notified on the previous working day and work is to commence within 2 hours of the normal starting time, the employer will not be required to provide lunch or pay for a meal time if taken.

16.10 **ALTERNATIVE TRANSPORTATION**

Where an employee is required to work unscheduled overtime, the Company will, on request of the employee, pay reasonable costs for alternative transportation home under the following conditions:

a) Provided that normal means of transportation is not available.

b) Where employees are parties in car pool arrangements, "normal means of transportation" shall be deemed to include car pools.

c) For purposes of this Clause, "unscheduled overtime" is defined as that overtime occurring where an employee is notified by their manager during their scheduled shift that they will be required to continue working beyond their scheduled quitting time.

16.11 **PREMIUM PAYMENTS**

a) **Helicopter Premiums**

1. Life insurance of not less than $150,000.00 shall be provided for employees working in or under or travelling in helicopters.

2. Employees who are actually engaged in working in or under helicopters shall be paid a premium of 25% over and above their base or floor rate, whichever is greater.

3. A helicopter premium of 25% of regular pay will be paid when an employee is travelling with another Company employee in receipt of a helicopter premium.

b) **High Time**

A high time premium of 10% of regular pay will be paid when an employee is actually working on staging and scaffolding, or where the employee is supported by a safety belt or rope, at heights of 9 meters (30 feet) or more above a fixed platform, safety net, or natural ground surface. This clause is applicable to work under bridges when the above conditions apply. The minimum premium payable will be that for one hour.

c) **Occupational Health and Safety**

The parties agree to maintain an Occupational Health and Safety Committee.

Employees who possess an Industrial First Aid Certificate and who are designated to act as a First Aid Attendant in addition to their normal job responsibilities, shall receive a monthly rate allowance of not less than the rates currently in effect in accordance with Company Policy OHS 01-07, which are:

Level	Designated Allowance ($/month)	Non-designated Allowance ($/month)
2	$ 90	$ 27
3	$180	$ 54

16.12 **GENERAL**

Where an employee is required to work under conditions not specified in this Agreement which the Union considers merits premium pay, an appropriate premium will be determined by agreement between the Parties, and if no agreement is reached, the matter can be handled under the grievance procedure.

16.13 **STANDBY ARRANGEMENTS**

a) An employee scheduled on standby, whether or not they carry a pocket pager, will be paid for two (2) hours at straight time for the 24 hour period commencing daily at 08:00 Monday to Thursday inclusive, 3 hours at straight time for the 24 hour period commencing at 08:00 Friday, and 4 hours at straight time for the 24 hour period commencing at 08:00 on a Saturday, Sunday or Statutory Holiday.

b) Where possible standby will be signed up on a voluntary basis with schedules posted at least 96 hours in advance. Should an employee be given less than 96 hours notice of standby duty, they will be under no compulsion to accept such duty.

c) No employee will be compelled to accept standby on 2 consecutive weekends or on 2 consecutive holiday weekends.

16.14 **TELEPHONE CONSULTATION**

Where an employee is consulted by a manager or delegate by telephone outside their normal hours of work concerning a problem of work, a telephone consultation premium will be paid as follows:

a) Pay per telephone consultation equivalent to 1/2 hour or the length of the call, whichever is greater, at overtime rates for calls prior to 23:00, and one hour's pay at overtime rates for calls between 23:00 and 07:00, except as indicated in (b) below.

b) If a second or successive telephone consultation takes place within 1/2 hour of the end of a preceding call, it will be construed as being part of the preceding call and therefore not be paid unless the combined time exceeds the minimum paid period in (a) above.

c) The telephone consultation premium will not be paid if an employee is on standby duty.

16.15 Employees who are assigned a paging device for the purpose of providing telephone consultation (as opposed to being on standby; ready and able to report to work) shall be compensated at the rate of one hour at straight time for each calendar day of such assignment and shall in addition receive the pay for telephone consultation specified by Article 16.14.

ARTICLE 17 HEADQUARTERS -- TRAVELLING ALLOWANCES, MOVING EXPENSES AND LIVING EXPENSES

17.01 a) All employees will have an established headquarters. This established headquarters will be the location where the employee normally works, reports for work, or the location to which s/he returns between jobs.

b) Employees hired for temporary work will be deemed to be headquartered at the location where they are recruited.

17.02 The Company will pay for transportation, meals and sleeping accommodation for employees travelling to or from a job from a point of hiring or on Company business.

17.03 a) All time spent in travel by public carrier, or as driver or passenger in a Company vehicle or properly authorized personal vehicle, to and from a headquarters or report point other than the employee's normal headquarters, shall be paid as time worked, except that when an employee commutes to/from such temporary headquarters or report point from their home or from lodging provided by the Company, only time spent commuting in excess of that amount of time it normally takes the employee to commute to their established headquarters will be paid as time worked.

b) Time spent in travelling at the request of the Company on any non-scheduled working day shall be paid to a maximum of 8 hours at overtime rates.

c) Time spent in travel between headquarters and the work site or the report point and the work site at the commencement and termination of each day's work, will be paid for as time worked.

d) A mileage allowance of not less than 52 cents per kilometer shall be paid for authorized use of a personal vehicle on Company business, in accordance with policy ADM 02-02 – Use of Personal Pool and Rental Vehicles.

17.04 Should an employee be discharged for cause or resign with more than 3 months' service while in the field, s/he will be paid travelling expenses back to their established headquarters. An employee laid off will be paid travelling expenses back to their established headquarters in accordance with Article 17.03.

17.05 Where employees are working and living away from their permanent headquarters, the Company will provide free board and lodging. Employees who elect to return home on weekends or on other days upon which no work is scheduled, shall, upon request, be granted "living allowance"of $45 for such non-working days on which they do not utilize the board and lodging provided by the Company.

17.06 Employees will be returned to their established headquarters at the expense of the Company prior to taking annual vacation and will be returned from established headquarters to the work site at the expense of the Company without any loss of paid holiday time.

17.07 At any point where the Company is responsible under this Agreement for board and lodging, a living allowance of $70 per day in lieu thereof may be granted at the request of the employee.

17.08 An employee directed to work away from their established headquarters shall be notified whether the change is to a position of a continuing nature or to a temporary job.

17.09 a) If the change is to a position of a continuing nature, the Company will bear the cost of moving expenses in accordance with Article 17.10. Should it not be possible to obtain suitable living quarters at the new location immediately, an allowance will be made for reasonable living expenses. The point to which the employee is then assigned to report for duty will become their established headquarters.

b) Moving expenses are defined as standard packing and moving charges, and transportation costs for the employee and their family plus incidental expenses up to $500. Incidental expenses would include such items as cleaning, disconnecting and reconnecting of appliances, etc. and are limited to the 2 residences involved.

c) Where management is the initiator of the transfer, consideration will be given to further reasonable expenses.

d) When employees choose to change their place of residence as a result of a reassignment of headquarters, they will be allowed time off with pay for the purpose of obtaining and moving into another home. The time off will be by arrangement with the immediate <u>Manager</u> concerned. Such time off will be in addition to any entitlement otherwise provided in respect to time spent in travel to the new location.

17.10 If an employee applies for another job and is successful in getting the job, the Company will pay their moving expenses if moving is necessary and the employee moves a minimum of 25 kilometers closer to their new headquarters.

17.11 An employee whose position becomes redundant and as a result is required to move to a new job location to continue in Company employment, shall be moved at Company expense regardless of the length of service or the time interval between moves.

17.12 Where an employee is granted a transfer for compassionate reasons under the provisions of this clause, the matter will be discussed with the Union, and the Company at its discretion may pay all or part of the employee's moving expenses.

17.13 An employee who is directed by the Company to change their headquarters or who becomes redundant due to automation, new equipment or new office procedures, shall be eligible, under the following conditions, for reimbursement for realtor's commission in selling their present home and legal fees in purchasing a new home in order to take another Company job:

a) the employee has been notified in writing that the change of jobs is of a continuing nature;

b) a change of headquarters is involved and the new headquarters is outside municipal boundaries of the present headquarters and where the parties agree that it is not practical for the employee to commute daily to their new headquarters;

c) the employee and/or the employee's spouse is the registered owner of the home being vacated.

d) costs are actually incurred and the employee provides receipts;

e) the employee has a minimum of 4 years accredited service with the Company; and

f) the employee continues to work for the Company for a minimum of 1 year;

17.14 An employee quartered in a commercial facility will be entitled to single room accommodation.

ARTICLE 18 SALARIES

18.01 a) Job groupings are established in accordance with the Company's job evaluation plan. The salary scales applicable to these groupings shall be as set out in the following schedules with effective dates as shown.

b) Salaries of certain employees are not covered by these scales and are set out elsewhere in this Agreement.

c) Monthly rates are computed on the basis of 217.4% of bi-weekly rates.

d) For conversion purposes only, hourly rates of pay are determined by dividing bi-weekly salaries by 75. (e.g. overtime and Part-Time Regular employees conversion, unless otherwise defined). For FTR legacy employees, for conversion purpose only, hourly rates of pay are determined by dividing bi-weekly salary by 70.

e) Depending on the circumstances of the job, job evaluation exclusion rates are set subject to negotiation with arbitration if required.

f) Effective January 1, 1999 all new hires, re-hires, and employees changing status from temp (hourly) to regular (salary) shall be paid by direct payroll deposit.

The employees shall provide the necessary banking information on the form(s) supplied by the company.

ARTICLE 18

SALARY SCALES EFFECTIVE December 1, 2007

MONTHLY SALARY SCALES						
GRP	MIN	STEP 1	STEP 2	STEP 3	STEP 4	STEP 5
3	2596	2698				3113
4	2894	3009	3124			3472
5	3157	3281	3407	3533		3781
6	3444	3576	3720	3859		4122
7	3754	3905	4048	4200	4350	4509
8	4009	4163	4328	4483	4644	4802
9	4372	4541	4713	4894	5063	5239
10	4765	4952	5139	5331	5524	5709
11	5198	5402	5602	5813	6022	6229
12	5665	5889	6111	6337	6565	6787
13	6181	6420	6663	6913	7155	7402
14	6587	6839	7102	7368	7629	7894

BI WEEKLY SALARY SCALES						
GRP	MIN	STEP 1	STEP 2	STEP 3	STEP 4	STEP 5
3	1194	1241				1432
4	1331	1384	1437			1597
5	1452	1509	1567	1625		1739
6	1584	1645	1711	1775		1896
7	1727	1796	1862	1932	2001	2074
8	1844	1915	1991	2062	2136	2209
9	2011	2089	2168	2251	2329	2410
10	2192	2278	2364	2452	2541	2626
11	2391	2485	2577	2674	2770	2865
12	2606	2709	2811	2915	3020	3122
13	2843	2953	3065	3180	3291	3405
14	3030	3146	3267	3389	3509	3631

SALARY SCALES EFFECTIVE APRIL 1, 2008

MONTHLY SALARY SCALES						
GRP	**MIN**	**STEP 1**	**STEP 2**	**STEP 3**	**STEP 4**	**STEP 5**
3	2674	2778				3207
4	2981	3100	3218			3576
5	3252	3378	3509	3639		3894
6	3548	3683	3831	3974		4246
7	3868	4022	4170	4326	4481	4644
8	4128	4287	4459	4618	4783	4946
9	4502	4678	4855	5042	5215	5396
10	4909	5100	5294	5492	5689	5881
11	5355	5565	5770	5987	6202	6415
12	5835	6065	6294	6526	6763	6992
13	6365	6613	6863	7120	7370	7624
14	6785	7044	7316	7589	7857	8131

BI WEEKLY SALARY SCALES						
GRP	**MIN**	**STEP 1**	**STEP 2**	**STEP 3**	**STEP 4**	**STEP 5**
3	1230	1278				1475
4	1371	1426	1480			1645
5	1496	1554	1614	1674		1791
6	1632	1694	1762	1828		1953
7	1779	1850	1918	1990	2061	2136
8	1899	1972	2051	2124	2200	2275
9	2071	2152	2233	2319	2399	2482
10	2258	2346	2435	2526	2617	2705
11	2463	2560	2654	2754	2853	2951
12	2684	2790	2895	3002	3111	3216
13	2928	3042	3157	3275	3390	3507
14	3121	3240	3365	3491	3614	3740

SALARY SCALES EFFECTIVE APRIL 1, 2009

MONTHLY SALARY SCALES						
GRP	**MIN**	**STEP 1**	**STEP 2**	**STEP 3**	**STEP 4**	**STEP 5**
3	2754	2861				3302
4	3070	3194	3313			3683
5	3350	3481	3613	3748		4011
6	3654	3794	3946	4094		4374
7	3983	4144	4296	4457	4615	4783
8	4252	4415	4594	4757	4926	5094
9	4637	4820	5000	5194	5372	5557
10	5057	5252	5452	5657	5861	6057
11	5515	5733	5944	6168	6389	6609
12	6011	6248	6483	6722	6965	7200
13	6557	6811	7070	7333	7592	7852
14	6989	7255	7535	7818	8092	8374

BI WEEKLY SALARY SCALES						
GRP	**MIN**	**STEP 1**	**STEP 2**	**STEP 3**	**STEP 4**	**STEP 5**
3	1267	1316				1519
4	1412	1469	1524			1694
5	1541	1601	1662	1724		1845
6	1681	1745	1815	1883		2012
7	1832	1906	1976	2050	2123	2200
8	1956	2031	2113	2188	2266	2343
9	2133	2217	2300	2389	2471	2556
10	2326	2416	2508	2602	2696	2786
11	2537	2637	2734	2837	2939	3040
12	2765	2874	2982	3092	3204	3312
13	3016	3133	3252	3373	3492	3612
14	3215	3337	3466	3596	3722	3852

SALARY SCALES EFFECTIVE APRIL 1, 2010

MONTHLY SALARY SCALES						
GRP	MIN	STEP 1	STEP 2	STEP 3	STEP 4	STEP 5
3	2837	2946				3402
4	3161	3289	3413			3794
5	3450	3585	3722	3861		4131
6	3763	3907	4063	4215		4505
7	4102	4268	4424	4591	4755	4926
8	4381	4548	4731	4900	5074	5246
9	4776	4965	5150	5350	5533	5724
10	5209	5409	5615	5826	6037	6239
11	5681	5905	6122	6352	6581	6807
12	6192	6435	6676	6924	7174	7416
13	6752	7015	7283	7552	7820	8087
14	7198	7472	7761	8052	8335	8626

BI WEEKLY SALARY SCALES						
GRP	MIN	STEP 1	STEP 2	STEP 3	STEP 4	STEP 5
3	1305	1355				1565
4	1454	1513	1570			1745
5	1587	1649	1712	1776		1900
6	1731	1797	1869	1939		2072
7	1887	1963	2035	2112	2187	2266
8	2015	2092	2176	2254	2334	2413
9	2197	2284	2369	2461	2545	2633
10	2396	2488	2583	2680	2777	2870
11	2613	2716	2816	2922	3027	3131
12	2848	2960	3071	3185	3300	3411
13	3106	3227	3350	3474	3597	3720
14	3311	3437	3570	3704	3834	3968

18.02

a) **Definitions**

1. By definition, "base rate" shall mean the monthly amount (according to the salary scale) paid to an employee, exclusive of overtime, premiums, allowances, trade differentials, etc.

2. By definition, "floor rate" shall mean a monthly amount paid to an employee consisting of their base rate plus a trade differential, as defined in Article 18.02(a) 3, for the purposes of maintaining a pay relationship between a job within the COPE bargaining unit and a job in another union within the Company.

3. By definition, "trade differential" shall mean the adjustment amount which must be added to the base rate of an employee in a floor rated job to increase the employee's pay to the floor rate established for the job.

4. By definition, "base position" shall mean a position in another bargaining unit within the Company.

b) **Criteria**

1. The purpose of floor rates is to establish and maintain a relationship between the salary paid to employees assigned to a position that entails a direct working relationship with members of other unions within the Company and the wages of those members.

2. Entitlement to a floor rate is conditional upon this direct working relationship complying with the following:

   a) the duties performed by the employee must be inter-related with the position in the other union over which the floor rate is based and must further relate to a major job responsibility of that base position; and

   b) the employee must be responsible for determining the methods and procedures to be followed by the members of another Union; and

   c) the employee must be responsible for ensuring that the work completed by the member(s) of the other Union conforms to the Company's specifications, standards and/or other relevant codes; and

   d) the member(s) of the other Union must be assigned to the employee to either:

      1) assist the employee in completing work assignments; or

      2) complete work assignments with the assistance and/or direction of the employee; or

3) receive technical training in one or more major job responsibilities where such training is of a nature that it will qualify the member(s) of the other Union to perform an approved position in their own bargaining unit, and where the employee is responsible for assessing the capability and eligibility of the trainees to be appointed to the end position; and

e) the working relationship between the employee and the members of the other Union must be an ongoing and demonstrative part of the COPE job; "once-only" or hypothetical situations will not attract a floor rate.

c) **Floor Rate Type**

Parity or a 5% differential will be determined as follows:

1) Parity: when all criteria in 18.02(b) are met except 18.02 2 (d) 3.

2) 5% Differential: when all criteria are met, or when all criteria are met except 18.02 2(d)1 and/or 18.02 2(d)3.

d) Monthly Floor Rate Calculation:

Where the regular monthly hours total 152.19 and the regular hours are 7.0 per day, or where the regular hours are total 163.06 and the regular hours are 7.5 hours per day, or where the regular monthly hours total 173.93 and the regular hours are 8 per day, the calculation shall be:

1) Parity =
1.00 x hourly rate of base position x regular monthly hours of base position;

2) 5% Differential =
1.05 x hourly rate of base position x regular monthly hours of base position.

18.02

e) **Administration**

1. Disputes arising from the application of the Floor Rate Criteria are subject to Article 3, Grievance Procedure, of the Collective Agreement.

2. Each Floor Rated Job will be reviewed and tested against the above defined criteria at the time the Floor Rate is established, and at least once every 3 years as a part of the Job Evaluation Section cyclical audit of all COPE bargaining unit Jobs with a report forwarded to the Parties in the attached format as a part of that review process.

3. Each Floor Rate established under this Article will be documented on a Trade Differential Sheet, Floor Rates will be recalculated when the wage for the base position is changed and will be effective on the same date as the change in wage. The local union will be advised in writing of recalculations of Floor Rates.

18.03 **LENGTH-OF-SERVICE INCREASES**

a) Progression along the salary scale will be at 12 month intervals.

b) Salary advances in all salary ranges shall be automatic except that such increases may be withheld for cause, providing that 2 months' notice of intent to withhold is given to the employee in writing, and a copy of such notice is mailed to the Union office. When, in the opinion of the Company, the employee has restored their performance fully at some subsequent date, he/she may regain their position within the salary scale on a non-retroactive basis.

c) Automatic salary increases for employees who are eligible shall be an amount equivalent to a full step increase of the appropriate salary range, irrespective of the employee's position in the range, provided that no employee may receive an increase beyond the maximum steps of the range.

d) An employee whose salary falls between steps on the salary range will receive length-of-service increases which equal the dollar difference between the steps in which the employee's salary fell before the increase except that no employee will receive a length-of-service increase which would place them above the maximum salary for the job.

18.03

e) Only one length-of-service increase will be granted an employee while they are on sick leave. After returning to work, they will next be entitled to an increase on the same date they would have been entitled to an increase had they not been absent for sickness.

f) Employees who have been on any other leave of absence in excess of 3 months during the length-of-service period will receive a prorated length-of-service increase; that is, for each completed month of service in their present job since their last length-of-service increase s/he will have 1/12 of the next length-of-service increase for that job added to their basic salary.

g) Time worked continuously on different jobs having the same group shall be cumulative.

h) When an employee is promoted s/he will receive a prorated length-of-service increase to their old salary based on the accrued time since the last length-of-service increase. Article 18.07 will then be used to determine the promotional increase.

i) Employees who are promoted will have their length-of-service date established on the anniversary date of their promotion.

j) An employee whose job is reclassified to a higher salary grade as a result of changes in duties and responsibilities or as a result of re-evaluation will receive the promotional increase as set out in Article 18.07 and will continue to receive their length-of-service increases on the new job on the same date as s/he would have received them had s/he been on the lower job. Employees who were at the maximum on the lower job will receive their first length-of-service increase on the higher job on the anniversary day of the job reclassification.

k) Temporary employees shall accrue service for salary progression purposes as long as breaks in service do not exceed 90 consecutive calendar days, after which the terms of Article 18.05 (b) apply.

18.04

a) Salaries and bi-weekly salary scales shall be increased by 2.5% on December 1, 2007.

b) Salaries and bi-weekly salary scales shall be increased by a further 3% effective April 1, 2008.

c) Salaries and bi-weekly salary scales shall be increased by a further 3% effective April 1, 2009.

d) Salaries and bi-weekly salary scales shall be increased by a further 3% effective April 1, 2010.

e) Both parties continue to endorse the philosophy that base salaries for classifications at Terasen are intended to be at or near market median, as determined by a joint market comparator surveying conducted by the parties.

f) 1. The parties shall initiate preparation for another joint market comparator survey no later than October 1, 2010. The survey process shall be similar to those previously conducted. The report will be similar to those previously issued.

2. Effective April 1, 2011, salaries and bi-weekly salary scales shall be adjusted by an amount that will re-establish their relationship to market median as determined by the survey, and in any event not less than 2.50%.

g) The 3% incentive pay component (subject to any Utility Scorecard gateway) shall continue during the life of this agreement. The 2011 EIP pay component (subject to any Utility Scorecard gateway) shall be increased to 3.5%. The formula shall be:

1. 1.0% shall continue to be based on Scorecard results. The 2011 Scorecard results (paid out in 2012) shall be increased to 1.5%.

2. 1.0% shall continue to be paid to each employee whose overall performance rating, pursuant to h) below, is at or above the "meets expectations" level.

3. 1.0% shall be paid to each employee whose total days of paid sick leave the prior year is less than 75% of the bargaining unit average.

h) all employees shall continue to participate in the Terasen Gas Performance Planning and Review process.

i). the incentive pay shall be based on the employee's annual base pay (including paid time off), excluding red and blue-circled treatment of the previous year, subject to attainment of results.

18.05 **HIRING RATES**

a) Employees, including those from other Unions within the Company, are to be hired at the minimum rate of their job group. New employees who have had experience directly applicable to their jobs may be paid up to and including step one. Higher starting rates than step one may be paid in exceptional cases provided agreement is reached between the Company and the COPE.

b) A person who has previously worked for the Company and is rehired into the same job classification as s/he held at the time of termination, shall start at the same step of the salary range as that person was being paid immediately prior to the termination and the full time of the step must be worked before progressing to the next step.

c) However, if the time away from the job exceeds one year, the individual will start one step below the step held when the termination occurred and the full time of the step must be worked before progressing to the next step. If the time away from the job exceeds 2 years, the individual will be treated as a new employee pursuant to Article 18.05 (a).

18.06

PROMOTIONS, DEMOTIONS AND TRANSFERS

The following definitions will apply in the event of job changes occurring within or between salary scale categories:

a) By definition, a "promotion" shall mean a move to a new job carrying a maximum step which is higher than the maximum step of the old job.

b) By definition, a "demotion" shall mean a move to a new job carrying a maximum step which is lower than the maximum step of the old job.

c) By definition, a "lateral transfer" shall mean a move to a new job which is neither a promotion or demotion as defined above.

d) By definition, a "temporary promotion" shall mean a promotion, as defined above, which lasts for one full working day or more and for 6 months or less.

e) By definition, "red-circled" shall mean that an employee's salary will be maintained above the maximum of the salary range for their job until such maximum is raised to a level above their salary.

f) By definition, "blue-circled" shall mean that an employee's salary will be maintained above the maximum of the salary range for their job and that such salary will be increased by all subsequent negotiated and length-of-service salary increases.

18.07 **PERMANENT PROMOTIONS**

a) An employee who is promoted from one salary group to another will receive an increase of 5% for each salary group of promotion after first determining a pro rata adjustment to their old salary based on the accrued time since the last length of service increase. No employee, subsequent to the application of this promotion formula, will receive less than the minimum or more than the maximum of the new range. Thereafter, progression along the salary scale will be at 12 month intervals.

b) When an employee is promoted from one floor-rated job to another floor-rated job they will receive an increase on their base rate in accordance with (a) above. Further, where their old floor rate is lower than their new floor rate they will receive the new floor rate; but where their old floor rate is higher than their new floor rate they will be red-circled at their old floor rate.

c) When an employee is promoted from a floor-rated job to a non-floor-rated job they will receive an increase on their base rate in accordance with (a) above. Further, where their old floor rate is higher than their new base rate they will be red-circled at their old floor rate.

d) When an employee is promoted from a position they have taken under the provisions of Article 18.10 (a) and (b), the following salary policy will apply:

1. If the employee had been on the lower grouped job more than one year they shall be promoted in accordance with 18.07 (a) above.

2. If the employee has been on the lower group job less than one year and is promoted to the same group they held prior to demotion, they will receive the salary they would have achieved had they remained on that higher job group level.

3. If the employee is promoted to a job group higher than they held prior to their demotion, their salary will be determined by applying firstly the provisions of (d) 2 and then the provisions of (a).

18.08 **TEMPORARY PROMOTIONS**

Definition:

a) "Temporary Promotion" means a promotion which lasts for one full working day or more.

1. An employee who is temporarily promoted from one salary group to another will receive an increase of 5% for each salary group of promotion. No employee, subsequent to the application of their promotion formula, will receive less than the minimum or more than the maximum of the new range.

2. Where an employee carries out the duties of a Manager, or another person outside of the bargaining unit, they shall receive a rate of 10% above the highest rate of persons supervised, or 10% above the employee's current rate, whichever is greater, for the entire period of such relief.

b) When an employee is in receipt of Manager premium pursuant to paragraph (a) (2), and works overtime the appropriate overtime premium will be applied to the employee's wage inclusive of the Manager premium.

c) An employee temporarily on a higher grouped job shall receive the benefit of length-of-service increases which they would have received on the lower grouped job and their salary shall be increased accordingly. A temporarily promoted employee will also be eligible for length-of-services increases on the higher grouped job if the temporary promotion is renewed and thus exceeds 12 months in duration. However, the salary resulting from a length-of-service increase on the higher grouped job shall at no time be higher than the salary the employee would have received had they been permanently promoted to that job. Increases in salary awarded to temporary promotions are withdrawn when the employee returns to their regular job. The salary at which they return to their regular job shall include any increases which would otherwise have come to them during the period of transfer.

d) In cases where apparent salary anomalies occur, resulting from transfers to and from temporary promotions, the Parties agree to discuss such cases on their merits, subject to recourse to the grievance procedure.

18.09 **LATERAL TRANSFERS**

a) When an employee is, by definition, laterally transferred from one floor-rated job to another floor-rated job they will retain their old base rate. Furthermore, where their old floor rate is lower than their new floor rate they will receive the new floor rate; but where their old floor rate is higher than their new floor rate they will be red-circled at their old floor rate.

b) When an employee is, by definition, laterally transferred from a floor-rated job to a non-floor-rated job they will retain their old base rate and be red-circled on their old floor rate.

18.10 **DEMOTIONS**

a) In the case of a demotion directly ascribable to the employee, for example through choice or as a result of inadequate performance, the following salary policy will apply:

1. If the employee has a year or more of service in the higher grouped job, upon demotion they will retain their rate if it is not beyond the maximum of the lower grouped job; if it is beyond maximum they will be reduced to the maximum of the lower group.

2. If the employee has less than one year's service in the higher-grouped job, upon demotion their salary will be that which they would have attained had they moved directly to the lower-grouped job on the same date that they moved to the higher-grouped job.

3. Under special circumstances, including health cases, the salary in the lower-grouped job will be negotiated by the Parties. Upon upward revision of the basic salary scale the employee will receive the general increases that accrue to their lower job grouping.

b) In the case of a demotion not directly ascribable to the employee, the following salary treatment shall apply:

1. Article 2 Re-evaluation - Red-Circle treatment.

2. Article 7 Layoff and Recall - Blue-Circle treatment for a period of two (2) years after which time Red-Circle treatment shall apply, unless the layoff is beyond the company's control; in which case 18.10(b)1 shall apply from the date of layoff.

3. Employees receiving blue-circle treatment as at the effective date shall continue to be salary protected for the full period of three years. Previously blue-circled treatment grandfathered employees shall continue to receive blue-circled treatment.

ARTICLE 19 EMPLOYEE DEFINITIONS

19.01 **Full-Time Regular (FTR)**

An employee hired to fill an ongoing position vacated by a regular employee or hired to fill a position which is of a continuing nature.

19.02 **Part-Time Regular (PTR)**

a) An employee hired to fill a part-time ongoing position vacated by a part-time regular employee or to fill a part-time position which is of a continuing nature.

b) Unless otherwise agreed with the Union, a part-time regular employee will work according to an assigned regular schedule but will not work more than 60 hours per bi-weekly pay period except that the employee may in addition relieve a full-time employee on leave of absence, sick leave or annual vacation without change to full-time regular status. A PTR employee will normally be scheduled a minimum of 24 hours bi-weekly. At the end of any bi-weekly sign-up period where the minimum of 24 hours is not scheduled, the employee(s) working those schedules shall have the right to choose layoff under the terms of the collective agreement.

1. An assigned regular schedule will be established by the Company at the time of hire and will be for a minimum period of 2 weeks.

2. Within an assigned schedule the days worked and the daily/weekly hours may differ.

c) A manager may change an established schedule but must provide 2 weeks notice of any change.

d) Notice of change is not required where a schedule is varied by mutual agreement between the employee and the manager.

e) The employee will participate in Benefit Plans in accordance with Article 21, and in the Pension Plan.

f) Sick leave and annual vacation entitlements shall be prorated on the basis of time worked according to service.

Part-Time Regular (PTR) (Cont'd)

19.02 g) Annual vacation and Statutory Holiday pay shall be paid bi-weekly as a percentage of gross bi-weekly earnings. The percentage paid shall be 10.4% if entitled to 3 weeks annual vacation and increased by 2% for each additional week of annual vacation earned. When additional statutory holidays are declared in accordance with Article 13.01 of this Agreement, then the percentage shall be increased by 0.4% for each additional holiday so declared. On each anniversary date, a part-time regular employee shall have the option of accruing annual vacation pay to be paid out at the time of taking annual vacation.

h) A part-time regular employee shall progress through the salary scale on the basis of accumulated hours worked (inclusive of A/V, Sick Leave and absence due to Workers Compensation) at the same job group and salary step. Such progression shall be determined by a quarterly review of accumulated hours and shall occur effective the first of the month in which the employee accumulated 1,826 hours.

19.03 **Temporary (Temp)**

a) An employee hired on an as-and-when required basis.

b) Unless otherwise agreed by the parties, a temporary employee is limited to a period of 18 months working full-time in connection with a specific project, work overload or seasonal peaks.

c) The temporary employee will be paid a rate based on the appropriate step on the salary scale which will recognize the employee’s accumulated service with the Company in the same or related job.

d) Annual vacation and Statutory Holiday pay shall be in accordance with Article 19.02(g).

e) The employee will not be entitled to any benefits provided in this Agreement. However, should such an employee’s period of employment exceed 60 days of accumulated service, s/he will be paid an additional 8% in lieu of sick leave and welfare benefits.

f) For conversion purposes only, effective January 1, 2008, for all new Temporary Employees (post –ratification) hourly rates of pay are determined by dividing bi-weekly salaries by 75 (e.g. overtime).

ARTICLE 20 TRAINING

20.01 Terasen Gas and the Union are committed to enhancing the employment prospects of all employees. To assist with this goal:

(a) At least on an annual basis each employee and their manager will conduct a performance review for the employee, and as part of this review attempt to identify known or anticipated threats to the employee's current job and career path as identified by the employee.

(b) A training needs profile will be developed as part of the performance review process. This profile will specify which of the following will be emphasized in the employee's training:

1. training for current tasks, or

2. training for anticipated requirements, which will include if necessary, career transition preparation for different job streams, both inside and outside the Company.

(c) The Joint Training Committee shall, as part of its mandate, explore emerging skillset requirements for employability. The Committee shall also develop a catalogue of various sources of training and education related to the emerging skillsets, and it will make this information available to all managers and employees.

(d) Regular employees will be credited with 37.5 hours of time off per calendar year to attend classes during regular working hours without loss of pay, benefits or seniority, under the following conditions:

1. This time shall be available after the employee has used 37.5 hours of their own banked time;

2. This time is for training identified in the employee's training needs profile, and when such training is only available during the employee's normal working hours;

3. Employees shall give as much notice as possible, and adjust their training schedule so as to minimize the effect of their absence on the department.

4. Disputes with respect to the use and scheduling of this time off shall be referred to the Joint Training Committee, and failing resolution shall be processed as grievances.

(e) The provisions of Articles 20.05 (a), (b) and (c) shall also apply.

20.02 Employees shall be granted leave of absence without pay upon request for the purpose of attending full-time studies at a recognized educational institution, under the following conditions:

a) the employee must provide their Manager written notice at least 2 calendar months prior to the commencement date of the desired leave;

b) the Company may recruit for a temporary replacement pursuant to Article 6, for the period of the employee's absence but the employee's leave shall commence on the day specified by the notice above whether or not a replacement has been recruited;

c) by notifying the Company in writing, the employee shall make themself available for work within one calendar month of the end of the requested time, such time not to exceed one calendar year;

d) the above time limit may be extended by mutual agreement between the employee and the Company. If the time limit is not extended and the employee does not make themself available for work within the time limit, the employee shall be presumed to have terminated on the last day of the time requested;

e) the employee shall not lose seniority as a result of the absence and shall not accrue seniority during the period of absence; and

f) the employee may elect to remain covered by any of the welfare plans of Article 21, and in that event shall reimburse the Company for the premium costs of such coverage.

20.03 The Company shall reimburse employees for registration fees and annual membership fees in any Professional Association, if such registration and membership is a requirement under the Qualification Section of the employee's job description, or at the discretion of the appropriate Vice-President.

20.04 An employee shall be given time off with pay to write examinations on a course approved pursuant to Article 20.05. The employee will also be allowed 3 clear hours off work immediately preceding the examination should the examination or any part of this leave coincide with normal working hours.

20.05 Employees may apply on the prescribed educational assistance form for financial aid to undertake a course of outside training. The degree of financial aid assumed by the Company will depend upon the circumstances involved as follows:

a) Full cost of training (tuition fees, required textbooks and such other expenses as may be approved by the Company) will be borne by the Company where the training is at the instigation of management (eg. Industrial First Aid Training). Such training requires written approval of a Regional Manager or Department Head.

b) The full cost of training (tuition fees, required textbooks and such other expenses as may be approved by the Company) will be reimbursed to a working employee upon successful completion of such training or course, where:

1. written approval has been obtained from the Company prior to the commencement of such training or course, and

2. the Company agrees that this additional training bears direct relevance to the employee's current job or recognized career path within the Company.

c) One-half the cost of training (tuition fees, required textbooks and such other expenses as may be approved by the Company) will be reimbursed to a working employee upon successful completion of such training or course, where:

1. written approval has been obtained from the Company prior to the commencement of such training or course, and

2. the Company agrees that this additional training would be helpful in broadening the individual's abilities in a work-related way or could be of future use to the employee in working with the Company.

ARTICLE 21 BENEFIT PLANS

21.01 MEDICAL COVERAGE AND EXTENDED HEALTH BENEFITS

EFFECTIVE JANUARY 1, 2011, SUPERCEDED BY FLEX BENEFITS PROGRAM CHANGES, AS PER THE ATTACHED SCHEDULE A – NEW BENEFITS SUMMARY

a) Regular employees shall be eligible to receive the basic medical and surgical coverage provided by the B.C. Medical Services Act through the Medical Services Plan.

b) In addition to the above, eligible employees as defined above shall also be covered by an Extended Health Care Plan similar to that offered by Pacific Blue Cross. The plan will pay 100% of all eligible expenses in excess of a $25.00 deductible per person or family each calendar year. The maximum benefit payable during the lifetime of any family member is $1,000,000.00.

Extended Health benefits to include standard vision care to a maximum of $150 per employee and dependent every two years.

c) Eligible new employees (except those hired for vacation relief) are covered effective the first day of the next month following the date of employment, except when the date of employment is the first day of the month, or first normal working day in the month, then coverage is effective from the first day of that month. Vacation relief employees are covered effective the first day of the month following 4 continuous months of service except when the date of employment is the first day or first normal working day in the month, then coverage is effective from the first day of the fifth month of continuous service.

d) Premiums for both plans will be paid by the Company. Participation in the plans is a condition of employment for all new employees as described above; however, employees covered by other medical plans may elect not to be covered by the above-noted plans of the Company.

e) Premiums shall continue to be paid on the foregoing basis for any subsequent compulsory basic medical, surgical and hospital plan introduced by the Provincial or Federal governments, unless the terms of such plans dictate otherwise.

f) Members of the Union who retire from the Company's service on pension and who have completed 10 years of service may continue to be covered under the above plans with the Company paying premiums indicated in this section.

NOTE: The word "month" as used above means "calendar month".

g) Effective January 1, 2012, the new Post-Retirement Benefits shall be implemented as per Schedule B – Post Retirement Benefits Summary. Current eligibility rules shall remain in effect for all eligible employees retiring prior to January 1, 2012 under the existing plan.

21.02 **GROUP LIFE INSURANCE**

EFFECTIVE JANUARY 1, 2011, SUPERCEDED BY FLEX BENEFITS PROGRAM CHANGES, AS PER THE ATTACHED SCHEDULE A – NEW BENEFITS SUMMARY

The Company will continue to provide all regular employees with life insurance benefits under the terms of its group life insurance policy. Coverage will be effective on the first day of the month following 3 months continuous service as follows:

a) The life insurance benefit is equal to 2 times the employee's annual salary, rounded to the next higher $1,000, if not already a multiple of $1,000.

b) For purposes of determining an employee's group life insurance coverage, "annual earnings" shall be computed semi-annually and shall be based on salary scales actually in effect on January 1st and July 1st each year.

c) The Company shall contribute 100% of the cost of the policy.

d) An employee who retires and draws an immediate Terasen Gas pension will be covered for 50% of the insurance in effect immediately prior to retirement. The amount will be reduced annually by 10% of the insurance in effect immediately prior to retirement until a minimum of $2,500.00 is reached. This minimum shall remain in effect for the remainder of the retired employee's life.

e) An employee receiving Long Term Disability benefits under Article 21.04 shall remain covered for the Life Insurance coverage in effect immediately prior to the disability.

21.03 **DENTAL PLAN**

EFFECTIVE JANUARY 1, 2011, SUPERCEDED BY FLEX BENEFITS PROGRAM CHANGES, AS PER THE ATTACHED SCHEDULE A – NEW BENEFITS SUMMARY

a) Regular employees, spouses and dependent children up to 21 years, or over 21 if in full-time attendance at an educational institution, shall be eligible for coverage under the Company's Dental Plan currently in effect with Pacific Blue Cross. The plan includes Plan A (100% payment of fees), Plan B (65% co-insurance), Plan C (50% co-insurance to a lifetime maximum of $3,000.00 per person enrolled in the Plan). Any other improvements to the benefit entitlements under the provisions of the Dental Plan covering Company employees during the life of this Agreement will be implemented for all COPE members covered by the Company Dental Plan. Payment of benefits under the Plan is based on the B.C. College of Dental Surgeons Schedule of Fees. Employees are eligible for enrollment in the Plan on the first day of the month immediately following 3 months continuous service.

b) The premium for such Plans shall be paid 100% by the Company.

21.04 LONG TERM DISABILITY

EFFECTIVE JANUARY 1, 2011, SUPERCEDED BY FLEX BENEFITS PROGRAM CHANGES, AS PER THE ATTACHED SCHEDULE A – NEW BENEFITS SUMMARY

a) The Company pays the full cost of the premium for a Long Term Disability Plan. The Plan provides a benefit to eligible employees at the rate of 70% of normal regular monthly earnings (to a maximum benefit of $15,000 per month) while sick or disabled. Benefits commence to eligible employees in the 16th week (27th week effective January 1, 2011) of continuous disability.

b) Coverage for regular employees will be effective on the first day of the month immediately following 3 months of continuous service.

c) This is a brief summary of the Plan's provisions. The Plan is subject to terms and conditions of the Contract with the Underwriter.

d) It is understood that the Plan may be altered or amended from time to time to reflect changes made under Article 10.15.

e) TERASEN GAS SICK LEAVE BANK: Ex-B.C. Hydro employees as at September 30, 1989, and who have banked sick leave entitlement on that date, will establish a non-renewable Terasen Gas Sick Leave Bank equal to 2/3 of that entitlement. This Bank may be used, at the employee's request, as a supplement to earnings while the employee is in receipt of sick leave or of Long-Term Disability payments at 70% of regular earnings. Payout of the Terasen Gas Sick Leave Bank will be 30% of regular earnings and will cease when the disability is over or when the Bank is exhausted.

f) Employees on paid sick leave on September 30, 1989 will establish their sick leave bank as at the date on which they are authorized to return to work.

g) While the benefits of this Plan include payments by government plans, such as Canada Pension and Workers' Compensation, the initial benefit under this Plan will not be reduced even if there are subsequent increases in government plans' payments.

h) The benefits payable from the Plan will increase at the rate of increase of the Consumer Price Index to a maximum of 3% per year.

21.05 **COVERAGE AND COST FOR EMPLOYEES ON LEAVE OF ABSENCE**

a) An employee on leave of absence without pay, for reasons other than sick leave or maternity leave for a period of 15 days or more in any calendar month is required to reimburse the whole cost of welfare plans as outlined in 21.01, 21.02, 21.03 and 21.04 above in respect of that month.

b) Company employees who are on leave of absence in accordance with Article 1.05 as full-time paid officers and representatives of the Union shall be eligible for coverage under all Company benefit plans, on condition the Company's share of the cost of such plans is borne either by the Union or by the employee.

NOTE 1: Coverage in all Benefit Plans will be effective on the first day of the month immediately following the completion of the qualifying period, if any.

NOTE 2: Further details of these plans are available upon request to the Human Resources Department.

21.06 The Company will continue with the existing Travel Accident policy that provides insurance for all employees up to an amount of $100,000 while travelling on Company business.

21.07

a) The Company will provide the Union with a copy of each Benefit Plan contract and any amendments made to such contracts.

b) The Company will ensure that employees shall suffer no loss or reduction of coverage as a result of a change in carrier of a Benefit Plan.

21.08 **FLEX BENEFITS PROGRAM**

a) The parties agree to maintain the current Employee Benefits program until December 31, 2010.

b) Effective January 1, 2011 a FLEX benefits program shall be implemented. As per the attached Schedule A – New Benefits Summary. The base option for Extended Health Benefits shall be Option 4.

c) The funding for this benefits program shall be based on the "percentage of base payroll" represented by the cost of benefits for bargaining unit employees in the 2007 calendar year, including the amount referenced by the actuarial evaluation (attached).

d) The percentage resulting from the above calculation shall be applied to the 2009 bargaining unit base payroll to yield a dollar amount which will fund the 2011 FLEX benefits program.

e) Thereafter, the same percentage (from the 2007 calculation) shall be applied annually to base payroll to yield a dollar amount, always two years "in arrears", e.g. the 2010 dollars shall fund 2012 benefits, 2011 dollars shall fund 2013 benefits, etc.

f) Effective January 1, 2011, each employee shall be credited with 4% of base pay which may, at the employee's option, be taken as PDOs (see Article 15.09a)) (@0.4% per day – full days only) or converted to a Health Spending Account, RRSP, contributions, cash, or applied or purchase benefits, in any combination not exceeding the 4% entitlement.

1. In November of each year, if an employee chooses not to make an election, the 4% shall be converted to 10 PDOs.

2. Cash and RRSP contributions shall be credited on a per pay period basis (24 pay periods)

3. HSA shall be credited at the beginning of the calendar year

4. Time off is credited at the beginning of the calendar year, and shall be prorated for employees who leave the Company during the same calendar year

Effective January 1, 2011 the 4% of base pay as referenced above shall be integrated into the FLEX benefits program.

WITNESS WHEREOF THE Company and the Union have caused their proper Officers and Representative affix their hand this _____ day of ________________, 2008.

TERASEN GAS INC.	CANADIAN OFFICE AND PROFESSIONAL EMPLOYEES UNION, LOCAL 378
____________________ Jan Marston	____________________ Brad Bastien
____________________ Jeff Marwick	____________________ Tim Bouzovetsky
____________________ John Turner	____________________ Bob Derby
	____________________ Karen Fisher
	____________________ Joe Nex
	____________________ Gerry Norton
	____________________ Kevin Smyth

Schedule 'A' – NEW Benefits Summary

MEMORANDUM OF AGREEMENT (2007 - 2012)

MSP				
▪ **Funded**	Flex Credits or Payroll Deductions = 100% FTR & 50% PTR (***working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly)***			
▪ **Taxable**	Depends on payment method, not taxable if paid by payroll deductions, taxable if paid by flex credits			
▪ **Opt Out**	Employees can opt out if covered under another plan. Portion of flex credits are credited back to the employee to use elsewhere.			
▪ **Employee Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
▪ **Dependent Eligibility**	Spouse and Children (to age 19 or full time students to age 25)			
▪ **Waiting Period**	1st of the month following date of hire			
Extended Health Care				
▪ **Funded**	Flex Credits or Payroll Deductions = 100% FTR & 50% PTR (***working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly)-Base Option***			
▪ **Opt Out**	Employees can opt out. Portion of flex credits are credited back to the employee to use elsewhere.			
▪ **Employee Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
▪ **Dependent Eligibility**	Spouse and Children (to age 19 or full time students to age 25)			
	Option 1	**Option 2**	**Option 3**	**Base Option**
▪ **Deductible**	N/A	$100	$0	$0
▪ **Maximum**	N/A	$500,000	$1 Million	$1 Million
▪ **Co-insurance**	N/A	60%	80%	100%
▪ **Prescription Drugs**				
○ Pay Direct Card	N/A	Yes	Yes	Yes
○ Formulary	N/A	Yes	Yes	Yes
○ Dispensing Fee Cap.	N/A	$8.50	$8.50	$8.50
○ Life Style Drugs (Oral Contraceptives, Anti-Obesity, Smoking Cessation, Fertility Drugs, and Erectile Dysfunction)	N/A	No	Yes	Yes
▪ **Paramedical Practitioners**	**Option 1**	**Option 2**	**Option 3**	**Base Option**
○ Acupuncturist	N/A	N/A	$250	$400
○ Podiatrist	N/A	N/A	$250	$400
○ Psychologist	N/A	N/A	$250	$400
○ Speech Language Pathologist	N/A	N/A	$250	$400
○ Chiropractor	N/A	N/A	$250	$400
○ Naturopath	N/A	N/A	$250	$400
○ Physiotherapist	N/A	N/A	$250	$400
○ Massage Therapist	N/A	N/A	$250	$400
○ Dietician	N/A	N/A	$250	$400
○ Private Duty Nursing	N/A	$25,000 LTM	$25,000 LTM	$25,000 LTM
▪ **Standard Durable Medical Equipment**	**Option 1**	**Option 2**	**Option 3**	**Base Option**
○ Lifetime Maximum	N/A	Subject to overall EHC Lifetime Maximum	Subject to overall EHC Lifetime Maximum	Subject to overall EHC Lifetime Maximum
▪ **Medical Aids and Supplies**	**Option 1**	**Option 2**	**Option 3**	**Base Option**
○ Hearing Aids	N/A	Dependent children only to a maximum of $500 / 5 calendar years	$500/5 yrs	$500/5 yrs

Schedule 'A' – NEW Benefits Summary

MEMORANDUM OF AGREEMENT (2007 - 2012)

○ Orthopedic Shoes / Orthotica	N/A	N/A	Combined maximum of $400 Adult per year $200 Child per year	Combined maximum of $500 Adult per year $300 Child per year
○ Wigs & Hairpieces	N/A	$600 LTM	$600 LTM	$600 LTM
▪ **Vision Care**	**Option 1**	**Option 2**	**Option 3**	**Base Option**
○ Eye Glasses/Contact Lenses	N/A	No	$150 / 24 Months	$250 / 24 Months
○ Eye Exams	N/A	No	$100 / 24 Months	$100 / 24 Months
▪ **Hospital – Semi Private Room**	N/A	Yes	Yes	Yes
▪ **Emergency Ambulance**	N/A	Yes	Yes	Yes
▪ **Out of Province**	Covered under the Travel Care Program			
Group Life Insurance				
▪ **Funded**	100% of the cost for Basic and Voluntary Life provided via flex credits			
▪ **Employee Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
▪ **Waiting Period**	Date of Hire			
▪ **Basic Life Insurance**	1 x Annual Salary			
▪ **Opt Out**	Compulsory			
▪ **Voluntary Life**	1 x Annual Salary			
▪ **Opt Out**	Yes – excess credits funded to employee			
▪ **Employee Optional Life**	Units of $50,000, Maximum $750,000			
▪ **Spouse Optional Life**	Units of $50,000, Maximum $750,000			
▪ **Child Optional Life**	$10,000			
Accidental Death & Dismemberment (AD&D)				
• **Eligibility** • **Waiting Period**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly Date of Hire Optional			
▪ **Employee Accidental Death &Dismemberment (AD &D)**	Units $50,000, Maximum $500,000			
▪ **Spousal Accidental Death &Dismemberment (AD &D)**	Spouse under the age of 70 Units $50,000, Maximum $500,000			
▪ **Child Accidental Death &Dismemberment (AD &D)**	Children (to age 19 or full time students to age 25) $10,000			
Dental Care				
▪ **Funded**	Flex Credits or Payroll Deductions = 100% FTR & 50% PTR (***working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly)-Base Option***			
▪ **Opt Out**	Employees can opt out. Portion of flex credits are credited back to the employee to use elsewhere.			
▪ **Employee Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
▪ **Dependent Eligibility**	Spouse and Children (to age 19 or full time students to age 25)			
	Option 1	**Option 2**	**Base Option**	**Option 4**
▪ **Deductible**	N/A	No	No	No
▪ **Plan A - Basic Preventative & Restorative Services**	N/A	60%	90%	100%
▪ **Plan A - Endodontic & Periodontic**	N/A	60%	90%	100%

Schedule 'A' – NEW Benefits Summary

MEMORANDUM OF AGREEMENT (2007 - 2012)

Services				
▪ **Plan B - Major Restorative - Crown, Dentures**	N/A	50%	70%	80%
▪ **Plan C – Orthodontics**	N/A	N/A	50%	60%
Maximums				
• Plan A & B (Annual)	N/A	$1,500	$2,500	$3,000
• Plan C (Lifetime)	N/A	N/A	$3,000	$3,500
Long Term Disability				
• **Funded**	Employer Paid (Base Option)			
• **Opt Out**	Must take one of four options			
• **Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
• **Waiting Period**	Date of Hire			
• **Indexing**	Optional – 5% Maximum			
• **Coverage**	**Base Option**	**Option 2**	**Option 3**	**Option 4**
	70% Taxable	60% Non Taxable	70% Indexed - Taxable	60% Indexed – non-Taxable
• **Maximum**	$15,000 Monthly			
Paid Sick Leave Allowance				
• **Funded**	100% Employer Paid			
• **Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
• **Waiting Period**	3 months following Date of Hire			
• **Coverage**	100% or 70% of earnings up to 26 weeks while ill or injured. Percentage of coverage varies depending on years of service.			
Travel Care				
▪ **Funded**	100% Employer Paid			
▪ **Employee Eligibility**	FTR & PTR working a minimum of 18.75 hrs per week and/or a total of 37.5 hrs bi-weekly			
▪ **Dependent Eligibility**	Spouse plus dependent children. Children up to the age of 19 or up to the age of 25 if full time student, or any age if disabled.			
▪ **Deductible**	No			
▪ **Coverage**	100% Eligible Emergency Medical Expenses to a lifetime maximum of $1,000,000.			
Business Travel Accident Insurance				
• **Funded**	100% Employer Paid			
• **Eligibility**	All Employees			
• **Waiting Period**	Date of Hire			
• **Coverage**	3 x Annual Salary			
Healthcare Spending Account				
	Employees may direct excess flex credits towards a Health Spending Account. Employees will have two years to spend funds allocated to their HSA.			

MEMORANDUM OF AGREEMENT (2007 - 2012)

Post Retirement Benefits – Effective January 1, 2012	
GENERAL INFORMATION	
▪ **Eligibility**	Employees retiring per the pension plan rules of their current pension plan and receiving an immediate pension are eligible for retiree benefits. Employees must work a minimum of 2 years full-time immediately prior to retirement in order to be eligible for benefits.
▪ **Survivor Benefits**	If the Joint & Survivor election is chosen: Coverage continues for the life of the spouse HSA eligibility will be reduced by 50% January 1st following the death of the retiree
▪ **Annual Deductible**	$1250 per person each calendar year to a maximum of $2,500
▪ **Maximum**	$500,000 lifetime
▪ **Coinsurance**	100%
EXTENDED HEALTH CARE DETAILS (Security Plan)	
▪ **Coverage**	100% of eligible expenses
▪ **Prescription Drugs**	Pay Direct Card Low cost alternative
▪ **Emergency Hospital**	Yes Semi Private Room
▪ **Emergency Ambulance**	Yes
▪ **Nursing**	$10,000/year (acute care only)
▪ **Medical Aids and Supplies – summary** (subject to claiming guidelines noted in the Pacific Blue Cross Booklet)	▪ Hearing Aids and repairs: maximum $500 every 5 calendar years ▪ Purchase of rental equipment (wheelchairs, hospital beds): $15,000 lifetime maximum (pre-authorization required) ▪ Ileostomy/colostomy supplies Mastectomy prosthesis ▪ Other (Combined maximum $500/person/year. Must be medically necessary to treat chronic and debilitating condition) o Splints, trusses, crutches, casts, custom fitted braces, cervical collars/traction kits, orthodics, stump socks, surgical stockings o Custom made orthopaedic shoes including repairs prescribed by a physician, podiatrist or chiropractor
▪ **Paramedical Practitioners**	Eligible expenses under the HSA (for example Acupuncturist, Podiatrist, Psychologist, Speech Language Pathologist, Chiropractor, Naturopath, Physiotherapist, Massage Therapist, Dietician)
▪ **Standard Durable Medical Equipment**	$15,000 lifetime maximum Preauthorization required for amounts in excess of $5,000
▪ **Vision Care** o Eye Glasses/Contact Lenses o Eye Exams	Available for reimbursement through the HSA
▪ **Dental Care**	Available for reimbursement through the HSA
▪ **Emergency Medical Travel**	Purchase of Private Insurance HSA eligible
Health Spending Account (HSA)	$2500 per year Any unused balance will be rolled forward and expire at the end of the second year

LETTER OF UNDERSTANDING #1

Exemptions

Deleted in 2007 (with the understanding that these position and future said position will remain exempt)

LETTER OF UNDERSTANDING #2

Mailing Services

Deleted in 2007 (moved to new article 1.16)

LETTER OF UNDERSTANDING #3

Customer Services Representative Leader

Deleted in 2007

LETTER OF UNDERSTANDING #4

Gas Controller Trainees

Deleted in 2007

LETTER OF UNDERSTANDING #4A

Relief Gas Controllers (RGC's)

Deleted in 2007

LETTER OF UNDERSTANDING #7

Gas Controllers

(original letter signed March 18, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

Gas Controllers in the Company's Vancouver office agree to vary certain terms and conditions of the Collective Agreement, as follows:

1. HOURS OF WORK

Gas Controllers Working Eight-Day Cycle:

Gas Controllers will work four 12-hour shifts within an eight day cycle. The normal cycle will be:

D	D	N	N	O	O	O	O
A	A	I	I	F	F	F	F
Y	Y	G	G	F	F	F	F
		H	H				
		T	T				

With one week's notice, this cycle may be altered to various combinations of day and night shifts, worked consecutively in the eight day cycle, except as provided for in Article 12.04 k) 1. i) - iii) and 2. i).

Day shifts will begin at 7:15 a.m. and end at 7:30 p.m. Total shift time is 12.25 hours with a 1.0 hour unpaid lunch break, for a standard shift of 10.75 straight time hours, plus 0.5 overtime hours.

Night shifts will begin at 7:15 p.m. and end at 7:30 a.m. Total shift is 12.25 hours with a 1.0 hour unpaid lunch break for a standard shift of 10.75 straight time hours, plus 0.5 overtime hours.

When more than one Controller is on shift, lunch breaks will be staggered and will be taken at or near the midpoint of the shift, as operations permit. When only one Controller is on shift, no lunch break will be taken, and the time will be compensated at overtime rates.

Each employee will receive three fifteen minute paid relief periods in each shift.

New Hires:

New Gas Controllers will work a standard Monday to Friday, 7.5 hour day, for no longer than one month (21 working days). Working hours will be 7:15 a.m. to 3:45 p.m., with a 1.0 hour unpaid lunch break and two fifteen minute paid relief periods in each shift. One 10.75 hour ADO will be accumulated during this period and placed in the Controller's time bank.

Gas Controllers

2. SHIFT PREMIUMS

As per Article 12.04(e) of the collective agreement

3. OVERTIME

All hours worked beyond the standard 10.75 hours per shift or 43 hours in an eight day cycle will be treated as overtime and paid out at the applicable overtime rate.

4. TIME OFF

Gas Controllers' time off entitlement will be calculated as follows:

a) Annual Vacation

Each Controller will be credited with 37.5 hours of Annual Vacation for each week of vacation entitlement earned in accordance with Article 14.

b) Statutory Holidays

Each Controller will be credited with 7.5 hours for each statutory holiday specified in Article 13.

c) Accumulated Days off

Each Controller will be credited with 127.5 hours per year as equivalent to 17 ADOs. A 10 hour standard day on this eight day cycle is equivalent to a 35 hour week. The additional 0.75 hours per day is worked to earn ADO entitlement.

Gas Controllers

For annual time off entitlement calculation, the total hours credited to the employees under (a), (b) and (c) above, plus any hours carried forward from the previous year, will be divided by 10.75 to calculate the number of shifts off each Controller is entitled to for the year (rounded up to the next whole shift).

5. RECONCILIATION

The total number of straight time hours worked by each Controller will be compared annually to the total number of straight time hours worked by other office staff during the same comparative period.

6. GENERAL

Scheduled time off shall not conflict with essential department requirements. Approval will not be unreasonably withheld.

Other areas in the Collective Agreement, such as sick leave, leaves of absence, banked overtime, etc. will be calculated on the basis of hours utilized to a maximum of 10.75 hours per shift.

For Terasen Gas

For COPE, Local 378

Jeff Marwick
Manager, Labour Relations

Brad Bastien
Senior Union Representative

Amended: November 6, 2007

The parties still intend to adjust this LOU to reflect the hours of work changes agreed to in the November 6, 2007 Memorandum of Agreement

LETTER OF UNDERSTANDING #7A

Transportation Coordinators

Deleted in 2007

.

LETTER OF UNDERSTANDING #9

Harassment in the Workplace

(original letter signed July 27,1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

Harassment in the workplace is covered in Company Policy HMR 01-08 Human Resources Policies and Guidelines "Promoting a Respectful Workplace" as below.

Promoting a Respectful Workplace

Purpose

This policy addresses the prevention and resolution of harassment and discrimination in the workplace.

Scope

This policy applies to all employees of the Company unless otherwise covered by a collective bargaining agreement with different related provisions.

Policy

The Company is committed to a work environment free from harassment and discrimination for all its employees. This policy prohibits, and is intended to prevent, harassment and discrimination of any type in the workplace, and to promote a workplace where employees and customers alike are treated with dignity and respect. The prohibition against workplace harassment and discrimination extends to all Company facilities and to all employees during the course of their employment, which includes business travel, off-site meetings, or Company social events. Further, the prohibition extends to all forms of workplace communication, including personal interaction, and any communication by e-mail, telephone, or in writing.

Harassment

Company personnel shall not engage in harassing activity which includes any behavior that demeans, humiliates, or embarrasses another employee such that a reasonable person should know that the behaviour is unwelcome and inappropriate in the workplace. This includes harassment prohibited by legislation including unwelcome verbal or physical conduct based on race, religious beliefs, colour, place of origin, gender, mental or physical disability, ancestry, marital status, family status, a criminal conviction, age, sexual orientation, or political beliefs.

Harassment that will not be tolerated by the Company includes verbal or physical abuse, threats, derogatory remarks, inappropriate jokes, taunts, or innuendo which demean or embarrass whether it be one event or a series of events or a course of conduct. Examples of harassment include:

- racial or ethnic slurs including racially related nicknames
- misuse of authority towards another employee (such as unfairness in employee selection or work assignment based on a prohibited ground)
- remarks, jokes, sexual invitations, innuendo, or taunting about a person’s body, age, marital status, gender, religion, accent, disability, or other prohibited ground
- leering, staring or gestures of a sexual nature

- display or communication of sexually explicit, pornographic, sexist, racist, or derogatory e-mails or material

- inappropriate physical contact such as patting, pinching, or that of a sexual or assaulting nature

- patronizing behavior, language, or terminology which reinforces stereotypes and undermines self-respect or adversely affects work performance or working conditions

Discrimination

Company personnel shall ensure that while performing Company related activities they shall not participate in discrimination against other Company personnel or customers. Discrimination involves treating any person or a group of persons in an unfair way based on a prohibited ground, including race, religious beliefs, colour, place of origin, gender, mental or physical disability, ancestry, marital status, family status, a criminal conviction, age, sexual orientation or political beliefs

Complaint Procedure

If you are being harassed or are the subject of discrimination in violation of this Policy, the Company encourages you to do the following:

1. Tell the perpetrator immediately that the harassing or discriminatory behavior is unwelcome and ask that it stop.

2. Record the incident, including date, time, location, and any possible witnesses.

3. Report the matter to a member of the Human Resources.

Upon receipt of a complaint, the Company shall do the following:

1. Keep the complaint strictly confidential. A timely investigation into the complaint will be undertaken and steps will be taken to resolve the problem informally in consultation with the complainant.

2. If the complaint cannot be resolved informally, both the complainant and the alleged perpetrator will be interviewed, as will any individuals who may be able to provide relevant information. All information will be kept in confidence.

3. If the investigation reveals evidence supporting the complaint of harassment, the perpetrator will be disciplined appropriately. Discipline may include suspension or dismissal, and the incident will be documented on the perpetrator's file.

4. If the investigation fails to reveal evidence to support the complaint, there will be no documentation placed on the alleged perpetrator's file.

5. Regardless of the outcome of a complaint made in good faith, the employee lodging the complaint, as well as anyone providing information, will be protected from any form of retaliation by either coworkers or superiors. This includes dismissal, demotion, unwanted transfer, or denial of opportunities within the Company.

LETTER OF UNDERSTANDING #9

Harassment in the Workplace

Responsibility of Management

It is the responsibility of management supervising the activities of other employees to take immediate and appropriate action to report or deal with incidents of harassment or discrimination of any type of brought to their attention or personally observed. Under no circumstances should a legitimate complaint be dismissed or downplayed nor should the complainant be told to deal with the matter personally.

This procedure is not intended to preclude another existing recourse that may be available to an employee (e.g. redress through the collective agreement, a Human Rights complaint, criminal charges, or civil litigation).

For Terasen Gas	For COPE, Local 378
Jeff Marwick Manager, Labour Relations	Brad Bastien Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING #10

Monthly Employee Information

Deleted in 2007 (Moved to Article 1.02(b)

LETTER OF UNDERSTANDING #11

Compassionate Leave – Columbia Natural Gas Limited

Deleted in 2007

LETTER OF UNDERSTANDING # 13

Hours of Work – Service Centre

(original letter signed May 17, 1990 between Fred Green (BC Gas) and R.G. Donnelly (OTEU))

Notwithstanding the provisions of Articles 12, 15 and 16 of the Collective Agreement between the parties, the following terms and conditions respecting Hours of Work, Statutory Holidays, ADOs, Premium Payments, and Work/Lunch breaks shall apply to employees staffing the Terasen Gas Service Centre.

1. The attached schedule of hours and days of work is a typical schedule of 7.5 hour shifts payable at straight time, except Sundays and Statutory Holidays. The schedule may be changed from time to time by mutual agreement of the parties and will generally be of a similar pattern, except that the Company will determine the number of employees on each shift in order to meet operational requirements.

2. The scheduled days off are inclusive of 11 days in lieu of statutory holidays and, for FTR Service Centre Reps., 15 ADOs.

3. Each <u>FTR</u> employee is entitled to two additional ADOs to be scheduled at a time mutually agreeable to the employee and the manager.

4. All regular scheduled time worked on a Sunday or statutory holiday will be paid at time and one-half (150%). Time worked beyond 7.5 hours will be paid at double time (200%).

5. Shift premiums shall be 1/2 hour at straight time for the afternoon shift and 1 hour at straight time for the graveyard shift.

6. Employees on graveyard shift will work from 0001 to 0700 hours inclusive and will take their work/lunch breaks at their work station in order to be available to answer the telephone.

For Terasen Gas — For COPE, Local 378

Jeff Marwick — Brad Bastien
Manager, Labour Relations — Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING # 13A

Designated Relief Service Centre Representative (DRSCR)

Deleted in 2007

LETTER OF UNDERSTANDING #13B

Non-Rotating Day Shifts – Service Centre

Deleted in 2007

LETTER OF UNDERSTANDING #14

Job Sharing

(original letter signed July 26, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

Definition

Job sharing is defined as dividing all the functions of one full-time regular (FTR) position between two regular employees, each of whom works part-time in a manner that provides full-time coverage for the position. A full-time regular position can only be job-shared with the approval of the Manager, Human Resources and the Union. The Manager is responsible for communicating the requirements of the job to both employees.

It is the intent that the time worked by the two job sharing partners will equate to that of a full-time regular employee. Neither of the partners in a job share relationship shall work less than 40% of the normal hours of work of the full-time regular position.

1. **General**

a) The Parties agree that all terms and conditions of the Collective Agreement in force and effect shall apply unless specifically altered herein.

b) Only regular employees are eligible to participate in job sharing arrangements unless otherwise mutually agreed by the Parties.

c) A job-share employee (other than a temporary employee as mutually agreed in 1.(b)), shall be classified as a part-time regular employee.

d) For the purpose of applying the overtime and shift differential provisions of this Agreement, the job share position will be treated as a full-time regular position. Accordingly, the combined time worked by the two incumbents will fall within the normal daily and weekly hours of work for the full-time position to a maximum of 7 hours per day or 35 hours per week. Any time worked through the combined efforts of the two incumbents which exceeds 7 hours per day or 35 hours per week shall be paid at overtime rates to the employee performing the work, except when the combined hours are beyond 7 per day and 35 per week for the purpose of attending training courses or Company programs. Shift premiums will be split appropriately, but will not exceed those paid for the normal shift of the full-time position.

e) Notwithstanding (d) above, a job-sharing employee may volunteer to work additional hours to cover workload demands that would otherwise be covered by another employee working part time. Premium pay will apply to all hours worked in excess of 7 in a day or 35 in a week by that employee.

f) Job sharing partnerships shall be restricted to employees working within commuting distance of the established headquarters where the job-share position exists.

g) All job-sharing employees must meet the qualifications of the position to be job-shared.

h) No employee is eligible to job share in a position in a paygroup higher than their current position.

Job Sharing

i) The regular position left vacant when two regular employees job-share will be posted in accordance with the provisions of Article 6, except as outlined in the trial period in 4 (a).

2. **Procedure**

a) Regular employees wanting to job share may request the manager to consider a proposal for a job sharing arrangement. In making a submission it is important that both employees realize they are entering a partnership. Their proposal must provide information on the qualifications and experience of each proposed partner and give details on how the arrangement will ensure the work is efficiently and effectively completed. Details which must be considered in the submission include:

1. Which functions will be shared and which functions will be performed by only one partner.

2. How load priorities will be determined on an on-going basis, and how these priorities will be communicated between partners to ensure nothing is missed.

3. Preferred work schedule of each partner and preferred start date.

4. Other information required by the manager.

b) Proposed job sharing arrangements will be discussed with the appropriate Human Resources Officer and for each job sharing arrangement there must be a written understanding signed by each partner, the employee's manager, Human Resources and the Union.

3. **Registration**

Regular employees who wish to job share should submit a proposal to their manager and the Human Resources Office. It is the responsibility of the employee to propose a qualified partner.

4. **Trial Period**

a) In order to allow the parties a reasonable time to test the suitability of the individual job sharing arrangement, a 6 calendar month trial period will be in effect at the beginning of each job sharing arrangement. Any temporary vacancy that is thereby created may be filled by the Company without posting for the 6 month trial period. For such backfill vacancies, preference will be given to the senior, qualified employee within the same work group where the vacancy exists, except where there are qualified employees on the recall list.

b) During the trial period, either party or either employee may terminate the job-share with 30 calendar days written notice.

Job Sharing

c) In the event that the job-share is terminated during the trial period, both employees will revert back to their former regular positions and status in all respects.

5. **Job Sharing Conditions**

a) Full-time regular employees who enter a job sharing arrangement shall change their status to part-time regular (PTR) and assume the salary of the shared position. In the case of a demotion, the employee will retain their salary if within the group salary range of the position, or Step 5 of the position group, whichever is lower. There will be no blue circle or red circle salary treatment as a direct result of job sharing.

b) Article 19.02(b), (c), and (d) do not apply to PTR job-sharing employees.

6. **Job Share Partner Absence**

Where an employee in a job share arrangement is absent from work for any reason, the Company shall first offer the work to the remaining partner (RP). In such instances, the extra hours worked, up to a maximum of 7 hours per day and 35 hours per week, will be paid at straight time rates. The RP will retain their status as a PTR employee for the duration of the partner's absence. If the RP declines to accept the extra hours the Company may fill the vacancy with a PTT employee.

7. **Filling a Job Share Vacancy**

a) In the event one of the partners leaves the job-share and where the parties and the RP agree the job-share should continue, the vacancy will be dealt with as follows:

b) The RP has 30 calendar days from the notice date of the original partner to find a replacement partner.

c) If no suitable partner can be found, the RP will have the option of filling the position on a full-time basis.

d) If the RP declines the option, s/he will be placed directly onto the recall list in accordance with Article 7.03 and the full-time position will be posted in accordance with Article 6.

Job Sharing

8. **Termination of Job Sharing Arrangement**

a) Individual job sharing arrangements may be terminated by the Manager or either party with 30 days written notice to the affected partner(s).

b) If one partner voluntarily leaves, the remaining partner (RP) will have the option of filling the position without posting on a full-time basis. If the RP declines the option of filling the full-time position, s/he will be placed directly onto the recall list in accordance with Article 7.03 and the full-time position will be posted in accordance with Article 6.

c) If the Manager, or either party terminates the job-share and neither partner voluntarily leaves, the full-time position will be posted in accordance with Article 6, and when filled, the remaining partner(s) will be placed on the re-call list in accordance with Article 7.03.

9. **Discontinuation of Job Sharing Letter of Understanding**

Either party may discontinue this Letter of Understanding on notice to the other party, following which job share partnerships in the trial period will be immediately discontinued. Existing job share partnerships past the trial period will be grandparented.

For Terasen Gas	For COPE, Local 378
Jeff Marwick Manager, Labour Relations	Brad Bastien Senior Union Representative

Amended: November 6, 2007

> The parties still intend to adjust this LOU to reflect the hours of work changes agreed to in the November 6, 2007 Memorandum of Agreement

LETTER OF UNDERSTANDING #15

Safety of Employees Working at Night

(original letter signed September 13, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

1. Except as provided in Article 16.10, when employees other than regular shift workers (Service Centre, Gas Control, etc.) are required to work overtime later than 2200 hours:

   a) the Manager shall, if requested by the employee, make arrangements for an escort to their motor vehicle or public transit or,

   b) if the employee is travelling by foot or to an insecure public transit destination, the Manager may, if requested by the employee, have the employee driven home by Company personnel or by taxi, at the Company's expense.

2. The Union and the Company agree to meet to discuss any extraordinary circumstances that may affect the safety of regular shift workers whose shift or overtime ends between dusk and dawn.

For Terasen Gas

For COPE, Local 378

Jeff Marwick
Manager, Labour Relations

Brad Bastien
Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING #19

Inter-Bargaining Unit Transfers

(original letter signed August 3, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

1. A COPE member with a minimum of five years seniority who has been selected to fill a job in another Terasen Gas Bargaining Unit and whose selection is successfully grieved will have the right to return to the position which s/he previously held as per Article 6.05 for a period of 3 months from the date of leaving the COPE Bargaining Unit.

2. COPE members with a minimum of 5 years seniority who are successful applicants on jobs in another Terasen Gas Bargaining Unit may retain their seniority for a period of two years from the date of leaving the COPE for the sole purpose of applying on future COPE job bulletins.

3. The leaving date will be confirmed to the COPE and the employee by the Company in writing.

4. No COPE seniority will be accrued while a member of the other Bargaining Unit.

5. Minimum dues must be paid to the COPE during the period of time in the other Bargaining Unit.

For Terasen Gas	For COPE, Local 378
Jeff Marwick Manager, Labour Relations	Brad Bastien Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING #20

Training/Travel Guidelines

(original letter signed July 20, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

The Company and the Union believe in the benefits of employee training and development. The purpose of training is to provide for upgrading of an employee's knowledge, skills and abilities in order to meet the requirements of their present position, or to develop toward future career alternatives.

The following provisions are intended to apply to job training courses which are directed by the Company. In situations where such training occurs away from an employee's established headquarters, and/or when the hours of training vary from an employee's normal hours of work, the employee will attend the hours of the training program, subject to the following:

1. The method of travel and time of departure should be discussed between the employee and <u>manager</u> in advance to obtain management approval on travel arrangements.

   By agreement with the manager, these guidelines may be varied to accommodate travel arrangements requested by the employee, however, authorized payments for travel time will be based on the least cost alternative.

2. On a day dedicated to training:

   a) all surplus travel time will be paid at straight time rates regardless of when it occurs;

   b) accrued time in training (inclusive of travel time related to attendance at the training course) which is in excess of the normal hours accrued in an employee's work day (inclusive of time normally spent in travel to and from work) will be paid at straight time rates;

   c) where formal (classroom) training extends beyond 6:00 p.m., such that the total accrued hours in training for the day (exclusive of travel time) exceeds the employee's (normal) regular daily hours, these training hours which exceed the normal daily hours will be paid at overtime rates.

Training/Travel Guidelines

3. On a day in which both training and normal work is performed:

   a) accrued time in travel, work, and training which is in excess of the normal hours accrued, in an employee's work day (inclusive of time normally spent in travel to and from work) will be paid at one and one-half (1-1/2) times the employee's hourly rate:

   b) where formal (classroom) training extends beyond 6:00 p.m. such that the total accrued hours for the day, exclusive of travel time, exceeds the employee's (normal) regular daily hours, these training hours will be paid at overtime rates.

4. If training occurs on an employee's regularly scheduled day off, the employee will have the day off rescheduled (without further compensation).

5. Time spent in travel on a Sunday, related to attendance at a training course, will be paid at straight time rates. When such travel commences prior to 5:00 p.m. the employee will be paid for the period from commencement of travel to 5:00 p.m., or to the time the employee arrives at their destination whichever time is latest. Any payment for Sunday travel related to attendance at a training course is limited to a maximum of a normal day's pay at straight time rates.

6. Time spent in travel on a Saturday, related to attendance at a training course, will be paid at straight time rates. When such travel commences later than 8:30 a.m., the employee will be paid from 8:30 a.m. to the time at which the employee arrives at their destination. Any payment for Saturday travel related to attendance at a training course is limited to a maximum of a normal day's pay at straight time rates.

7. Under this Letter, employees may elect to bank any premium hours accrued in lieu of receiving pay, subject to the terms of Article 16.07.

For Terasen Gas

Jeff Marwick
Manager, Labour Relations

For COPE, Local 378

Brad Bastien
Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING # 21

Co-Operative Educational Students

(original letter signed June 22, 1994 between Fred Green (BC Gas) and Scott Watson (OTEU))

This will confirm the conditions with respect to the hiring of students under a Co-operative Education Program.

1. For the purposes of this letter, a co-op student is a student who is enrolled as an undergraduate in a co-op program at a recognized B. C. College or University at all times during the period of employment.

2. It is the intent of the Parties that participation in this program will not adversely affect existing jobs or bargaining unit work covered by the Terasen Gas/COPE Collective Agreement. The employment of Co-op Educational Students shall not be utilized by the Employer to avoid the creation, continuance or filling of any regular or temporary jobs as defined in the Collective Agreement. Co-op Students shall not be employed to backfill for:

   a) leave of absence replacements;
   b) special projects which disallows training or employment opportunity to bargaining unit employees;
   c) emergent considerations.

3. Terasen Gas will ensure that any co-op student employed under this Letter of Understanding will have a maximum employment period of four (4) continuous months. Each such period of continuous employment for each student shall be deemed to be one (1) work term.

4. Co-op students may be re-employed by Terasen Gas provided there is at least one co-op period of absence between periods of employment. In such instances, the co-op student will advance one step on the salary schedule noted below.

5. All co-op students will be required to become and remain COPE members for the duration of their work term. Co-op students will be classified as temporary (Co-operative Education). Co-op Education Students will not be entitled to apply for regular or temporary COPE-affiliated bulletined positions.

6. Either Party retains the right to discontinue participation in Co-operative Education programs with four months notice to the other.

7. COPE will be advised of the student's name, position and department prior to placement.

8. When more than two students are required in any one department, such will be subject to agreement of the Parties.

9. No more that four (4) co-op students would be hired in any four (4) month period without mutual agreement.

10. Co-op students will be entitled to the same premium provided for employees under Article 19.01(b)7 in lieu of vacations, statutory holidays and Article 19.01(d) 4 in lieu of benefits.

Co-Operative Educational Students

11. Co-operative Educational Students shall receive salary treatment in accordance with the following schedule, which is based progressively on the number of Work Terms worked by each student:

WORK TERM	PAY GROUP
1	Group 3 Minimum
2	Group 3 Maximum
3	Group 3 Maximum
4	Group 4 Maximum
5	Group 4 Maximum

The above rates shall be subject to change at any time by mutual Agreement of the parties.

12. The Co-operative Educational Students Program as described in this Letter of Understanding shall apply for the term of the Collective Agreement unless modified by mutual agreement of the Parties.

For Terasen Gas

For COPE, Local 378

Jeff Marwick
Manager, Labour Relations

Brad Bastien
Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING #22

LTD Employees Returning to Work

(original letter signed July 5, 1996 between Fred Green (BC Gas) and Bill Bell (OTEU))

1. When employees return from a period of sickness or disability after their positions have been filled, the Company will attempt to place them in a regular position for which they are qualified in accordance with HMR-01-08, subject to agreement of the Union . The position will be at the same salary level, or as near as possible to the employee's previous rate.

2. (a) In the event placement is not immediately possible, or the employee does not wish to accept the placement(s) offered, the employee may choose to bump back into their previously held position if it is occupied by a less senior employee. This bumping option is limited to a period of two years from the date long term disability payments became effective.

   (b) If their previously held position is occupied by a more senior employee, the employee will be entitled to exercise their bumping options pursuant to Article 7.02 and/or layoff to recall protection under Articles 7.02(d), and 7.03.

3. If the employee returns after more than two years from the date long term disability payments became effective and there are no placements options, or the employee chooses not to accept the placement options offered, the employee will be placed on the recall list pursuant to Article 7.02(d) and 7.03.

For Terasen Gas

Jeff Marwick
Manager, Labour Relations

For COPE, Local 378

Brad Bastien
Senior Union Representative

Amended: November 6, 2007

LETTER OF UNDERSTANDING# 23

Terasen Gas Utility Employees on Secondment to Terasen Gas International Inc. for Overseas Projects

Deleted in 2007

LETTER OF UNDERSTANDING #25

Transportation Coordinators

Deleted in 2007

LETTER OF UNDERSTANDING #28

Contract Continuation Agreement (Adjustment Plan – AP)
A Successorship between Terasen Gas Utility and Customerworks

Deleted in 2007

LETTER OF UNDERSTANDING #29

Electronic Job Postings

Deleted in 2007 – Refer to LR Forum

LETTER OF UNDERSTANDING #30

Consolidation of Overtime, Vacation and ADO Timebanks

Deleted in 2007

LETTER OF UNDERSTANDING #31

Hours of Work - Emergency and Operations Representatives

(original letter signed November 12, 2002 between Franz Scherubl (BC Gas) and Bill Bell (OPEIU))

The company and union agree to vary certain terms and conditions of the Collective Agreement as they apply to the shift work of Emergency and Operations Representatives (E&ORs). The company and union agree that a shift schedule with a combination of 12 hour and 8 hour shifts (inclusive of lunch break) will meet the required 24 hour 7 days a week coverage while benefiting the E&ORs by providing more frequent scheduled time off, including more weekends. To create this rotating shift schedule, the 11 days in lieu of statutory holidays and 17 ADOs will be pre-scheduled into the shift rotation and time off will be pre-scheduled and subject to operational requirements.

1. Shift Structure
   The attached schedule of hours and days of work is a typical schedule of a 7 week forward rotation, with a combination of 12 and 8 hour shifts payable at straight time. The schedule is intended to incorporate relief coverage from within the group.

2. Working Hours
   The total number of straight hours worked by each E&OR will be equal to the total number of straight time hours worked in a year by other office staff during the same year (i.e. 35 hours per week for 52 weeks).

3. Work and Lunch Breaks
   a) When more than one employee is on shift, lunch breaks will be staggered and will be taken at or near the midpoint of the shift or as operations permit and will be one half hour. As well, employees on the night shift will take their lunch breaks at a time when employees on the afternoon shift can provide coverage (i.e. before the end of the afternoon shift). When only one employee is on shift, the lunch break will be taken at the workstation, paid at straight time and the shift will be reduced by 0.5 hour.

   b) Each employee shall receive 3 work breaks of 15 minutes in a 12 hour shift or 2 work breaks of 15 minutes in an 8 hour shift. The work breaks will be staggered and shall be taken one in each 4 hour period of the shift.

4. Overtime Payments
   All hours worked in excess of the regularly scheduled shift (i.e. 8 or 12 hours) will be paid for at the rate of double time. All hours worked on a scheduled day off shall be paid at the rate of double time unless appropriate notice of change of schedule is given (per article 12.04k).
5. Annual Vacation
   a) All annual vacation shall be pre-scheduled.

   b) Sign up for vacation per article 14.05 of the collective agreement will be in order of seniority from the 3rd quarter seniority list, and will be completed by December 1st of each year. The approved schedule will be posted by January 15th of the following year.

Hours of Work - Emergency and Operations Representatives

6. Time Off
   E&ORs' time off entitlement will be calculated as follows:

   a) Annual Vacation
      Each E&OR will be credited with 37.5 hours of annual vacation for each week of vacation entitlement earned in accordance with Article 14.

   b) Statutory Holidays
      Each E&OR will be credited with 7.5 hours for each statutory holiday as specified in article 13.

   c) Accumulate Days Off (ADOs)
      Each E&OR will be credited with 127.5 hours per year as equivalent to 17 days ADOs. ADOs will be pre-scheduled into the shift schedule and will deplete the time bank on an hour for hour basis to a maximum of 11.5 hours per day.

7. General
   a) Scheduled time off shall not conflict with essential department requirements and will be subject to the availability of relief within the group of E&ORs.

   b) Other areas in the Collective Agreement, such as sick leave, leaves of absence, banked overtime, etc. will be calculated on the basis of hours utilized to a maximum of 11.5 hours per day.

8. Trial Period
   There will be a trial period of up to 2 complete 7 week forward rotations. Prior to the end of the trial period, the parties will meet to discuss continuation of the shift schedule and this LOU.

9. Discontinuation of the Letter of Understanding
   Either party may discontinue this Letter of Understanding on 30 days written notice to the other party.

For Terasen Gas	For COPE, Local 378
Jeff Marwick Manager, Labour Relations	Brad Bastien Senior Union Representative

Amended: November 6,2007

The parties still intend to adjust this LOU to reflect the hours of work changes agreed to in the November 6, 2007 Memorandum of Agreement

LETTER OF UNDERSTANDING #32

Leader & Work Leader Selections

The Company and the Union acknowledge that Leader and Work Leader positions, are subject to a higher job selection criteria than an average position. For all Leader and Work Leader classifications, selections shall be made giving equal weight to each of the following six (6) factors:

1. Seniority
2. Expertise
3. Initiative
4. Problem solving & results orientation
5. Customer Focus
6. Business understanding & alignment

For Terasen Gas

Jeff Marwick
Manager, Labour Relations

For COPE, Local 378

Brad Bastien
Senior Union Representative

Signed: November 6, 2007

LETTER OF UNDERSTANDING #33

Labour Relations Forum

This Letter of Understanding sets out the basis for establishing and maintaining an ongoing Labour Relations Forum (Forum) between the Union and the Company.

It is understood that a favourable relationship cannot be simply negotiated or mandated, it must be developed together by the parties to the relationship. Representatives of the Union and the Company therefore acknowledge the need to work jointly with each other and with their principals toward the development of a harmonious relationship.

The union and the Company also recognize that many factors, both internal and external, have created and will continue to create new challenges to an effective working relationship. The parties therefore wish to set out the principles and guidelines for the establishment of the Forum and to identify the way in which the Union and the Company intend to address certain labour relations issues on an ongoing basis. Nothing in this document is intended to abrogate any rights presently held by either party. The parties also recognize that in striving to meet their objective of establishing a stable and productive working relationship, periodic amendments to this document may be required from time to time.

One of the objectives of establishing this Forum will be to have a mechanism in place to respond to certain issues raised by either party which, if not dealt with in a timely fashion, could adversely affect the relationship between the parties. The parties recognize the importance of developing a consultative Forum for purposes of securing and maintaining a Collective Agreement that reflects the ongoing needs of the parties bound by it and which seeks to build labour relations stability within the Company.

1. Working/Problem Solving Sessions

A consultative Forum (known as the Labour Relations Forum) will be established, maintained, and scheduled, to enable the parties to deal with certain issues for the purpose of improving the Labour Relations environment within the Company. This Forum will consist of regularly scheduled meetings between the parties, and other such meetings as required, with the expectation that there would be no less than four meetings per year.

2. Representation

There will be two designated representatives assigned from each party. The designated representatives will coordinate their respective agendas and will work toward the resolution of issues brought forward. Other participants may be brought in by the parties on an "as required" basis to act as a resource in helping resolve the issues being addressed.

3. **Issues to be Addressed**

Issues brought forward by the parties include, but not be limited to, the following proposed changes to the collective agreement:

1) Management doing bargaining unit work (Article 1.09)
2) Working at home (Article 1.16)
3) Alternative dispute resolution system
4) Medical Certificate (including "5" consecutive days")(Article 10)
5) Job Evaluation Plan (Article 2)
6) Electronic Job Postings (formerly (LOU #29)
7) Name of Mediator
8) EIP

Other mutually agreed non-bargaining issues from either party; and, business focused operational issues that have a labour relations impact may be submitted.

Every effort will be made to deal with “resolvable issues” as expeditiously as possible. In regard to such issues, the parties will endeavor in good faith to arrive at resolutions without external assistance. However, the parties agree that some “resolvable issues” may require third party assistance, and the parties will therefore set out to agree to appoint a standing mediator who may be called upon as the parties determine.

4. Resolution Implementation

Resolutions to issues that involve changes to the Collective Agreement shall be announced and implemented as the parties determine. It is understood that some resolutions may require a ratification procedure.

5. Communications

Communication of Forum resolutions will be jointly coordinated. To that end, the parties will keep joint minutes. In addition, each party will be free to engage in direct communications with their respective constituents, with a copy of such communiqués being sent to the other party.

The parties believe that in order to achieve a positive labour relations environment there must be open communications and trust between the parties and a shift towards a more constructive approach to resolving issues of mutually concern. In support of the objective to achieve and maintain positive labour relations, the parties commit themselves to the principles of the Labour Relations Forum.

For Terasen Gas	For COPE, Local 378
Jeff Marwick	Brad Bastien
Manager, Labour Relations	Senior Union Representative

Signed: November 6, 2007

LETTER OF UNDERSTANDING #34

Re: Part-Time Regular Employees (PTR)

The Company and the Union agree that the following shall apply to all Part-time Regular employees. This includes all PTR employees on payroll at time of ratification (including Job Shares), and all new PTR employees (post-ratification) working 18.75 hour or more per week or working 37.5 hours or more per pay period:

1. Wages & Hours of Work

For PTR employees on payroll at time of ratification (including Job shares), hourly wages shall be based on a 7.0 hour day (or a 35 hour work week).

Effective January 1, 2008, for new PTR employees (post-ratification), hourly wages shall be based on 7.5 hour day (or a 37.5 hour work week). For conversion purposes only, hourly rates of pay are determined by dividing bi-weekly salaries by 75 (e.g. overtime).

Housekeeping Note: Delete the second sentence of Article 16.01

2. Allocation for time off

Effective January 1, 2008, new PTR employees (post-ratification) shall receive a 4% allocation in lieu of days off, which will be credited annually, and can be re-directed to a Health Spending Account, RRSP contributions, cash, or the Employee Savings plan.

3. Annual Vacation Entitlement

Effective January 1, 2011, Annual Vacation entitlement shall be improved for all PTR employees as follows:

Years of Service	Vacation %
<1 year	Up to 6%
1-7 years	6%
8 - 17 years	8%
18 - 24 years	10%
25+ years	12%

4. Employee Savings Plan

Effective January 1, 2008, new PTR employees (post-ratification) shall be entitled to the Employee Savings Plan, which consists of a Company contribution of an amount equal to 3% of base pay.

5. Employee Incentive Plan

All PTR employees shall be eligible for the Employee Incentive Plan.

6. Employee Benefits Program

New PTR employees (post-ratification) shall go to the new flexible benefits program with 50% flex credits, effective January 1, 2008.

For PTR employees on payroll at time of ratification (including Job Shares), the current Employee Benefits Program shall be maintained until December 31, 2010. Effective January 1, 2011, with the implementation of the new flexible benefits program:

- PTR employees on payroll at time of ratification (including Job shares) shall continue to be covered under the existing benefit program referred to as "traditional" benefits program. Effective January 1, 2011, all current PTR employees will move to the "flexible" benefit program and will be provided with the same level of flex credits granted a Full-time Regular, provided the employee has not at any time changed their employment status from PTR, regardless of their employment status effective January 1, 2011. Any PTR status change post ratification will be treated the same as a new hire.

- PTR employees on payroll at time of ratification (including Job Shares) and all new PTR employees (post-ratification) shall be entitled to the improved 26 week Sick Leave entitlement.

7. Post-Retirement Benefits

PTR employees on payroll at time of ratification (including Job Shares) retiring prior to January 1, 2012 shall remain eligible for the current Post-Retirement Benefits. Effective January 1, 2012, PTR employees on payroll at time of ratification (including Job Shares) retiring on pension with 10 or more years of pensionable service shall be eligible for the NEW Post-Retirement Benefits.

For Terasen Gas

For COPE, Local 378

Jeff Marwick
Manager, Labour Relations

Brad Bastien
Senior Union Representative

Signed: November 6, 2007

SCHEDULE 'C'

JOB TITLES BY SALARY GROUP

JOB TITLE	JOB GROUP
Relief Clerk	3
Data Entry Clerk	4
MAC and Wireless Support Clerk	4
Office Services Clerk	4
Operations Support Representative 1	4
Switchboard Operator/Receptionist	4
Communications Assistant	5
Engineering Secretary	5
Field Operations Assistant	5
LNG Plant Support Clerk	5
Marketing Support Assistant	5
Office Services Leader	5
Operations Support Representative 2	5
Project Clerk	5
Regulatory Affairs Assistant	5
Accounts Payable Support Clerk	5
Time Clerk	5
Training Assistant	5
Transmission Compliance Assistant	5
Transmission Permit Representative	5
Accounts Payable Clerk 2	6
Budget & Costing Clerk 1 (Interior)	6
Contracts & Projects Administrator	6
Engineering Clerk	6
Gas Load Control Clerk 2	6
GIS Drafter 1	6
Marketing Support Representative	6
Measurement Technologies Assistant	6
Operations Support Assistant	6
Operations Support Representative 3	6
Project Management Administrative Assist	6
Property Service Clerk	6
T & D Surveyor 1	6
Technical Sales Support Assistant	6
Time Administrator	6
Training System Analyst	6

AM/FM Completions Work Leader	7
Asset Accounting Analyst 1	7
Credit Card Administrator	7
Credit Card Program Administrator	7
Damage Prevention Coordinator	7
Dispatcher	7
Emergency & Operations Representative	7
Facilities Coordinator - Office Systems	7
Financial Accounting Clerk 3	7
Forms Analyst/Designer	7
Infrastructure Support Technician	7
Measurement Analyst 2	7
Operations Support Rep Work Leader	7
Payroll Administrator	7
Training Program Coordinator	7
Web Specialist	7

Accounts Payable Leader	8
Accounts Payable System Support Analyst	8
Asset Accounting Analyst 2	8
Claims Adjuster 1	8
Contract & Finance Coordinator	8
Contract & Finance Coordinator - Gas Sup	8
Financial Accounting Clerk 4	8
GIS Drafter 3	8
I&CT Contract & Finance Coordinator	8
Install Coordinator 1	8
Internal Communications Writer	8
Inventory Analyst 2	8
IT Communications Coordinator	8
Lands Administrator	8
Marketing Services Representative	8
Measurement Analyst	8
Operations Financial Analyst	8
Operations Financial Planning Manager	8
Operations Process Analyst 1	8
Pipeline & Right of Way Inspector	8
Planning and Design Technician	8
Resource Management Coordinator	8
T & D Surveyor 2	8
Technical Standards Writer	8
Technologist 1 - Capacity Planning	8
Technology 1 - Capacity Planning	8
Technologist 1 – Instrumentation	8
Vehicle Fleet Contract & Finance Coordinator	8

Communications Coordinator	9
Designer, Communication Services	9
Engineering Drafter 3	9
GIS Drafter Leader	9
Install Coordinator 1 Workleader	9
Measurement Business Analyst	9
Operations Financial Coordinator	9
Operations Process Analyst 2	9
Pipeline right of Way Representative	9
Pipeline & Right of Way Inspector WL	9
Planning and Design Technologist 1	9
Procurement Specialist	9
QA/QC Technician	9
Technician 4 - Corrosion Control	9
Technologist 2 - Capacity Planning	9
Technologist 2 - Field Measurement	9
Technologist 2- Instrumentation & Communication	9
Telecommunications Coordinator	9
Writer/Researcher	9

Business Technology Integrator	10
Commercial Account Rep	10
Distribution Operations Analyst	10
Engineering Drafting Workleader	10
Financial Accounting Analyst	10
Financial Accounting/Credit Analyst	10
Gas Control Coordinator	10
Gas Supply Operations Analyst	10
Industrial Hygiene Tech	10
Install Coordinator	10
Install Coordinator 2	10
Insurance Analyst	10
Lands Representative	10
Lead Designer, Communication Services	10
Maintenance Analyst	10
Measurement Services Business Analyst	10
Operations Process Analyst 3	10
Planning and Design Technologist 2	10
Planning and Design Workleader	10
Process Support Analyst	10
Procurement Work Leader	10
Senior Procurement Specialist	10
Senior Rates Analyst	10
Senior Research & Evaluation Analyst	10
Tech 3-Geographic Info Systems	10
Technician 3 - Laboratory	10
Technologist 3 - Capacity Planner	10
Technologist 3 - Capacity Planning	10
Technologist 3 - Environmental Support	10
Technologist 3 - Pipeline Design/Drafter	10
Technologist 3 - Plant Design/Drafter	10
Technologist 3 - SCADA	10
Technologist 3 - Measurement Technologies	10
Training Technologist	10
Workleader - Corrosion Control	10

Application Support Analyst	11
Application Support Analyst - Gas Supply	11
Financial Accountant	11
Gas Controller	11
Property Representative	11
Property Tax Specialist	11
Right of Way Project Coordinator	11
Senior Regulatory Work Leader	11
Tax Analyst II	11
Technologist 4 - Capacity Planning	11
Technologist 4 - Measurement	11
Technologist 4 - Plant Design	11
Technologist 4 - SCADA	11
Technologist 4 - Electrical Design	11
Technologist 4 - Energy Utilization	11
Technologist 4 - Instrumentation Design	11
Technologist 4 - Pipeline Design	11
Technologist 4 - Project Specialist	11
Technologist 4 – Quality Assurance Work Leader	11
Workleader - Instrumentation and Communication	11

Data Analyst	12
Document/Content Management Webmaster	12
Infrastructure Planning Specialist	12
Senior Data Integration Analyst	12

AGREEMENT

BETWEEN

TERASEN GAS INC.

AND

LOCAL 213 OF THE INTERNATIONAL BROTHERHOOD
OF ELECTRICAL WORKERS

This Agreement is effective April 1, 2006 and applies to employees of Terasen Gas Inc., Terasen Gas Vancouver Island Inc. and Terasen Gas Whistler Inc. hereinafter designated and known as "Terasen", or the "Company" and who are members of Local 213 of the International Brotherhood of Electrical Workers hereinafter designated and known as "IBEW 213" or the "Union".

EXPIRY DATE: MARCH 31, 2011

Table of Contents

1. GENERAL

1.01

The management, operation, direction and promotion of the working force is vested exclusively in the management, subject to the terms of this Agreement. Any changes in practice not specifically covered by the Agreement shall be the subject of discussion and/or negotiation during the life of this Agreement, as long as they are within the control of the Company.

1.02

The following working conditions shall take effect upon the ratification of this Agreement and be binding upon the parties hereto and shall govern all employees of Terasen referred to herein.

1.03

Letters or memoranda of understanding which may be written are to be signed by the Company and the Union and are effective for the duration of the current Collective Agreement. Upon expiry they may be extended by mutual agreement between the parties in writing

1.04

The operation of Sections 50(2) and 50(3) of the Labour Relations Code is hereby excluded pursuant to Section 50(4) of the said Code.

1.05

This Agreement expires 31 March 2011. Notwithstanding, the Agreement shall continue thereafter until a new Agreement is signed; or, until 72 hours following strike or lockout notice, at which time the Collective Agreement will cease to apply.

1.05.1

Either party may at any time give to the other party four (4) months' or more written notice of its intention to re-open the Agreement on the day of expiry or any day thereafter. The Agreement shall be re-opened on the date specified in such notice

1.06

Terasen will indemnify and hold harmless the Company employees from legal liabilities imposed upon them arising from their normal course of employment. The Company does not and cannot be expected to assume risk from mistakes by employees which are made by going beyond the scope of their employment or which arise from grossly negligent conduct.

1.07 Regular Employee

One who holds a permanent, posted job, and does not include a new employee serving his initial probationary period.

1.08

Where the singular or masculine is used in this Agreement, these words shall be construed as meaning the plural or feminine where the context requires. Conversely, the reverse is equally true.

1.09

Seniority is a date and not an accrued period of employment. Service is an accrued period of employment and it includes credit for all paid time off and approved leaves of absence.

2. RECOGNITION OF UNION

2.01

Terasen recognizes the Union and will not discriminate against any employee because of his connection with it.

2.01.1

The Company agrees that all employees affected by this Agreement shall, within one month after appearing on the payroll, become and remain thereafter members of the Union in good standing as a condition precedent to continued employment with Terasen.

2.01.2

Properly qualified officers of the Union shall be recognized by Terasen for the purpose of discussing any grievance of any employee.

2.02 Check Off

The Company shall forward the names of all new employees affected by this Agreement to the Secretary of the Union within fourteen days from the first day such employees begin work, and agrees to deduct an amount equal to the prevailing Union dues from such employees' pay cheques on their first full pay period and thereafter. The Company further agrees to deduct from the employees' pay cheques any assessment which may be made against any member of the Union.

2.03 Union Representative

The Company will furnish a pass to each representative of the Union to the Company's plants and shops.

2.03.1

An employee elected or appointed to office in the Union which requires his absence from employment shall retain his seniority rights, and shall upon his retirement from such office return to employment.

2.04

It shall be a requirement that representatives of the Union shall notify the Company of any representatives' intentions to visit any work location. Such notification may be given by telephone to the Manager or Supervisor concerned. The Human Resources Department will advise the Union as to the Manager or Supervisor in each area to contact.

2.05

In case the Union suspends or expels any of its members for reason of misconduct, the Company agrees to suspend or dismiss from its service any employee so affected upon presentation of satisfactory proof of such misconduct.

3. CONDITIONS OF EMPLOYMENT

3.01

It is a condition of employment that, subject to the shift work provisions of the Agreement, all employees shall accept shift work when efficient operation or service requirements necessitate.

3.02

Employees who are terminated will discontinue their participation in the employee benefits and concessions covered in Articles 13, 14, 15, 16, and 17 subject to the provisions of the respective plans.

3.03

Temporary employees may be hired for a period of six (6) months or less. The Union shall be advised in writing of the names of all temporary employees and the period for which each is hired. Temporary employees shall not accumulate seniority nor be eligible for pension, MSP, extended health, group life, dental, or long-term disability benefits.

3.03.1

Temporary employees are not eligible for the benefits described in Articles 20.04, 24.02.1, 24.03, 24.04, 24.05.

3.03.2

Summer students may be hired for up to five months. They shall not be engaged in the installation of mains or services, nor shall they work with escaping gas. Summer students shall be paid basic entry rate (student rate) for all work performed.

3.04

Employees will carry wallet size plasticized I.D. cards with photograph while on duty.

4. PROBATIONARY PERIODS

4.01 New Employees

All new regular employees shall be placed on probation for a period of twelve (12) months exclusive of all time on layoff. During this probationary period the Company may terminate employment of a new employee, without the necessity of providing any reason for doing so provided the Union may raise as a grievance the question whether or not there was discrimination. Where a new employee is not notified of termination of employment before the end of his probationary period it is understood that his application for employment has been approved. This probationary period shall not be affected by changes in classification.

4.02 Employees Who Transfer To A New Classification

Any employee who is transferred to a new classification at his request or as a result of selection in a job competition shall be considered as a probationary employee in the new classification for a period of twelve (12) months except for employees transferring into the following classifications who shall be on probation for a period of three (3) months:

Materials Truck Driver	
Equipment Operator 1/2	Clean-Up Truck Driver
Shop Assistant	Recycling Mechanic
Material Handler	Truck Driver
Painter	Labourer
Materials Shipper/Receiver	

4.02.1

During this probationary period, the employee may choose to return to his previously-held classification or he may be directed by the Company to return to his previously-held classification should management consider him unsuitable for the new classification. Should he return to his previously-held classification under these circumstances he will do so without loss of seniority in his previously-held classification, but shall forfeit seniority in the new classification.

4.02.2

An employee selected and transferred to another classification prior to completing his probationary period shall not lose classification seniority as a result. However, if he returns to such a classification for any reason he will have to complete the remainder of the probationary period. The only exception to this would be in the following classifications, wherein probation in the lower classification will not have to be finished upon completion of probation in the higher classification:

L.N.G. Plant Operator 1/2	Fitter Welder 1/2/3	System Operations Technician/Apprentice
Customer Service Technician 1/2	Shop Mechanic 1/2/3	Measurement Technician Measurement Mechanic 1/2/3
Commercial S&ST/Sr S&ST	Sr. Pipeline Tech/Pipeline Tech 1/2	EODM/DMX/DM/DA
Welder 1/Crew Leader/DM/DA	Compression & Controls Technician 1/2/3/4	Stores Leader/Sr. Material Handler/Materials Shipper Receiver/Material Handler

4.02.3

Upon completion of such probationary period, an employee may no longer choose to return to his previously-held classification.

5. CHANGES IN WORKING CONDITIONS

5.01 New Classifications

When the Company creates any new classification, the wage rate and working conditions, shall, if possible, be set by agreement before an employee starts work on the classification, but if no agreement is reached before work commences, the results of final settlement shall be retroactive to the time the new classification was set up.

5.01.1

If the parties fail to reach agreement with respect to the wage rate of the new classification, either party may refer the matter to John Kinzie (or a substitute agreed to by the parties) for final settlement by final offer arbitration, within thirty (30) days of the company's unilateral implementation of the new classification and wage rate. The arbitrator shall give equal weight to both internal and external wage rate comparisons in determining the appropriate rate for the new classification.

5.02 Maintenance of Wage Rate

When, at the Company's convenience, and not because of lack of work, an employee is taken off a higher-paid classification and put on a lower-paid classification, he shall continue to receive the higher rate of pay.

5.02.1

When an employee's machine is under service and/or repair he shall receive his regular Equipment Operator's rate of pay for the remainder of that shift.

5.03 Contractors

If a regular employee or the employee's relief has to be demoted because of lack of work the employee will not retain the higher rate if contractors are not employed doing similar work to the demoted employee in that particular employee's section, unless the demoted employee has accumulated one year's seniority in the higher paid classification in which case the employee will retain the higher rate of pay for one month only.

5.03.1

If a regular employee or the employee's relief has to be demoted because of lack of work, the employee will retain the regular rate if contractors are still employed doing similar work to the demoted employee in that particular employee's section.

5.03.2

The Company shall not cause the layoff of a regular employee due to a shortage of work in a section by utilizing a contractor to do work in that section which is done by that employee classification.

5.03.3 (formerly LOU #2)

When employees bump into another section, to avoid permanent layoff, the company agrees to protect employees from "bumping through" (as per the Larson Award) in the receiving section, by agreeing not to lay off Distribution Apprentices if contractors are employed doing similar work to that classification in that section.

5.03.4. (formerly LOU #2)

The Union recognizes that from time to time the Company will re-organize its structure for reasons of corporate efficiency. This may result in changes to boundaries of sections referred to in this Article.

The Company will make all reasonable efforts to minimize the impact on individual employees with respect to this Article when changes in section boundaries become necessary.

A section is defined as a sub-group of a Department or Division in the Coastal and Island Regions (e.g. C & M, CS, Transmission sections), and a District within the Interior Region.

5.04 Redundancy Due to New Equipment or Methods

Employees who become redundant due to the introduction of new equipment or methods shall be eligible for training to equip them to use the new equipment, or for qualifying for new classifications.

5.05 Severance Pay upon Redundancy and for Health Cases

The Company will provide one week's severance pay for each year of service to employees who, in the Company's opinion, become health cases to the extent that they may not continue in their classification, or become redundant due to the introduction of new methods, equipment or organization and who cannot be trained for new classifications.

5.05.1

Medical disputes related to severance pay may be referred to a medical consultant selected by the Company.

5.05.2

In both cases a minimum of five (5) years' service is required.

6. GRIEVANCES

6.01

Except as modified by Article 6.01.05, complaints shall first be discussed with the immediate Manager concerned.

6.01.1 Stage I:

Failing settlement at the complaint stage, the grievance shall be presented in writing to the immediate Manager with a copy to the Labour Relations Department giving details of the alleged violation and the relevant Collective Agreement Article(s).

6.01.2 Stage II:

Failing settlement at Stage I, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Department Head with a copy to the Labour Relations Department.

6.01.3 Stage III:

Failing settlement at Stage II, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Vice-President, and the Vice-President, Human Resources (or delegates).

6.01.4

Grievances which are committed to writing shall involve a two-week time limit for processing through the levels involved.

6.01.5

(a) Grievances which allege that preference has not been given a job applicant pursuant to Article 8.01 must be presented to the selecting manager or supervisor, or to the Human Resources Department, within two weeks of the date of the Notice of Selection, unless the employee has not received the Notice within two weeks, in which case the grievance must be presented within five working days of receipt of the Notice.

(b) The Union has the right to refer a union and/or policy grievance to the Company at Stage III of this grievance procedure by presenting such a grievance to the Company's Manager, Labour Relations in writing.

(c) The Company has the right to refer a company grievance to the Union at Stage III of this grievance procedure by presenting such a grievance to the Union's Assistant Business Manager in writing.

6.02 Arbitration

Where a difference arises between the parties relating to the dismissal, discipline, or suspension of an employee, or the selection of an employee for a vacancy, or to the interpretation, application, operation, or alleged violation of this Agreement, including any question as to whether a matter is arbitrable, either of the parties, without stoppage of work, may, after exhausting any grievance procedure established by this Agreement, notify the other party in writing of its desire to submit the difference to a Board of Arbitration. The said Board shall consist of three persons, one appointed by the Company, one by the Union, and a Chairperson who shall be chosen by the two appointees; or by mutual agreement it can consist of a single arbitrator chosen by the parties of this Agreement.

6.02.1

Should the parties fail to agree on the selection of a single arbitrator then the three-person Board of Arbitration will apply. Should the appointed members, in the case of a three-person Board, fail to agree upon a Chairperson, they shall request the Minister of Labour to appoint a person to fill the position.

6.02.2

The Union or the Company must refer the matter to arbitration within one month after its rejection by either party.

6.02.3

The decision of the Board of Arbitration or single Arbitrator shall be final and binding on both parties.

6.02.4

Each party shall pay the fees and expenses of its appointee and one-half the fees and expenses of the Chairman, or one half of the fees and expenses in the case of a single arbitrator.

6.02.5

The employees shall continue to work while the above outlined grievance procedure is in progress.

6.03

Notwithstanding all of the foregoing provisions of this Article, the following procedure may be implemented by mutual agreement as follows:

"Where a difference arises between the parties relating to the dismissal, discipline, or suspension of an employee, or to the interpretation, application, operation, or alleged violation of this Agreement, including any question as to whether a matter is arbitrable, during the term of the Collective Agreement, an arbitrator agreed to by the parties, shall at the request of either party,

a) investigate the difference;
b) define the issue in the difference; and
c) make written recommendations to resolve the difference within five (5) working days of the date of receipt of the request; and, for those five (5) working days from that date, time does not run in respect of the grievance procedure."

6.04

All disciplinary write-ups will be removed from an employee's record after a two and one-half (2-1/2) year period of working time, if requested by the employee, provided no further disciplinary action has been taken during that two and one-half (2-1/2) year period.

7. SENIORITY

7.01

There are four different types of Seniority, defined as follows:

7.01.1 Union Seniority:

a. Union Seniority is the date the employee was last hired into Terasen, Centra Gas B.C., Centra Gas Whistler, Inland Natural Gas, Columbia Gas or any predecessor Company as a regular employee with IBEW 213 membership.

b. Employees in the Metro and Fraser Valley Units who transferred from one Unit to another at the employee's request (not on a bulletin) prior to June 1, 1974 forfeited Union Seniority in their previous Unit(s) but only with regard to bulletining and bumping. (See 8.01.5)

7.01.2 Regional Seniority:

a. There are three (3) Seniority Regions in the Company:
   - Coastal Region is the Lower Mainland (defined as both Metro & Fraser Valley).
   - Interior Region is the Interior (defined as the ex-Inland, Columbia, and Fort Nelson Gas companies).
   - Island Region is Vancouver Island, the Sunshine Coast, Whistler and Squamish (defined as ex-Centra including Whistler, plus Squamish).

b. Regional Seniority is the date of hire into the Coastal or Interior Region on or before July 28, 1989. Employees hired after July 28, 1989 do not obtain Coastal or Interior Regional Seniority. Regional Seniority is the date of hire into the Island Region on or before December 31, 2003. Employees hired after December 31, 2003 do not obtain any Regional seniority.

c. Employees possessing Regional Seniority in Coastal or Interior region who transferred to the other (Coastal or Interior) region between July 28, 1989 and June 2, 1991 also established Regional Seniority in the other region on the date of hire into the other region.

d. Employees leaving a region after June 2, 1991 shall forfeit Regional Seniority in the region they are leaving.

7.01.3 Unit Seniority:

a. There shall be six areas of Unit Seniority in the Company:
   (i) Metro
   (ii) Fraser Valley

(iii) Interior
(iv) Victoria (Capital Regional District)
(v) North Island (including Sunshine Coast)
(vi) Sea to Sky (Whistler and Squamish)

Unit Seniority is the date of the employee's most recent selection letter to a Unit.

7.01.4 Classification Seniority:

a. Classification Seniority is the date of an employee's selection letter to a classification. Prior to October 7, 1968, Classification Seniority was established on the date of commencement in the classification for employees selected to classifications in Metro and Fraser Valley.

When the two (2) week posting period of two or more bulletins for a classification within a unit overlap, and when the selections are made within six (6) weeks of each other, a common classification seniority date will apply to those selected.

b. An employee may establish Classification Seniority in all Units.

c. A Classification Seniority date, once established, shall not be affected by selection to another job, lay-off or bumping.

d. An employee who returns to his previously-held classification pursuant to Article 4.02.1 shall forfeit seniority in his new Classification and the employee and the Union will be notified in writing.

An employee demoted voluntarily or for cause shall lose classification seniority and the employee and the Union will be notified accordingly in writing.

We have also reached agreement as to the interpretation of the words 'demoted voluntarily", in the first line of this article. So as not to conflict with what is now article 7.01.4(c), an employee who bulletins into a lower-paying job will not normally lose classification seniority. When a demotion occurs in this fashion (by bulletin), classification seniority will be lost only if the employee has documented performance problems in the classification s/he is leaving. These problems will be of a nature and severity that suggests the employee may not be suitable for that classification. See Article 4.02.1

e. An employee who refuses recall to a classification on a seniority basis will forfeit his Classification Seniority in the seniority Unit.

f. Employees hired after December 31, 2003 shall have common Union Seniority rights throughout the Company. Employees hired into the Coastal or Interior Regions of the Company after July 28, 1989 shall have common Union Seniority rights within the Coastal and Interior Regions.

g. Employees holding Classification Seniority in the following job categories shall be considered to hold Classification seniority in the lower levels of the same job category as specified below:

Category	Category	Category	Category	Category
Mechanical Foreman	Warehouse & Delivery Leader	Mechanical Foreman	Measurement Shop Leader	Building Operations & Maintenance Leader
Fitter Welder 1	Stores Leader	Shop Mechanic 1	~~Measurement Technician~~ Measurement & Controls Technician	Shop Mechanic 1, 2 & 3(B&U)
Fitter Welder 2	Senior Material	Shop Mechanic 2	Measurement	Building Maintenance

	Handler		Mechanic 1	Worker
Fitter Welder 3	Material Handler		Measurement Mechanic 2	

Category	**Category**	**Category**	**Category**	**Category**
Distribution Service Agent	Distribution Service Agent	System Operations Technician	C&CT 1	Senior Pipeline Technician
Senior Sales & Service Technician	Welder 1 (Crew Leader (Arc))	System Operations Apprentice	C&CT 2	Pipeline Technician I
Customer Service Technician 1	Crew Leader		C&CT 3	Pipeline Technician II
Customer Service Technician 2	Distribution Mechanic DMX		C&CT 4	Pipeline Labourer
	Distribution Apprentice			

h. Shop Assistants and Distribution Apprentices shall have common Classification Seniority, so that seniority established in one classification shall be deemed to have also been established in the other classifications.

7.01.5 The Company will provide the Union with a current seniority list once each calendar year.

7.02 APPLICATION OF SENIORITY

7.02.1 Job Bulletins:

Union Seniority and Regional Seniority shall be taken into consideration when an applicant is being considered for a bulletined job. (See Article 8.01.1.1)

7.02.2 Layoff

a. In core level classifications (Labourer; Shop Assistant; Distribution Apprentice), in which a layoff occurs, the employee with the least Union Seniority within a Coastal Unit, or an Interior or Island Headquarters will be the first to be laid off. In all other classifications, in which a layoff occurs, the employee with the least job Classification Seniority within a Coastal Unit or an Interior or Island Headquarters will be the first to be laid off, except in Interior or Island Headquarters with less than three employees where ability, skill set and efficiency, as indicated by the employee's general record with the Company may determine the order of layoff.

b. A regular employee who is designated for permanent layoff shall be given (2) weeks' written notice provided that he has completed a period of employment of at least (6) consecutive months. Notice will increase to (3) weeks on completion of a period of employment of (3) consecutive years; thereafter, (1) additional week's notice for each subsequent completed year of employment up to a maximum of (8) weeks' notice. The period of notice shall not coincide with an employee's annual vacation. The notice period shall be extended if an employee is on vacation by the number of days between the notice date and the end of the employee's vacation. The notice is not postponed.

c. The Company will pay the following portion of the layoff notice as severance pay:

NOTICE REQUIRED	MINIMUM SEVERANCE PAY	BALANCE OF NOTICE
2 weeks	1 week	1 week
3 weeks	1 week	2 weeks

4 weeks	2 weeks	2 weeks
5 weeks	2 weeks	3 weeks
6 weeks	3 weeks	3 weeks
7 weeks	3 weeks	4 weeks
8 weeks	4 weeks	4 weeks

d. The Company retains the right to pay the balance, or a portion thereof, as additional severance pay in lieu of notice.

e. Employees being bumped are not entitled to layoff notice, but will receive the minimum severance pay specified by 7.02.2 (c) above, if they revert to laid off status.

f. For severance pay due to redundancy or for health cases, see Article 5.05.

g. No regular employee in a District will be laid off while a contractor is being used for work normally performed by that employee, except contractors completing a specific project or specific out-of-town assignment may continue to work for a maximum of 15 working days.

7.02.3 Bumping

a. Bumping is a process used by regular employees to avoid lay-off by displacing an employee with less Classification or Union Seniority. Notice of layoff must occur in order to trigger bumping rights. The laid-off employee's wage rate will be the same as the classification bumped and he may choose one of the following five options. The employee must prioritize all options in case his first choice is unavailable. Once an option has been chosen, the employee must bump into the first available location *(which will be identified by the Company*) in the numerical sequence specified. For example, if an employee in Williams Lake chooses option 2 and the employee with the least Classification Seniority in his District is in Chetwynd, then he has no further options and must go to Chetwynd.

Option #1 - Bumping into a lower level of current job category
An employee may bump down into the lower levels of your same job category as specified in Article 7.01.4 g., displacing the employee with the least Classification Seniority at each level: first, in his current Interior or Island Headquarters or Coastal Unit; second, in his current Interior or Island District; third, in his current Interior or Island Unit; fourth, in his former Unit; or

Note: Unit Seniority in the Island Units prior to January 1, 2004 is not recognized for purposes of bumping into "former Unit".

Option #2 - Bumping into the same level of current classification
An employee may bump the employee in his current classification with the least Classification Seniority: first, in his current Interior or Island District; second, in his current Interior or Island Unit; third, in his former Unit; or

Option #3 - Bumping into the most recent previously-held classification
If an employee has previously held other classifications, he may bump the employee in his most recent previously-held existing classification with the least **Classification Seniority**: first, in his current Interior or Island Headquarters or current Coastal Unit; second, in his current Interior or Island District; third, in his current Interior or Island Unit; fourth, in his former Unit. When an employee is unable to bump into his most recent previously-held existing classification due to lack of seniority, s/he may bump into the next previously-held existing classification, and so on. This type of bumping can only occur in the employee's reverse order of his job history.

An employee cannot bump into the same classification as the one he currently holds, even when it is in a different unit. That would be an Option #2 bump; or

Option #4 - Bumping into a core level classification

An employee may bump the employee with the least Union Seniority in the core level classifications; Labourer, Shop Assistant; Distribution Apprentice in the following numerical sequence; first, in his current Interior or Island Headquarters or current Coastal Unit; second, in his current Interior or Island District; third, in his current Interior or Island Unit; fourth, in his former Unit, fifth, Company-wide: and, only if no bumps are available in the above core level classifications, he may bump a Distribution Mechanic at each stage of the sequence. For example, First; core level if available, then DM in his current Interior or Island Headquarters; Second; core level if available, then DM in his current Interior or Island District or current Coastal Unit, etc.

An employee who has bumped based on Option #4 (Union Seniority) cannot be bumped out of the new position/location by another employee using Option #2 (Classification Seniority). He can only be bumped by a more senior employee using Union Seniority under Option #4.

Option #5 - Recall List:

If an employee is unable, or chooses not to exercise any of the above options, he will be laid off to the recall list pursuant to Article 7.03.1.

b. In cases of equal Classification Seniority, Union Seniority shall govern. In cases of equal Classification and equal Union Seniority, Unit Seniority shall govern. In cases of equal Classification, equal Union and equal Unit Seniority, the employee(s) with the least points, based on their most recent performance review, will be laid off. To determine the number of points, the Company will assign points for each category of the fourteen standard performance measures, as below:

	Unsatisfactory	Developing Towards	Achieving
Productivity	1 or 2	3 or 4	5 or 6
Quality of Work	1 or 2	3 or 4	5 or 6
Job Knowledge	1 or 2	3 or 4	5 or 6
Work Attitude	1 or 2	3 or 4	5 or 6
Safety	1 or 2	3 or 4	5 or 6
Judgement	1 or 2	3 or 4	5 or 6
Interpersonal Skills	1 or 2	3 or 4	5 or 6
Coping Ability	1 or 2	3 or 4	5 or 6
Public Relations	1 or 2	3 or 4	5 or 6
Housekeeping	1 or 2	3 or 4	5 or 6
Personal Appearance	1 or 2	n/a	5 or 6
Communication	1 or 2	3 or 4	5 or 6
Attendance	1 or 2	Marginal 3 or 4	Satisfactory 5 or 6
Punctuality	1 or 2	n/a	Satisfactory 5 or 6

c. The employee will notify his Manager in writing of his bumping option selection within five (5) working days of receiving his layoff notice and bumping options, or he will relinquish all bumping rights.

7.03 Recall for Regular Employees:

7.03.1.

A laid off employee shall retain recall rights for twelve (12) months from the date of layoff and will be eligible for recall in order of Classification Seniority to any previously held classification, first, to his Interior or Island Headquarters or Coastal Unit; second, to his Interior or Island District or Coastal Region; third, to his Interior or Island Unit; fourth, to his former Unit and fifth, to any core level classification, Company-wide, as specified in Article 7.02.3 a., Option 4, in order of Union Seniority.

In maintaining the principle of ‘first on, last off”, recall to the core level classifications shall be based on Union Seniority. Such recall shall be applicable only to the headquarters of initial displacement.

For example, DMs who have been displaced as a result of bumping or layoff from their headquarters shall have the right to be recalled into the core classification in their headquarters of origin based on Union Seniority.

7.03.2

Employees recalled within twelve (12) months will not be considered new hires. Employees who have not been recalled within twelve (12) months will be terminated.

7.03.3.

If a recalled employee refuses a permanent position within his Interior or Island Headquarters or Coastal Unit, he shall forfeit all seniority and right to recall, except if he is in continuous, unbroken, full-time attendance at an educational institution in British Columbia to a maximum of five (5) continuous, unbroken years from the date of layoff.

7.03.4

Recall to temporary positions shall not exceed three months cumulative and will not result in an extension to the twelve (12) month recall period.

7.03.5

Employees who cannot be recalled due to an accident or illness, confirmed by a medical certificate from a mutually-agreed physician, will have their twelve (12) month recall period extended for the period of the illness or disability to a maximum of an additional six (6) months.

7.03.6

Contractors will not be engaged to perform work within the classification or job description of laid-off employees, except when the duration of the work is less than twenty (20) working days.

7.03.7

Subject to qualifications, no new employees will be hired until all eligible laid-off employees have been recalled from the recall list.

7.03.8

Employees who are laid off shall leave their current address and telephone number with the Human Resources Department and the Union. The onus shall rest with the employee to immediately notify the Human Resources Department and the Union in writing of any change of address or telephone number.

7.03.9

Employees on permanent layoff who remain on the recall list may continue in the welfare benefit plans for the period of time which they are on the recall list (maximum 12 months) providing they are not employed elsewhere. The Company will pay for such participation. (See Article 7.04.13)

DISPLACED (Have exercised their bumping rights)	**LAID OFF** (Street)
• Employees displaced will only have recall rights to the classification and location of initial displacements	• Recall to any previously-held classification is only applicable to employees laid off to the street • If the employee accepts recall to a location other than his original headquarters in a lower classification, he shall only have recall rights to his position of initial layoff in his home headquarters

Notwithstanding Article 7, the intent is to get the employee back to his/her position of origin.

7.04 Temporary Layoff, Bumping and Recall

7.04.1

No less than two weeks prior to the anticipated last day of work, the supervisor shall meet with the employees to formulate a schedule which maximizes the use of employee legacy and choices days and Supplementary vacations if applicable to avoid or postpone layoff.

All construction employees in an Interior headquarter must use their legacy and choices days and then Supplementary Vacation, if applicable, in order to avoid or delay the layoff of any construction employee within that headquarters.

Any employee may volunteer to use some or all of his overtime bank and/or banked time to avoid or delay the layoff of another employee as long as the offer is made when the manager meets with the employee to formulate the schedule under Article 7.04.2. (See Article 33.01.2)

7.04.2

The time off/layoff schedule can be revised by mutual agreement as may be warranted by weather, workload, or other relevant consideration.

7.04.3

If the employee's legacy and choices days and Supplementary Vacation, if applicable, are exhausted before sufficient work is available, s/he will be laid off.

7.04.4

From time to time it may be necessary to lay off employees in the following classifications: Welder 1 (Crew Leader (Arc)); Crew Leader; Distribution Mechanic; DMX; EO/DM; Equipment Operator ‘P’; Distribution Apprentice; Operations Technician; or classifications derived from or substantially identical to these classifications on a temporary [*herein defined as not exceeding one hundred and twenty-two (122) continuous calendar days*] basis for a variety of weather, workload or business reasons. [Note: If the layoff exceeds 122 continuous calendar days, the employee will be permanently laid off pursuant to Article 7.02.2 (b) and retain full 12-month recall rights from the date of permanent layoff pursuant to Article 7.03.1.]

7.04.5

Employees shall receive 10 working days written notice of layoff along with their bumping options. The employee will notify his manager in writing of his bumping option selection within (5) working days of receiving his layoff notice and bumping options or he will relinquish all bumping rights.

7.04.6

Employees in the following job categories: Crew Leader, Welder 1 (Crew Leader (Arc)), EODM, Operations Technician, Equipment Operator “P”; receiving temporary layoff notice may exercise their bumping rights for the period of temporary layoff by temporarily bumping the Distribution Mechanic with the least Union Seniority and, only if no bumps are available in that classification, they may bump into the core classifications (Labourer, Shop Assistant; Distribution Apprentice). In both instances, the sequence will be: first, in his current Interior or Island Headquarters or Coastal Unit, second, in his current Interior or Island District or Current Coastal Region; third, in his current Interior or Island Unit.

Employees in the following job categories; Distribution Mechanic, DMX and core level classifications; receiving temporary layoff notice may exercise their bumping rights for the period of temporary layoff by temporarily bumping the employee with the least Union Seniority in the core classifications: (Labourer, Shop Assistant, Distribution Apprentice). The sequence will be: first, in his current Interior or Island Headquarters or Coastal Unit, second, in his current Interior or Island District or current Coastal Region; third, in his current Interior or Island Unit.

a. His wage rate will be the same as the classification bumped and he will not be entitled to any moving, travel, or board and lodging expenses.

b. He must continue to work at the other headquarters until he is laid off or recalled to his regular headquarters;

c. District status will not accrue at any temporary headquarters, for the purpose of applying for temporary job postings.

7.04.7

A regular employee who is laid off to the recall list may qualify himself for temporary recall at any Interior or Island Headquarters or Coastal Unit, Company-wide by notifying his Manager.

7.04.8

When all laid-off regular employees in a Unit have been recalled, all other regular laid-off employees from other units who have qualified themselves for temporary recall shall be recalled in order of Union Seniority.

7.04.9

If an employee refuses recall to a temporary position in excess of ten (10) working days in his Coastal Unit or Interior or Island District, he will lose his right of temporary recall for the duration of his temporary layoff.

7.04.10

An employee recalled to another District or Unit must continue to work there until he is laid off or recalled to his regular District or Unit.

7.04.11

Where an employee bumps to a classification in Option #4, Article 7.02.3, he shall pay his own moving expenses.

7.04.12

Regular employees on seasonal or temporary layoff, and who remain on the recall list may continue participation in the group life, health benefits, and dental plans at Company expense for a maximum of twelve (12) calendar months, unless they are employed elsewhere and eligible for these same types of benefits.

8. POSTING OF JOB VACANCIES

8.01 Regular Positions:

8.01.1.l

The Company will post bulletins on a Company-wide basis.

8.01.l.2

The Company shall post bulletins advising all employees covered by this Agreement of any positions to be filled. All bulletins must conform to the Agreement, but where any position is created, Article 5.01 shall apply and such bulletins shall conform to the new job as agreed upon.

8.01.1.3

All regular employees covered by this Agreement shall have the right to apply for bulletined positions. Except for applicants applying for a promotion or for a lateral move within the same classification, an employee will not be eligible to compete for bulletined positions during his probationary period in the job he currently holds. For purposes of this clause "promotion" means applying for a position which pays a higher normal base rate than the base rate of the employee's regular job.

Employees applying for positions that include an automatic progression or an apprenticeship are deemed to have applied for the higher level position for the purpose of this article.

8.01.l.4

(a) All job bulletins are to be posted at least two weeks before closing date to allow for receipt of applications. Copies of such bulletins will be mailed to employees who do not report daily to headquarters where bulletins are posted.

(b) Within three months of the closing date on a job bulletin, the Company may select applicants for the bulletined position(s) from the bulletin summary for the job bulletin without posting a new job bulletin for the same position(s).

8.01.l.5

Subject to ability and efficiency, Union and Regional seniority shall be the governing factors in selections. (For seniority purposes, selection will be based first by Regional Seniority and followed by Union Seniority, except that Squamish selection is based on Union Seniority only).

For the Measurement Group Leader, Warehouse & Delivery Leader, Measurement Shop Leader, Mechanical Foreman/Shop Leader, Building Operations & Maintenance Leader and Distribution Service Agent classifications, selections shall be made giving equal weight to each of the following six (6) factors:

(i) Seniority
(ii) Expertise
(iii) Initiative
(iv) Problem-solving & results orientation
(v) Customer focus
(vi) Business understanding & alignment

For the Instructor classification, the final responsibility for selection rests with the Company, subject to the Company's decision not being arbitrary or discriminatory. A representative of the Union may be present during the interview process for the above-named classifications, however will not be a participant in the interview.

8.01.l.6

The Company's history of an employee's general record shall determine the employee's ability and efficiency.

8.01.l.7

The Company will inform the Union of the names and seniority date of all applicants to posted bulletins.

8.01.l.8

The Company will review any applicant which the Union Business Agent believes deserves special consideration before the applicants are notified, but the ultimate responsibility of selection shall be the Company's and it shall be sole judge in this matter.

8.01.2

Bulletins for regular positions to be filled permanently shall be posted as expeditiously as possible and selections shall be made within six (6) weeks. During the six (6) week interim period the Company may select relief or other qualified employees to perform the work without accruing regular seniority.

8.01.3 (formerly 8.01.4)

If as a result of a job bulletin, the transfer of employees from a "section" should leave that "section" with a depleted work force so that operation requirements would be adversely affected, the Company may delay the transfer of such employees until their respective trained replacements are available. Any such employee retained by a "section" as described above would not lose any job classification seniority in their new position.

8.01.3.1 (formerly 8.01.4.1)

If the employee's transfer on a promotion is delayed by more than three weeks for the Company's convenience, the employee will nevertheless receive the regular wage rate of the new position effective the first day of the fourth week following the date of the letter confirming acceptance.

8.01.4 (formerly Article 8.01.3)

An employee who moves to another unit will be considered to be junior in classification seniority in the position to which the employee was selected. The employee will then accrue job classification seniority in the standard way.

8.01.5

Effective June 1, 1974, job bulletining was introduced on a Coastal region-wide basis. Employees who had transferred, at their own request, to a labourer's position in a different seniority unit prior to June 1, 1974 shall have thereby relinquished all previous Union Seniority and shall have established a new Union Seniority date for job selection purposes. This clause creates no entitlements for the former employees of the BC Hydro Victoria Gas Operations.

8.01.5.1

The Union Seniority date of such employees for job selection purposes is the unit seniority date they established on transfer to the Labourer's position in the different seniority unit.

8.02 Senior Sales and Service Technicians: (Interior)

The Company shall continue to employ the current, regular Senior Sales and Service Technicians at each headquarters where there are one or more Customer Service Technicians in addition to the Senior. These Senior SSTs shall receive the entitlements of Article 7 if/when their position is discontinued. (formerly LOU #32)

8.02.1 (formerly 8.07.2)

A full-time requirement for a Customer Service Technician may occur in a town where more than one fully-ticketed Customer Service Technician already holds a bulletined job. In that case, a Customer Service Technician position will be posted, but non-ticketed employees would also be invited to apply.

8.02.2 (formerly 8.07.3)

If there is no ticketed person available (either an existing employee or one from outside the Company), then non-ticketed applicants will be given consideration. The Company will normally not consider applicants with less than two (2) years' service. If a suitable candidate with the proper ability and efficiency and working experience has applied, then a Sales & Service Technician 3 position would be awarded to the successful non-ticketed applicant.

8.03 Special Situations: (Interior)

8.03.1

Situations may arise where there is a full-time requirement for short periods of time for a Distribution Apprentice to perform other work assignments. In filling such a job, a Distribution Apprentice capable of performing the necessary work may be hired or kept on to perform that work even though another Distribution Apprentice with more seniority who is not capable of performing that work is on lay-off.

8.03.2

In determining whether or not an employee is capable of performing the "necessary work", his previous ability and efficiency will be considered. When the "necessary work" requires a special skill or experience such as welding, equipment operating, etc., the person selected to perform such work will have previously demonstrated a related level of performance that is acceptable to the Company. Except to overcome operational or personnel difficulties, when the "necessary work" does not require an easily identified skill or experience requirement, the Company must, prior to recalling an employee to work, discuss a potential selection with the local Shop Steward. The selection shall be subject to the grievance procedure. When the requirements for utilizing those special skills or experience ceases, then normal seniority provisions governing lay-off and recall would prevail.

8.04 Branch Managers: (Interior)

8.04.1

Whenever a Branch is operated by one (1) employee, which employee is classified as a "Branch Manager", such employee may carry on work that would ordinarily come within the jurisdiction of the Union.

8.04.2

Staffing with respect to one (1) employee Branches is the sole responsibility of the Company until such time as the one (1) employee can no longer handle the duties that fall within the jurisdiction of IBEW 213, PROVIDED, HOWEVER, when such one (1) employee towns exceed one thousand (1,000) or more active gas meters the Company will add an additional Customer Service Technician to carry out the work that would normally fall within the jurisdiction of the Union.

8.04.3

The class of employees used in each of the towns is the responsibility of the Company. Neither 8.04.1 nor 8.04.2 above shall be used to reduce the numbers of employees or the classifications currently in effect in their towns.

8.04.4

Only an I.B.E.W. Distribution Service Agent or Customer Service Technician may replace a Branch Manager of a one- (1) employee town, while he is on vacation or on sick leave.

9. TEMPORARY VACANCIES (formerly LOU NO. 31)

9.01

Except as otherwise detailed in this Article, temporary vacancies shall first be filled by qualified employees within the work group.

9.01.1

In the Metro and Fraser Valley Units, the crew is the work group (formerly from LOU NO. 61)

9.01.2

In the Interior and Island, all positions reporting to a first-line supervisor/manager constitute a work group, except that the Distribution Apprentice classification is deemed to be a Construction position.

9.02

If qualified employees are not available within the work group, or additional resources are required from outside the work group for more than six consecutive weeks, bulletins shall be posted in accordance with Article 8.01.1, except that, notwithstanding Article 8.01.1.1., temporary bulletins shall be posted within the District.

9.02.1

Temporary vacancies for LNG Plant Operator, Instructor and Interior Pipeline Crew shall be posted throughout the Company.

9.02.2

Employees traveling and/or relocating to fill a temporary vacancy shall do so on their own time and expense.

9.03

Temporary bulletin holders shall be called when a temporary vacancy exceeds six consecutive weeks, or when it is filled from outside the work group.

9.04

Release for temporary demotion is at Company discretion.

9.05

When and if the temporary bulletin holder has not worked in the temporary classification for more than 12 months and if the holder no longer meets the required qualifications for the position, the temporary bulletin shall expire unless the employee was denied work in the temporary classification at Company convenience.

9.06

A temporary bulletin holder may decline transfer pursuant to that bulletin only if he is working outside of his regular classification at the time, and the transfer would be to a lower-paying classification than the one he is currently occupying.

9.07

Employees may hold only one temporary bulletin at any one time.

9.08

If there are no qualified applicants on bulletined relief positions, the Company shall appoint junior qualified employees to fill such vacancies.

10. MOVING EXPENSES (formerly Article 9)

10.01

The Company will pay moving expenses where an employee is selected for a bulletined regular job in another unit (Coastal Region) or another headquarters (Interior or Island Regions) and where the employee moves to his new Unit or headquarters as applicable, under the following conditions:

(a) where the employee is promoted;

(b) where a lateral transfer or demotion is involved providing the employee has more than four years' service and has not been moved at the Company's expense within the previous four years;

(c) where an employee successfully applies for a bulletined regular job of a continuing nature and where the job disappears after the employee has assumed it;

(d) where the Company directs an employee to move (eg. pursuant to Articles 4.02 or 28.01), or where the Company requests an employee to fill a job which requires the employee to move.

10.02

Moving expenses are defined as standard packing and moving charges and transportation costs for the employee and his resident family plus incidental expenses up to $350. Incidental expenses would include such items as housecleaning and disconnecting and reconnecting of appliances and utilities.

10.02.1

Up to three days off with pay will be allowed for purposes of moving and establishing in the new location.

10.02.2

All expense claims must be supported by receipts.

10.03

Where an employee is directed by the Company to change his headquarters to fill a job, the Company will pay moving expenses as defined above.

10.04

The Company will pay all costs for moving, pursuant to the provisions of Article 10.01, on a one-time basis, resulting from "demotions" arising due to restricted work or due to failing physical ability, wherein the employee affected exercises his rights under the Agreement either by way of seniority or alternatively, as the successful applicant for a bulletined job.

10.05

Should it not be possible to obtain suitable living quarters at the new location immediately, the Company will pay for reasonable accommodation and a meal allowance per calendar day for a period not to exceed 30 calendar days, at the option of the employee, as follows:

a) $40.00 meal allowance per day if the employee stays in a housekeeping unit,
b) $50.00 meal allowance per day if the employee stays in a non-housekeeping unit.

10.06

The Company will not pay moving expenses where:

a) A regular employee transfers to another headquarters permanently at his own request.
b) An employee on probation is choosing to return to his previously-held classification pursuant to Article 4.02.
c) An employee is recalled to his previous region after having bumped pursuant to Article 7.02.3.

10.07

Where an employee bumps to a core-level classification under Article 7.02.3, Option #4, he shall pay his own moving expenses.

10.08

Notwithstanding any other provision of this Agreement, when successive vacancies result from an initial vacancy being filled by bulletin; and employees have received paid moves on two consecutive bulletins pursuant to the successive vacancies; the Company is not liable for moving expenses on any other successive selections, unless such move is into one of the other Regions.

11. ACCREDITED SERVICE

11.01

Accredited service means the total of all periods of service as a regular or temporary employee of Terasen, or as an employee of a predecessor company or organization. For employees hired after April 1, 1991, accredited service means the total of all periods of service as a regular or temporary employee of Inland Natural Gas or Columbia Natural Gas or their subsidiaries or predecessors, or as an employee of the former B. C. Hydro Gas Division or as an employee of Centra Gas (BC) or Centra Gas Whistler.

11.01.1

Periods during which an employee is laid off are not recognized in the calculation of accredited service.

11.01.2

Accredited service is not related to the calculation of any type of seniority.

12. TRAINING

See Article 28.08 - Re: Travel outside of normal working hours

See Article 30.06.2 - Re: Varying Hours of work when attending training courses

12.01 Grade A Gas Fitting Training Course (formerly LOU NO.16A)

Grade A training courses are available to employees through night school or college. This training course totals approximately 160 hours and requires an additional 80 hours with approximately 40 hours of theoretical and 40 hours of field training. This additional 80 hours of daytime training will be provided by the Company which will pay the employee forty hours at regular straight-time rates. The employee will absorb the remaining 40 hours through annual vacation, vacation overtime leave or other banked time.

12.01.1

If training is not practical during normal working hours due to operational requirements, then the equivalent training time shall be provided after normal working hours. The maximum of 40 hours straight-time paid by the Company will still apply.

12.02 Training of Fitter Welders (formerly LOU NO.21)

12.02.1

The Company will provide training for IBEW 213 Gas employees to qualify as Fitter Welders, by use of Company welding schools, by use of Vocational or similar institutes, or by suitable combinations of these, to assist in meeting Company Fitter Welder requirements. This arrangement shall not preclude the hiring of Fitter Welders from any other sources.

12.02.2

The progression of Fitter Welder trainees through the program will be as follows:

Fitter Welder 3	0 - 24 months
Fitter Welder 2	24 - 36 months

12.02.3

At the time of selection to the program a Fitter Welder 3 may receive up to six months' credit based on management's assessment of the recruits prior experience and qualifications. After 12 months as a Fitter Welder 3 (or proportionately less time if advance credit is given) a Fitter Welder 3 will be paid at the Fitter Welder 2 rate while performing production work on pressure piping or fittings. Upon attaining Fitter Welder 2 status, the trainee will be considered as a probationary employee until he completes the program.

12.02.4

During the training period attendance at evening classes may be required; this time will be unpaid. Transportation to and from training classes must be provided by the employee.

12.02.5

Details of the selection procedures and other matters will be as follows:

12.02.5.1 Selection of Trainees:

Selection of Fitter Welder 3's shall be by the Company. The selection may include the following factors and procedures, not necessarily in this sequence or order of importance:

a) Verification of work performance and duties performed during previous employment both within and outside the Company.

b) Satisfactory physical fitness, which may be verified by medical examination by Terasen Health Services or its delegate, including: eyesight, agility, respiratory problems or illnesses, allergies to welding materials, etc.

c) Verification of education.

d) Good safety record, both personal and vehicle, must have demonstrated sustained safe work habits and adherence to safety regulations and practices; must be able to pass Company driving tests.

e) Practical tests and examinations in welding school or shops, which may include: an oxyacetylene welding test job, a test piece to mark out and prepare by working from a drawing, a test run on SMAW work after demonstration and instruction and other items related to a Fitter Welder's work.

f) Interview by a selection panel of two to five selectors.

g) Seniority shall not be a major consideration in the selection.

12.02.5.2 Rights of Withdrawal from Program:

a) A Fitter Welder 3 may revert to his previous Job Classification at his own request at any time before the expiry of three calendar months from the day of commencement of his training. Seniority in the previous Job Classification shall recommence from the seniority held on the day of commencement of training; time spent as Fitter Welder 3 shall not be included.

b) A Fitter Welder 3 may not voluntarily withdraw from the training program at any time between the day after three months from the day of commencement of training and promotion to Fitter Welder 2. Such voluntary withdrawal may only be by resignation from the Company employment.

c) A Fitter Welder 3 may withdraw from the training program at any time for reasons of health, as confirmed by Terasen's Health Services Department, and shall then be eligible for any other Job Category for which he is qualified by previous training and/or experience and current state of health, but shall not have the right to resumption of the previously-held Job Category after the first three months of the program.

12.02.5.3 Rights to Bid on Other Jobs During and After This Course:

a) A Fitter Welder 3 may bid on non-welder jobs during the period when he may withdraw from training in accordance with Article 38.02.5.2 a) only and at no other time.

b) A Fitter Welder 2 who was trained as a Fitter Welder 3 for more than 12 months in all, may not bid on other than Fitter Welder positions until he has completed a minimum of two years' service as Fitter Welder 2 and 1 in total.

12.02.5.4 Rights on Successful Completion of Course:

a) On completion of training and qualification as Fitter Welder 2 the employee shall be offered any Fitter Welder vacancy before any hiring from other than Fitter Welder Job Classifications or from outside the Company may be considered.

b) The Fitter Welder 3 program is intended to assist in meeting Terasen Fitter Welder requirements but it does not exclude hiring Fitter Welders from any other sources after Article 38.02.5.4 a) above has been observed.

12.02.5.5 Appointment to Vacancies after Completion of Course:

a) After qualifying as Fitter Welder 2, the employee shall be required to accept any Fitter Welder position at any location with Gas Transmission & Distribution Division or its successors; if the employee declines this position, he shall be treated as in Article 38.02.5.5 b) below.

b) After completion of training, if there is no requirement for a Fitter Welder 2 anywhere within Gas Transmission and Distribution Division, the newly-qualified Fitter Welder 2 shall be employed and paid in the Job Categories listed below. The Job Categories are listed in descending order of choice as work is available; such work availability shall be determined by Terasen:

(i) Shop Mechanic 1 (Welding Shop)
(ii) Crew Leader
(if so employed before training as Fitter Welder 3)
(iii) Customer Service Technician
(if so employed before training as Fitter Welder 3)
(iv) Distribution Mechanic/Distribution Apprentice (if so employed before as Fitter Welder 3)

Should no work be available in any of these Categories, the employees shall be declared redundant in accordance with Article 7.05 of the Agreement dated 1979 April 1.

12.02.5.6 Numbers to be trained:

a) The intent of the Fitter Welder 3 training program is to provide sufficient trained and competent Fitter Welders to assist in meeting the Company's foreseen needs for such employees.

b) It is agreed that this training program must not raise false hopes, nor must it train people for whom there will be no requirement later.

c) The number of Fitter Welder 3's selected and trained shall be based upon the Company's prediction of its future need for Fitter Welders and shall be entirely at Company discretion.

12.03 (formerly Article 37.05.4)

The Company shall pay costs and provide reasonable training time for all welder qualification tests.

12.03.1 (formerly Article 37.05.4.1)

The Company shall pay costs of fitter licenses and renewal fees.

12.04 Corrosion Control Technologist Trainee & Measurement and Controls Technician Trainee – Victoria Unit Only (formerly LOU #5 – Victoria Unit & LOU#21 – Victoria Unit)

The Company will provide training for IBEW 213 Company employees to qualify respectively as Corrosion Control Technologists or, Measurement & Controls Technicians by use of the Company's existing qualified staff, enrolment in Corrosion apprenticeship program or an Instrumentation apprenticeship program, by use of Vocational or similar institutes, or a suitable combination of these, to assist in meeting the Company's Corrosion Control Technologist requirements or the Company's Measurement & Controls Technician requirements. This arrangement shall not preclude the hiring of Corrosion Control Technologist Trainee or, Measurement & Controls Technicians from any other source.

A Corrosion Control Technologist Trainee shall receive 80 percent of the hourly rate paid a Corrosion Control Technologist and increases at one year intervals of 5 percent up to the 100 percent rate upon successful completion of the 4-year training program.

A Measurement & Controls Technician Trainee shall receive 80 percent of the hourly rate paid a Measurement & Controls Technician and increases at one year intervals of 4 percent up to the 100 percent rate upon successful completion of the five-year training program.

At the time of the selection to the program, the Corrosion Control Technologist Trainee or the, Measurement & Controls Technician Trainee may receive up to 24 months credit if they have a Technologist's Diploma based on the apprenticeship Branch of Skills and Training of the recruit's prior experience and qualifications.

Evaluation and selection of the applicants will consider the certificates and/or licenses held by the applicant which are indicative of the skills required to enroll in the instrumentation apprenticeship program.

12.04.1 Rights to Withdrawal form Program

Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee upon completion of their first year in the position/program may not voluntarily withdraw from the program.

12.04.2 Rights to Bid on Other Jobs during this Program

A Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee who has respectively entered into a Corrosion training program or an instrumentation training program may not bid on other positions posted within Terasen Gas.

A Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee who respectively accepts another Corrosion position or another Measurement position with Terasen Gas shall continue their wage progression until such time as their training is complete regardless of the corrosion position or the measurement position applied for.

12.04.3 Training Requirements

The Company shall ensure the Corrosion Control Technologist Trainee or the Measurement & Controls Technician Trainee respectively works under the direction of a Corrosion Control Technologist or a, Measurement & Controls Technician and receives the required training and skills to complete the program.

The Union recognizes the need for the Trainee to travel to other areas of the Terasen Gas system to ensure adequate training and completion of the program.

12.04.4 Program Completion

A Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee who fails to pass their post secondary training in any one year of their apprenticeship, the Company will provide one additional leave of absence up to six (6) weeks, without pay to attend the next available training session and examination, or longer if required.

A Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee who fails their post secondary training twice within a given year of their apprenticeship or fails in any two years of the 4 year program shall revert to their previously held position or an equivalent position in accordance with Article 4.02.1. The Company may, at its discretion, review any extraneous circumstances that may have prevented the successful completion of the post-secondary training.

A Corrosion Control Technologist Trainee or a Measurement & Controls Technician Trainee who fails their post-secondary training in any one year of their program shall have their wage progression postponed until such time as they successfully complete the training and examination.

12.05 Compression & Controls Technicians (CCT) – Trades Qualifications & Apprenticeship(formerly Part 1 of LOU NO.59)

a) Those CCTs and new employees to this classification who do not hold an Interprovincial or B.C. Provincial Trades Qualification Certificate or Exemption Certificate in Electrical, will be required to obtain the Electrical TQ through an apprenticeship program. Those who have obtained an Exemption Certificate will enter into an apprenticeship at the Company's discretion.

b) An employee who has relevant training and experience shall write a slotting exam as provided by the Apprenticeship Branch.

c) An employee who fails any apprentice year twice may be terminated or reassigned, at the Company's sole discretion.

12.05.1 Apprenticeship

a) School Terms will be scheduled by the Company to meet operational requirements.

b) Travel, accommodation and meal expenses during the school term will be by agreement between the employee and the manager based on what is reasonable in the circumstances and generally within the practice followed for Company training. Failing agreement between the employee and the manager, agreement will be reached between the Union and the Company.

c) Employees shall continue to receive their regular, straight time wages for all time associated with the school term. If the employee is required to perform Company work during the school term, the regular hours of work or overtime provisions will apply. If the employee is required to repeat a school term, all time and expenses associated with the repeated term are the responsibility of the employee.

d) Books and supplies as prescribed by the Apprenticeship Branch will be reimbursed by the Company.

e) Employees hired after June 13, 2004 shall contribute 15 days of their own time per year to classroom time.

f) Employees and internal hires hired before June 13, 2004, who do not have the trade qualification or an Exemption Certificate shall not be required to contribute any of their own time to classroom time.

g) Employees hired after June 13, 2004 and who receive the benefits of this Article 38.05 (i.e. the employee is in the apprenticeship program for a required TQ) are not eligible for the Attraction/Retention Premium.

13. GROUP LIFE INSURANCE

****SUPERCEDED BY FLEXIBLE BENEFITS PLAN CHANGES, EFFECTIVE JANUARY 1, 2011****

13.01

The Company and employees who are covered by this Agreement shall continue with the benefits of group life insurance as provided under the terms of the policy with The Manufacturers Life Insurance Company (Manufacturers Life) Policy No. 4517, Div 60-600, dated January 1, 1998, and amendments thereto.

13.02

All employees certified under this Agreement must join the group insurance plan as provided by the Company.

13.03

The Company shall contribute one hundred percent (100%) of the cost of the policy.

13.04

The life insurance benefit is equal to two (2) times the employee's basic annual earnings as calculated at the time of death, rounded to the next higher $1000, if not already a multiple of $1000.

13.05

Life insurance is payable in the event of an employee's death from any cause. The benefit is payable in a lump sum to the employee's designated beneficiary.

13.06

An employee who retires and draws an immediate Terasen pension will be covered for 50% of the insurance in effect immediately prior to retirement. The amount will be reduced annually by 10% of the insurance in effect immediately prior to retirement until a minimum of $2,500 is reached. This minimum shall remain in effect for the remainder of the retired employee's life. (see 2004 Adjustment Plan for treatment of employees who retired from Centra Gas B.C. or Centra Gas Whistler).

13.07

An employee receiving Long Term Disability benefits under Article 17 shall remain covered for the Life Insurance coverage in effect immediately prior to the disability.

13.08

The Company will continue to provide Travel Accident Insurance for employees traveling on Company business, providing benefits equivalent to (or greater than) that provided as of March 31, 2006.

14. HEALTH BENEFITS

****SUPERCEDED BY FLEXIBLE BENEFITS PLAN CHANGES, EFFECTIVE JANUARY 1, 2011****

14.01

The Company and the eligible employees who are covered by this Agreement shall continue with the Medical Services Plan of British Columbia and the Extended Health Benefits Plan. The Company will pay the full cost of the premium of the plans.

14.02

The Medical Services Plan (MSP) covers such things as medical, surgical, obstetrical and optometric services.

14.03

The Extended Health Benefits Plan pays for some services not covered by MSP. The Plan will pay 100% of all eligible expenses in excess of a $25 deductible per person or family each calendar year. The maximum benefit payable during the lifetime of any family member is $1,000,000.

Extended Health Benefits Plan to include standard vision care to a maximum of $150 every two years per person enrolled in the plan.

15. DENTAL PLAN

****SUPERCEDED BY FLEXIBLE BENEFITS PLAN CHANGES, EFFECTIVE JANUARY 1, 2011****

15.01

All employees as hereinafter defined are eligible to enroll in the Company's Dental Plan currently in effect with Pacific Blue Cross. The plan includes:

Plan A - 100% payment of fees
Plan B - 65% co-insurance (effective 92.04.01)
Plan C - 50% co-insurance to a maximum of $3,000 lifetime benefits per person enrolled in the plan.

15.02

Payment of benefits under the Plan is based on the B.C. College of Dental Surgeons' Schedule of Fees. Regular employees are eligible for enrollment when they have accumulated more than six (6) months of Company service or after three (3) months of continuous service.

15.03

An employee being placed on lay-off status will be given the option of maintaining Dental Plan benefits, pursuant to Articles 7.03.9 and 7.07.

15.03.1

An employee electing to maintain dental benefits who is not covered pursuant to Article 7.07 must pay the full one hundred percent (100%) monthly premium cost, in advance, for the period of lay-off. If the period of lay-off extends longer than anticipated, the employee must make arrangements to pre-pay the full one hundred percent (100%) monthly premium for the extended period of lay-off.

15.03.2

When an employee who has maintained Dental Plan benefits during lay-off is recalled to work, the Company will begin contributing towards his Dental Plan benefit premiums beginning the first day of the month coincident with, or following, the date of recall to work.

15.03.3

An employee electing not to maintain dental benefits during lay-off, will have that coverage cease on the last day of the month coincident with, or following, his date of lay-off.

15.03.4

When an employee who has not maintained Dental Plan benefits during lay-off is recalled to work, the benefit will be restored on the first day of the month coincident with, or following, one (1) month after recall.

15.04

The Company shall pay one hundred percent (100%) of the Dental Plan premium.

16. PAID SICK LEAVE ALLOWANCES

****SUPERCEDED BY FLEXIBLE BENEFITS PLAN CHANGES, EFFECTIVE JANUARY 1, 2011****

16.01

An employee becomes eligible for paid sick leave benefits after accumulating three (3) months of service with the Company.

16.02

Employees who are unable to work as a result of a disability caused by an off-the-job sickness or accident will be eligible to receive the following paid sick leave.

PERIOD OF SERVICE WITH THE COMPANY AT PREVIOUS JULY 1			PAID SICK LEAVE ALLOWANCE PER PLAN YEAR	
			NO. OF WEEKS FULL	70%
3 mos	-	1 yr less 1 day	1	14
1 yr	-	2 yrs less 1 day	2	13
2 yrs	-	3 yrs less 1 day	3	12
3 yrs	-	4 yrs less 1 day	4	11
4 yrs	-	5 yrs less 1 day	5	10
5 yrs	-	6 yrs less 1 day	6	9
6 yrs	-	7 yrs less 1 day	7	8
7 yrs	-	8 yrs less 1 day	8	7
8 yrs	-	9 yrs less 1 day	9	6
9 yrs	-	10 yrs less 1 day	10	5
10 yrs	-	11 yrs less 1 day	11	4
11 yrs	-	12 yrs less 1 day	12	3
12 yrs	-	13 yrs less 1 day	13	2
13 yrs	-	14 yrs less 1 day	14	1
14 yrs or more			15	0

Employees who were not with the Company at the previous July 1st, will have their period of service determined as the period of time from the date their employment with the Company commenced until the date of their disability.

16.03

A plan year is defined as a twelve (12) month period beginning on July 1, and ending on June 30.

16.04

For purposes of this Article, "regular earnings" means the hourly wage rate in effect at the date of disability, for the employee's normal job classification, multiplied by 7.5 hours per day (37.5 hours per week) or 8 hours per day (40 hours per week) as appropriate.

16.05

When the entitlement at full regular earnings has been exhausted, employees will be eligible to receive further paid sick leave benefits of seventy percent (70%) of regular earnings for the balance of a fifteen (15) week period.

16.06

Any unused days of paid sick leave allowance at full regular earnings cannot be carried over from one plan year to the next. If a disability continues into a new plan year, the amount of benefits at full regular earnings for that disability in the new plan year will be the balance of what is left from the previous plan year's full regular earnings entitlement.

16.07

Whenever possible, employees shall schedule medical and dental appointments outside of normal working hours.

16.07.1

Where it is not possible for an employee to schedule such appointments outside of normal working hours, the employee will not have the first hour of any such leave deducted from their sick leave and their pay.

16.07.2

The second hour of such leave will be deducted from the employee's overtime bank, or if the employee has no overtime bank, will be without pay.

16.08

If an employee has received fifteen (15) weeks of paid sick leave benefits and returns to active duty, the employee will have his entitlement as at the previous July 1, reinstated after one (1) months service in the case of a new disability, and after three (3) months service in the case of the same or a related disability.

16.08.1

If a disabled employee has exhausted his paid sick leave benefits prior to the expiry of the 15 - week elimination period for Long Term Disability, he shall be paid seventy percent (70%) of regular earnings for the balance of the elimination period.

16.09

Benefits under this plan will be reduced by any benefits an employee may be eligible to receive under any government sponsored plan, other than Employment Insurance. Income benefits from any individual disability policy which has been purchased by an employee will not be considered in determining benefit entitlement under this plan.

16.09.1

Terasen Sick Leave Bank: Employees in the Coastal Region as at September 30, 1989, or in the Victoria Unit as at December 31, 2003 and who have banked sick leave entitlement on that date, will establish a non-renewable Terasen Sick Leave Bank equal to two-thirds (2/3) of that entitlement. For North Island and Whistler employees, the Company will calculate a sick leave bank on the same basis as though they had been a Victoria employee, given their length of service as at December 31, 2003. This Bank shall be used as a supplement to earnings while the employee is in receipt of sick leave or of Long Term Disability payments at 70% of regular earnings. Payout of the Terasen Sick Leave Bank will be thirty percent (30%) of regular earnings and will cease when the disability is over or when the Bank is exhausted.

16.09.1.1

Coastal employees on paid sick leave on September 30, 1989 will establish their sick leave bank as at the date on which they are authorized to return to work. Former Centra employees on paid sick leave on December 31, 2003 will establish their sick leave bank as at the date on which they are authorized to return to work.

16.09.1.2

When the sick leave bank is exhausted, or in the case of employees who do not have a sick leave bank, the employee's other time banks shall be used to supplement earnings as above, in the following order:

1. Prior Year Bank
2. O/T Bank
3. Choices
4. Current Bank AV (earned entitlement only)
5. True Bank Prior Year

16.10

Employees absent from work for any of the following reasons will not be eligible for paid sick leave benefits:

(a) Disabilities which occur while on an unpaid leave of absence, except where the unpaid leave of absence has been granted for Union business if such leave does not exceed fourteen (14) days;
(b) Disabilities which occur while an employee is locked out, on strike, walk-out or other work stoppage;
(c) Disabilities which occur while the employee is on maternity leave;
(d) Disabilities covered by any Workers' Compensation Act;
(e) Disabilities caused by intentionally self-inflicted injuries or disease; while serving in the Armed Forces; while participating in a riot, war or civil disobedience; or while committing a criminal offence or serving a prison sentence.

16.11

When an employee is given notice of lay-off and the employee subsequently becomes disabled within two (2) months of the effective date of the lay-off, the paid sick leave benefits will terminate on the effective date of the lay-off.

16.12

Employees with health problems will be considered for severance pay providing the employee is not receiving long term disability benefits.

16.12.1

Subject to agreement of the Union, the Company may refer an employee to a vocational health practitioner with the goal of improving the employee's health and/or work environment; the objective being a sustained return to work and/or improved attendance.

The referral and discussion with the practitioner shall be coordinated by the Human Resources Department, and the usual confidentiality surrounding medical issues shall apply.

16.12.2

Any accommodation of employee disability is subject to discussion with the Union.

16.12.3

The referral is at Company expense and compensation for time off shall be covered by sick leave, LTD payments, or WCB payments as appropriate.

16.13

At the request of the Company, employees will provide a medical certificate from a licensed physician substantiating any disability extending beyond five (5) consecutive days, or to substantiate frequent absences (in excess of four (4) occurrences in any twelve (12) consecutive months).

16.14

It is understood that the Plan may be altered or amended from time to time in order that the Plan will continue to meet the standards of the Employment Insurance Regulations and thereby qualify the Company for a full premium reduction.

17. LONG TERM DISABILITY PLAN

****SUPERCEDED BY FLEXIBLE BENEFITS PLAN CHANGES, EFFECTIVE JANUARY 1, 2011****

17.01

The principle of the Plan will be to provide, subject to the terms of the contract with the underwriter, benefits at the rate of seventy percent (70%) of regular earnings (to a maximum benefit of $4000/month) while sick or disabled. The Plan will commence in the sixteenth (16th) week of continuous disability. The Company shall pay one hundred percent (100%) of the cost of the policy. All employees certified under this agreement must join this group insurance plan.

17.02

While the benefits of this Plan include payments by government plans, such as Canada Pension and Workers' Compensation, the initial benefit under this Plan will not be reduced even if there are subsequent increases in government plans' payments.

17.03

Effective January 1, 1992, the benefits payable from the Plan will increase at the rate of increase of the Consumer Price Index to a maximum of 3% per year, pursuant to the terms and conditions of the contract with Maritime Life Assurance Company.

18. PROLONGED ILLNESS

18.01

If, through sickness or accident, an employee is incapable of taking over his customary job, he may work at some other suitable job until he is physically fit to resume his customary work. In doing so he will not lose any seniority on his customary job.

18.02

In the event of an employee becoming partially handicapped physically to the extent of his not being able to perform all aspects of his job satisfactorily, the Company will exert its best efforts towards placing the employee on other available work as near to the level of his previous rate as possible, bearing in mind vacancies available and qualifications required.

18.03

In certain cases, the Company and the Union may be able to make certain changes in shift sign-ups, seniority provisions, etc. to alleviate such cases, and these will be discussed between the parties and acted upon if there is mutual consent.

18.04

While it is the intent of the Company to assist wherever possible in the types of instances mentioned above, the Company is not obliged to "find work" when productive vacancies are not available.

19. ACCIDENTS AT WORK

19.01

If an employee is injured at work, such employee shall receive full pay for the day of his injury if unable to carry out his duties assigned to him.

19.02

In cases where employees are receiving Workers' Compensation Board "Wage Loss Benefits" and provided such employees are not laid off, the Company will pay the difference between the employee's actual income and eighty-five percent (85%) of the employee's normal weekly straight time wages and the Company will bear its normal share of the cost of enrollment in all benefit plans.

19.03

For the purpose of this Article, "actual income" is defined as income from the Workers' Compensation Board, Canada Pension and the Company's long term disability plan.

19.04

The Workers' Compensation Supplement will not be greater than that required to give the employee an aggregate income, not including income from individual or private sources, equal to the employee's normal weekly straight-time wage after the deduction of income tax.

19.05

Employees receiving the Workers' Compensation supplement will apply for long term disability benefits and/or Canada Pension Plan benefits if requested to do so by the Company.

20. LEAVE OF ABSENCE

20.01

Officers of the Union shall be granted leave of absence on Union business insofar as the regular operation of the service will permit and shall be given precedence over any other application for leave on the same day. The Company will invoice the Union for wages paid to employees on leave of absence for Union business.

20.01.1

Reasonable written notice to the Company must be given; and if this is not done, reliefs will be made at straight-time rates only.

20.01.2

The Union will bear the costs of overheads when employees are on leave for Union business. Their overheads shall amount to 30% of base rate.

20.02

Employees shall be granted leave of absence on application to their respective manager or supervisor where such leave of absence does not exceed fourteen days insofar as the proper operation of the service will permit.

20.02.1

All applications for a longer period shall be made through the Business Agent of the Union and taken up with the proper official of the Company and dealt with in accordance with the priority of the application.

20.02.2

Three months' absence shall be granted if desired after one year's service insofar as the proper operation of the service will permit.

20.02.3

No leave of absence for more than fourteen days will be recognized unless jointly approved by the Company and the Union.

20.02.4

No leave shall be granted for the purpose of entering other occupations.

20.02.5

Leave granted for the business of the Union shall not be included in this clause.

20.03

When the Company requires employees covered by this Agreement to attend meetings, it shall make up any lost time and the same shall apply when a shop steward takes up a grievance.

20.03.1

This provision will not apply, however, in the case of meetings called at the request of the Union or any meeting required to negotiate a new Agreement.

20.04

Leave of absence with pay will be granted an employee for jury duty or to appear in court as a subpoenaed witness.

20.04.1

Any compensation received from the court for this service will be forwarded to the Company.

20.04.2

In cases where an employee's private affairs have occasioned a court appearance, such leave to attend court will be without pay.

20.05

Leave of absence for sickness or any purpose up to a total of one (1) month in any period (excluding paid vacation) shall not reduce the annual vacation an employee would otherwise qualify for.

20.05.1

Where a leave exceeds one (1) month his annual vacation with pay shall be reduced by one eleventh (1/11) for each full month of absence in excess of one (1) month. For the purpose of this proration "absence" shall not include time off work for annual vacation or Legacy Days and Choices Days or Overtime Bank Days.

20.06

Compassionate leave of absence with pay shall be granted an employee upon application in the event of the death of a spouse (including common-law spouse), mother, father, step-parents, sister, brother (including step-sister or step-brother), son, daughter (including common-law or step-children), mother-in-law, father-in-law, brother-in-law, sister-in-law, or grandparent(s). The first three (3) days of such leave shall be at Company expense. Leave granted in excess of three days up to a maximum of five days shall be charged to the banked time of such employee. In the event that such additional time cannot be charged to banked time, an employee may elect to have such leave of absence in excess of three (3) days up to a maximum of five (5) days without pay.

20.07

Absences due to W.C.B. will not reduce subsequent annual vacation entitlement during the first twelve (12) consecutive months of absence. No vacation entitlement shall accrue for the remaining period of the absence.

20.07.1

Vacation accumulation in excess of an annual entitlement will be cashed out.

20.07.2

When the employee returns to work, he shall take the current year's vacation accrual in the current year, and the annual entitlement which was carried forward shall be taken in the following calendar year.

20.08

An employee who is granted leave of absence from the Company, with or without pay, shall not lose any type of seniority.

21. STATUTORY HOLIDAYS

21.01

When the word "holidays" appears in this Agreement, it shall be deemed to mean New Year's Day, Good Friday, Easter Monday, Victoria Day, Canada Day, B.C. Day, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day, and Boxing Day, or days in lieu of as declared by the Provincial or Federal Governments and any additional holiday not related to the above gazetted by the Provincial or Federal Governments.

21.02

All employees covered by this Agreement who are active or on paid leave at the time shall receive the foregoing eleven statutory holidays with pay per year.

21.02.1

Employees on the payroll shall be interpreted to mean all employees on the payroll who do not miss a particular statutory holiday on account of leave of absence from the Company's service.

21.03 Statutory Holiday Compensation for Day Workers and Rotating Shift Workers

21.03.1 Employees not scheduled to work:

21.03.1.1

a) Holiday falls Monday through Friday: one day's pay at straight-time.

b) Holiday falls Saturday or Sunday: When a holiday falls on a Saturday or Sunday and another day is not declared in lieu thereof by the Provincial or Federal Government in accordance with 21.01, a day off in lieu thereof will be designated by the Company either on the last working day immediately preceding or the first working day immediately following the weekend on which the statutory holiday falls.

- i) Employees shall be notified of days so designated for the following year not later than 30 September of the preceding year.
- ii) Any changes to the posted schedule shall be by mutual agreement.
- iii) If mutual agreement is not reached with respect to holidays falling on the weekend, the following shall apply:
  - a) Holiday falls Saturday - previous Friday off with pay.
  - b) Holiday falls Sunday - following Monday off with pay.

21.03.1.2 Day Workers scheduled to work:

a) Holiday falls Monday through Friday:

- i) One day's pay at straight-time.
- ii) Double time for hours worked, paid for straight-time hours worked, premium time to overtime bank.

21.03.1.3

a) Employees providing weekend coverage (days, afternoons or nights) will also provide coverage on statutory holidays or days designated in lieu by Terasen immediately preceding or following the weekend.

b) Where an employee provides weekend coverage on a Monday, the Monday will not be considered in determining the rotation for weekend coverage and shifts.

21.03.2

Employees who are not scheduled to work a statutory holiday and are called to work shall be paid for straight and premium time when two hours or less has been worked.

21.03.2.1

When more than two hours are worked, the conditions outlined in 21.03.1 shall apply in proportion to number of hours worked.

22. ANNUAL VACATION

22.01 Definitions

"Year" shall mean calendar year.

"Calendar Year" shall mean the twelve month period between January 1st and December 31st inclusive.

"Service" shall mean accredited service as defined in Article 11.

"Day(s)" shall mean working day(s).

22.02

An employee shall earn his annual vacation entitlement for any calendar year only when he reaches his anniversary, although he may take his annual vacation anytime during that calendar year, except employees in the Interior Region who were employees prior to August 1, 1989, whose anniversary date for the purposes of this Article is defined to be July 1.

22.02.1

Vacation entitlement will be advanced in January of the calendar year it is earned, and it will be prorated for new hires based on the year of hire service.

22.03

Employees who complete the years of service shown under column (1) shall have the number of days of Annual Vacation with pay during that year and subsequent years as provided in column (2):

22.03.1 Standard Model (Province-Wide)*

*Applicable to employees hired after September 4, 2006 and those who elected the Standard Model

(1)	(2)
<1 year of service	up to 15 days of vacation
1-7 years of service	15 days of vacation
8-17 years of service	20 days of vacation
18-24 years of service	25 days of vacation
25+ years of service	30 days of vacation

22.03.2 Legacy Model - In the Coastal Region

(1)	(2)
<1 year of service	up to 15 days of vacation
1-9 years of service	15 days of vacation
10-17 years of service	20 days of vacation
18-29 years of service	25 days of vacation
30+ years of service	30 days of vacation

22.03.3 Legacy Model - In the Interior and Island Regions

(1)	(2)
<1 year of service	up to 15 days of vacation
1-7 years of service	15 days of vacation
8-17 years of service	20 days of vacation
18-29 years of service	25 days of vacation
30+ years of service	30 days of vacation

22.04 Vacation Scheduling

22.04.1

For the purpose of scheduling annual vacation, it is understood that each employee's vacation entitlement shall be granted between the first day of January and the following first day of January.

22.04.2

All employees with sufficient annual vacation entitlement shall receive fifteen (15) days (or longer where work load permits) on the regular summer write-up which extends from 1 May to 30 September each year.

22.04.2.1

During the summer write-up 15% of the work force in any classification (or greater where work load permits) in any given section shall be entitled to be on annual vacation at any one time.

22.04.3

The Company will confirm each period of signed-up annual vacation at least fifteen (15) days before it begins.

22.04.3.1

If the Company requires an employee to change his signed-up vacation period and the employee can prove that he has suffered financial loss as a result, the Company shall recompense the employee for such loss.

22.04.4

The Company reserves the right to determine whether or not it is practicable for an employee to take more than three weeks of vacation consecutively.

22.05

An employee returning from an unscheduled absence of longer than fifteen (15) weeks (eg. LTD, WCB) is entitled to vacation time off to a maximum of one week for each full calendar month remaining in the calendar year, unless the time off had been scheduled and approved prior to the absence. (For example, an employee returning during September may schedule a maximum 3 weeks for the balance of the year). Any remaining vacation time shall be cashed out.

22.06 Callback to Work When on Vacation:

An employee who has begun his annual vacation and is called back to work by the Company shall be paid at overtime rates for the remaining portion of his vacation during which he has had to work, and within a reasonable period of time he will also receive the remaining portion of his scheduled annual vacation without further vacation pay.

22.07 Calculation of Vacation Pay:

Payment for Annual Vacation will be based upon straight time earnings during the second last complete pay period prior to vacation or at the applicable rate of 6%, 8%, 10%, or 12% of the current calendar year's earnings, whichever is greater.

22.08

If an employee becomes disabled as a result of sickness or accident before his vacation is due and his disability continues throughout the rest of the vacation year, vacation privileges shall be carried over only to the following year, if the employee so decides.

22.09

Regardless of an employee's vacation entitlement by service, he shall only receive that portion of vacation entitlement earned in the current year based on the total time worked during the current “year”.

22.10 Annual Vacation Sign-up Construction Maintenance (Coastal Only):

A master sign-up sheet showing personnel names in order of rotation shall be posted in a conspicuous location in the respective departments and employees shall participate in the construction and maintenance annual vacation sign-ups.

22.11 Supplementary Vacation (Interior, <u>and North Island and Whistler</u> - <u>Legacy Model</u> Only)

a) On the date an employee attains five (5) years' service with the Company, he shall be credited with five (5) days' supplementary vacation which may be taken at any time prior to the employee attaining ten (10) years' service.

b) On the date an employee attains ten (10) years' service with the Company, he shall be credited with ten (10) days' supplementary vacation which may be taken at any time prior to the employee attaining fifteen (15) years' service.

c) On the date an employee attains fifteen (15) years' service with the Company, he shall be credited with five (5) days' supplementary vacation which may be taken at any time prior to the employee attaining twenty (20) years' service.

d) On the date an employee attains twenty (20) years' service with the Company, he shall be credited with ten (10) days' supplementary vacation which may be taken at any time.

e) Annual vacation scheduled pursuant to Clauses 22.01 to 22.04 shall take precedence over the scheduling of supplementary vacation.

f) Supplementary vacation shall not conflict with essential departmental requirements.

g) Supplementary vacation shall be paid at the wage rate in effect at the time the vacation is actually taken.

h) Supplementary vacation is a non-cumulative time-off entitlement only and no payment will be made in lieu of supplementary vacation not taken during the specified five (5) year period.

23. REST BREAKS

23.01

Employees will be allowed a fifteen (15) minute rest break twice daily.

23.01.1

It is understood that rest breaks must not inconvenience the public or expose anyone to hazard, nor will members of construction or maintenance crews be permitted to leave the job site.

23.01.2

Rest breaks are to be taken as close to mid-morning and mid-afternoon as is practical without detracting from operating efficiency.

24. GLOVES, TOOLS, AND CLOTHING

24.01

Clothes, gloves, work tools, etc. shall be provided free of charge to all employees covered by this Agreement, wherever required.

24.01.2

Employees shall turn in worn-out clothes, tools, gloves, equipment, etc., before receiving new issues of any article provided by the Company.

24.02

Workers' Compensation Board (WCB) Regulations require that certain employees wear properly-fitted eye protection under prescribed work conditions.

24.02.1

Where corrective lenses are required in safety spectacles, the Company will reimburse each employee requiring corrective safety spectacles an amount of $100.00 providing that the spectacles conform to Canadian Standards Association (CSA) Standard Z94.3-M92.

24.02.2

Reimbursement provisions apply only for corrective safety spectacles.

24.03

When safety footwear and Company approved rainwear is advisable on the job and approved by the manager or supervisor, the employee will be reimbursed as follows:

a) 50% of the cost of up to two sets of rainwear to a maximum of $100 per calendar year, or 50% of the cost of insulated, fire-retardant coveralls.

b) 50% of the cost of up to three pairs of CSA approved footwear or 100% of the cost of repairs to two pairs of CSA approved footwear in a calendar year OR a combination of either in a calendar year, to a maximum of $165/yr or $330 every two years.

24.04

Customer Service Technicians and where applicable, Distribution Service Agents shall be supplied with a standard uniform and a common winter jacket as required and on return to the Company of worn out garments.

24.05

One insulated vest shall be issued to all field personnel except those specified in Article 24.04.

24.05.1

Replacement vests shall be issued, as required, on return of the worn out vest.

24.05.2

Cleaning and repair of vest will be the employee's responsibility.

24.06

All classifications will be supplied with tailored coveralls.

24.06.1

A clean pair will be supplied as required, but normally not more often than once per week.

24.06.2

Under certain circumstances uniforms will be protected by conventional coveralls supplied by the Company.

24.07

Clothing which is destroyed in the course of employment by means other than by normal use shall be replaced at the expense of the Company.

24.07.1

It is understood that clothing which can be cleaned or otherwise rehabilitated cannot be considered to be destroyed.

25. DRIVING VEHICLES

25.01

Any employee competent to do so shall, upon request, drive any vehicle assigned to him by the Company.

25.01.1

If this duty involves the necessity for such an employee to hold other than a Class 5 license, the Company shall bear the cost of such licenses and associated expenses, excluding point penalty premiums.

25.02

All employees are required to hold a valid Class 5 driver's license, except for disabled new employees who may not qualify to drive a Company vehicle if such is not a requirement of the job.

25.02.1

Employees are required to notify their manager or supervisor in the event of loss or suspension of their driver's license. The Company and the Union shall endeavour to accommodate such employees by placing them in positions where a driver's license is not a critical, day-to-day requirement, so long as this can be achieved without cost to the Company.

25.03

An employee must be the holder of the appropriate license or permit prior to operating equipment or vehicles that require other than a Class 5 Drivers' License. For example, an Equipment Operator I, EODM, Pipeline Technician 1, Equipment Operator P and every other classification for which it is a stated qualification will be required to be the holder of a valid Class 1 Driver's License with an Air-Brake Endorsement for entry into and/or retention of the classification unless formally excused from these requirements by the Company.

26. SAFETY WORKING PROCEDURES

26.01

Safe working procedures shall be in line with current rules and regulations of WorkSafe BC of the Provincial Government of British Columbia insofar as they may apply.

26.01.1

Each employee undertakes to comply with WorkSafe BC's Occupational Health & Safety Regulations, and the Company will orient each new employee to these rules and regulations.

26.02

Where existing regulations are inadequate, safe working procedures shall be discussed by a Joint Health and Safety Committee consisting of four members chosen by the Union and four members chosen by the Company.

26.02.1

A Joint Health and Safety Committee shall meet at the request of either party.

26.02.2

If a Joint Health and Safety Committee cannot reach a decision, the matter shall be referred to the WorkSafe BC for a ruling.

26.02.3

The decisions of a Joint Health and Safety Committee shall become part of the Company's Safety Practices Manual.

26.03 Dog Safeguards

The Company shall encourage and be receptive to suggestions regarding any devices, methods or procedures which may deter or prevent dog attacks. Such devices, methods or procedures shall be approved by a Joint Health and Safety Committee before use.

26.04 Employees Entering Unattended Premises

In situations where employees anticipate an element of risk or hazard, they will provide the address of the premises, and advise Service Centre to contact their supervisor in the event they fail to call back within a pre-arranged time.

27. SHOW-UP TIME (moved to Article 30.01.3 in 2006)

27. HEADQUARTERS PROCEDURES

METRO UNIT

27.01

Metro Unit employees may be assigned outside of the Metro boundaries subject to the terms of Articles 278, and 28.

27.02 Headquarters - Metro

A headquarters is defined as a municipal area within a District, consisting of a city, town, municipal district or an unorganized territory, or a combination of the above. Headquarters are established by the Company to provide the personnel necessary to meet the work requirements in the various population centers throughout Metro. Headquarters and their boundaries shall be subject to adjustment by the Company as growth patterns, work loads, population densities and other related operating conditions require. An outline of the boundaries will be provided to all employees concerned by separate work bulletins.

Metro District

1. Vancouver City and U.E.L.
2. Municipality of Burnaby and City of New Westminster
3. Port Moody, Port Coquitlam, Coquitlam and Anmore
4. North Vancouver City and District and West Vancouver
5. Municipality of Richmond

27.03 Mustering Points (Metro)

Locations within a headquarters at which an employee or crew starts and stops the working day. Mustering points are established and designated by the Company. The Company may designate the work site as a mustering point when crew strength is comprised of four or more employees and the job is expected to last longer than two days. Four employees shall include the crew leader, all Company employees and all equipment operators and welders functioning as a member of the crew. The Company will provide one or more mustering points of a permanent nature to serve each headquarters area.

27.04 Assignment of Headquarters (Metro)

27.04.1

All regular employees will be assigned one headquarters, with the exception of .2, .3, .4, .5, .6 below.

27.04.2

New employees with less than 12 months service and temporary employees shall not be assigned a permanent headquarters. They shall be assigned to work in any headquarters within the unit as required.

27.04.3

A Labourer shall not be assigned a permanent headquarters. He shall report for work to any headquarters within the Unit as required. A regular Labourer must be given notice on the previous day for a change in headquarters.

27.04.4

A Distribution Apprentice shall report for work to any headquarters within the Region as required. On completion of one year of service, a Distribution Apprentice may elect:

Headquarters Group A: Burnaby, New Westminster, Vancouver, University Endowment Lands, and Richmond;

Headquarters Group B: Burnaby, New Westminster~~,~~ Port Moody, Port Coquitlam, Coquitlam and Anmore; or

Headquarters Group C: Burnaby, New Westminster, West Vancouver, and North Vancouver City and District,

within which they shall be assigned to work in any headquarter as required.

The Company will designate the number of positions available for election within each of these headquarters groups.

27.04.5

Personnel employed on System Survey shall not be assigned a permanent headquarters. They shall report for work to any headquarters within the Metro area as required. (formerly Article 28.04.4)

27.04.6

Fitter Welders shall normally report to Burnaby Operations or may be assigned to a muster point within the headquarters area of their residence or headquarters immediately adjoining the headquarters area of their residence. In the case of employees residing outside of the Metro area, assignment may be made to a headquarters area within Metro adjoining or closest to the employee's area of residence.

27.04.7

Employees in .4, .5, and .6 must be given notice on the previous day of a change in headquarters.

27.04.8

An employee selected to a bulletined position is subject to a change of section and assigned headquarters to meet the requirements of the position.

27.04.9

When additions or replacements are selected through the bulletining process, employees holding seniority in those classifications shall have first opportunity to elect a change of headquarters or District through the annual election process.

27.04.10

The Company will issue an election form annually in the third week of October to all regular employees to state headquarters preferences for the coming calendar year. During the calendar year election forms may be withdrawn but a new election form may only be completed if the employee changes his permanent address or if his headquarters is changed for reasons other than a change elected under the Article. The Company shall not be responsible for moving or other costs incurred by employees relocating under this Article.

27.04.11

When conditions require an employee to work in a District or Unit or headquarters to which he is not assigned the employee shall travel on Company time, and transportation shall be provided by the Company, unless the travel time from the employee's home to the temporary headquarters is no greater than normal travel time to the employee's permanent headquarters, in which case both time and transportation shall be the responsibility of the employee. When travel time and/or expenses are paid, these shall only be for the additional travel to the temporary headquarters, and travel time shall be at premium rates.

27.04.12

Assignment to the Interior Region shall be on a voluntary basis only. This does not apply to Compression and Controls Technicians (CCTs) as there is an expectation that they will be temporarily reassigned to compressor stations throughout the system as required. (formerly LOU #59, Part 4)

27.05

System Operations Technicians and Customer Service Technicians 1 and 2 in Metro shall normally be assigned to Burnaby Operations or may be assigned to an elected headquarters as determined by workload requirements.

27.05.1

When a vacancy occurs, employees in these classifications shall have an opportunity to elect a new headquarters on the basis of classification seniority.

27.05.2

The last vacancy(ies) will be filled by section bulletin or by appointment(s) in order of reverse seniority should there be no response to the bulletin.

27.06

Should any area of conflict exist between Metro Headquarters Procedure in Articles 27.01 to 27.05 and Change of Headquarters Article 28.01 as it applies to Metro, the Metro Headquarters Procedure shall take precedent.

27.07 FRASER VALLEY UNIT

27.07.1

The Fraser Valley Unit employees may be assigned outside the boundaries of the Fraser Valley service area as required to meet installation, operating and maintenance needs on the transmission system, rights-of-way and other related functions subject to the terms of Articles 27 and 28.

27.07.2 Headquarters - Fraser Valley

A headquarters is defined as a municipal area within a District consisting of a city, town, municipality, or an unorganized territory, or a combination of the above. Headquarters are established by the Company to provide the personnel necessary to meet the work requirements in the various population centers throughout the Fraser Valley. Headquarters and their boundaries shall be subject to adjustment by the Company as growth patterns, work loads, population densities, and other related operating conditions require. An outline of the boundaries will be provided to all employees concerned by separate work bulletin.

Headquarters:
1. Delta (Goudy)
2. Surrey (Roebuck)
3. Langley
4. Abbotsford
5. Chilliwack
6. Maple Ridge (Albion)
7. Mission
8. South Surrey (Sunnyside)
9. Agassiz (Kent)

27.07.3 Mustering Points (Fraser Valley)

27.07.3.1

Locations within a headquarters at which an employee or crew starts and stops the working day. Mustering points are established and designated by the Company (usually these are crew compounds or buildings. For Customer Service Technicians, a mustering point could also be their homes.)

27.07.3.2

Employees who muster from their homes shall start the working day there but shall stop work at any location within their assigned headquarters area, or if they are working elsewhere they shall stop work at their headquarters boundary. The Company may designate the work site as a mustering point when crew strength is comprised of four or more employees and the job is expected to last longer than two days. Four employees shall include the crew leader, all Company employees and all equipment operators and welders functioning as a member of the crew.

27. 07.3.3

Present mustering points are:

Valley East District:

Chilliwack Headquarters	- Yale Road West
Abbotsford Headquarters	- Progressive Way
Maple Ridge Headquarters	- Albion
Langley Headquarters	- Production Way
Agassiz Headquarters	- Kent

Valley West District:

Surrey Headquarters	- Surrey Operations
	- Roebuck
	- Sunnyside
Delta Headquarters	- Goudy

27. 07.4 Assignment of Headquarters (Fraser Valley)

27. 07.4.1

All regular employees will be assigned one headquarters, with the exception of .4.2 and .4.3 below.

27. 07.4.2

New employees with less than twelve months service and temporary employees shall not be assigned a permanent headquarters. They shall be assigned to work in any district and headquarters as required.

27. 07.4.3

A Distribution Apprentice shall report for work to any headquarters within the Region as required. On completion of one year of service a Distribution Apprentice may elect a permanent headquarters, except that the nine (9) Distribution Apprentices with least seniority in the Fraser Valley unit shall not be assigned a permanent headquarters, and shall report to any headquarters within the district as required.

A Labourer shall not be assigned a permanent headquarters. He shall report for work to any headquarters within the district as required. A regular Labourer must be given notice on the previous day for a change in headquarters.

27.07.4.4

An employee selected to a bulletined position is subject to a change of district and assigned headquarters to meet the requirements of the position.

27. 07.4.5

When additions or replacements are selected through the bulletining process, employees holding regular seniority in those classifications shall have first opportunity to elect a change of headquarters or district. In the Construction and Maintenance Section this opportunity will be given by use of the annual election process as described in 27.07.4.6.

In the Customer Service Section employees will be notified when headquarter vacancies occur. This will provide the opportunity for senior employees to elect a change of headquarters prior to posting of the vacancy.

27. 07.4.6

The Company will issue an election form annually in the third week of October to all regular Construction and Maintenance field employees to state district and headquarter preferences for the coming calendar year. During the calendar year election forms may be withdrawn but a new election form may only be completed if the employee changes his permanent address or if his headquarters is changed for reasons other than a change elected under this article. The Company shall not be responsible for moving or other costs incurred by employees relocating under this Article.

27. 07.4.7

When conditions require an employee to work in a district or unit or headquarters to which he is not assigned the employee shall travel on Company time and transportation shall be provided by the Company, unless the travel time from the employee's home to the temporary headquarters does not exceed normal travel time to the permanent headquarters, in which case time and transportation shall be the employee's responsibility. When travel time and/or expenses are paid, these shall only be for the additional travel to the temporary headquarters, and travel time shall be at premium rates.

27.07.4.8

Assignment to the Interior Region shall be on a voluntary basis only. This does not apply to Compression and Controls Technicians (CCTs) as there is an expectation that they will be temporarily reassigned to compressor stations throughout the system as required. (formerly LOU NO.59, Part 4)

27. 07.4.9

Should any areas of conflict exist within "Fraser Valley Headquarters Procedure" Article 27.07 and "Change of Headquarters" Article 28.01 as it applies to the Fraser Valley, the Fraser Valley Headquarters Procedure shall take precedence.

27.08 INTERIOR UNIT

27. 08.1

The Interior service area will be comprised of four (4) Divisions and eight (8) Districts as follows:

Northern Division	- Prince George District
	- Fort Nelson District
Central Division	- Kamloops District
Okanagan Division	- Vernon District
	- Kelowna District
	- Penticton District
Kootenay Division	- Trail District
	- Cranbrook District

27. 08.2 Headquarters (Interior)

a) The Company shall designate a headquarters for each employee and the employee shall report to his headquarters at the beginning of his working day or shift except as otherwise specified in this Agreement.

b) A headquarters is defined as a municipal area within a District consisting of a city, town, municipal district or an unorganized territory, or a combination of the above. Headquarters are established by the Company to provide the personnel necessary to meet the work requirements in the various population centers throughout the Region. Headquarters and their boundaries shall be subject to adjustment by the Company as growth patterns, work loads, population densities and other related operating conditions require.

27. 08.3 Mustering Points (Interior)

Designated buildings or other locations within a headquarters at which an employee or crew starts and stops the working day. Mustering points are established and designated by the Company. The Company agrees that Mustering Points will adhere to reasonable standards of safety, security, cleanliness and good order in keeping with the purposes for which they are intended. This includes appropriate washroom and change-room facilities.

27. 08.4

a) The Company shall have the right to establish rallying points, which will be locations to which employees will report directly and be ready to commence and stop work at the usual working hours. It is understood that a rallying point shall not be more than twenty (20) kilometers from the normal crew headquarters and that a rallying point will be established only where a job is expected to last longer than two (2) days.

b) It will be the responsibility of the Company to provide return transportation from the rallying point to the normal crew headquarters on the first day the new job site is designated, and also the Company will be responsible for returning any employees to the rallying point, should they require such transportation, upon conclusion of the job. At the beginning of the first day and at the conclusion of the last day, all travel between the rallying point and regular headquarters shall be during normal working hours or at overtime rates.

c) Travel to and from the rallying point, except as noted in Paragraph (b) above, will be the responsibility of the employee.

27. 08.5

Employees shall travel to their working places from the designated headquarters of the Company on Company time and return on Company time except as noted in Paragraph (a) above.

27. 08.6

Should any areas of conflict exist between Interior Headquarters Procedure Article 27.08 and "Change of Headquarters" Article 29 as it applies to the Interior, Article 27.08 shall take precedent.

27.09 ISLAND UNITS

27. 09.1

The former Centra Gas and Squamish Gas service areas will be comprised of three Units and four Districts as follows:

Victoria Unit	- Capital Regional District
North Island Unit	- Nanaimo District
	- Courtenay District
Sea to Sky Unit -	- Whistler/Squamish District

27. 09.2 Headquarters (Island)

a) The Company shall designate a headquarters for each employee and the employee shall report to his headquarters at the beginning of his working day or shift except as otherwise specified in this Agreement.

b) A headquarters is defined as a municipal area within a District consisting of a city, town, municipal district or an unorganized territory, or a combination of the above. Headquarters are established by the Company to provide the personnel necessary to meet the work requirements in the various population centers throughout the District. Headquarters and their boundaries shall be subject to adjustment by the Company as growth patterns, work loads, population densities and other related operating conditions require.

27. 09.3 Mustering Points (Island)

Designated buildings or other locations within a headquarters at which an employee or crew starts and stops the working day. Mustering points are established and designated by the Company. The Company agrees that Mustering Points will adhere to reasonable standards of safety, security, cleanliness and good order in keeping with the purposes for which they are intended. This includes appropriate washroom and change-room facilities.

27. 09.4

a) The Company shall have the right to establish rallying points, which will be locations to which employees will report directly and be ready to commence and stop work at the usual working hours. It is understood that a rallying point shall not be more than twenty (20) kilometers from the normal crew headquarters and that a rallying point will be established only where a job is expected to last longer than two (2) days.

b) It will be the responsibility of the Company to provide return transportation from the rallying point to the normal crew headquarters on the first day the new job site is designated, and also the Company will be responsible for returning any employees to the rallying point, should they require such transportation, upon conclusion of the job. At the beginning of the first day and at the conclusion of the last day, all travel between the rallying point and regular headquarters shall be during normal working hours or at overtime rates.

c) Travel to and from the rallying point, except as noted in Paragraph (b) above, will be the responsibility of the employee.

27. 09.5

Employees shall travel to their working places from the designated headquarters of the Company on Company time and return on Company time except as noted in Paragraph (a) above.

27. 09.6

Should any areas of conflict exist between Island Headquarters Procedure Article 27.09 and "Change of Headquarters" Article 29 as it applies to the Island, Article 27.09 shall take precedent.

28. CHANGE OF HEADQUARTERS

28.01

The Company may designate a change of headquarters for any employee either on a temporary or a permanent basis providing notice is given during proper hours of the previous working day.

For a temporary change of headquarters, transportation will be as outlined in Article 27 wherever reasonable.

28.01.1

When an employee is required to work out-of-town, or away from his permanent headquarters, all reasonable living expenses incurred by the employee will be paid by the Company provided it is unreasonable for the employee to return to his residence or permanent headquarters at the end of the day.

28.01.2

Temporary changes of headquarters shall not exceed one year in duration after which such change will become permanent.

28.01.3

Should the Company designate a permanent change of headquarters for an employee, the employee shall be notified that the change is permanent, and the Company shall pay the cost of moving the employee's personal effects and travelling expenses. (See Article 10.02)

28.02

In Metro, if, because of a shortage of work outside of the Company's control, an employee cannot be kept employed in his own headquarters he will be transferred to the nearest headquarters to his own in which work is available. Where the situation continues for a period in excess of five working days, the employee will be considered to have a change of headquarters and shall report daily to a muster point in the new headquarters at regular starting and quitting times, providing his own transportation. This provision will not apply if contractors are being used in the employee's permanent headquarters area.

28.03

No employee posted to a permanent job or given a permanent change of headquarters shall receive board and lodging unless the job or change of headquarters subsequently becomes temporary, in which event he shall receive board and lodging on a retroactive basis if he should qualify for it pursuant to the above. Board and lodging on a retroactive basis shall not apply when a permanent posting becomes temporary at the request of the employee concerned.

28.04

Should an employee resign, or be discharged for cause, while in the field he will be paid for all time worked and allowed travelling expenses back to either his regular headquarters or his point of hiring, as he may request.

28.05

Use of employee vehicles for business travel is not a condition of employment. When employees use their own vehicle for business travel, they will be reimbursed at the mileage rate in effect at that time, and the Company will advise the Union of the current rate and changes thereto.

28.06

Employees will receive straight time equivalent for all travel outside of normal working hours for employee orientation, training, selection interviews, and purposes other than "work". Examples of purposes other than "work" include focus group meetings, cross Company updates, safety meetings, etc. so long as attendance at these events is not compulsory.

28.06.1

Travel time is defined as actual time if surface (not to exceed air equivalent if employee chooses surface) or, if air, scheduled flying time plus two (2) hours, and, if from a distant branch office, normal surface time from home to airport.

28.07

Employees working on out-of-town assignments may choose either:

(a) Company-paid room and board; or

(b) Company-paid room only, plus $50 per day for meals and incidental expenses.

(c) Employees travelling for purposes other than "work" (see Article 28.06) may claim $55 (in lieu of room, board and incidentals), for every night they would otherwise have been entitled to a Company-paid room.

When the per diem covers travel in the U.S. it will be paid in U.S. dollars.

<u>28</u>.08 <u>Change of Headquarters within a Lower Mainland Unit (Distribution Services)</u> <u>(formerly LOU NO.39)</u>

If fluctuations in the workload occur within a mustering point work area, employees may be transferred on a temporary basis to an adjacent muster, without penalty to the Company providing the transfer is for a period in excess of five (5) consecutive working days, except when in relief of unscheduled absence of another employee. Transfers will be based on reverse seniority. Transfers without penalty will not be allowed if contractors are working the affected work area.

<u>28</u>.09 <u>Change of Headquarters between Lower Mainland Units (Distribution Services)</u> <u>(formerly LOU NO.39)</u>

Notwithstanding the provisions contained in Articles <u>27.04.11 and 27.07.4.7</u>, employees may be transferred because of fluctuations in the workload in their muster work areas, without penalty to the Company under the following conditions:

a) Coquitlam muster employees may be transferred on a temporary basis to Maple Ridge muster and vice versa.
b) Richmond muster employees may be transferred on temporary basis to Goudy muster and vice versa.
c) There shall be no contractors used within these work areas while transfers (per a and b above) are in effect.
d) This arrangement will not be used to reduce the combined number of employees assigned to the four mustering points.
e) Transfers between musters shall be by reverse seniority.

<u>28</u>.10 <u>Change of Headquarters between the Victoria and North Island Units</u>

<u>The terms and conditions of the Articles 28.08 and 28.09 above shall also apply as between the Victoria and North Island Units.</u>

<u>29. RELIEF OF MANAGERS OR SUPERVISORS</u>

<u>29</u>.01

An employee temporarily relieving a Manager or Supervisor shall receive a ten percent (10%) differential over his normal rate of pay or a ten percent (10%) differential over the rate paid to the highest-paid category supervised, whichever is greater.

After normal working hours the employee may revert to his regular classification.

<u>30. HOURS OF WORK</u>

<u>30</u>.01

<u>(a) Standard Model</u>

<u>All IBEW 213 hired after September 4, 2006 will be on the Standard Model.</u>

<u>Eight working hours shall constitute a normal working day. Employees will be paid for seven and one-half (7.5) hours with a one-half (1/2) hour to their True Bank for each eight-hour day.</u>

(b) Legacy Model

Employees hired prior to September 4, 2006 shall have the option to remain on the Legacy Model. Those on the Legacy Model will have an option once per year to transfer to the Standard Model. This choice is irrevocable.

Coastal Region/Victoria Unit

Eight working hours shall constitute a normal working day. Employees will be paid for seven and one-half (7.5) hours with a one-half (1/2) hour to the True Bank for all 8 hour days.

Interior/North Island

Seven and one-half (7.5) working hours shall constitute a normal working day with seven and one-half hours (7.5) hours pay.

30.01.1

All employees shall be expected to be at their work location in their work clothes and shall commence work at the stated starting times at the beginning of the shift and following recognized meal and rest periods.

All employees shall be expected to remain at work until commencement of the stated meal and rest periods and at the end of the day until the stated quitting time.

30.01.2 Meal Breaks

Meal breaks taken on Company time shall not exceed thirty minutes.

30.01.3 Show-up Time (formerly Article 27.01)

When employees are required to report for work at their regular starting time and there is no work available, they shall be paid two hours time for such show-up.

30.02 Posting of Schedules

All schedules dealing with rotation cycles for standby or weekend coverage, late shift coverage, shift work, etc. in all departments will be posted seven calendar days in advance of such schedule going into effect or the usual overtime provisions will apply, but only to the shifts worked on the new schedule that fall within the seven day notice period.

30.02.1

Notwithstanding the foregoing, when the Company changes an L.N.G. Operator from day work to shift work with less than three days' notice he shall receive premium rates for the first shift only following the changeover.

30.02.2

No penalty will be paid when an L.N.G. Operator is changed from shift work to day work.

30.02.3

When an employee is scheduled to provide late or weekend coverage on Saturdays and/or Sundays he will be paid at prevailing straight-time rates.

30.03 Day workers Relieving Shift Workers

For the purpose of computing premium pay, a day worker who reports for shift work shall be considered to be a day worker for the first three shifts and thus for this period will be entitled to:

(a) overtime rates for all time worked other than his normal working hours;

(b) in addition, overtime rates for Saturday, Sunday and Statutory Holidays that fall within the first three shifts.

<u>30</u>.04 Relief Work:

For the purpose of computing premium pay, a relief worker who provides holiday or sickness relief shall be paid overtime rates for the first shift and for Saturday, Sunday and statutory holidays that fall within the first set of shifts (5, 6 or 7 days - whichever the shift consists of). Such premium will be paid for the first set of shifts following transfer from the employee's regular classification. It will not apply to subsequent shift changes which occur while the employee is acting in the relief capacity. However, a relief employee will not be required to work more than 2 complete sets of shifts without 2 days off.

<u>30</u>.04.1

When a change in shift is involved in order to assume the relief position, and the relief employee is required to work on two consecutive shifts, the second shift will be considered normal overtime. Under such circumstances the following relief shift will be considered the shift to which the "first" penalty applies.

<u>30</u>.04.2

Relief workers will assume the days off of the previous set of shifts worked. If they are called upon to work these days they shall be entitled to overtime rates of pay.

<u>30</u>.05 Eighty-Hour Guarantee (Coastal <u>Region</u> and <u>Victoria Unit</u> Only)

When an employee is required in any one period (ten days) to change from day work to shift work, or vice versa, and loses time thereby, he shall be guaranteed a minimum of eighty <u>(80)</u> hours straight-time pay irrespective of actual number of hours worked for that period at the rate which is the weighted average of the two or more day or shift jobs at which he has been required to work.

<u>30</u>.06 Day Work

(a) – Standard Model

<u>Except as otherwise provided, normal hours of work for day workers shall be from 0800 to 1630 hours, Monday to Friday, inclusive.</u> A one-half (1/2) hour unpaid lunch break will normally be taken at or near the mid-point of the shift.

(b) – <u>Legacy Model</u>

Except as otherwise provided, normal hours of work for day workers shall be from 0800 to 1630 hours, Monday to Friday, inclusive, <u>in</u> the Coastal <u>Region</u> and the Victoria Unit, and from 0800 to 1600 hrs., Monday to Friday inclusive, in the Interior, North Island and Sea to Sky. A one-half (1/2) hour unpaid lunch break will normally be taken at or near the mid-point of the shift.

<u>30</u>.06.1

Subject to agreement of the Union, starting times may be varied from day to day where mutual agreement can be reached between a group of employees and the Company, and neither the Union's nor the Company's agreement will be unreasonably withheld.

<u>30</u>.06.2

Hours of work may be varied by up to one hour each way from an employee's normal start time when attending training courses.

30.07 Exceptions to Normal Day Time Hours

30.07.1 Customer Service Section

(a) Standard Model

The normal working hours for all employees working in the Customer Service sections shall be 0800 to 1200 and 1230 to 1630 Monday to Friday, except in the Coastal Region, normal working hours shall be 0830 to 1200 and 1230 to 1700, Monday through Friday. A one-half (1/2) hour unpaid lunch break will normally be taken at or near the mid-point of the shift.

Flexible start/finish times may be introduced in the Coastal Region and Victoria Unit Customer Service as follows: the options are 0730-1600, 0800-1630, 0900-1730 and 0930-1800. The selection of the option shall be mutually agreed upon between the employee and the manager or supervisor in order that departmental work requirements and schedules are effectively accommodated. In the event of a conflict, normal working hours shall prevail.

(b) Legacy Model

The normal working hours for employees working in the Customer Service sections are as follows:

Coastal Region
0830 – 1700 Monday through Friday

Victoria Unit
0800 – 1630 Monday through Friday

Interior/North Island (including Sea to Sky)
0800 – 1600 Monday through Friday

A one-half (1/2) hour unpaid lunch break will normally be taken at or near the mid-point of the shift.

Flexible start/finish times may be introduced in Coastal Region and Victoria Unit Customer Service as follows: the options are 0730-1600, 0800-1630, 0900-1730 and 0930-1800. The selection of the option shall be mutually-agreed upon between the employee and the manager or supervisor in order that departmental work requirements and schedules are effectively accommodated. In the event of a conflict, normal working hours shall prevail.

30.07.2

In the Coastal Region the following exceptions may apply:

(a) Materials Truck Drivers may be scheduled to work 0730 to 1130 and 1200 to 1600 according to present practice.

(b) Work may also be scheduled on the basis currently in practice where Materials Truck Drivers, Machine Shop personnel, Welding Shop personnel, Pre-fab Shop personnel and distribution crew employed between 0700 and 1800 and these shifts shall be a straight eight hours with the lunch period being taken on Company time.

30.07.3 Transmission Section

To accommodate special needs such as forest closures and minimum shut-in times, these employees may be scheduled to work any eight consecutive hours, including a one-half hour paid lunch break, between 0600 and 1800. The Company will not unreasonably invoke this Clause.

30.07.4 Customer Service Technicians (Interior, North Island and Sea to Sky Units)

Customer Service Technicians may be scheduled to work 1000 to 1800 (Standard Model) or 1030 to 1800 (Legacy Model) upon 7 days' notice, or the usual overtime provisions will apply, but only to those shifts which fall within the seven (7) day notice period.

30.07.5 10 Hour Shifts – Customer Service Technicians (formerly Article 31.11)

The selection of this option shall be mutually-agreed upon between the employee and the manager or supervisor in order that departmental work requirements and schedules are effectively accommodated. In the event of a conflict, normal working hours shall prevail.

Subject to the above, the ten-hour shifts shall include a one-half hour paid lunch period, and the Saturday shift shall be paid a 10% shift premium for all straight-time hours worked. These shifts shall be offered on the basis of seniority.

30.09 Two Shift Operations

Where two shift operations are carried out they shall alternate at the proper scheduled times as far as service requirements permit.

30.10 Rotation Shifts - Stores Groups

When rotating shifts are required in the Stores groups, the shift arrangement shall be as follows:

Day Shift:

0730 to 1600 hours or 0800 to 16:30 hours	8-1/2 hours elapsed time, 1/2 hour off for lunch.

Afternoon Shift:

1600 to 2400 hours	8 hours elapsed time, supper to be eaten on the job.

Night Shift:

2400 to 0800 hours	8 hours elapsed time, supper to be eaten on the job.

30.11 SPECIAL SHIFT SCHEDULES (Coastal Region and the Victoria Unit)

30.11.1 Customer Service Section: 3 shift, 24 hour, 7 days a week coverage.

Day	Afternoon	Night
Monday to Friday		
0830 to 1700	1600 to 2400	2400 to 0800
Saturday and Sunday		
0800 to 1600		
Statutory Holidays		
0800 to 1600	1600 to 2400	2400 to 0800

Schedule: 2 shift, 7 days a week coverage.

Day	Afternoon
Monday to Friday	
	1400 to 2200
0830 to 1700	1600 to 2400
Saturday and Sunday	
0800 to 1600	1600 to 2400
Statutory Holidays	
0800 to 1600	1600 to 2400

30.11.1.1

Some flexibility may be permitted by mutual agreement to meet seasonal work fluctuations. The Company may designate any or all of the employees who are on 7 days a week, day-shift coverage to work 0800 - 1630 Monday through Friday.

30.11.1.2 Rotation:

Weekend and Statutory Holiday rotation to allow up to 15 shifts in any calendar year to be worked without penalty and may be scheduled consecutively with late shift during the regular summer write-up which extends from May 1 to September 30 each year.

30.11.1.3

Afternoon and night shifts – Afternoon shift rotation to allow up to seven (7) shifts in any calendar year to be worked without penalty but no more frequent than three times a year for night shift.

30.11.1.4 Work Weeks and Days Off

Work Week	Days Off
Monday to Friday	Saturday and Sunday
Monday to Sunday	Monday and Tuesday or Thursday and Friday

30.11.1.5 Additional Afternoon Shifts – Coastal Region and Victoria Unit Only

Subject to operational requirements up to three Customer Service Technicians in the Coastal Region and the Victoria Unit may be scheduled additional shifts as follows:

Day	Afternoon
Monday to Friday	1300 to 2100
	1400 to 2200 (by mutual agreement)

Shift rotation to allow up to six (6) shifts in any calendar year to be worked without penalty. This rotation will include either alternative but will be independent of regular afternoon shift (1600 to 2400) and will not be scheduled consecutively with a weekend shift. Seven (7) days' notice will be given or the usual overtime provisions will apply, but only to those shifts which fall within the seven day notice period.

At the annual signup the employee may opt for the 10-hour shift or the 1400 to 2200 shift in lieu of the 1300 to 2100 shift, subject to reasonably anticipated business requirements.

30.11.2 All Other Sections:

Schedule: Afternoon and night shifts may be scheduled as follows:

Day	Afternoon	Night
Monday to Friday	1600 to 2400	2400 to 0800
Saturday and Sunday	1600 to 2400	2400 to 0800

30.11.2.1 Rotation:

The rotation cycle for both afternoon and night shifts shall be no more frequent than one week in any eight (8) week period.

30.11.2.2 Work Week and Days Off:

The normal work week for both afternoon and night shifts shall be one of the following:

Work Week	Days Off
Monday to Friday	Saturday and Sunday

or Monday to Saturday	Sunday and Monday
or Monday to Sunday	Monday and Tuesday

30.11.2.3 Measurement Shop

Schedule: Afternoon shift may be scheduled as follows:
Hours of Work
Monday to Friday 1600 to 2400

30.12

Any of the foregoing schedules for various shifts may be modified by mutual agreement.

30.13 Shift Premium for Afternoon and Night Shift Work

The shift premium for afternoon and night work shall be 10% of the normal pay rates. The 10% premium shall only be paid on the actual shift hours worked.

30.13.1

If the shift is extended by overtime, then the overtime payment of 200% will be based on the normal rates.

30.13.2

An employee who provides weekend, day-shift coverage as part of a seven, consecutive day shift rotation shall receive a 10% premium for all straight-time hours worked on the Saturday and the Sunday.

30.14 Peak Shaving/Standby Plants/Compressor Stations

30.14.1

Shift work may be instituted by the Company when it is necessary in the operations of the Company's peak shaving and/or standby plants and/or the Company's compressor stations, except LNG Plants.

30.14.2

Conditions for working these shifts will be as follows:
Monday to Friday Inclusive

Day Shift	08:30 - 16:30 -	1/2 hour lunch, 7-1/2 hours' pay
Afternoon Shift	16:30 - 00:30 -	8 hours work, 8-1/2 hours' pay and supper on job
Night Shift	00:30 - 08:30 -	8 hours work, 9 hours' pay and supper on job

30.14.3

The conditions below shall apply to any employee called upon to work shifts:

a) Twenty-four (24) hours' notice must be given by the Company prior to commencement of the shift, or overtime pay will apply;

b) If an employee is asked to extend his day shift, he shall receive the prevailing overtime rate;

c) Any employee called out for shift work shall be guaranteed seven and one-half (7-1/2) or eight (8) hours' pay, providing, however, he has not worked seven and one-half (7-1/2) or eight (8) hours' during the preceding twenty-four (24) hours.

30.14.4

All employees working on peak shaving and/or standby plants and/or compressor stations who begin work on Saturday will receive double time. Employees called out on Sunday or a statutory holiday shall receive double time. Employees called out on Saturdays, Sundays, or statutory holidays will be paid only for hours actually worked but will be guaranteed a minimum of two (2) hours' pay at the prevailing rates.

30.15 Four (4) Day Week for employees in the Interior and Island Regions (formerly LOU NO. 58)

For the following Interior and Island Region employees only:

(a) Measurement & Controls Technicians
(b) Measurement Group Leader
(c) Operations Technician
(d) System Operations Technician/Apprentice
(e) Compression & Controls Technician
(f) Millwright
(g) Employees when engaged in system survey
(h) Employees when engaged in transmission line patrol

30.15.1

These employees may, by mutual agreement with their manager, work a four-day-week when scheduled out-of-town for an entire calendar week.

30.15.2

These employees shall work three (3) ten (10) hour days, followed by one (1) seven-and-one-half (7.5) hour day (Legacy Model); or they shall work four (4) ten (10) hour days (Standard Model).

30.15.3

No overtime will be paid for the normal working hours described above.

30.15.4

If a statutory holiday occurs during the week, the four-day work-week can be scheduled only if the stat falls on the scheduled seven-and-one-half hour work day (the Thursday);

30.15.5

Productivity - as measured by number of activities, time per activity, and unit cost per activity - must be maintained or improved; Customer satisfaction must be maintained or improved; Safety record must be maintained or improved; Work must be completed according to procedures and policies.

30.15.6

There shall be no additional cost to the Company (including additional management time to administer Article 30.15).

30.16 Compressed Work Week - Measurement Department–North Island Unit Only (formerly LOU NO. 3 – North Island Unit)

The Company and the Union agree all employees of the Measurement Department – North Island shall participate in the 4 x 10 compressed work week schedule.

30.17 Port Melon Compressor Station – Shift Rotation Schedule (formerly LOU NO. 8 – North Island Unit)

The Company and the Union agree to the employee shall normally work a five (5) days on and two (2) off schedule. During the peak season, and if operational requirements permit, there may be an opportunity to revert to a 4 x 10 compressed work week schedule.

31. WEEKEND COVERAGE AND STANDBY

31.01 Definitions

31.01.1

"Weekend Coverage" is a term used to denote Saturday and/or Sunday and statutory holiday work where personnel are employed on the job at regular work locations to do work as assigned within the hours of coverage provided.

31.01.2

"Standby" is the term used to denote service provided by an employee from his residence. Standby coverage is necessary in order to provide instant response to calls of an urgent nature.

31.01.2.1

Personnel on standby are required to be contactable by telephone at their residence or a nearby residence with telephone where operational conditions permit.

31.02 Customer Service Technicians (Coastal Region and Victoria Unit)

Weekend Coverage: Coastal Region will be scheduled to provide weekend, day shift coverage on Saturdays, Sundays and statutory holidays. Weekend coverage may be scheduled in the Victoria Unit at the Company's discretion.

31.02.1

The rotation cycle for weekend coverage shall be no more frequent than one week in any four-week period.

31.02.2

At the Company's discretion Customer Service Technicians in the Victoria Unit may be scheduled to provide standby on a rotational basis to a maximum of one week in four.

31.03 Customer Service Technicians and Distribution Service Agents in the Interior, North Island and Sea to Sky Units (formerly # 1 from LOU NO.60)

As a group, Customer Service Technicians, Distribution Service Agents in the Interior, North Island and Sea to Sky units shall provide standby and emergency response on a 24x7x365/366 basis.

31.03.1 (formerly #2 from LOU NO.60)

In towns employing classifications other than those classifications listed in 31.03, other qualified employees may volunteer to join the standby pool to the extent that capacity will allow (e.g. if those classifications listed in 31.03 are covering all the standby among them, there will be no capacity for others to join the standby pool). These other employees must commit to the standby pool for periods of not less than one calendar year.

31.03.2 (formerly #3 from LOU NO.60)

Failing agreement on some alternate arrangement, all employees in a standby pool are expected to provide standby equally over the course of a year. In the event of an unscheduled absence by an employee who is scheduled to provide standby coverage, another employee from the standby pool shall cover the period of absence and shall be compensated at the appropriate standby premium rate.

31.03.3 (formerly #4 from LOU NO.60)

In all one-employee towns, the employee must provide not less than 40 complete calendar weeks of standby coverage each calendar year. Normally the employee in a one-employee town will schedule "off-standby" only in one calendar-week blocks.

31.03.4 (formerly #5 from LOU NO.60)

Employees on standby have the option of handing off parts of weeks to other qualified, Company-authorized resources within the town. This hand-off is the responsibility of the employee, and must be formally documented.

31.03.5 (formerly #6 from LOU NO.60)

Within each of the following six geographic areas, all Customer Service Technicians are expected to share out-of-town standby equitably within their own geographic area:

- Chetwynd to Williams Lake
- 100 Mile House to Merritt
- Salmon Arm to Revelstoke (including Vernon)
- Kelowna to Princeton (including Osoyoos)
- Grand Forks to Trail (including Nelson)
- Creston to Sparwood

31.03.6 (formerly #8 from LOU NO.60)

There is no requirement for the Company to dispatch a second resource into a one-employee town unless the regular employee, in that town is on time off. Therefore, the employee in a one-employee town shall bank their days in lieu of stats for the purpose of taking time off in one week blocks.

31.03.7 (formerly #10 & #11 from LOU NO.60)

Employees in one-employee towns may book off the week of Christmas no more than once every three years. Out-of-town coverage for the week of Christmas shall be rotated among all the employees in their standby pool.

31.04 System Operations Technician/Measurement & Controls Technician/Employees in the Interior Region and North Island and Sea to Sky Units

31.04.1

When scheduled by the Company, System Operations Technicians in the Metro Distribution Department, Measurement & Controls Technicians in the Victoria Unit, and employees in the Interior Region and North Island and Sea to Sky Units, will provide standby on weekends and statutory holidays, and shall be paid at prevailing standby rates for each weekend and statutory holiday as defined in 21.01, and which falls on other than a Saturday or a Sunday. In addition, Customer Service Technicians in branch offices may be scheduled to provide standby in relief of the Branch Manager, as required.

31.04.2

For any time worked the standby worker shall be paid the prevailing overtime rates over and above the standby pay.

31.04.3

Weekend standby will commence at the end of the day shift on Friday and will end at the beginning of the day shift on Monday.

31.04.4

When a statutory holiday falls on either a Tuesday, Wednesday or Thursday, standby will commence at the end of the day shift on the preceding day and will terminate at the beginning of the day shift on the following day.

31.04.5

When a statutory holiday falls on a Friday standby will commence at the end of the day shift on Thursday and will terminate at the end of the day shift on Friday.

31.04.6

When a statutory holiday falls on a Monday standby will commence at the start of the day shift on Monday and will terminate at the start of the day shift on Tuesday.

31.04.7

In the event of two consecutive statutory holidays falling on weekdays with a separate standby employee for each holiday, the total standby duty time will be equally divided between the employees.

31.05 Weekend Coverage and Standby (Coastal Region and Victoria Unit) Construction and Maintenance Section

31.05.1

Weekend coverage on the day shift shall be provided from 0800 hours to 1600 hours for which eight hours will be paid. Please refer also to Article 31.06.

31.05.1.1

The rotation cycle for weekend coverage shall be no more frequent than one week in any eight-week period.

31.05.2

Sunday and Monday will be the regular days off when Saturday coverage is worked; when Saturday and Sunday coverage is worked, Monday and Tuesday will be the regular days off.

31.05.2.1

Where an employee is eligible for Monday and Tuesday as days off, he may, with the consent of his manager or supervisor, work those days and take the following Thursday and Friday off, preceding the next weekend.

31.05.2.2

The crew providing weekend coverage will also provide coverage on the statutory holidays immediately preceding or following the weekend.

31.05.2.3

Where the weekend crew provides weekend coverage on a Statutory Holiday on a Monday, the Monday will not be considered in determining the rotation cycle for weekend coverage.

31.05.3

Crews scheduled for afternoon shift, 1600 to 2400 hours, Monday through Friday, shall following this shift, provide standby at prevailing rates from their homes to 0800 hours the following morning.

31.05.4

The Company shall provide an electronic paging device, in the areas where such equipment is available, to facilitate communications.

31.05.4.1

Personnel on standby shall use pagers as per local operating instructions and in such a manner as to insure continuity of communication.

31.05.4.2

Pagers must be activated during periods when the home telephone is engaged or out of repair and when traveling to and from the home at the beginning and end of the standby shift in a non-radio equipped vehicle.

31.05.5

Crews on weekend coverage day shift, Saturday and Sunday, will provide standby at prevailing rates from their homes from 1600 hours to 0800 hours the following morning.

31.05.6

Where an afternoon weekday shift is not scheduled, a day shift crew will provide standby at prevailing rates from their homes from 1630 to 0800 hours the following morning.

31.06 Remuneration for Standby (unless otherwise provided in this agreement)

31.06.1

Effective January 1, 2007, standby remuneration is $500 per week ($50/weekday and $125/Saturday and Sunday). Stat holidays as described in Article 21 or days recognized in lieu of, shall be compensated at $50/day plus an additional day off with pay during the following 30 days. This is in addition to statutory holiday pay as specified in Article 21.

Effective January 1, 2009, standby remuneration is $450 per week ($40/weekday and $125/Saturday and Sunday). Stat holidays as described in Article 21 or days recognized in lieu of, shall be compensated at $40/day plus an additional day off with pay during the following 30 days. This is in addition to statutory holiday pay as specified in Article 21.

31.06.2

Weekend and statutory holiday standby will commence at the end of the day shift preceding the weekend or holiday and will end at the beginning of the day shift following the weekend or holiday.

31.06.2.1

For any time worked during the standby period, overtime will be at the prevailing rates over and above the guaranteed standby pay.

31.07

The weekend coverage and/or holiday coverage as described in Articles 31.02 and 31.06 above may be cancelled and replaced by an employee on standby at prevailing rates. In the Coastal Region schedules shall be posted as per Article 30.02.

31.07.1

For any time worked during the standby period, overtime will be at the prevailing rates over and above guaranteed standby pay.

31.08 Customer Service Technicians and Distribution Service Agents in the Interior (formerly #7 from LOU NO. 60)

The standby premiums shall be as follows:

Monday to Friday:	$30/day
Saturday and Sunday (24-hour standby):	$75/day
Saturday (when day shift coverage is provided):	$50/day
Days observed as statutory holidays:	$30 plus one paid day off in lieu

31.08.1

Effective January 1, 2007 all out-of-town standby coverage and all standby in excess of 30 weeks in a calendar year by an individual employee shall be paid at $360 per week ($30/weekday & $105/SatSun).

Effective January 1, 2009:
(a) basic standby coverage shall be paid at $360 per week ($34/weekday & $95/SatSun).

(b) all out-of-town standby coverage and all standby in excess of 30 weeks in a calendar year by an individual employee shall be paid at $400 per week ($34/weekday & $115/SatSun).

31.08.2 (formerly #9 from LOU NO.60)
All employees may deposit their standby premiums into their overtime bank.

31.09 All Employees in the Vancouver Island Region (formerly #32 from the TGVI Adjustment Plan)

The standby premiums shall be as follows:

Monday to Friday:	$44/day
Saturday and Sunday (24-hour standby):	$90/day
Saturday (when day shift coverage is provided):	$60/day
Days observed as statutory holidays:	$44 plus one paid day off in lieu

32. OVERTIME

32.01 Overtime Rates

All time worked on any day in excess of the hours specified by Article 30 shall be compensated at 200% of the straight-time hourly rate.

32.02 Overtime - Shift Workers

32.02.1

Time worked by shift employees in excess of normal hours in twenty-four shall be compensated for at overtime rates, but this provision shall not apply where a shift worker reverts to a regular day job.

32.02.2

Where a shift worker fails to report to work and a relief worker cannot be obtained, the employee on the job will be required to work at the proper overtime rates until relieved.

32.03 Meal Breaks

32.03.1

During overtime the Company shall compensate employees for meal breaks at overtime rates.

32.03.1.1

Meal breaks during overtime shall not exceed thirty minutes.

32.03.1.2

When unscheduled overtime is worked the Company will pay reasonable costs for meals.

32.03.1.3

Normally, the Company will make every reasonable effort to provide work crews on the job site with good quality and substantial quantities of food, however, if a restaurant exists within approximately 3.2 kilometers (two miles) or within ten minutes of driving time, the manager or supervisor may authorize a meal away from the job site.

32.03.1.4

Beverages shall be provided for employees at the work site at two hour intervals.

32.03.1.5

Employees working scheduled overtime will supply their own meals.

32.03.2

Jobs extending beyond normal working hours shall not involve a meal period during the first two hours of overtime. Following this, meals shall be provided at intervals of four hours of work. It is understood that when an employee is working overtime beyond normal working hours, and it is reasonable to expect the work to extend at least two hours beyond the end of the regular workday, the employee may take a beverage break at a reasonable point in time between the start of overtime and the overtime meal period.

32.03.3

Employees who have worked beyond a meal break period in order to complete the job may elect one half hour pay at overtime rates in lieu of a meal. This election can be made only for the last earned meal during overtime.

32.03.4

Employees must turn in a meal receipt for each meal to be refunded.

32.04 Call Out Overtime

32.04.1

An employee called out on emergency work shall be paid a minimum of two hours from time of call at the appropriate overtime rate.

32.04.2

When an employee commences work four hours or less prior to the start of his regular day or shift, he shall receive overtime_rates (200%) from the time of the call out to the starting time of his regular day or shift (regardless of time worked), after which he shall be compensated at the regular rate for time worked on his regular day or shift.

32.05 Rest Time

32.05.1

Where an employee commences overtime work earlier than four hours prior to his regular working day or shift, he shall not return to, nor continue into, his working day, or shift unless otherwise requested, until he has had eight hours time off which shall be calculated from the time his overtime work finished.

32.05.1.1

He shall be paid for his regular working day or shift at straight-time until the eight hours rest time expires at which time he must return to work to qualify for the remainder of his working day or shift at straight-time rates.

32.05.2

Notwithstanding the above, if the eight hour rest period expires four hours or later after the normal starting time of the shift, an employee will not be required to return to work to qualify for the remainder of the working day at straight-time rates.

32.05.2.1

Article 32.05.2 does not apply if two hours or less expires between the time the employee is called out and the employee returns home.

32.05.3

Where an employee is requested to return to work before he has completed his eight hour rest period he shall continue to be compensated at the overtime rate for all time worked, plus straight-time for the difference between the portion of the rest period taken and eight hours.

32.05.3.1

Where an employee is requested to continue to work into his working day or shift without rest time he shall continue to be compensated at the overtime rate for all time worked, plus straight-time for his regular day or shift.

32.05.4

Where an employee returns to work on a regular day or works into a regular day without rest time, and without his manager's or supervisor's authorization to do so, the overtime provision of this article shall not apply.

32.06 Interior, North Island and Sea to Sky Units Only:

32.06.1

When construction crews are scheduled to stay overnight at a location away from their own headquarters for period in excess of two (2) working days, and when required work is available in that location, then one and one-half (1-1/2) hours of overtime will normally be assigned each regular working day unless otherwise determined by the Company.

32.06.2

When overtime work is required within an employee's own branch or headquarters, and when the overtime work is within the scope of the work normally performed, then qualified employees who have indicated they would be available for such overtime work will be given first opportunity for call-outs.

32.06.2.1

Prior to implementing the above, a Manager or Supervisor may take corrective action to overcome operational or personnel difficulties and make a situation safe.

33. OVERTIME BANK

33.01

While all overtime is compensated at 200% pursuant to Article 32.01, the dollar amount of the overtime premium shall be deposited into an overtime bank.

33.01.2 Overtime Leave Bank for Employees Subject to Seasonal Layoff (formerly LOU NO. 63)

Employees in classifications/locations subject to seasonal layoff as determined by Terasen may deposit the entire 200% overtime compensation into their overtime bank. (See Article 7.04)

Employees who make such election agree to use part of their overtime bank for the purpose of postponing or avoiding seasonal layoff. The equivalent of the first ten days pay deposited into the employee's overtime bank each year shall be made available for scheduling time off, at the discretion of the Company, in order to postpone or avoid seasonal layoff.

33.02

The balance of each employee's overtime bank shall be enhanced by any applicable general increases effective on the same date as the general increase.

33.02.1

It is the intent of this clause that the balance of each employee's bank shall be shown on the paystub. Furthermore, it is intended that the amount of time off for each employee in any calendar year shall be subject to a reasonable limit so that the competence and effectiveness of the employee, his work unit, and the operation is adequately maintained in keeping with the demands of a gas utility.

33.03

Notwithstanding the other provisions of this clause, the Union agrees to cover all emergency work required by the Company.

33.03.1

The scheduling of any time off shall be subject to operational requirements as determined by the Company.

33.04

An employee may be granted time off from the Overtime Bank on the prior understanding that he can be recalled to work a normal schedule at regular straight time rates of pay and thus the leave may be so cancelled without penalty to the Company.

33.05 (formerly 34.07)

Employees may cash out any portion of their Overtime Bank by completing the prescribed form supplied by the Company, or take paid leave of absence subject to the balance available in the Overtime Bank and the conditions set out in this Article.

33.05.1 (formerly 34.07.1)

All banked overtime leave is paid at the employee's regular classification.

33.06 (formerly 34.08)

The amount and date of time off from the Overtime Bank shall be subject to agreement by the employee and his manager or supervisor. (See Article 33.01.2)

33.07 (formerly 34.16)

It is understood that time off will be taken during such working periods which will not require the Company to replace the absent employee (Interior, North Island and Sea to Sky Units only).

34. TRUE BANK DAYS, CHOICES DAYS, LEGACY DAYS

34.01 Standard Model (Province-wide)

34.01.1 True Bank Days

True Bank Days are earned days.

All employees (except part-time employees) on the Standard Model shall work an eight (8) hour day and deposit one-half (1/2) hour into their true bank for each day so worked. If the employee is not at work for the full eight (8) hour day, the one-half (1/2) hour is not earned and not deposited to the True Bank for that day.

All True Bank days earned in the current year (and deposited into the 'True Bank Current Year') shall be taken in the year following the year in which they were earned (from the 'True Bank Prior Year').

Effective January 1, 2009, the True Bank Current Year and the True Bank Prior Year shall change from a dollar ($) bank to an hourly bank, and be reflected as such on employee pay statements.

If an employee is temporarily working in a higher classification, the employee's regular base one-half (1/2) hour will go to the True Bank Current Year and the difference between the employee's base and upgrouped rates of pay shall be paid out.

True Bank Days (from the 'True Bank Prior Year') must be taken as time off, it is not cashable by the employee. Any True Bank Days not taken as days off by the end of the year following the year in which they were earned shall be moved into a temporary transitional dollar bank which shall be cashed out by the end of the year 2009, and thereafter shall be cashed out at year end. Effective January 1, 2009, the rollover into the temporary 'Transitional Dollar ($) Bank' shall be based on the base rate of pay at the time of transfer.

34.01.2 Choices Days

Choices Days are a time off entitlement earned based on service during the current calendar year. All employees shall be credited each calendar year with ten (10) Choices Days (the equivalent of 4% of the base wage), prorated for partial years. These Choices Days may be taken as time off or converted to a Health Spending Account, RRSP, or cash, in any combination not exceeding the 4% entitlement.

34.01.3

Choices Days entitlement shall be advanced in January of the calendar year it is earned.

34.01.4

Choices Days entitlement shall be reduced by one-eleventh (1/11th) for each full month of absence in excess of one (1) months absence in the preceding year. For the purpose of this proration "absence" shall not include time off work for annual vacation, True Bank Days or Choices Days or Overtime Bank Days.

34.01.5

True Bank days and Choices days may be scheduled at management's discretion to a combined maximum of 14 days. The balance of time off may be taken as time off for layoff avoidance (first priority), or time off scheduled at the employee's discretion but subject to operational requirements

34.01.6

Where scheduling conflicts arise, inverse order of seniority will prevail, i.e. employee with the least amount of seniority will have the first opportunity to schedule Choices Days.

34.01.7

No less than five (5) days must be taken at any one time unless where mutually acceptable to the Company and the employee.

34.01.8

Any untaken Choices Days at the end of the year shall be paid out at the employee's current rate of pay.

34.02 Legacy Model - Coastal Region & Victoria Unit

34.02.1 True Bank Days

True Bank Days are earned days.

All employees (except part-time employees) on the Legacy Model – Coastal Region & Victoria Unit shall work an eight (8) hour day and deposit one-half (1/2) hour into their true bank for each day so worked. If the employee is not at work for the full eight (8) hour day, the one-half (1/2) hour is not earned and not deposited to the True Bank for that day.

All True Bank days earned in the current year (and deposited into the 'True Bank Current Year') shall be taken in the year following the year in which they were earned (from the 'True Bank Prior Year').

Effective January 1, 2009, the True Bank Current Year and the True Bank Prior Year shall change from a dollar ($) bank to an hourly bank, and be reflected as such on employee pay statements.

If an employee is temporarily working in a higher classification, the employee's regular base one-half (1/2) hour will go to the True Bank Current Year and the difference between the employee's base and upgrouped rates of pay shall be paid out.

True Bank Days (from the 'True Bank Prior Year') must be taken as time off, it is not cashable by the employee. Any True Bank Days not taken as days off by the end of the year following the year in which they were earned shall be moved into a temporary transitional dollar bank which shall be cashed out by the end of the year 2009, and thereafter shall be cashed out at year end. Effective January 1, 2009, the rollover into the temporary 'Transitional Dollar ($) Bank' shall be based on the base rate of pay at the time of transfer.

34.02.2 Legacy Days

Legacy Days are a time off entitlement earned based on service during the current calendar year. Employees are entitled to up to nine (9) Legacy Days.

34.02.3 Choices Days

Choices Days are a time off entitlement earned based on service during the current calendar year. All employees shall be credited each calendar year with ten (10) Choices Days (the equivalent of 4% of the base wage), prorated for partial years. These Choices Days may be taken as time off or converted to a Health Spending Account, RRSP, or cash, in any combination not exceeding the 4% entitlement.

34.02.4

Legacy Days and Choices Days entitlement shall be advanced in January of the calendar year it is earned.

34.02.5

Legacy Days and Choices Days entitlement shall be reduced by one-eleventh (1/11th) for each full month of absence in excess of one (1) months absence in the preceding year. For the purpose of this proration "absence" shall not include time off work for annual vacation, Legacy Days, True Bank Days or Choices days or OvertimBank Days..

34.02.6

True Bank Days, Legacy Days and Choices Days may be scheduled at management's discretion to a combined maximum of 14 days. The balance of time off may be taken as time off for layoff avoidance (first priority), or time off scheduled at the employee's discretion but subject to operational requirements.

34.02.7

Where scheduling conflicts arise, inverse order of seniority will prevail, i.e. employee with the least amount of seniority will have the first opportunity to schedule Legacy Days

34.02.8

No less than five (5) days must be taken at any one time unless where mutually acceptable to the Company and the employee.

34.02.9

Any untaken Legacy or Choices Days at the end of the year shall be paid out at the employee's current rate of pay.

34.03 Legacy Model – Interior Region & North Island Unit (including Sea to Sky)

34.03.1 Legacy Days

All employees on the Legacy Model – Interior Region & North Island Unit (including Sea to Sky) shall work a seven and one-half (7 ½) hour day, five (5) days per week.

Legacy Days is a time off entitlement earned based on service during the current calendar year. Employees are entitled to up to seven (7) Legacy Days.

34.03.2 Choices Days

Choices Days is a time off entitlement earned based on service during the current calendar year. All employees shall be credited each calendar year with ten (10) Choices Days (the equivalent of 4% of the base wage), prorated for partial years. These Choices Days may be taken as time off or converted to a Health Spending Account, RRSP, or cash, in any combination not exceeding the 4% entitlement.

34.03.3

Legacy Days and Choices Days entitlement shall be advanced in January of the calendar year it is earned.

34.03.4

Legacy Days and Choices Days entitlement shall be reduced by one-eleventh (1/11th) for each full month of absence in excess of one (1) months absence in the preceding year. For the purpose of this proration "absence" shall not include time off work for annual vacation or Legacy Days and Choices Days or Overtime Bank Days.

34.03.5

Legacy Days and Choices Days may be scheduled at management's discretion to a combined maximum of 14 days. The balance of time off may be taken as time off for layoff avoidance (first priority), or time off scheduled at the employee's discretion but subject to operational requirements.

34.03.7

Where scheduling conflicts arise, inverse order of seniority will prevail, i.e. employee with the least amount of seniority will have the first opportunity to schedule Legacy Days.

34.03.8

No less than five (5) days must be taken at any one time unless where mutually acceptable to the Company and the employee.

34.03.9

Any untaken Legacy or Choices Days at the end of the year shall be paid out at the employee's current rate of pay.

35. DEFINITIONS, DUTIES AND JURISDICTIONS

35.01

Deleted in 2006.

35.02

When a portable compressor is delivered to a job and there is no recognized operator, any classification at or above the Equipment Operator 2 rate can operate same.

35.03

When crews are renewing or enlarging a service, they shall complete the job by connecting the service to an existing meter.

35.04

Where minor alterations to a service are required, a Customer Service Technician assisted by a Distribution Apprentice shall complete the job as required.

35.05 Crew Composition - (Coast Only) -

Insert 1 – Distribution Mechanic Apprentice plus Note 1 as per page 113 of the white C/A (into J/D?).

35.06

It is understood that the content of the job description and definitions do not limit the actions of any gas employee or crew to attend emergencies and take remedial action within their capabilities to make safe.

35.07

The job descriptions are contained in Schedule B and form part of the collective agreement.

36. WAGE SCHEDULE

36.01

The basic rate for all employees shall be hourly, unless otherwise mutually-agreed.

36.01.1

The Wage Schedule is contained in Schedule A.

36.02

An employee shall be paid the rate for the job which he is doing on an hourly basis, except that where an employee puts in four or more hours in a day on a higher-paid job, he shall be paid for the whole regular work day (or for all time worked if less than eight hours is worked in a day) at the rate for the higher-paid category, excluding bonus payments.

36.03 BONUS ALLOWANCES (formerly Article 37.05)

36.03.1

All employees who are openly exposed to odorant or apply pesticides and sterilants shall receive a bonus of one dollar sixty cents ($1.60) per hour. The minimum bonus allowance shall be two (2) hours and the Company shall also provide plastic aprons, gloves and rubber boots for odorant tank filling.

36.03.3

An employee directed to provide instruction to a group of employees shall receive his regular rate or 105% of the gas tradesman rate, whichever is the greater.

36.03.4

When the Clean-up Truck Driver supervises two or more employees, his rate will be increased by 5%. When required to drive a tandem-axle truck equipped with air brakes, he shall receive the Equipment Operator 1 rate of pay.

While acting as an Equipment Operator and supervising two or more employees, his rate will be increased 5% above the Equipment Operator 1 rate.

<u>36</u>.03.5

If a crew is composed of seven or more employees, excluding the Crew Leader, System Operations Technician <u>or</u>, <u>Measurement & Controls Technician,</u> the Crew Leader<u>,</u> System Operations Technician <u>or</u>, <u>Measurement & Controls Technician</u> in charge of the crew shall be paid at 110% of his rate.

<u>36</u>.03.6

When a Distribution Mechanic is directing the work of two or more employees on leakage survey he shall be paid the rate of Crew Leader.

<u>36</u>.03.7

When a Fitter Welder 1, Shop Mechanic 1 (Machine Shop), Shop Mechanic 1 (Buildings and Utilities), or Machinist is required by the Company to act as a Lead Hand, he shall be paid 3% above his regular rate while so acting.

<u>36</u>.03.8 (Taken from Inspector Job Description)

<u>The minimum rate to be paid to any inspector will be that of a Crew Leader. In the event, however, that an employee is presently being paid a higher rate, then such employee will receive the rate of pay under which he is presently employed.</u>

37. PAY DAYS

37.01

Employees shall be paid every two weeks. Payment shall be made by cheque every other Friday for all wages due up to and including the Thursday of the week previous to pay day. The Company may change the latter day to Wednesday at such a time as it is to become general practice. If a regular pay day falls on a holiday, all employees shall be paid on the preceding working day.

All employees are encouraged to choose direct payroll deposit. All new hires will be on direct payroll deposit as a condition of employment.

Schedule A

IBEW Wage Schedule			Interior wage rate paid to all employees effective Jan 1/07			
Ratification Date: August 30, 2006	2.85%		2.5%	3%	3%	3%
Classification	**2006**		**2007**	**2008**	**2009**	**2010**
	4-Sep		**1-Apr**	**1-Apr**	**1-Apr**	**1-Apr**
	Coastal	**Interior**	**Company-Wide**			
Measurement Group Leader	34.16	36.45	37.36	38.48	39.63	40.82
Measurement Shop Leader	32.45	34.62	35.49	36.55	37.65	38.78
Mechanical Foreman/Shop Leader	32.45	34.62	35.49	36.55	37.65	38.78
Warehouse & Delivery Leader	32.45	34.62	35.49	36.55	37.65	38.78
Gas Distribution Planner	32.00	34.14	34.99	36.04	(See Planning & Design Techt)	
Building Operations & Maintenance Leader	31.81	33.94	34.79	35.83	36.90	38.01
Compression & Controls Technician 1	31.81	33.94	34.79	35.83	36.90	38.01
Distribution Service Agent	31.81	33.94	34.79	35.83	36.90	38.01
Facilities Technician	31.81	33.94	34.79	35.83	36.90	38.01
Instructor	31.81	33.94	34.79	35.83	36.90	38.01
LNG Plant Operator 1	31.81	33.94	34.79	35.83	36.90	38.01
Corrosion Control Technologist	30.79	32.85	33.67	34.68	35.72	36.79
Design Machinist	30.79	32.85	33.67	34.68	35.72	36.79
Electrician	30.79	32.85	33.67	34.68	35.72	36.79
Electronic Control Technician 1 (Merged w/MCT 1)						
Fitter Welder 1	30.79	32.85	33.67	34.68	35.72	36.79
Measurement & Controls Technician 1	30.79	32.85	33.67	34.68	35.72	36.79
Millwright	30.79	32.85	33.67	34.68	35.72	36.79
Planner	30.79	32.85	33.67	34.68	(See Planning & Design Techt)	
Senior Pipeline Technician	30.79	32.85	33.67	34.68	35.72	36.79
System Operations Technician	30.79	32.85	33.67	34.68	35.72	36.79
Welder 1	30.79	32.85	33.67	34.68	35.72	36.79
Electronic Control Technician 2 (Merged w/MCT 2)						
Fitter Welder 2	29.42	31.39	32.17	33.14	34.13	35.15
LNG Plant Operator 2	29.42	31.39	32.17	33.14	34.13	35.15
Machinist	29.42	31.39	32.17	33.14	34.13	35.15
Mains & Service Planner	29.42	31.39	32.17	33.14	34.13	35.15
Measurement & Controls Technician 2	29.42	31.39	32.17	33.14	34.13	35.15
Senior Sales and Service Technician	29.42	31.39	32.17	33.14	34.13	35.15
Senior Shop Mechanic	29.42	31.39	32.17	33.14	34.13	35.15

IBEW Wage Schedule				Interior wage rate paid to all employees effective Jan 1/07			
Ratification Date: August 30, 2006	2.85%			2.5%	3%	3%	3%
Classification	**2006**			**2007**	**2008**	**2009**	**2010**
	4-Sep			**1-Apr**	**1-Apr**	**1-Apr**	**1-Apr**
	Coastal	**Interior**		**Company-Wide**			
System Operations Technician 18	29.42	31.39		32.17	33.14	34.13	35.15
Customer Service Technician 1(**$25.52+2%+2.85%)	28.87**	30.80**		31.57	32.52	33.50	34.51
Customer Service Technician 1 CRD (Red-circled) --	29.01	30.95		31.57	32.52	33.50	34.51
50% of GI until they catch up	(1.43%)	(6.7%)		(2.0%)	(3.0%)	(3.0%)	(3.0%)
Compression & Controls Technician 2	28.63	30.55		31.31	32.25	33.22	34.22
Crew Leader	28.30	30.20		30.96	31.89	32.85	33.84
Distribution & Service Technician (Merged w/CST 1)							
Equipment Operator "P"	28.30	30.20		30.96	31.89	32.85	33.84
Inspector	28.30	30.20		30.96	31.89	32.85	33.84
Measurement Mechanic 1	28.30	30.20		30.96	31.89	32.85	33.84
Operations Technician	28.30	30.20		30.96	31.89	32.85	33.84
Pipeline Technician 1	28.30	30.20		30.96	31.89	32.85	33.84
Sales and Service Technician (Merged w/CST 1)							
Shop Mechanic 1	28.30	30.20		30.96	31.89	32.85	33.84
Stores Leader	28.30	30.20		30.96	31.89	32.85	33.84
Tie-In Technician (Merged w/CST 1)	28.30	30.20					
Utilization Technician 1 (Merged w/CST 1)							
Yard Foreman	28.30	30.20		30.96	31.89	32.85	33.84
Painter	27.65	29.50		30.24	31.15	32.08	33.04
Paving Foreman	27.65	29.50		30.24	31.15	32.08	33.04
Senior Material Handler	27.65	29.50		30.24	31.15	32.08	33.04
Station Mechanic 2	27.65	29.50		30.24	31.15	32.08	33.04
System Operations Apprentice	27.65	29.50		30.24	31.15	32.08	33.04
Compression & Controls Technician 3	27.04	28.85		29.57	30.46	31.37	32.31
Equipment Operator/Distribution Mechanic (EODM)	27.02	28.83		29.55	30.44	31.35	32.29

IBEW Wage Schedule				Interior wage rate paid to all employees effective Jan 1/07			
Ratification Date: August 30, 2006	2.85%			2.5%	3%	3%	3%
Classification	**2006**			**2007**	**2008**	**2009**	**2010**
	4-Sep			**1-Apr**	**1-Apr**	**1-Apr**	**1-Apr**
	Coastal	**Interior**		**Company-Wide**			
Planning and Design Techt – Replaces GD Planner (CRD) and Planner (NI) – Effective May 22, 2008*							
Start Rate					*30.11	31.01	31.94
Step 1					*31.28	32.22	33.19
Step 2					*32.47	33.44	34.44
Step 3					*33.68	34.69	35.73
Step 4					*34.89	35.94	37.02
Step 5					*36.07	37.15	38.26
Distribution Mechanic/Excavator (DMX)	26.49	28.26		28.97	29.84	30.74	31.66
Customer Service Technician 2 ($25.25 +2% + 2.85%)	26.49	28.26		28.97	29.84	30.74	31.66
Distribution Mechanic	25.97	27.71		28.40	29.25	30.13	31.03
Electronic Control Technician 3 (Merged with MCT 3)							
Equipment Operator 1	25.97	27.71		28.40	29.25	30.13	31.03
Fitter Welder 3	25.97	27.71		28.40	29.25	30.13	31.03
Leak Survey Technician	25.97	27.71		28.40	29.25	30.13	31.03
Materials Shipper/Receiver	25.97	27.71		28.40	29.25	30.13	31.03
Materials Truck & Trailer Operator				28.40	29.25	30.13	31.03
Measurement & Controls Technician 3	25.97	27.71		28.40	29.25	30.13	31.03
Measurement Mechanic 2 (18 month)	25.97	27.71		28.40	29.25	30.13	31.03
Pipeline Technician 2	25.97	27.71		28.40	29.25	30.13	31.03
Recycling Mechanic	25.97	27.71		28.40	29.25	30.13	31.03
Sales & Service Technician 3 (12 month) (Merged w/CST 2)							
Shop Mechanic 2	25.97	27.71		28.40	29.25	30.13	31.03
Utilization Technician 2 (Merged w/CST 2)							
Compression & Controls Technician 4	25.45	27.16		27.84	28.68	29.54	30.43
Material Handler	25.14	26.82		27.49	28.31	29.16	30.03
Materials Truck Driver	25.14	26.82		27.49	28.31	29.16	30.03
Truck Driver	25.14	26.82		27.49	28.31	29.16	30.03
Building Maintenance Worker	24.49	26.13		26.78	27.58	28.41	29.26
Clean-Up Truck Driver	24.49	26.13		26.78	27.58	28.41	29.26
Electronic Control Technician 3 (start) (Merged with MCT 3 start)							
Equipment Operator 2	24.49	26.13		26.78	27.58	28.41	29.26

IBEW Wage Schedule			Interior wage rate paid to all employees effective Jan 1/07			
Ratification Date: August 30, 2006	2.85%		2.5%	3%	3%	3%
Classification	2006		2007	2008	2009	2010
	4-Sep		1-Apr	1-Apr	1-Apr	1-Apr
	Coastal	Interior	Company-Wide			
Measurement & Controls Technician 3 (start)	24.49	26.13	26.78	27.58	28.41	29.26
Measurement Mechanic 2 (start)	24.49	26.13	26.78	27.58	28.41	29.26
Pipeline Labourer	24.49	26.13	26.78	27.58	28.41	29.26
Pressure and Measurement Technician 3 (start)	24.49	26.13	26.78	27.58	28.41	29.26
Shop Assistant	24.49	26.13	26.78	27.58	28.41	29.26
Shop Mechanic 3 (B&U)	24.49	26.13	26.78	27.58	28.41	29.26
Utility Assistant	23.54	25.12	25.75	26.52	27.32	28.14
Labourer	22.62	24.14	24.74	25.48	26.24	27.03
Field Operations Assistant	22.30	23.79	24.38	25.11	25.86	26.64
Student Rate	19.48	20.79	21.31	21.95	22.61	23.29

Distribution Apprentice	2.85%		2.5%	3%	3%	3%
			2007	**2008**	**2009**	**2010**
	2006		**1-Apr**	**1-Apr**	**1-Apr**	**1-Apr**
	Coastal	**Interior***	**Company-Wide**			
Start Rate (75% of DM rate) (DA3)	19.48	20.79	21.31	21.95	22.61	23.29
End of Year 1 (82% of DM rate)(DA2)	21.30	22.73	23.30	24.00	24.72	25.46
End of Year 2 (90% of DM rate) (DA1)	23.37	24.94	25.56	26.33	27.12	27.93
End of Year 3 (100% of DM rate)(DM)	25.97	27.71	28.40	29.25	30.13	31.03

Compression & Controls Technician						
	2.85%		2.50%	3%	3%	3%
	2006		**2007**	**2008**	**2009**	**2010**
	Coastal	**Interior**	**Company Wide**			
Compression & Controls Technician 1 (100%)	31.81	33.94	34.79	35.83	36.90	38.01
Compression & Controls Technician 2 (90%)	28.63	30.55	31.31	32.25	33.22	34.22
Compression & Controls Technician 3 (85%)	27.04	28.85	29.57	30.46	31.37	32.31
Compression & Controls Technician 4 (80%)	25.45	27.16	27.84	28.68	29.54	30.43

	2006	**1-Apr-07**	**1-Apr-08**	**1-Apr-09**	**1-Apr-10**
DEPENDENT BACKHOE OPERATORS					
(Lower Mainland/Fraser Valley):					
Hourly Rate (Inc. Hoe-pack) (per hr)	67.50	69.50	71.00	73.00	75.50
Hourly Rate Truck & Trailer	7.00	7.00	7.50	7.50	7.50
Total Both	74.50	76.50	78.50	80.50	83.00
Overtime Rate	89.00	89.00	89.00	99.00	99.00
Grinder Sweeper (per hr; if required)??					

	2006	**1-Apr-07**	**1-Apr-08**	**1-Apr-09**	**1-Apr-10**
CRD DEPENDENT BACKHOE/DUMPTRUCKS:					
Hourly Rate (Inc D-Truck & Equip)	77.00	78.75	81.50	84.00	86.50
Overtime Rate	89.00	89.00	89.00	99.00	99.00
	2006	**1-Apr-07**	**1-Apr-08**	**1-Apr-09**	**1-Apr-10**
DEPENDENT DUMP TRUCK OPERATORS:					
Hourly Rate (2006 rate re-based to $45 + 2.85%)	$46.28	$47.44	$48.86	$50.33	$51.84
Overtime Rate	$67.50	$67.50	$73.29	$73.29	$77.76

SCHEDULE B – JOB DESCRIPTIONS

Building Maintenance Worker (New)
Building Operations and Maintenance Leader (Replaced by Facilities Technician)
Clean-Up Truck Driver
Compression & Controls Technician
Corrosion Control Technologist
Crew Leader
Customer Service Technician 1
Customer Service Technician 2
Design Machinist (New)
Distribution Apprentice
Distribution Mechanic
Distribution Mechanic/Excavator
Distribution Service Agent
Electrician
Equipment Operator "P"
Equipment Operator I
Equipment Operator II
Equipment Operator/Distribution Mechanic
Facilities Technician (Previously Building Operations and Maintenance Leader)
Field Operations Assistant
Fitter Welder 1
Fitter Welder 2
Fitter Welder 3
Inspector
Instructor
L.N.G. Plant Operator 1
L.N.G. Plant Operator 2
Labourer
Leak Survey Technician
Machinist
Mains & Service Planner
Material Handler
Materials Shipper/Receiver
Materials Truck Driver
Materials Truck & Trailer Operator (New)
Measurement & Controls Technician
Measurement Group Leader
Measurement Mechanic
Measurement Shop Leader
Measurement Technician???? No job description.
Mechanical Foreman (Machine Shop)
Mechanical Foreman (Prefabrication Shop)
Mechanical Foreman (Welding Shop)
Millwright
Operations Technician
Painter
Paving Foreman
Pipeline Labourer
Pipeline Technician 1
Pipeline Technician 2
Planning &Design Technologist (Replaces Planner (NI) and Gas Distribution Planner (CRD)
Recycling Mechanic

Senior Material Handler
Senior Pipeline Technician
Senior Sales and Service Technician
Senior Shop Mechanic 1 (Buildings & Utilities)
Shop Assistant
Shop Mechanic 1 (Buildings & Utilities)
Shop Mechanic 1 (Machine Shop)
Shop Mechanic 1 (Prefab)
Shop Mechanic 1 (Welding Shop)
Shop Mechanic 2 (Buildings & Utilities)
Shop Mechanic 2 (Machine Shop)
Shop Mechanic 2 (Prefab)
Shop Mechanic 2 (Welding Shop)
Shop Mechanic 3 (Buildings & Utilities)
Station Mechanic 2
Stores Leader
System Operations Apprentice 1 and 2
System Operations Technician
Truck Driver
Warehouse and Delivery Leader (Replaces Materials Leader)
Welder 1
Yard Foreman (Metro)

BUILDING MAINTENANCE WORKER

Duties and Responsibilities:

1. A Building Maintenance Worker shall carry out semi-skilled operations such as inspecting equipment, lubricating equipment, changing filters, performing minor repairs, de-icing yard and walkways, adjusting doors, dismantling and preparing equipment for installation or repair.
2. Shall clean equipment and building components using mechanical or hand-operated equipment, carry out dismantling of designated tools and equipment to permit servicing and assist with the assembly of similar equipment.
3. Shall use hand and power operated tools such as hand drills, sanders, saws, impact wrenches, pipe wrenches, threaders, power brushes and stud setters required to carry out the work.
4. Shall also use power operated machines such as salter, baler, compactor, pipe threading machine, hydraulic press, drill press, grinders, etc.
5. Shall assist in the dismantling and assembly of equipment.
6. Will work under direction as required by the nature and complexity of the job.
7. Shall operate all mechanized equipment used in Building Maintenance, such as cranes, compactors, balers, salters, electric/gas shop trucks, forklifts and similar equipment.
8. Duties will include cleaning of tools and equipment and general housekeeping.

CLEAN-UP TRUCK DRIVER

Shall perform work required to reinstate work locations to their original condition such as restoration of lawns and gardens; replacement of concrete walks; temporary repairs of paved areas; reconstruction of fences, walls, etc.

Shall deliver or pick up select materials and spoil at work sites.

Shall operate a truck for the transportation of required tools and materials.

May supervise the work of one other employee.

When two or more employees are being supervised the rate will be increased by 5%.

When required to drive a tandem-axle truck equipped with air brakes, he shall receive the Equipment Operator 1 rate.

COMPRESSION & CONTROLS TECHNICIAN

Duties & Responsibilities*:

1. Shall perform all duties associated with transmission compressor stations and control, SCADA, and electronic measurement facilities including, but not limited to, the following; the installation, programming, activation, trouble shooting, operation and maintenance of mechanical, pneumatic, hydraulic, electrical, electronic, control and computer equipment.
2. Shall ensure that the predictive analysis and preventative maintenance schedules are developed and maintained.
3. Shall provide comprehensive documentation of construction, inspection, commissioning, operation and maintenance work.
4. Shall provide supervision to other employees and contractors as it relates to compression and control activities.

5. Shall ensure efficient operation of the workgroup, including work group planning and scheduling as it relates to these duties and responsibilities.
6. Shall keep abreast of changing technology as it relates to the "Duties and Responsibilities".
7. In the event there is insufficient work as outlined above or more urgent work elsewhere, s/he may be temporarily scheduled for work for which s/he is qualified in other departments.

Progression:

On completion of satisfactory service and subject to demonstrated ability and competency to perform the full range of duties at each level of a CCT, progression will be as follows:

CCT 4 – After two years of service as a CCT 4 will progress to a CCT 3.
CCT 3 – After two years of service as a CCT 3 will progress to a CCT 2.
CCT 2 - After one year of service as a CCT 2 will progress to a CCT 1.
CCT 1 – End Classification.

1. Demonstrated ability is the ability of the employee to progressively perform all aspects of the work identified within the CCT job description.
2. Appropriate competency requirements for progression are being developed as part of the CCT training profile. The training profile will be adjusted subject to changing competency requirements.
3. An employee shall not be denied progression due to lack of training or exposure to equipment, which is not attributable to the employee.

Implementation

Effective Monday, December 4, 2000:

1. All ten incumbent ECTs associated with compression and controls will be reclassified to CCT1. They are: Dale Babb, Troyce Beglaw, Stuart Bolland, Mark Cerina, Nelson Cobra, Wes Dann, Allen Dermody, Jim Howe, Barry Kleven, and Ed Rilkoff.
2. For purposes of this reclassification only, and without prejudice to any future issue involving these or other employees, or any other reclassification or reorganization, each of these ten named employees is deemed presently qualified as a CCT1, even though all do not meet all of the formal qualifications.
3. For purpose of this reclassification only, and without prejudice to any future issue involving these or other employees, or any other reclassification or reorganization, those employees who are already at the ECT1 classification (namely: Dale Babb, Troyce Beglaw, Mark Cerina, Allen Dermody, and Barry Kleven) will continue to receive the ECT1 rate of pay until the CCT1 rate surpasses the ECT1 rate, at which time they will receive the CCT1 rate of pay (they are being red circled).
4. Those employees currently at the ECT2 classification (namely: Stuart Bolland, Nelson Cobra, Wes Dann, Jim Howe, and Ed Rilkoff) will be paid the CCT1 rate effective Monday, December 4, 2000.
5. Each employee's classification seniority as a CCT shall be the date of his reclassification or selection to the CCT classification (December 4, 2000 for the ten employees being reclassified).

CORROSION CONTROL TECHNOLOGIST

Under the direct supervision of the Manager, Customer Service, will be responsible for the operation and maintenance of the Company's distribution corrosion prevention program, perform special leak surveys, as required, and carries out other duties, as assigned.

Duties & Responsibilities

1. Is responsible for the operation and maintenance of the Company's distribution corrosion prevention program by:
   (a) traveling to each District, as directed, and performing field surveys;
   (b) analyzing the results of the surveys and undertaking remedial actions, as required;

(c) identifying and repairing faults on the cathodic protection system, including the repair or adjustment of rectifiers;
(d) providing technical direction and training to other employees with regard to measurement and regulation activities;
(e) installing or assisting in the installation of rectifiers, anodes, test stations, and other cathodic protection facilities;
(f) preparing comprehensive and legible reports on the results of all surveys, including recommendations for the consideration of the Manager.

2. Performs other duties, as assigned by the Manager, including, but not limited to:
   (a) Calibration and repair of all associated equipment within capabilities.

CREW LEADER

The Crew Leader is responsible, under the general direction of a manager or supervisor, for the effective scheduling, completion, and documentation of the work of a crew engaged in the construction, maintenance, and operation of the gas transmission and distribution systems.

The Crew Leader shall also do plastic fusion, thermic welding and oxyacetylene welding and shall use the tools and instruments required on gas distribution work such as pneumatic, hydraulic or gasoline operated paving breakers, rock drills, vertical test hole drills, horizontal earth augers, compaction equipment, etc.

The Crew Leader shall use line stopper and hot tap pressure control and line break equipment, electronic pipe and valve locators and combustible indicators of the hot wire or flame ionization types.

The Crew Leader shall install distribution pipe, fitting and related components, and carry out repairs and alterations to mains and services, assist in the construction, maintenance, and operation of gate and district regulator stations, and analyze gas samples in the field using an ethane detector or similar equipment.

The Crew Leader shall be responsible for making as-built reports of work done and complete reports pertaining to the crew's day-to-day work.

CUSTOMER SERVICE TECHNICIAN 1

Must be competent in a variety of skilled functions related to public safety, consumer relations and the welfare of company property.

This shall include troubleshooting to a wide range of gas burning equipment and associated control media as required to identify safety issues and to make safe the appliance.
Must exercise good judgment, under general terms of reference, in carrying out remedial action and/or suspending service with proper follow-up action under codes and other requirements.

Must construct, test and certify piping installations, metering and gas pressure regulating equipment on the company's behalf to strict standards and governmental codes.

Must carry out follow-up maintenance programs. This shall include service to gas burning equipment and associated control media.

The Customer Service Technician 1 shall be required to provide repair and adjustment service to all equipment indigenous to the residential and commercial field. A maximum 816 Mega joules (750,000B BTU's) per hour to any customers' equipment with a flame guard safety such as thermocouple, thermobulb or bimetal element.

Shall install and field-maintain gas measurement and pressure regulation equipment including perform PFM and other work up to and including all meter sets that utilize a single run configuration, with or without a bypass (excluding instrument and turbine meter sets).

Shall carry out a variety of tests related to gas utilization involving the testing for and measurement of O_2, CO, CO_2 and other products of combustion and take such remedial action as is indicated;

Shall investigate, locate and categorize gas leakage on an emergency basis on either the consumers' premises or the company's system and take all necessary action to protect the public and eliminate hazard.

Shall carry out a variety of other duties as required to assist other operational areas such as system pressure surveys, field work for Gas Supply Department and carry out surveys. Assist a System Operations Technician.

Shall carry out surveys, installations and maintenance of all components of distribution system and gas burning equipment at company locations involved in the distribution of natural and other gases.

Shall handle emergency incidents such as fires, explosions, asphyxiations, unplanned outages and in so doing, take certain initiatives and also cooperate with fire, police and other authorities and other company groups.

Shall be responsible for the operation of portable L.N.G. vaporization equipment including: purging operations, liquid transfer, putting on and off line in a safe and efficient manner and for the overhaul of all mechanical components on such equipment.

Shall install house-lines, recesses, relief stacks, or vent lines for any volume or delivery pressure except that actual turn-on may be done by a System Operations Technician when the limits of this job description are exceeded.

In Interior/Island locations with four (4) or less field employees, the Customer Service Technician will functions as a Customer Service Technician and/or Crew Leader in every respect and, in addition, may operate excavation equipment if trained to do so. When required, and trained to do so, they shall perform oxy-fuel welding procedures.

They will be expected to operate a variety of tools and equipment associated with the delivery of the above.

In regard to consumer relations, shall offer current and potential customers technical and promotional advice on such matters as space heating, water heating, cooking, clothes drying, and the general heating and insulation requirements of their residence. They shall be conversant with the relative advantages of natural gas for these uses.

The Customer Service Technician 1 must have a valid Provincial Grade B Gas fitter's license and one year's field experience in the Customer Service Technician 2 classification.

When required, and trained to do so, they shall also perform tie-in welds to connect meter sets to the gas distribution system and shall be certified for the prescribed Terasen Gas, CSA approved oxy-fuel welding procedures (this role will be secured through a separate posting and selection process for both permanent and relief positions). This paragraph applies only to the tie-in role.

CUSTOMER SERVICE TECHNICIAN 2

Must be competent in a variety of skilled functions related to public safety, consumer relations and the welfare of company property.

This shall include troubleshooting to a wide range of gas burning equipment and associated control media as required to identify safety issues and to make safe the appliance.

Must exercise good judgment, under general terms of reference, in carrying out remedial action and/or suspending service with proper follow-up action under codes and other requirements.

Must construct and test minor piping installations not requiring a gas fitter's license, or assist a Customer Service Technician 1.

Must carry out follow-up maintenance programs. This shall include service to gas burning equipment and associated control media.

The Customer Service Technician 2 shall be required to provide repair and adjustment service to all equipment indigenous to the residential and commercial field. A maximum 816 Mega joules (750,000 BTU's) per hour to any customers' equipment with a flame guard safety such as thermocouple, thermo bulb or bimetal element.

Shall install and field-maintain gas measurement and pressure regulations equipment including perform PFM and other work to and including all meter sets that utilize a single run configuration, with or without a bypass (excluding instrument and turbine meter sets).

Shall carry out a variety of tests related to gas utilization involving the testing for and measurement of O_2, CO, CO_2 and other products of combustion and take such remedial action as indicated;

Shall investigate, locate and categorize gas leakage on an emergency basis on either the consumers' premises or the Company's system and take all necessary action to protect the public and eliminate hazard.

Shall carry out a variety of other duties as required to assist other operational areas such as system pressure surveys, field work for Gas Supply Department and carry out surveys. Assist a Customer Service Technician 1 or System Operations Technician.

Shall carry out surveys, installations and maintenance of all components of distribution system and gas burning equipment at company locations involved in the distribution of natural and other gases.

Shall handle emergency incidents such as fires, explosions, asphyxiations, unplanned outages and in so doing, take certain initiatives and also cooperate with fire, police and other authorities and other Company groups.

Shall be responsible for the operation of portable L.N.G. vaporization equipment including: purging operations, liquid transfer, putting on and off line in a safe and efficient manner and for the overhaul of all mechanical components on such equipment.

Shall install house-lines, recesses, relief stacks, or vent lines for any volume or delivery pressure except that actual turn-on will be done by a System Operations Technician where loads or pressures listed in this job description are exceeded.

They will be expected to operate a variety of tools and equipment associated with delivery of the above.

In regard to consumer relations, shall offer current and potential customers technical and promotional advice on such matters as space heating, water heating, cooking, clothes drying, and the general heating and insulation requirements of their residence. Shall be conversant with the relative advantages of natural gas for these uses.

In Interior/Island locations with four (4) or less field employees the Customer Service Technician 2 will function as a Customer Service Technician 2 and/or Distribution Mechanic in every respect and, in addition, may be up-graded on a temporary basis to operate excavation equipment if trained to do so. When required, and trained to do so, they shall perform oxy-fuel welding procedures.

The CST 2 must hold a Provincial Gasfitter's License Utility Grade and will be required to obtain their Provincial Gasfitter's License Grade B within 12 months of qualifying to write for it (i.e. holding a Provincial Gasfitter's License Utility Grade for 2 years). Failure to obtain the Provincial Gasfitter's License Grade B within this 12 month period shall result in the employee being returned to his previously-held classification. The Customer Service Technician 2 will automatically be promoted to Customer Service Technician 1 upon attaining the Provincial Gas Fitter's License Grade B and upon completion of a twelve month period of probation as a Customer Service Technician 2.

When required, and trained to do so, they shall also perform tie-in welds to connect meter sets to the gas distribution system and shall be certified for the prescribed Terasen Gas, CSA approved oxy-fuel welding procedures (this role will be secured through a separate posting and selection process for both permanent and relief positions). This paragraph applies only to the tie-in role.

DESIGN MACHINIST

Responsibilities:

1. develop, design, improve and produce equipment and components utilized in the Gas industry.
2. Shall be required to research and develop new concepts or solutions to problems associated with field equipment and gas system components and tooling.
3. Shall work with engineering drawings, sketches, or original parts and, if required, produce accurate working drawings or sketches or components.
4. Shall act as Lead Hand when authorized. A Lead Hand shall coordinate the work on projects where more than one tradesman (or higher paid classification) is employed. Management will determine where Lead Hands are required. Pay will be on a while-so-acting basis at plus 3% of their regular rate. No seniority will accrue.
5. Shall provide instruction and training with respect to equipment and components to individuals and groups inside and outside the Company.
6. Shall set up and direct operations on a range of machine tools for other operators.

DISTRIBUTION APPRENTICE

DISTRIBUTION MECHANIC

A Distribution Mechanic shall use tools and procedures required for the construction, maintenance and operation of the gas transmission and distribution systems.

Shall assist in the installation of distribution pipe, fittings and related components and in carrying out repairs and alterations to mains and services.

Shall install prefabricated single meter sets on new services, up to and including 400 series meters at delivery pressures not exceeding 14 kPa (2psi) *(formerly associated with 'B' Crew).*

Shall conduct system leakage and hazard surveys.

Will assist in the construction and maintenance of gate and district regulator stations.

Shall use the tools and instruments required on gas distribution work such as pneumatic, hydraulic or gasoline operated paving breakers, rock drills, vertical test hole drills, horizontal earth augers, compaction equipment, etc.

Shall use line stopper and hot tap pressure control and line break equipment electronic pipe and valve locators, dew point test equipment such as the Chandler and Elnor and combustible indicators of the hot wire of flame ionization types.

Shall analyze gas samples in the field using an Ethane detector or similar equipment.

Shall do thermic and oxyacetylene welding and, if required, shall be certified or recertified for the prescribed B.C. Government pressure piping gas welding certificate.

Shall carry out heat fusion operations on plastic pipe systems and shall certify or recertify for the prescribed Terasen Plastic Pipe Heat Fusion Certificate.

In conducting system leakage and hazard surveys the DM shall carry out all operations necessary in buildings or on the street to locate, classify, pinpoint and vent gas leakage to a safe condition pending repairs.

May direct the work of one other employee when engaged in carrying out system surveys including venting of leakage.

Shall be paid the rate of Crew Leader when directing the work of two or more men on leakage survey.

When conducting Leak Survey, shall assess and repair minor leaks as follows: limited to the use of light tools; no interruption of gas or regulator adjustment; and limited to residential services.

DISTRIBUTION MECHANIC/EXCAVATOR (DMX) (See LOU #56)

The DMX will function as a DM/A in every respect, and in addition will operate various excavation equipment such as Bobcats, mini-excavators and mini-backhoes, and other equipment of similar or lesser complexity. Equipment such as “walk-along-plows” and “vac-trucks” are not considered excavation equipment in this context and will therefore be operated by DM/A’s as well as DMX’s.

The DMX will be treated as a unique classification (e.g. for purposes of headquarter selection) but with common classification seniority with the DM. Employees bumping a DMX based on DM classification seniority must be able to operate the excavation equipment in a productive, safe and competent manner with a reasonable amount of appropriate training. If the bumping employee cannot meet this standard s/he must bump a regular DM

DISTRIBUTION SERVICE AGENT

Duties and Responsibilities:

1. The Distribution Service Agent will be responsible to carry out operational, service installation and maintenance activities within the framework of Company objectives, policies and programs; and shall ensure the public is protected from any unsafe act or condition pertaining to the transmission and distribution of natural gas.
2. The Distribution Service Agent will administer an office and report to an Install/Operate Manager.
3. Perform all the duties of a Sales and Service Technician and be responsible for gas service to all customers on the distribution system.
4. Responsible to give technical direction and leadership to Company and contractor personnel involved in any aspect of installing, operating, maintaining and abandoning the gas system.
5. Responsible to schedule the work load, direct crews and contractors to ensure proper priorities are met.
6. Keep up to date with all policies and procedures and have a good working knowledge of all standard practice instruction, Company objectives, policies and programs and the job breakdown manual.
7. Sales related activies as required.

ELECTRICIAN

The Electrician shall perform the full scope of electrical work which falls within the capability of a Journeyman Electrician.

Without limiting the generality of the foregoing, he shall install, test, adjust, modify, inspect, troubleshoot, maintain and repair main and auxiliary equipment and apparatus. This may include, but not necessarily be limited to work on: electric wiring, distribution panels, transformer connections, electronic components, electric motor servicing, motor control and related circuitry, HVAC control systems, communication and data circuits, fire alarm and security systems.

May also be assigned other building maintenance tasks which he is capable of performing.

May be required to perform electrical and other building maintenance work at any Company facility, including shops, yards, offices, musters, gate stations, regulator stations, etc.

Qualifications

1. B. C. Journeyman Electrician trade qualification.
2. Minimum of two year’s satisfactory industrial electrical maintenance experience at journeyman level.
3. Proficiency in reading electrical/electronic control diagrams.
4. Demonstrated ability to work independently and maintain a high level and quality of performance.
5. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis; must have safe driving record and be able to pass Terasen driving tests.

EQUIPMENT OPERATOR P

An employee so classified shall, with minimum supervision, perform the duties of an Equipment Operator 1 and, as required, those involving the operation and maintenance of the Company's pipeline equipment used for both routine construction and emergency situations involving pipeline facilities.

Without limiting the generality of the foregoing, the duties of an Equipment Operator P include:

1. Operating and maintaining any of the following equipment: combination hydraulically operated backhoe and front end loader (four wheel drive type included); trenching machines of all sizes; portable or permanently mounted cranes, truck tractor units; lowbed, highboy or pole trailers; crawler tractors; sidebooms, bending machines; air compressors and like machines.
2. Operating and maintaining the Company's high pressure drilling and stopple equipment. This includes, but is not limited to, equipment such as drilling machines, plugging or line stopping machines, sandwich valves and hydraulic pumps.
3. Reviewing and maintaining the inventory levels of various items required for the Company's high pressure drilling and stopping machines and recommending any necessary changes.
4. Directing the work of employees who are acting as helpers in drilling or stopping machine operations.
5. Ensuring the safekeeping and proper handling of all instruments, equipment and tools assigned to him; including that all is carried out as per Company standards.
6. Performing all duties of an Equipment Operator I.
7. Performing other duties as required.

Qualifications

1. Holder of a current Class 1 British Columbia Driver's License with air endorsement.
2. Demonstrated ability to install, operate and maintain high pressure drilling and stopping equipment (i.e. T.D. Williamson & Mueller equipment).
3. Demonstrated ability to operate all other equipment required by duties 1, 2 and 6.
4. Demonstrated ability to work independently, with minimal supervision.
5. Demonstrated ability to direct the activities of other employees that are acting as helpers.
6. Capable of lifting, carrying and placing heavy material, equipment and supplies as required.
7. Ability to communicate verbally, and in writing, clearly and concisely.
8. Knowledge of the Company standards and policies directly affecting the assigned duties.
9. Demonstrated mechanical aptitude to perform the duties of this position correctly and safely.

Additional Information

1. The incumbent must be willing to travel extensively and be away from home on business for extended periods of time.
2. The incumbent will be expected to schedule annual vacations, and other time off, so that it does not conflict with peak construction periods (see Article 16.05).

EQUIPMENT OPERATOR I

(Merged with Machine Operator 1 in 1991)

An Equipment Operator 1 shall operate and provide running maintenance on any of the following or similar equipment: backhoes, front-end loaders, trenching machines, portable cranes, crawler tractors, side booms, direct bury plowing machines or any equipment which requires up to a Class 1 Driver's License (with air endorsement).

May be assigned responsibility for the operation, maintenance, and housekeeping of the pipe yard, as well as all administrative duties required of that function, and will receive a 3% increase to his hourly rate for this responsibility.

EQUIPMENT OPERATOR II
(Merged with Machine Operator II in 1991)

An employee so classified shall operate and provide running maintenance on the following equipment: compressors, power operated barholing units, front-end loaders, forklifts, or any other small equipment they may be required to operate.
In the Interior employees so classified shall be capable of learning the correct procedures for operating and maintaining heavy and light equipment. On completion of 6 months cumulative service as an Equipment Operator 2 and obtaining a Class 1 Driver's License (with air endorsement) they will qualify for the Equipment Operator 1 rate of pay when assigned to work as an Equipment Operator 1.

EQUIPMENT OPERATOR/DISTRIBUTION MECHANIC (EODM) (See LOU #56)

The EODM will function as a DM or DMX in every respect, and in addition will operate equipment associated with the EO1 classification and other equipment of similar or lesser complexity.

In the Interior, EO1's will be promoted to EODM subject to their ability to perform all of the duties of the DMX in a productive, safe and competent manner with a reasonable amount of appropriate training. EODM will be a separate classification with separate classification seniority.

FACILITIES TECHNICIAN

1. Ensures the efficient operation and maintenance of company facilities by performing all duties required for this purpose, or as assigned by the manager and/or designate.
2. Directs the work of the contractors and other workgroup categories in such a manner that the work is carried out safely, efficiently and expeditiously.
3. Provides technical direction and leadership to Company, contractors and other workgroup categories involved in any aspect of inspection, installation, maintenance and operations of company facilities, their electrical & mechanical systems, utilities and grounds.
4. Assists in planning work tasks related to the operation and maintenance of company facilities, their electrical & mechanical systems, utilities and grounds.
5. Assist in the development, implementation, and instruction of training and operating programs.
6. Applies the related code requirements, institutional practices and company policies & standards as they related to the operation and maintenance of company facilities.
7. Ensures that the facility structural systems, electrical & mechanical systems, life safety systems, utilities and grounds are functioning optimally.
8. Inspects the work of contractors and other workgroup categories maintaining, modifying and overhauling facilities and utilities in order to ensure that work is completed to company standards.
9. Works with tools and carries out maintenance and modification to facilities, their electrical & mechanical systems, utilities and grounds other than where prohibited by codes.
10. Completes all documentation required by the position.
11. May also be assigned other Facility tasks that the individual is capable fo performing.

FIELD OPERATIONS ASSISTANT

1. Provides administrative and clerical support for the area and may be sole administrative support person for the location. May work in a team or teams of staff representing more than one location. Acts as an assistant to Manager(s) including:
    (a) intercepts and processes clerical technical/administrative inquiries and considers complex alternatives to determine corrective action;

(b) prepares and/or composes a variety of correspondence, reports, presentation materials, charts and forms;
(c) determines processing priorities and/or consults with others as appropriate, acts to meet deadlines or follows up with others to ensure deadlines are met;
(d) reviews incoming correspondence, acts on when appropriate or redirects to appropriate place/person;
(e) develops and communicates office procedures with Manager to ensure efficiency and effectiveness of office;
(f) sets up and maintains filing systems (paper and e-files), including creating new files as operations dictate; maintains bring forward files and follows up as required;
(g) opens and distributes incoming mail and other related correspondence. Organizes and arranges courier access and dropoff to locations for further handling, including locating and flagging file references related to items received; prepares and sends outgoing mail; may administer the postage machine.
(h) maintains and updates various manuals/books such as Standards;
(i) maintains stationary levels and orders forms;
(j) maintains a variety of logs, records, information and spreadsheets.

2. As required, assists management to research, gather information and compile in reports & variance reviews. Uses own judgement to determine what information should be utilized in reports. Formats reports, analyzes information, takes action to resolve or advises Manager. May access SAP and Business Warehouse to compile reports.
3. Provides Construction and Operations support as required.
4. Acts as the main administrative contact for office or department; answers enquiries, answers telephone, arranges meetings, books attendees, facilities and arranges catering. may attend meetings and take minutes.
5. Arranges travel and accommodation reservations for department staff, including obtaining confirmation of reservations, initiating and processing forms to provide for issuance of cash advances. May administer petty cash fund.
6. Checks and codes documents such as invoices and expense claims:
   (a) checks and codes invoices for correct work order/account numbers for managerial approval;
   (b) generate and process expense claims for field crews
7. May be required to travel to attend company meetings or provide backfill.
8. Performs other duties of a minor nature including driving a vehicle which do not affect the value of the job.

FITTER/WELDER 1

A Fitter/Welder 1 shall perform all operations in the shop necessary to fabricate (using gas metal arc, manual arc or oxy-fuel welding) the pressure piping and vessel systems used on gas transmission and distribution networks. This will include interpretation of engineering drawings, spool sheets, etc., laying out of the job, fit up and welding preparation of all components and the pressure testing of completed assemblies and sub-assemblies to determine weld and joint integrity. It will also include the fabrication of non-pressure components and the installation of pressure controlling devices, their associated instrumentation and control lines in prefabricated regulator vaults or similar assemblies.

In the field the F/W 1 shall do pipe line welding including hot tap welds, fire welds and leak repair welds on lines operating up to and including transmission line pressures.

In conformance with Terasen Welder qualification tests and CSA Standard Z184 for Gas Transmission and Distribution Systems, a Fitter/Welder 1 shall be required to qualify and re-qualify when necessary, as prescribed by the Code for Welders welding on piping to operate at hoop stresses of 20% or more of the specified minimum yield strength.

Shall act as Lead Hand when authorized. A Lead Hand shall coordinate the work on projects where more than one tradesman (or higher paid classification) is employed.

Management will determine where Lead Hands are required.

Pay will be on a while-so-acting basis at plus 3% of his regular rate.

No seniority will accrue.

FITTER/WELDER 2

A Fitter/Welder 2 shall perform all operations in the shop necessary to fabricate (using manual arc, gas metal arc or oxy-fuel welding) the pressure piping and vessel systems used on the gas transmission and distribution networks, insofar as his certificates of competency permit. This will include interpretation of engineering drawings, spool sheets, etc., laying out of the job, fit up and welding preparation of all components and the pressure testing of completed assemblies and sub-assemblies to determine weld and joint integrity. It will also include fabrication of non-pressure components and the installations of pressure controlling devices, their associated instrumentation and control lines in prefabricated regulator vaults or similar assemblies.

In the field he shall weld on the transmission and distribution systems within the scope of his certificate of competency including hot taps, fire welds and leak repair welds.

In conformance with Company welder qualification tests and CSA Standard Z184 for Gas Transmission and Distribution Systems, a Fitter/Welder 2 shall be required to qualify and re-qualify when necessary, as prescribed by the Code for Welders welding on piping to operate at hoop stresses of less than 20% of the specified minimum yield strength.

Upon satisfactory completion of 12 months' service in this position, the Fitter/Welder 2 will be reclassified to Fitter/Welder 1.

FITTER/WELDER 3

The Fitter Welder 3 is a designated training position.

Employees selected for this training shall undertake practical and classroom training, instruction and practice in welding, fitting and associated skills and knowledge required to achieve the intermediate Level of the Program Content of Welder Training as published by VCC/VVI or PVI.

Training may take place in Company Welding Schools, Vocational Institutes or other suitable establishments. Some classes may be held outside normal day-work hours.

After initial training in welding, a Fitter Welder 3 shall perform assigned duties in the Welding Shops including the duties of a Shop Mechanic 2 (Welding Shop). In addition, a Fitter Welder 3 shall perform welding on pressure piping and systems within the scope of his welding qualifications and certification.

A Fitter Welder 3 shall display good aptitude and proficiency during training, noting that training may be terminated at the Company's discretion for insufficient aptitude, inadequate progress, insufficient application to training or studies or for misconduct.
Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis; must have a safe driving record and be able to pass Company driving tests.
2. Demonstrated a good mechanical aptitude.
3. Must possess or test and qualify in these tests to CSA Standard Z184 and the Company welding procedures: OAW-1, OAW-2, OAW-3, and in addition shall display above-average aptitude and proficiency in oxyacetylene welding.
4. Possess, as a Fitter Welder 3, all the educational qualifications for entry into Welder Training Programs as specified by the B.C. Ministries of Labour and Education and/or VCC/VVI or PVI.
5. Be physically agile and shall have good eyesight; shall not be subject or prone to respiratory problems or illnesses or allergic to the materials and conditions encountered in the practice of welding. A medical examination by Terasen Health Services or its delegate may be required.
6. Shall display, in evaluation tests, sufficient learning ability, good manual dexterity and good mechanical aptitude.
7. Ability to work alone and maintain a high level and quality of performance.
8. Initiative and sense of responsibility.
9. Prior experience in gas system construction and maintenance for minimum of three (3) years.

Other Considerations:
1. Considerable bending and lifting.
2. Exposed to weather.
3. Working hours may vary to accommodate training class schedules; some evening classes may be involved that will require the employee(s) attendance on their own time. Evening classes will not normally exceed two (2) evenings per week for part only of the year.

<u>INSPECTOR</u>

The minimum rate to be paid to any inspector will be that of a Crew Leader. In the event, however, that an employee is presently being paid a higher rate, then such employee will receive the rate of pay under which he is presently employed.

<u>INSTRUCTOR</u>

1. Develops and presents training courses and other presentation material for use inside and outside the Company.
2. Instructs and trains individuals or groups in the classroom or on the job in all aspects of gas system construction, operation and maintenance, including:
   (a) Analytical skills, trouble shooting and problem-solving diagnosis.
   (b) Applicable Provincial and Federal Codes and Regulations, internal policies and current standards.
   (c) Customer and public relations techniques.
   (d) Principles of leadership, organization and administration.
   (e) Safety practices and procedures.

4. May be required to investigate emergency or hazardous situations and submit reports on causes and recommended remedial action.

<u>LNG PLANT OPERATOR 1</u>

An employee so classified shall meet the qualifications and perform all of the duties of an LNG Plant Operator 2.

Shall work without supervision, direct the work of other employees and contractors, and make decisions as required to achieve and maintain optimum plant operation.

Shall train the LNG Plant Operator 2 in all aspects of the operation of the plant, and in all maintenance procedures at the Plant.

LNG PLANT OPERATOR 2

The LNG Plant Operator 2 shall operate the LNG Plant and perform required maintenance at the LNG Plant under the direction of an LNG Plant Operator 1 or the LNG Plant Superintendent. At times when the Plant is not liquefying or sending out, he shall operate auxiliary equipment and perform required maintenance without direct supervision.

Shall operate equipment and processes such as: LNG storage tank; cycle gas and boil off gas compressors; gas purification, liquefaction processes; send out equipment including LNG pumps, vaporizers, odorizer; nitrogen generator with associated equipment; cooling equipment; standby diesel generator; measurement, instrumentation, control and gas analysis equipment.

Shall operate the Plant equipment on manual control in the event of an equipment failure, particularly under critical circumstances.

Shall direct and carry out appropriate action during emergency incidents or fires until relieved by someone of higher authority.

Shall maintain a log of pressures, temperatures and volumes and make adjustments to control the operation and advise the oncoming operator of problems or unusual conditions.

Will load mobile LNG equipment as required.

Shall safely cool down equipment and maintain the Plant in a state of readiness, for peak shave sendout at short notice.

Shall maintain liaison with Gas Control for communication on send out and liquefaction.

Shall report all questionable conditions to the Plant Superintendent.

Shall do running repairs and general maintenance.

Shall do major repairs, overhaul, general maintenance, painting and grounds maintenance during periods when time and responsibilities permit.

Shall arrange for specialist maintenance service as required.

Shall perform duties as assigned, including preparation of reports, manuals and procedures; jobs in other sections of the Company; and operate a Terasen vehicle.

LNG Operator 2 will be in the entry position. Progression from an LNG Operator 2 to an LNG Operator 1 will be dependent upon demonstrated competence to carry out all aspects of the job.

This will include successful completion of a prescribed training program from IGT, and a hands-on operating test to demonstrate proficiency.

Must obtain and hold a Refrigeration Operator Certificate or a Power Engineer's Certificate (Fourth Class) from the Boiler and Pressure Vessels Safety Branch of the Ministry of Municipal Affairs, Recreation and Culture (MOMARC).

Must be able to operate the Plant on his own under all conditions, except sendout, where two operators are normally required.

Progression from an LNG Plant Operator 2 to an LNG Plant Operator 1 may occur after one year. If he fails to progress to LNG Operator 1 within two years he shall revert to his previously-held position. In the case of relief operators, times will be considered cumulatively.

Qualifications
1. Must have a thorough knowledge of physics, chemistry, electricity and basic process control equivalent to one year post high school and must have the ability to acquire a thorough knowledge of the gas liquefaction process.
2. Should have experience with some or all of the following, or the ability to acquire thorough knowledge quickly: Flow meters; electronic and pneumatic instrumentation; large heavy-duty compressors with electric motor drives; LNG pumps and gas vaporizers.
3. Process plant operating experience and/or process plant maintenance experience at a journeyman level highly desirable.
4. Must be able to work under stress and work alone.
5. Must be able to maintain records and logs of Plant operation.
6. Must be capable of keeping abreast of new technology as it applies to Plant operation.
7. Must be in good physical condition, be able to climb ladders and have no fear of heights.
8. Must qualify to drive Terasen vehicles.

Shift Coverage
Plant operators will work shifts as required*. The operators will work day shift on a normal day shift basis at the LNG Plant on maintenance or overhaul or in other areas of the Company as required.

*Rotating 12-hour shift presently 3-2, 2-3, 2-2.

<u>LABOURER</u>

An employee so classified must hold a current B.C. Class 5 Driver's License. Shall perform unskilled work under supervision as assigned, such as excavation, traffic control and manual backfilling. Shall be trained to use tools and equipment to allow him to progress to the Utility Assistant classification after a probationary period of twelve (12) months.

<u>LEAK SURVEY TECHNICIAN</u>

An employee so classified must hold a current B.C. Class 5 Driver's License. Must be capable of carrying out routine leak surveys and operating pipe locators and combustible gas indicators of the hot wire or flame ionization type on distribution and transmission facilities and be capable of doing related minor maintenance work. Must be capable of working without direct supervision. May be required to operate light equipment and assist in the installation of distribution mains and services. Is not required to supervise the work of other employees when assisting in the installation of mains and services. May perform plastic fusion under the direction of a Crew Leader.

<u>MACHINIST</u>

Shall have served a recognized apprenticeship with a BCTQ equivalency or have a minimum of four years varied experience in the operation of machine tools such as lathes, planing, slotting, milling, shaping, and grinding machines.

Shall be qualified and capable of working from Engineering drawings or sketches and independently setting up, laying out, and successfully completing work of a journeyman calibre.

Shall use instruments and testing equipment associated with close tolerance machining and fitting operations such as measurement devices, plug, thread and other gauges, material hardness testers, etc.

Shall set up and direct operations on a range of machine tools for other operators.

Shall carry out machining and fitting operations required in overhaul of all sizes of four and two cycle internal combustion engines, hydraulic motors and drives, hydraulic jacking and pumping equipment, air compressors, water pumps, pneumatic equipment, line stopper, hot tap and pressure control equipment, welding equipment, and other equipment, used in Gas Distribution work.

Shall carry out heat treatment of materials as necessary.

Shall act as Lead Hand when authorized.

A Lead Hand shall coordinate the work on projects where more than one tradesman (or higher paid classification) is employed.

Management will determine where Lead Hands are required.

Pay will be on a while-so-acting basis at plus 3% of his regular rate. No seniority will accrue.

MAINS AND SERVICE PLANNER

Duties & Responsibilities:
Under the direction of the Planning & Design Technologist, they will plan gas service and meter set renewals, new installations, replacements and alterations, including staking of main and service running lines and locating other utilities. They will provide on-site advice and guidance to Company work crews on work order implementations to overcome problems encountered and to other public utilities, municipal work crews and contractors whose work impacts on gas system planning or operations. They may provide technical advice and guidance to customers on alternative types of equipment or appliance applications. In addition, they will identify needs for private or municipal property access in cooperation with municipal authorities and other Company departments and obtain property owners' signatures on legal agreement documents. Developing and maintaining records on the effects of Municipal project planning on existing or planned gas distribution system and recommending action and priorities as well as compiling plans and sketches of layouts of service lines, meter sets and their locations, premise piping layouts, etc. on an as required basis will form some of their duties.

Qualifications:
Must have:
They will be a high school graduate and have related post secondary courses in drafting. Technical report writing is desirable. Knowledge of the gas distribution systems and installation practices, utilization and installation codes is required along with knowledge of design and layout of Municipal Services including water, sewer, lighting, telephone and power.

MATERIAL HANDLER

(Replaces Storeman and Shipper Receiver - Machine Shop)

Receives, unloads, inspects, records, stores, issues, loads, and ships equipment and materials as required or assigned.

Takes inventory; performs housekeeping duties; minor maintenance, repairs and assembly; operates material handling equipment; and performs administrative duties as required or assigned.

May be required to contact suppliers.

MATERIALS SHIPPER/RECEIVER

(Replaces Materials Receiver and Senior Storeman)

Coordinates and performs all duties associated with the receiving and shipping function of the Company's central warehouse.

May be required to perform the duties of a Material Handler.

MATERIALS TRUCK DRIVER

(Replaces Stores Truck Driver)

Loads, unloads, and transports materials and equipment in a safe and efficient manner.

Utilizes and operates all material and equipment required in the performance of the job.

Takes inventory, fills orders when assigned and performs administrative duties required of the job.
Is responsible for good housekeeping, stocking and safekeeping of all materials and equipment in compounds and stores, and on stores trucks.

Operates any vehicle which requires up to a Class 3 licence with air endorsement.

MATERIALS TRUCK & TRAILER OPERATOR

Duties & Responsibilities:

1. A materials Truck & Trailer Operator operates any vehicle which requires up to a Class 1 license with air brake endorsement.
2. Shall tow the LNG tanker.
3. Shall deliver pipe and operate the crane throughout the company’s operating territory.
4. Loads, unloads, and transports materials and equipment in a safe and efficient manner.
5. Shall be required to work in several areas such as yard and Stores at the discretion of the Warehouse Foreman.
6. Utilizes and operates all material and equipment required in the performance of the job.
7. Takes inventory, fills orders when assigned and performs administrative duties required of the job.
8. Is responsible for good housekeeping, stocking and safekeeping of all materials and equipment delivered in compounds and stores.
9. Must be available for out-of-town deliveries on short notice.

MEASUREMENT & CONTROLS TECHNICIAN

Duties & Responsibilities:

In accordance with Company Measurement Standards shall conduct measurement and regulating duties as follows:

1. Installing, testing, activating, adjusting, calibrating, maintaining, repairing, proving, trouble shooting, operating and evaluating the pressure regulation, measurement and system control and

monitoring equipment used in gas transmission, distribution and NGV systems according to company standards.

2. Program and operate all electronic natural gas measurement devices such as flow computers, electronic correctors, satellite communications systems, RTU's and other data collection equipment, and ensuring their proper operation and accuracy.
3. Completing detailed and accurate reports on pressure regulation and measurement matters such as technical reports, problem analysis and maintaining paper/electronic databases for above.
4. Providing technical direction, training and leadership to Company and Contractor personnel involved in any aspect of Measurement Standards, including installing, maintaining and abandoning regulation and measurement equipment.
5. Assisting with budgeting and maintain inventory control.
6. Available for on-call duties when scheduled.
7. Responsible for all measurement duties in his/her assigned are without supervision, and also be capable of system wide coverage (on-call, vacation coverage, etc.)

MEASUREMENT GROUP LEADER

Duties & Responsibilities:

The prime responsibility for this position is to ensure that on-specification gas is received, transported and delivered to customers safely, economically and accurately with minimal gas losses. Related duties and responsibilities include:

1. All duties of a Measurement & Controls Technician (formerly Sr. Measurement Technician).
2. Directing the activities of all Measurement & Controls Technicians dispersed throughout company operating districts including frequent travel to districts.
3. Providing leadership, coaching and administering training and skills development for all Measurement & Control Technicians.
4. Participation in the recruitment process of all Measurement positions.
5. Ensure all components of metering and/or regulating stations, system alarms, and non-PFM meter sets are efficiently sized, installed, operated, and maintained in accordance with company standards.
6. Administering capital, operating and maintenance budgets for the measurement activities.
7. Administering the documentation of unmetered gas losses to meeting accounting and environmental needs.
8. Utilizing data gathered from all available sources to determine, document reconcile and mitigate unaccounted for gas.
9. Administering the documentation of gas quality, including energy content, dew points, odorants and sulfurs for all systems.
10. Liaising with manufacturers, other utilities, associations, and government and participate in company standards development in order to research and ensure that the company's measurement practices consider best available technology.
11. Coordinating overall measurement activities with customers and other company groups.

Qualifications:

~~Qualifications of a Senior Measurement Technician.~~

a) A relevant Engineering,Technical Degree or Technologist Diploma or an acceptable equivalent.
b) Proven leadership, interpersonal, and administrative skills.
c) Excellent verbal and written communication skills are essential.
d) A minimum of five (5) years experience in a leadership role.
e) A minimum of seven (7) years experience in the measurement field

MEASUREMENT MECHANIC

(Merged with Meter Repairman 1, 2 and 3)

Preamble:
The company and the union have agreed to address a unique situation in the Measurement Shops by establishing this classification to encompass the Measurement Mechanic 1 and Measurement Mechanic 2 job classifications. Incumbents will learn the principles and practices of gas measurement and regulation, and the skills and techniques required to perform the duties of the job, by training and hands-on experience over a 30-month period.

The job posted will be that of Measurement Mechanic, and applicants will be considered in the following order:

1. Those who meet the required qualifications and are judged immediately able to satisfactorily perform all of the duties of the Measurement Mechanic job description. Any such applicants hired will receive the Measurement Mechanic 1 rate of pay;
2. Those who meet the required qualifications and are judged immediately able to satisfactorily perform all of the duties associated with the Measurement Mechanic 2 rate of pay;
3. All other applicants who meet the required qualifications.

In instances where departmental requirements are such that skilled applicants are required, selection may be based only on criteria #1, or criteria #1 or #2, and the job bulletin will state such requirement.

During the first 18 months on the job, incumbents will be paid at the Shop Assistant rate of pay and their work will be under the general direction of a Measurement Mechanic 1, or higher classification. Subject to satisfactory completion of the required training, and demonstrated ability to perform at least those duties associated with domestic and small commercial regulators and meters up to and including the 28 cu.m/h (1,000) series (including assembly of sub-assemblies), booking in meters, and duties of lesser skill, incumbents will progress to the Measurement Mechanic 2 rate of pay after 18 months of service in the classification.

Subject to satisfactory completion of any further training, and demonstrated ability to perform all aspects of the Measurement Mechanic job without direct supervision, incumbents will progress to the Measurement Mechanic 1 rate of pay after 12 months of service at the Measurement Mechanic 2 rate of pay, at which time they will be expected to take responsibility for all duties associated with the Measurement Mechanic job description.
Exceptions: Shop Assistants who have held a regular, bulletined position in the Measurement Shop for at least 12 months immediately prior to selection will progress to Measurement Mechanic 2 rate after 12 months in the Measurement Mechanic classification.

Applicants from a classification equal to or higher than Measurement Mechanic 2 on the wage schedule, will be paid at Measurement Mechanic 2 rate for 24 months before progressing to Measurement Mechanic 1 rate.

Acceleration to the MM2 rate may also be possible for an applicant judged to have relevant and related mechanical or measurement experience. Typically, related mechanical experience could reduce the time for progression to MM2 rate to 12 months, and related measurement experience could reduce the time of progression to 6 months.

Job Description:

Subject to the terms of the preamble during the incumbent's training phase, the Measurement Mechanic will perform all of the following duties without direct supervision, as well as all other duties associated with the operation of the Measurement Shop which are of an equal or lesser skill level as the duties listed:

1. Repair, adjust, prove, maintain and issue all classes of meters, auxiliary devices and regulators;
2. Understand and operate all measurement apparatus used to maintain metering and regulation devices;

3. Analyze all data derived from proof and other tests, and make proper determination as to type and scope of repairs and adjustments so as to ensure continued accurate performance with due regard to repair cost controls;
4. Adhere to all requirements for the shop Quality Assurance program;
5. Assemble metering and regulation sub-assemblies;
6. Accurately and neatly complete all documentation;
7. Assist the Measurement & Controls Technician and the Measurement Shop Leader as required, with duties of equal or lesser skill than those required of a Measurement Mechanic.
8. As a fully training incumbent, provide assistance in training those who are still in the training phase of the classification.

MEASUREMENT SHOP LEADER
(Replaces Mechanical Foreman (Measurement Shop))

Performs all of the duties associated with the operation of the Coastal or Interior Measurement Shop.

Directs and trains Measurement Mechanics and other classifications as required or assigned.

Ensures the efficient operation of the Measurement Shop by performing all of the duties required for this purpose, or assigned by the Supervisor or Manager.

Acts as liaison between the Measurement Shop and other company departments as required.

Assists the Manager or Supervisor in the development of long-term strategies for the Measurement Shop.

MECHANICAL FOREMAN (MACHINE SHOP)

Shall direct the work of the men under his charge in such a manner that the work may be carried out safely, efficiently and expeditiously.

Shall give technical direction and leadership to tradesmen with respect to the fabrication, repair and operation of tools and equipment used in the shop operation and serviced or built by the shop for work on the gas transmission and distribution systems.

Will also supply technical guidance and training to field personnel in the mechanical operation and maintenance of equipment such as line stopper and line break control equipment.

Shall be familiar with laying out metal work from drawings and sketches including planning of tooling and fabrication sequences for bench and machine tool production to obtain optimum efficiency and to complete fabrication or repairs on schedule.

Shall be familiar with machine shop standards and with dimensional and other tolerances applicable to metal fabrication, and with the testing instruments and techniques used in the inspection of mechanical components machined or otherwise fabricated to close tolerances.

Shall use tools and be familiar with set-up procedures for common machine tools such as lathes, milling machines, radial drills, etc.

Shall be responsible for ensuring that records of loaned out equipment from the Shop Tool Room are accurately recorded, that inventories of tool and equipment repair parts and spares are kept up to standard. Shall report to his manager or supervisor where schedules cannot be met or where problems in the operation, repair or fabrication of tools and equipment come to his notice.

Shall keep records of repair work carried out and materials used in repair of units and prepare all other necessary written reports related to the operation of the shop.

MECHANICAL FOREMAN (PREFABRICATION SHOP) (Previously: Mechanical Foreman (Meter Assembly Shop))

Shall direct the work of the employees under his charge in such a manner that the work may be carried out safely, efficiently and expeditiously.

Shall give technical direction and leadership to tradesmen with respect to the fabrication, alteration, testing repair and operation of large volume metering and pressure regulating assemblies.

Shall provide a close control and ensure adequate supplies at all times of all shop materials, inventory requirements including stocks of new and repaired pressure regulators, assemblies and a wide variety of replacement parts having due regard for usage, obsolescence, lead time for deliveries and other factors affecting essential materials.

Shall be familiar with the related Federal, Provincial Governments Code requirements as well as Terasen Policies and standards.

Shall schedule the work of the shop to meet planned completion dates.

Shall report to his manager or supervisor where problems arise in meeting completion dates for work.

Shall provide technical guidance and training for Utilization Technicians.

Shall inspect all completed work and witness pressure tests and proper settings of equipment.

Shall work with tools, carry out repair and assembly work.

Must hold a valid Provincial Grade B Gas Fitter's License.

MECHANICAL FOREMAN (WELDING SHOP)

Shall direct the work of the men under his charge in such a manner that the work may be carried out safely, efficiently and expeditiously.

Shall give technical direction and leadership to Fitter Welders and Shop Mechanics with respect to welding standards, welding codes and welding procedures.

Shall be familiar with operating requirements and interpretation of welding regulations in various codes applicable to the work carried out, such as CSAZ184, ASME Part IX, API 1104, Gas Group Welding standard practice instructions, etc., and be familiar with non-destructive testing methods, such as radiographic, ultrasonic, dye penetrant and magnetic particle type inspections, their scope and limitations and their application in the day to day work in the shop.

Shall ensure that equipment and components for the gas transmission and distribution systems fabricated in the shop conform with design drawings, welding code requirements and testing procedures.

Shall schedule the work of the shop to meet planned completion dates by ensuring that all materials are on hand and fabrication sequences are established and adhered to.

Shall report to his manager or supervisor where problems arise in meeting completion dates for work.

Shall assist in training programs by demonstrating welding and shop tool operation.

Shall work with tools, carry out pressure welding and, if required, be certified or recertified in conformance to Company Welder qualification tests and CSA standard Z-184 for Gas Transmission and Distribution systems.

Shall inspect all completed work and witness that pressure tests, where required, have been carried out and documented and make all necessary written reports, and as constructed drawings of work completed, etc. as required.

MILLWRIGHT

Duties & Responsibilities:

1. Shall perform all duties associated with transmission compressor stations, internal inspection of turbo machinery, trouble shooting, operation and maintenance of mechanical, pneumatic, hydraulic, and rotating equipment.
2. Shall develop and maintain predictive analysis and preventative maintenance schedules.
3. Shall prepare comprehensive documentation of construction, inspection, commissioning, operation and maintenance work.
4. Shall direct the work of other employees and contractors as it relates to compression mechanical maintenance activities.
5. Shall ensure safe, reliable and efficient operation of the workgroup, including work group planning and scheduling as it relates to these duties and responsibilities.
6. Shall keep abreast of changing technology as it relates to the "duties and Responsibilities".
7. In the event there is insufficient work as outlined above or more urgent work elsewhere, they may be temporarily scheduled for work for which they are qualified in other departments.
8. May be required to provide on call/standby coverage, and extensive travel may be required.

OPERATIONS TECHNICIAN

Duties and Responsibilities:

1. Performs valve operations, maintenance and repair on all valves including station valves and heaters.
2. Maintains and repairs buried and above-ground valves in D.P./I.P./T.P. piping; patrol and leak survey T.P. and I.P. piping systems; maintains transmission line right-of-way (e.g. slashing/clearing, marker posts); and perform cathodic and transmission/distribution rectifier readings.
3. Measures and fills odorant at all types of odorant facilities used by Terasen; operates odorant transfer systems and equipment and provides ongoing maintenance of safety equipment (e.g. eyewash stations, fire extinguishers, breathing air apparatus, spill kits).
4. Accurately documents problems found by using as built drawings and pipeline mosaics; completes all paper work on jobs being performed.
5. directs employees working as part of a crew.
6. Drills out, stops off and completes pressure control fittings as required.

Qualifications:

1. Valid Class 1 Driver's License with air brake ticket, if required.
2. Ability to obtain Transportation of Dangerous Goods Certificate.
3. Ability to use applicable tools, equipment and instruments.
4. Ability to understand and operate odorizing systems used by Terasen (Wick/Bypass/Injection).
5. Ability to learn transferring and measuring procedures related to odorant work.

6. Ability to plan and direct the work of others in a safe, efficient, expeditious manner and the ability to provide technical training and work leadership.
7. Demonstrated ability to exercise judgment, act on own initiative and work independently maintaining a high level and quality of performance.
8. Ability to prepare summaries, reports and complete work orders, etc., quickly and accurately.
9. Demonstrated ability to communicate effectively in person and by radio.
10. Ability to understand, follow and retain verbal and written instructions.
11. Demonstrated safe work habits and adherence to safety regulations.
12. General good health, and adequate physical strength, agility and dexterity to perform duties in remote and isolated areas for extended periods. Exposed to extreme weather conditions and wildlife.

PAINTER

Shall prepare and paint any gas distribution piping, equipment or buildings using brush, roller or spray equipment and to specification provided.

Shall operate and use sand and glassbead high pressure blasting equipment.

Drive company vehicles as required.

PAVING FOREMAN

Shall work on a paving crew and use the equipment and tools (trucks, heavy-duty tamper, pavement roller, rake, etc.) and supervise the work of men under his charge engaged in permanent (hot) paving repairs on roadways, driveways and other public and private properties so as to ensure that the work is carried out safely, efficiently, and expeditiously. This shall include that all repairs are carried out in accordance with Provincial, Municipal, and Company Standards.

Shall, when necessary, communicate as required to indicate that roadways under repair will be closed or restricted and take the necessary steps to barricade, flag and properly "sign" all work areas for guidance and protection of vehicular traffic and workmen.

Shall do the clerical work required.

PIPELINE LABOURER

Duties & Responsibilities:
Participate in pipeline operations and maintenance as directed, including but not limited to the following:
1. Clean and paint transmission system above ground appurtenances.
2. Vegetation control (utilizing chain saws, power trimmers, manual slashing etc.) on pipeline right-of-way and facilities, including block valve and pigging barrel sites.
3. Repair and replace right-of-way markers, line markers and other signage.
4. Provide manual labor for excavations, replacements and system improvements.
5. Removal and re-application of damaged pipeline coatings.
6. Assist in maintenance of all work equipment.
7. Willing and able to spend extended periods of time away from home base working on system facilities.
8. Oversee site operations for company employed student Labourers as required.

Qualifications:
a) Grade 12 or equivalent education.
b) Valid Class 5 BC Driver's License.
c) Must be in good physical condition.
d) Effective communication skills.
e) Possess basic computer skills.
f) Demonstrate safe work habits and adherence to safety regulations.
g) Demonstrate a good mechanical aptitude for operations and construction work.
h) Equipment operating (backhoe, dozer, etc.) skills would be an asset.
Note: There is no progression from Pipeline Labourer to Pipeline Technician II.

PIPELINE TECHNICIAN I

Duties & Responsibilities:
1. Perform all duties of a Pipeline Technician II
2. Respond to emergencies on the gas transmission system and carry out appropriate actions involving damage to the system or the escape of gas.
3. Perform all duties associated with pipeline system blow-downs.
4. Install, operate and maintain all new Transmission Pipeline Facilities as required.
5. Calibration of line-break valve equipment.
6. Conduct pressure tests for new facilities.
7. Perform pipeline integrity programs including, but not limited to: smart pigging, marine pipeline inspections, and cathodic protection system maintenance and surveys.
8. Perform (or supervise a contractor performing) right-of-way maintenance including, but not limited to: vegetation control, erosion control, system modifications etc.
9. Construct (or assist with directing a contractor to construct) capital upgrades/projects on the Transmission pipeline system.
10. Maintaining detailed and accurate records of works performed.
11. Perform any other pipeline operational or maintenance duties as directed.
12. May be required to participate in on-call program.

Qualifications:
a) Qualifications of a Pipeline Technician II, plus the ability to perform duties and responsibilities of a Pipeline Technician I.
b) Thorough understanding of the operating principles of gas transmission operations.
c) Ability to evaluate conditions quickly and accurately and makes decisions to achieve optimum results, particularly under emergency and/or stressful circumstances.
d) Capable of reading and interpreting Engineering drawings, technical reports and operating manuals.
e) Class 1 Drivers license with air endorsement.
f) Must have three years experience as a Pipeline Technician II.

PIPELINE TECHNICIAN II

Duties & Responsibilities:
1. Perform all duties of a Pipeline Labourer.
2. Operate pipe and cable locating instruments.
3. Assist with responding to emergencies on the gas transmission system.
4. Assist with pipeline system blow-downs.
5. Inspect and maintain pipeline right-of-ways and facilities as directed.
6. Assist with transmission pipeline integrity programs.

7. Provide inspection for third party crossings or infringements of the pipeline system under guidance from more experienced personnel.
8. Drive, operate and maintain all equipment used in Transmission Operations work.
9. Perform any other pipeline operational or maintenance duties as directed.
10. May be required to participate in on-call program.

Qualifications:

a) Qualifications of a Pipeline Labourer, and 3 years experience in the natural gas industry, plus the ability to perform duties and responsibilities of a Pipeline Technician II.

b) Class 1 drivers license with air endorsement is desirable but not mandatory.

c) Progression to a Pipeline Technician I will require a minimum of three years of experience in transmission pipeline operations as well as successful completion of a work-related examination developed by the Company.

d) Valve maintenance experience is desirable.

<u>PLANNING & DESIGN TECHNOLOGIST</u>

Duties & Responsibilities:

1. Ensures the efficient operation and maintenance of company facilities by performing all duties required for this purpose, or as assigned by the manager and/or designate.
2. Directs the work of the contractors and other workgroup categories in such a manner that the work is carried out safely, efficiently and expeditiously.
3. Provides technical direction and leadership to Company, contractors and other workgroup categories involved in any aspect of company facilities, their electrical & mechanical systems, utilities and grounds.
4. Assists in planning work tasks related to the operation and maintenance of company facilities, their electrical & mechanical systems, utilities and grounds.
5. Assists in the development, implementation and instruction of training and operating programs.
6. Applies the related code requirements, institutional practices and company policies & standards as they related to the operation and maintenance of company facilities.
7. Ensure that the facility structural systems, electrical & mechanical systems, life safety systems, utilities and grounds are functioning optimally.
8. Inspects the work of contractors and other workgroup categories maintaining, modifying and overhauling facilities and utilities in order to ensure that work is completed to company standards.
9. Works with tools and carries out maintenance and modification to facilities, their electrical & mechanical systems, utilities and grounds other than where prohibited by codes.
10. Completes all documentation required by the position.
11. May also be assigned other Facility tasks that the individual is capable of performing.

Qualifications (Must Have):

1. Inter-Provincial Journeymen’s Refrigeration Mechanic Ticket
2. Inter-Provincial Journeymen’s “B” Gasfitter’s Ticket
3. Minimum 5 years Journeymen’s directly-related and relevant facilities experience in operation, maintenance, construction and commissioning of related electrical & mechanical systems and utilities.
4. Demonstrated experience in troubleshooting and programming VFD, DDC, DCS and/or PLC control systems
5. Proficiency in developing & interpreting facility systems design & construction drawings
6. Demonstrated leadership and decision-making capabilities and ability to work effectively with a minimum of supervision
7. Demonstrated ability to communicate verbally, and in writing, clearly and concisely
8. Intermediate understanding of Preventative & Predictive Maintenance Theory and Programs

9. Demonstrated ability to effectively analyze & troubleshoot system problems, prepare written administrative documentation and keep accurate records
10. Expert understanding of systems used to maintain and operate company facilities, i.e. electrical & mechanical systems, utilities and grounds
11. Demonstrated intermediate knowledge of Facility codes, regulatory requirements and industry practices
12. Intermediate understanding of Microsoft Office applications
13. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis; must have Class 5 Driver's License and a safe driving record.

Additional Information

1. Department has varying start times to provide coverage from 0600 to 1800 hours
2. May be required to work out of town within Terasen Gas service territory
3. Standby coverage may be required.

<u>RECYCLING MECHANIC</u>

Shall work in the recycling operation and shall supervise employees as assigned in carrying out the following duties: Sorting all items returned from the field into recoverable materials or scrap; scrap shall be properly sorted to maximize the value of disposal.

All recoverable items shall be restored to usable condition; restored items will be sorted by Stores folio numbers and returned to stock using the prescribed routines.

Shall be responsible for the efficient and effective operation of this section and will recommend methods and procedures that will achieve the highest possible dollar return from our change-out material.

Will report directly to the Manager or Supervisor of salvage operations.

Qualifications:

1. Demonstrated mechanical aptitude.
2. Demonstrated work leadership ability.
3. Demonstrated good written and verbal communication skills and interpersonal skills in dealing with external shops, etc.
4. Demonstrated initiative and sense of responsibility.
5. The ability to work independently with minimal direction.
6. Demonstrated safe work habits and efficient work history.

NOTE: When the current incumbent in the Recycling Mechanic classification leaves that classification it shall be eliminated.

<u>SENIOR MATERIAL HANDLER</u>

(Replaces Warehouseman)

Performs all of the duties associated with the operation of a warehouse and its delivery system.

Directs other employees who may be assigned to the warehouse.

Is responsible for taking inventory, and performing all administrative duties required by the job.

SENIOR PIPELINE TECHNICIAN

Duties & Responsibilities:

1. Perform all duties of a Pipeline Technician I.
2. Direct and control safety on the job, in the shop and at field locations.
3. Provide technical direction and leadership to Company and Contractor personnel involved in any aspect of Transmission Pipeline operations and maintenance.
4. Train subordinate employees in the use of equipment, tools and instruments specific to pipeline operations and maintenance.
5. Responsible for daily work assignments of Transmission Operations crew.
6. Responsible for planning, scheduling and implementing construction projects as requested.
7. Respond to emergencies on the Transmission System, and direct and carry out appropriate actions involving damage to the system or the escape of gas.
8. Responsible for site supervision of all hot work and tie-ins on the transmission pipeline.
9. Maintain accurate operations, construction and maintenance records.
10. Monitor and maintain status of emergency equipment.
11. Keeps up-to-date with all job related Company policies and procedures.
12. Participate in "0n-call" program.

Qualifications:

a) All the qualifications required of a Pipeline Technician I, plus the ability to perform the duties and responsibilities of a Senior Pipeline Technician.
b) Proven ability to supervise employees.
c) Proven ability to provide job specific training to Transmission employees.
d) Superior communications skills.
e) Must have three years experience as a Pipeline Technician I.

SENIOR SALES AND SERVICE TECHNICIAN

The Senior Sales and Service Technician must qualify for all lower classifications in Sales & Service, and be able to perform all duties associated with those qualifications without supervision.

The Senior Technician is the day-to-day work leader for one or more distribution field personnel engaged in all work identified with the sales and service function. As such, the Senior Technician is responsible, under the general direction of a manager or supervisor branch manager, for orientation and training, for effective scheduling, for on-the-job direction, for all related documentation, and for reporting to the supervisor/manager.
The Senior Technician must be able to carry out the duties of this classification under only general direction and with a minimum of supervision, and must be able to relieve a branch manager when so assigned.

The Senior Technician must be able to service the full range of gas burning equipment and associated control media in the residential and commercial fields; exercise judgement under general terms of reference in carrying out remedial action and/or suspending service with proper follow-up action under codes and other requirements; construct, test and certify piping installation metering and gas pressure regulating equipment to Terasen standards and government codes; and carry out follow-up maintenance programs.

The Senior Technician offers current and potential customer technical and promotional advice on all matters relating to their requirements, including matters of utilization (such as efficiency, conservation and insulation), and participates in the company's merchandise sales program.

The Senior Technician must be able to repair, adjust and service all equipment in the residential and commercial fields to the full extent of the B ticket; maintain in-the-field gas measurement and pressure regulating equipment; carry out a variety of tests related to gas utilization involving the testing for and measurement of oxygen and carbon dioxide and other products and take remedial action as required; carry out a variety of duties in support of other departments (e.g. system pressure surveys, marketing programs, etc.); act as a technical resource for other distribution field personnel related to fitting, relighting and other Sales & Service work; and take responsibility for directing response to major emergency incidents such as fires, explosions, asphyxiation, and unplanned outages, and in so doing take all necessary initiatives, including direction of fire police and other authorities, as well as other Terasen personnel.

This classification requires a high degree of technical organizational leadership and communication skills. It is filled by appointment by the Company based on ability and seniority.

SENIOR SHOP MECHANIC 1 (BUILDINGS & UTILITIES)

Shall be responsible for the inspection and maintenance of Company buildings, their utilities and grounds within a designated area.

Shall ensure that heating, air conditioning and ventilation equipment, water, gas, electricity, sewerage, drainage, fire alarm and fire sprinkler systems, etc., are functioning properly.

Shall inspect the work of contractors maintaining, modifying and overhauling these buildings and utilities in order to ensure that work is satisfactorily completed.

Shall provide direction to personnel assigned to him and shall work with tools. He shall carry out minor maintenance and modification to buildings and their utilities of a general nature other than where prohibited by codes.

Shall carry out seasonal overhaul of air conditioning plant and heating plant including boilers, pumps, compressors, etc.

Shall complete all inspection reports and other documents required by the position.

Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis; must have safe driving record.
2. Minimum of two years building maintenance experience as a Shop Mechanic 1 (Building and Utilities).
3. Demonstrated leadership capabilities and ability to work with a minimum of supervision.
4. Thorough understanding of Lochburn building utility system.
5. Demonstrated ability to analyze system problems and prepare written reports and keep accurate records.
6. Ability to plan, organize and monitor the work of employees under his direction.

SHOP ASSISTANT

A Shop Assistant shall carry out semi-skilled operations in a Shop such as uncrate, clean and prepare for assembly all parts, equipment, raw materials, etc. used for fabrication or repair in a Shop and/or field.

Shall clean items returned from the field using mechanical or hand operated equipment, carry out dismantling of designated tools and equipment to permit servicing and assist with the assembly of similar equipment.

Shall use hand and power operated tools such as hand drills, sanders, saws, impact wrenches, pipe threaders, power brushes and stud setters required to carry out his work.

Shall also use power operated machines such as pipe threading machine, hydraulic press, drill press, grinders, etc.

Shall carry out standard prefabricated assemblies and assist in the assembly of pipe and fittings during the construction and/or maintenance of prefabricated meter sets, regulator stations or similar assemblies.

Will work under direction as required by the nature and complexity of the job.

Shall operate all mechanized material handling equipment used in the shops such as cranes, electric shop trucks, forklifts and similar equipment.

Duties will include cleaning of shop tools and equipment and general housekeeping in the Shops.

(*) Deleted Ref. to 'Common Seniority' in 1989.

<u>SHOP MECHANIC 1 (BUILDINGS & UTILITIES)</u>

Shall be responsible for the inspection and maintenance of Company buildings, their utilities and grounds within a designated area.

Shall ensure that heating, air conditioning and ventilation equipment, water, gas, electricity, sewerage, drainage, fire alarm and fire sprinkler systems, etc. are functioning properly.

Shall inspect the work of contractors maintaining, modifying and overhauling these buildings and utilities in order to ensure that work is satisfactorily completed.

Shall direct the work of Utility Assistants assigned to him and will work with tools.

Shall carry out minor maintenance and modification to buildings and their utilities of a general nature other than where prohibited by codes.

Shall carry out seasonal overhaul of air conditioning plant and heating plant including boilers, pumps, compressors, etc.

Shall complete all inspection reports and other documents required by the position.

<u>SHOP MECHANIC 2 (BUILDINGS & UTILITIES)</u>

Shall be responsible for the inspection and maintenance of Company buildings, their utilities and grounds within a designated area.

Shall ensure that heating, air conditioning and ventilation equipment, water, gas, electricity, sewerage, drainage, fire alarm and fire sprinkler systems, etc., are functioning properly.

Shall inspect the work of contractors maintaining, modifying and overhauling these buildings and utilities in order to ensure that work is satisfactorily completed.

Shall direct the work of Utility Assistants assigned to him and will work with tools.

Shall carry out minor maintenance and modification to buildings and their utilities of a general nature other than where prohibited by codes.

Shall carry out seasonal overhaul of air conditioning plant and heating plant including boilers, pumps, compressors, etc.

Shall complete all inspection reports and other documents required by the position.

After satisfactorily completing 12 months service in the position, shall be classified as Shop Mechanic 1.

Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis, must have safe driving record and be able to pass Company driving tests.
2. Good mechanical aptitude including carpentry and blueprint reading.
3. Minimum of two years related industrial building maintenance experience.
4. Basic knowledge and experience in heating and ventilating.
5. Ability to work with minimum of supervision.
6. Ability to supervise work of Utility Assistants when required and to coordinate and inspect work of building contractors.
7. Experience in keeping and processing related records.

Other Considerations:

1. On feet most of day.
2. Considerable bending and lifting.

Automatic progression to Shop Mechanic 1 would occur upon the completion of 12 months satisfactory service.

SHOP MECHANIC 3 (BUILDINGS & UTILITIES)

The Shop Mechanic 3 (B&U) is a designated training position.

Employees selected for this training undertake a program of study leading to certification by BOMA (Building Owners' and Managers' Association) as a Systems Maintenance Technician (SMT). The SMT program consists of five courses of study related to Building Maintenance plant and systems. Courses are taken on the employee's own time, either in BOMA's training facility in Vancouver or on a supervised home study program.

The Shop Mechanic 3 uses appropriate hand-and power-operated tools to perform a variety of duties such as preventative maintenance services; minor repairs and construction tasks involving carpentry, plumbing, mechanic and other trades; and assists other Shop Mechanics and Electrician in major construction, repair and overhaul projects.

Duties include cleaning and maintenance of shop tools and equipment and general housekeeping in the Building Maintenance Shop.

Drives company vehicles as required.

A Shop Mechanic 3 must demonstrate good aptitude and proficiency for this type of work during training.

Upon satisfactory completion of 12 months service in this position, the successful completion of two modules of the BOMA SMT program, and meeting the ability qualifications of the Shop Mechanic 2 classification, the employee shall be classified as a Shop Mechanic 2. If s/he fails to progress to Shop Mechanic 2 within 18 months, sh/e shall revert to her/his previously-held classification.

Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis.
2. A safe driving record and able to pass Company driving tests.
3. Demonstrated mechanic ability.
4. Physical fitness and agility to be able to perform all duties effectively and efficiently. Physical demands include working in restrictive locations and enclosures, considerable bending and lifting, climbing and working on ladders, and on feet most of the day.
5. Ability to work alone and maintain a high level and quality of performance.
6. Ability to complete two modules of the BOMA SMT program within 18 months.

<u>SHOP MECHANIC 1 (MACHINE SHOP)</u>

A Shop Mechanic 1 shall be required to fabricate and repair a range of tools, instruments and equipment used in gas distribution work including modifications, binning and outfitting of work vehicles to suit gas distribution applications.

Shall direct the work of a Shop Mechanic 2 and Shop Assistants when assisting him.

Shall use manual and power operated hand tools and machine tools such as grinders, drill press and hydraulic press including set-up of these machines.

Shall operate lathes, milling machines, etc., including minor set-up work on these machines.

Shall carry out overhauls of all sizes of four and two cycle internal combustion engines, hydraulic motors and drives, hydraulic jacking and pumping equipment, air compressors, water pumps, pneumatic equipment, line stopper, hot tap and pressure control equipment, welding equipment, etc.

Shall do oxyacetylene welding and brazing and heat treatment required in repair and fabrication of tools, but shall not be required to possess pressure welding certificates.

Shall act as Lead Hand when authorized.

A Lead Hand shall coordinate the work on projects where more than one tradesman (or higher paid classification) is employed.

Management will determine where Lead Hands are required.

Pay will be on a while-so-acting basis at plus 3% of his regular rate. No seniority will accrue.

<u>SHOP MECHANIC 2 (MACHINE SHOP)</u>

A Shop Mechanic 2 shall be required to fabricate and repair a range of tools, instruments and equipment used in gas distribution work including modifications, binning and outfitting of work vehicles to suit gas distribution applications.

Shall direct the work of Shop Assistants when assisting him.

Shall use manual and power operated hand tools and machine tools such as grinder, drill press, hydraulic press, etc., including set-up of these machines.

Shall carry out overhauls of all sizes of four and two cycle internal combustion engines, hydraulic motors and drives, hydraulic jacking and pumping equipment, air compressors, water pumps, pneumatic equipment, line stopper and hot tap and pressure control equipment, welding equipment, etc.

Shall do oxyacetylene welding and brazing required in repair and fabrication of tools, but shall not be required to possess pressure welding certificates.

After satisfactorily completing 12 months service in the position, shall be classified as Shop Mechanic 1.

SHOP MECHANIC 1 (PREFAB SHOP)

A Shop Mechanic 1 shall be required to construct, fabricate, assemble, disassemble, alter, test and repair all types of Industrial/Commercial/ Residential meter sets, manifolds, and piping assemblies and shall bench test and adjust regulators and confirm function. Shall use manual and power operated tools, equipment and machinery. Shall use oxyacetylene equipment to heat pipe and fittings for alignment during the assembly of meter sets. The Shop Mechanic 1 (Prefab) must have a valid Provincial Grade B Gas Fitters License, and must have successfully completed the probationary period for the Shop Mechanic 2 (Prefab) or the Utilization Technician 2 positions.

Qualifications

1. Good mechanical aptitude and pipe fitting abilities.
2. Knowledge of meter sets, piping assemblies and industrial regulators and proficiency in the use of hand and power operated tools, equipment and machinery, including oxyacetylene equipment.
3. Proficiency in interpreting work orders, mechanical drawings, sketches and written instructions and be able to accurately record completed work.
4. Ability to work with minimum supervision and maintain a high level and quality of performance.
5. Ability to direct the work of Shop Mechanic 2's and Shop Assistants.
6. Demonstrated safe work habits and efficient work history.
7. Grade B Gas Fitter License.

SHOP MECHANIC 2 (PREFAB SHOP)

A Shop Mechanic 2 shall be required to construct, fabricate, assemble, disassemble, alter, test and repair all types of Industrial/Commercial/Residential meter sets, manifolds, and piping assemblies and shall bench test and adjust regulators and confirm function. Shall use manual and power operated tools, equipment and machinery. Shall use oxyacetylene equipment to heat pipe and fittings for alignment during the assembly of meter sets. The Shop Mechanic 2 (Prefab) will automatically be promoted to Shop Mechanic 1 (Prefab) upon attaining the Provincial Grade B Gas Fitters Licence and upon completion of the twelve months period of probation for the Shop Mechanic 2 (Prefab). Failure to obtain the Class B license within the twelve month period shall result in the employee being returned to his previously held classification.

Qualifications

1. Good mechanical aptitude and the ability to acquire pipe fitting skills.
2. Capable of acquiring a thorough knowledge of meter sets, piping assemblies and industrial regulators and become proficient in the use of hand and power operated tools, equipment and machinery, including oxyacetylene equipment.

3. Capable of becoming proficient in interpreting work orders, mechanical drawings, sketches and written instructions and be able to accurately record work done.
4. Initiative and sense of responsibility.
5. Ability to work with minimum supervision and maintain a high level and quality of performance.
6. Ability to direct the work of Shop Assistants.
7. Demonstrated safe work habits and efficient work history.

SHOP MECHANIC 1 (WELDING SHOP)

A Welding Shop Mechanic shall be required to fabricate and repair a range of tools and equipment used in gas distribution work and direct the work of Shop Assistants when required.

Shall use manual or power operated hand tools and machine tools, including combination punch and metal forming press, power rollers, power shears, metal bandsaw, punch press, nibblers, drop hammer, drill press, spot welder, hot forging equipment, etc.

Shall carry out electric arc and oxyacetylene welding, brazing and heat treatment of metals, but shall not be required to possess pressure welding certificates.

Shall do other semi-skilled work required in the shop.

SHOP MECHANIC 2 (WELDING SHOP)

A Welding Shop Mechanic shall be required to fabricate and repair a range of tools and equipment used in gas distribution work and direct the work of Shop Assistants when required.

Shall use manual or power operated tools and machine tools, including combination punch and metal forming press, power rollers, power shears, metal bandsaw, punch press, nibblers, drop hammer, drill press, spot welder, hot forging equipment, etc.

Shall carry out electric arc and oxyacetylene welding, brazing and heat treatment of metals, but shall not be required to possess pressure welding certificates.

Shall do other semi-skilled work required in the shop.

After satisfactorily completing 12 months service in the position, shall be classified as Shop Mechanic 1.

Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis; must have safe driving record and be able to pass Company driving tests.
2. Mechanical aptitude.
3. Ability to acquire a thorough knowledge of theory and operation of tools and equipment relating to the distribution system.
4. Ability to become proficient in the use of hand and power operated tools required in maintaining and overhauling mechanical equipment.
5. Ability to become proficient in carrying out complete overhaul of gasoline motors, pumps, pneumatic tools, line stopper equipment, and other tools used on the gas system.
6. Ability to become proficient in interpreting work orders, mechanical drawings, sketches and written instruction and record work done.
7. Initiative and sense of responsibility.
8. Ability to work independently and maintain a high level and quality of performance.

Other Considerations:
1. On feet most of day.
2. Considerable bending and lifting.

Automatic Progression to Shop Mechanic 1 would occur upon the completion of 12 months satisfactory service.

STATION MECHANIC 2

The Station Mechanic 2 will assist in the operation and maintenance of all pressure and flow control stations including the Huntingdon Gate Station, Regulator Stations, City Gate Stations, Thermal and Turbine Power Generating Stations and any other stations or regulator vaults.

Shall assist in servicing, operating and adjusting odorization and station heater equipment.

Shall use all tools and instruments required to carry out maintenance work on station equipment including overhaul of pressure control and limiting devices such as self-actuated type regulators, filters, scrubbers, meters, valves and odorization equipment.

Shall adjust pressure control equipment and operate stations manually as required.

Shall work in conjunction with Instrument Shop personnel and the Gas Load Control Centre if required.

Shall change pressure, temperature and flow recorder charts as directed and check stations to ensure that all pressure control devices are in good operating condition and left at the designated set points.

Shall check for and repair minor station piping leaks.

Shall relight heater pilots and burners, adjust heater thermostats and carry out other minor checks and adjustments on station heaters.

Shall assist in the operation and maintenance of portable and satellite L.N.G. facilities.

Shall relieve as a System Operations Technician when required, and if qualified.

Will carry out the duties of a Distribution Mechanic
, when required except those that he may be unqualified to perform, such as welding.

Qualifications:
1. Must have Grade 12 education with Grade 11 Mathematics and Physics or equivalent.
2. Must have the ability to acquire a thorough understanding of the operating principles of gas pressure regulation, flow meters, pneumatic instrumentation.
3. Should have some experience in the operation and maintenance of gas metering and regulating stations.
4. Must complete courses of study in the basic principles of gas measurement and regulation, as requested by the Company.
5. Must have demonstrated an ability to evaluate and react appropriately to normal and/or emergency operating conditions.
6. Must be able to maintain good records and reports.
7. Must be able to carry out his duties with a minimum of supervision.
8. Must be capable of being trained to interpret engineering drawings, technical reports and operating manuals.
9. Must be in good physical condition.

<u>STORES LEADER</u>

(Replaces Stores Foreman and Material & Equipment Man)

Performs all of the duties associated with the operation of the stores and delivery system.

Trains and directs the work of Material Handlers and others as required or assigned.

Ensures the efficient operation of the stores by performing all duties required for this purpose, or assigned by the manager or supervisor.

Acts as liaison between stores and other company departments as required or assigned.

<u>SYSTEM OPERATIONS APPRENTICE AND SYSTEM OPERATIONS TECHNICIAN-18</u>

(Replaces Industrial Technician, Station Mechanic 1 and Pressure & Measurement Technician 1, 2 and 3)

A System Operations Apprentice shall be trained in all job skills identified within the System Operations Technician job description, and shall progressively perform all aspects of this work without supervision as stipulated by the System Operations Apprentice Program.

Technical Qualifications:
Must Have:

- Possession of a valid Provincial Class B Gasfitter's License
- Grade 12 education with math 12 and Physics 12, or equivalent
- Post secondary training in pneumatic and electronic process instrumentation, equivalent to 6 units of the BCIT Electrical and Electronic Technology curriculum or another equivalent, recognized post secondary curriculum;

  OR

  Possession of a valid Provincial Class A Gasfitter's License
- Post secondary training in pneumatic and electronic process instrumentation, equivalent to 6 units of the BCIT Electrical and Electronic Technology curriculum or another equivalent, recognized post secondary curriculum;

  OR

- A Technologist Diploma in Instrumentation or a field related to the natural gas industry.

Progression:
After a total of thirty-six months satisfactory performance, and subject to demonstrated ability to perform all core competency job skills identified in the System Operations Apprentice Dacum job profile, and subject to possession of a valid Provincial Class A Gasfitter's License or, in the case of an apprentice with a Technologist Diploma have successfully passed the exam of the Provincial Class A Gasfitter's License program, a System Operations Apprentice shall progress to System Operations Technician.

Progression to the 18-month rate is also subject to meeting the appropriate competency requirements which are being developed as part of the SOA Program.

An employee shall not be denied progression due to lack of internal training opportunities which are not attributable to the employee.

SYSTEM OPERATIONS TECHNICIAN (SOT)

(Replaces Industrial Technician, Station Mechanic 1 and Pressure & Measurement Technician 1, 2 and 3)

A System Operations Technician shall, without direct supervision:

- install, activate, maintain and repair all equipment used in flow control/gate/regulation/ valve and customer metering stations, including but not limited to pressure control, measurement, telemetry and odorant systems; and all classes of gas utilization equipment, including satellite propane and LNG facilities, and NGV compressor and dispenser systems.

- operate mobile LNG transport and vaporization systems.

- direct the work of others, who are acting as helpers or providing support services on job sites.

- perform other duties of a similar or lesser complexity as required.

Technical Qualifications:
Must successfully complete the System Operations Apprentice program, and possess a valid Provincial Class A Gasfitter's License, or in the case of an employee with a Diploma of Technology, have successfully passed the exam of the Provincial Class A Gasfitter's License program.

TRUCK DRIVER

Operates appropriate vehicles and equipment for the purpose of pick up and delivery of tools, equipment, materials and debris or spoil to and from the various worksites, muster points, and operations centres.

Required to load, unload and transport cargo in a safe and efficient manner.

Required to work alone or as part of a crew on worksite restoration such as repair of lawns and gardens, replacing concrete walkways, pavement repairs, fence or wall reconstruction and other related duties.

May be required to supervise the work or one or more employees.

Responsible for ensuring vehicle is clean and in safe operating condition.

Must be able to operate any vehicle which requires up to a Class 3 licence with air endorsement.

WAREHOUSE & DELIVERY LEADER

1. Perform all of the duties associated with the operation of the Central Warehouse and Meter Warehouse.
2. Training and directing the work of Shipper/Receivers, Material Handlers, Material Truck Drivers, Measurement Mechanics, Senior Material Handler, Stores Leader and others as required or as assigned.
3. Maintaining an adequate workforce by reviewing staff requirements and time off requests, and making recommendations to the Warehouse and Delivery Manager.
4. Scheduling and rescheduling work in response to rapidly changing workload, and prioritizing receipt and delivery of goods in response to critical requirements.

5. Acting as a liaison between the Warehouse and the Meter Shop, Purchasing, Accoutns Payable, Regional Warehouses, and other departments as required or assigned.
6. Maintaining source document files, e.g. Purchase orders, receipts, return or vendor, etc.
7. Adhere to all requirements for the Meter Quality Assurance Program.
8. Providing procedural expertise with regard to the inventory and meter control systems and material acquisition requirements to all client groups throughout the company.
9. Monitoring and maintaining control or receipts of manufactured stock, remanufactured meters, recalled meters and new meters.
10. Coordinating inventory checks, counts, and controls as required or assigned by the Warehouse and Delivery Manager.
11. Assists the Manager in the development of long-term strategies for the Warehouse and Delivery group.

WELDER 1

A Welder 1 shall perform all operations in the shop necessary to fabricate (using gas metal arc, manual arc or gas welding), pressure piping and vessel systems used on gas transmission and distribution networks. This will include interpretation of engineering drawings, spool sheets, etc., laying out of the job, fit up and welding preparations of all components and the pressure testing of completed assemblies and sub-assemblies to determine weld and joint integrity. It will also include the fabrication of non-pressure components and installation of pressure controlling devices, their associated instrumentation and control lines in prefabricated regulator vaults or similar assemblies. In the field shall do pipe line welding including hot tap welds, fire welds and leak repair welds on lines operating up to and including transmission line pressures. Shall be required to hold a minimum B welding qualifications registered in his/her log book; registered with the Boiler and Pressure Vessels Branch of B. C.; and must be able to obtain Company oxy-acetylene welding ticket. Will be responsible for running a crew for the installation and maintenance of transmission and distribution mains and services, regulator and meter sets. Will be responsible for making as-built drawings and completing the routine reports called for in his day-to-day work.

May be required to operate high pressure tapping and stopping equipment, propane plants, and mainline compressors, and carry out routine operating and maintenance duties in gate stations. Shall be responsible to the designated Manager or Supervisor for the operation of a town distribution system.

Shall direct and carry out appropriate actions during emergency incidents involving the escape of gas where potential hazard to persons or property exists.

This employee will act as a crew leader as required, as well as carry out welding functions with the crew.

YARD FOREMAN - (METRO)

The Yard Foreman shall direct the work of persons under his charge in such a manner that the work may be carried out safely, efficiently and expeditiously.

The Yard Foreman shall plan, organize, coordinate and direct yards work as directed by his manager or supervisor. This may include any and all facets of yards work required by the Metro Gas Distribution Department.

Areas of responsibility are to include any or all aspects of the Yard Operations.

The Yard Foreman shall liaise with and assist other areas and sections with labour and/or equipment and meet material handling needs as required.

The Yard Foreman will operate and do running maintenance on all types of support vehicles and equipment.

The Yard Foreman will train others as required, make all necessary written reports, prepare requisitions, sign for materials received and prepare time sheets for employees under his or her direction.

Is responsible for, and shall also perform the duties of the Recycling Mechanic.

Qualifications:
Must Have:

1. Demonstrated safe work habits and adherence to safety regulations and practices on a sustained basis.
2. Must have safe driving record and be able to pass the Company driving tests.
3. Mechanical aptitude.
4. Practical experience in the use of wheeled material handling equipment, mobile cranes, front end loaders, forklifts, dump trucks, etc. Must have experience in basic preventive maintenance of these units.
5. Demonstrated work leadership ability.
6. Demonstrated good written and oral communication.
7. Initiative and sense of responsibility.
8. The ability to work independently under general direction and maintain a high level of quality of performance.

July 10, 1989

LETTER OF UNDERSTANDING NO. 1

Deleted in 1999.

July 10, 1989

LETTER OF UNDERSTANDING NO. 2

Deleted in 2006. Incorporated into Article 5.

July 10, 1989

LETTER OF UNDERSTANDING NO. 3

Deleted in 1999.

LETTER OF UNDERSTANDING NO. 4
*(AMENDED)**- NEEDS SOME MORE WORK***
(Originally dated November 12, 1987, and signed by R. Dowling & L.J Seppala)

Re: 12-Hour Shifts at LNG Plant

Terasen and Local 213 of the IBEW will continue to be bound by the current collective agreement. However, commencing pay period 25, November 13, l987, the shift rotation for LNG Plant Operators will be a 3-2-2 configuration (3 on, 2 off, 2 on, 3 off . .) with a day shift from 08:00 to 20:00 and a night shift from 20:00 to 08:00. It is understood that this shift rotation shall not result in increased costs to Terasen, nor shall it result in decreased benefits to members of the Union. Therefore, all relevant Articles of the Agreement will be interpreted, with reference to LNG Plant Operators, so as to maintain the same costs and benefits contained in the current Agreement.

It is agreed that Operators will be paid in the following manner:

Sick Leave

Days will be converted into their hourly equivalent. Employees will be kept on their shift schedule and paid 12 hours per scheduled working day absent.

Long Term Disability

Employees will continue to be paid 70% of normal earnings based on a 40 hour work week.

WCB

Employees will continue to be paid 85% of normal earnings based on a 40 hour work week.

Leave of Absence for Jury Duty

Employees will be kept on their shift schedule and paid 12 hours for each scheduled working day absent.

Paid Leave of Absence Compassionate

Days will be converted into their hourly equivalent to a maximum of 24 hours.

Statutory Holidays

Each statutory holiday listed in Article 21.01 results in 8 hours being placed in each Operator's Statutory Holiday Time Bank.

An Operator not scheduled to work a Statutory Holiday will be paid 8 hours of straight time from the Statutory Holiday Time Bank.

An Operator scheduled to work shall receive double time for the hours worked. In addition, Operators who work the statutory holiday may choose to be paid 8 hours straight time or take time off from the Statutory Holiday Time Bank. Time off is taken in 12 hour days with the year-end balance paid out in cash.

Annual Vacation

Annual Vacation entitlement pursuant to Article 22.03 will be converted into its hourly equivalent and put into a bank. Time off can then be taken in 12 hour days with remaining partial days paid out in cash.

Any operator who completes a full year of service on the 12-hour shift schedule shall receive 112 hours vacation with pay in the succeeding year in addition to whatever entitlement he is eligible to receive under Article 22.03.

Such operator shall receive at least 96 hours on the summer write up as described in Article 22.04.

An operator with less than a full year's service on the 12-hour shift schedule shall receive in the succeeding year that proration of 112 hours shift vacation as determined by the number of days worked during the preceding year on a 12-hour shift divided by the total number of days which would have been worked on a normal 12-hour shift.

Posting of Schedules

Pursuant to Article 30.02.1 an operator will receive overtime premium for the first 8 hours of the shift notwithstanding the fact that the Operator's first shift is 12 hours long.

Penalty Pay

Days will be converted into their hourly equivalent and the maximum penalty pay will remain 24 hours.

Overtime

All references to an 8 hour day shall be substituted with a 12 hour day. The Union and Terasen agree to make joint application to the Director of Employment Standards for a variance of hours application.

True Bank, Legacy & Choices Days

Legacy (if applicable) and/or Choices Days will be converted into its hourly equivalent and put into a bank. Time off can then be taken in 11.25 hour days.

True Bank Days are earned days. All employees shall work a twelve (12) hours day and deposit three-quarters (3/4) hour into their true bank for each day so worked. If the employee is not at work for the full twelve (12) hour day, the three-quarters (3/4) hour is not earned and not deposited to the true bank for that day.

All True Bank Days earned in the current year shall be taken in the year following the year in which they were earned.

True Bank Days shall be taken as days off by the end of the year following the year in which they were earned or moved into a temporary transitional dollar bank which shall be cashed out by the end of the year 2009.

Twenty-Four Hour Coverage

When service requirements necessitate twenty four hour coverage, normal hours of work for shift workers shall be from 08:00 to 20:00 hours, Day Shift and from 20:00 to 08:00, Night Shift. Shift work shall be scheduled on a rotating basis and the period of schedule shall be a 3,2,2 configuration or an agreed to derivative. Shift times or the length of schedule may be changed when mutually agreed between Terasen and the employees concerned in any one operation. Terasen shall provide adequate relief at all times.

Shift Coverage

Plant Operators will work a 3,2,2, configuration when Plant requirements necessitate 24 hour coverage. The Plant may require 24 hour coverage for a portion of the year only. When 24 hour coverage is not required the Operators will work day shift or a shift cycle basis at the LNG Plant on maintenance and overhaul or they will work in other areas of the Coastal Region on a five and two basis.

In keeping with the spirit of this Letter of Understanding, any other Article of the Agreement which doesn't contemplate a 12 hour shift rotation will be interpreted, where necessary, in such a way as to maintain the integrity of the agreement by neither increasing costs nor decreasing benefits to the parties to the agreement.

Either party may terminate this Letter of Understanding by giving written notice of not less than 2 pay periods. Reversion to an eight hour day will not result in any additional cost to the Company. Removal of the consent of either party terminates this Letter of Understanding.

On behalf of Terasen Gas Inc.:	**On behalf of IBEW, Local 213:**
Jeff Marwick	Gord Van Dyck
Date	Date

LETTER OF UNDERSTANDING NO. 6

(AMENDED)

(Originally signed by R. Dowling & F. Scherubl, included in the 1991-1994 Collective Agreement, and amended in the 2001-2006 Collective Agreement)

Re: Retired Employees

Employees who retire on an immediate Terasen pension after ten years service may continue to be covered by MSP and EHB at Company expense. Effective January 1, 2002, EHB increased to a lifetime maximum of $100,000.

This Letter of Understanding only applies to eligible retirees who retire prior to January 1, 2011. Effective January 1, 2011, the post retirement benefits eligibility and coverage agreed to in the March 31, 2008 Memorandum of Agreement shall apply for all employees who retire.

On behalf of Terasen Gas Inc.:	On behalf of IBEW, Local 213:
Jeff Marwick	Gord Van Dyck
Date	Date

LETTER OF UNDERSTANDING NO. 7

(AMENDED)

(Originally signed by R. Dowling & F. Scherubl, and included in the 1991-1994 Collective Agreement)

Re: Travel Accident Insurance

The present policy of providing Travel Accident Insurance for employees travelling on company business, or a policy providing equivalent benefits, will remain in effect.

This Letter of Understanding shall expire on December 31, 2010.

On behalf of Terasen Gas Inc.:	On behalf of IBEW, Local 213:
Jeff Marwick	Gord Van Dyck
Date	Date

October 1975

LETTER OF UNDERSTANDING NO. 11

Deleted in 1994

LETTER OF UNDERSTANDING NO. 16

Deleted in 1999

LETTER OF UNDERSTANDING NO. 16A
(Supercedes LOU#16 signed 14 August 1975)

Deleted in 2006. Incorporated into Article 38

November 9, 1979

LETTER OF UNDERSTANDING NO. 17

Deleted in 2006.

November 9, 1979

LETTER OF UNDERSTANDING NO. 18

Re: Use of Contractors

The Union recognizes the Company's need to utilize contractors to carry out portions of its work. The Company recognizes the union's concerns regarding maintenance of its membership.

It is the Company's position to maintain a basic IBEW work force to match a predictable base load of work, and not to limit the long-term growth of Local 213 membership through the use of contractors, under normal system expansion.

Both the Union and the Company recognize that from time to time, work in excess of normal growth or normal expansion levels becomes necessary. When this occurs, the use of contractors, or Local 213 members, or both, shall be determined by operating requirements.

LETTER OF UNDERSTANDING NO. 21

Training of Fitter Welders

Deleted in 2006. Incorporated into Article 38.

AGREEMENT WITH RESPECT TO GAINSHARING

Replaced by Scorecard/Employee Incentive Plan in 2002

January 12, 1995

LETTER OF UNDERSTANDING NO.28

Employee Rotation

Deleted in 1999.

January 12, 1995

LETTER OF UNDERSTANDING NO.29

Employee Diversity

Deleted in 1999.

January 12, 1995

LETTER OF UNDERSTANDING NO. 30

Seasonal or Temporary Layoff (Interior Only)

Deleted in 2001.

January 12, 1995

LETTER OF UNDERSTANDING NO. 31

Temporary Vacancies (Also known as "Relief" and "Interchange")

Deleted in 2006. Incorporated into Article 9

June 23, 1993

LETTER OF UNDERSTANDING NO. 32

Senior Sales and Service Technician

Deleted in 2006. Incorporated into Article 8.02

LETTER OF UNDERSTANDING NO. 33

(AMENDED)

(Originally signed & dated January 12, 1995)

Re: Joint Consultative Committee (JCC)

The Company and the Union have a mutual desire to work together to ensure business success now and in the future. This success will be determined by our ability to operate in a competitive environment. It will require that we make the right business decisions and that the Company and the employees are prepared to meet the challenges a changing work environment will bring.

The parties agree to establish a joint consultative committee as follows:

1. The JCC shall consist of up to three (3) management members, and up to three (3) union members, as well as the Assistant Business Manager from the IBEW and a labour relations representative from the Utility.

2. The purpose of the JCC is to promote the cooperative resolution of workplace issues, to anticipate, respond and adapt to changes in the Utility's business, to foster the development of work related skills, to promote workplace productivity, and to continue to work on standardizing the collective agreement throughout the company.

3. The JCC shall meet initially at the request of either party, and set a date for subsequent meeting(s) prior to adjournment.

4. Both parties shall submit agenda items no later than ten days prior to each meeting, and each member of the JCC shall receive a copy of the complete agenda no later than seven days prior to the meeting;

5. The JCC shall approach issues from a "mutual gains" perspective;

6. The JCC is not a substitute for the grievance procedure.

The JCC shall meet a minimum of once per year for the purpose of reviewing the Utility's work (activity) projections. Part of this review shall be discussion of in-house versus contractor work.

Employee-members of the JCC shall continue to receive their regular, straight time wages for all time associated with JCC work, and the Utility shall reimburse travel and accommodation costs for those travelling to a meeting.

On behalf of Terasen Gas Inc.:	**On behalf of IBEW, Local 213:**
Jeff Marwick	Gord Van Dyck
Date	Date

<u>LETTER OF UNDERSTANDING NO. 34</u>

Work Sharing – Dependent Backhoe Contractors (DBC)
Southern & Western regions

Deleted in 2006. Incorporated into Appendix A.

<u>LETTER OF UNDERSTANDING NO. 35</u>

Application of Force Majeure

Deleted in 2006. Incorporated into Appendix A.

<u>LETTER OF UNDERSTANDING NO. 36A</u>

Standby Coverage in the Interior

Deleted in 2001. Substituted with LOU NO.60

<u>LETTER OF UNDERSTANDING NO.37</u>

Temporary Time-Frame Extension to Article 28.04.4

Deleted in 1999.

<u>LETTER OF UNDERSTANDING No. 38</u>

(AMENDED)
(Combined LOU NO. 38 and LOU NO.54A)
(LOU NO. 38, originally dated June 17, 1998, and signed by F. Green and R. Dowling)
(LOU NO. 54A, originally signed by F. Scherubl and R. Loski, included in the 1999-2001 Collective Agreement)

<u>Re: Job Site Mustering – Coastal Region, Interior Region and Island Units</u>

For an employee to commence job-site mustering requires mutual agreement between the employee and the manager. It will normally occur only in situations where there is a demonstrable increase to an employee's effectiveness in performing his/her job.

1. For an employee, the agreement to job-site muster is voluntary, and irrevocable.

2. An employee choosing job-site mustering will:
   (a) Take a Company vehicle home and park it in a location approved by the Company and
   (b) Travel on his own time to and from his first and last call within a 20 km radius from his residence. If his first or last job is beyond the 20 km radius, the extra distance is traveled on Company time.

3. To ensure adequate coverage, if a job-site-mustered employee relocates his residence subsequent to entering into job-site mustering, mutual agreement between the employee and the manager (per the preamble) will be required to continue with job-site mustering.

4. No employee may job-site muster outside a designated Terasen service area.

5. All employees accept responsibility for responding to after-hours callouts and will normally make themselves available for such callouts . In the event of a significant disruption, due to earthquake, fire, flood, hurricane, general system outage, etc., all employees must radio or phone in their availability as soon as possible.

6. The Company vehicle must not be operated for personal use or to transport people or items, other than on Terasen business.

7. When the vehicle is parked, all doors, windows and bins must be closed and locked. Items likely to be the target of theft must be hidden from view as much as practical. Employees assume all risks associated with personal property left in the vehicle.

8. The vehicle must be kept clean and orderly at all times. The employee is responsible for making arrangements for mechanical maintenance. Cleaning of the vehicle (including washing) must be done during non-working hours.

9. The manager may require that the vehicle be returned to a Terasen compound for all absences exceeding 3 calendar days.

10. When an employee will be commuting between home a Terasen compound for 3 or more consecutive days, s/he may be required to leave the vehicle at the compound.

11. A job-site mustered employee who does not comply with the foregoing will be directed by his manager to return the Company vehicle and muster from his designated compound.

12. This Letter of Understanding expires on March 31, 2011, unless renewed by the parties in writing.

On behalf of Terasen Gas Inc.:	**On behalf of IBEW, Local 213:**
Jeff Marwick	Gord Van Dyck
Date	Date

LETTER OF UNDERSTANDING NO. 39

Deleted in 2006. Incorporated into Article 29

LETTER OF UNDERSTANDING NO. 39A

Deleted in 2006.

LETTER OF UNDERSTANDING NO. 39B

Deleted in 2006. Incorporated into Article 29

LETTER OF UNDERSTANDING NO. 40

Continuous Bargaining Process

Deleted in 1999.

LETTER OF UNDERSTANDING NO. 53

Revised Language - Seniority / Layoff / Bumping / Recall

Deleted in 2001. Incorporated as new Article 7.

LETTER OF UNDERSTANDING NO. 54

Job Site Mustering - Kamloops District Pressure Measurement Technicians

Deleted in 1999.

LETTER OF UNDERSTANDING NO. 54A

Job Site Mustering – Interior & Island Units

Deleted in 2006. Incorporated into LOU NO.38.

LETTER OF UNDERSTANDING NO. 55

Regarding Reductions in the Number of Dependent Backhoe Contractor/Operators

Deleted in 2001.

LETTER OF UNDERSTANDING NO. 56

Regarding the various roles of Construction and Maintenance (C&M) Crews

Deleted in 2006. Incorporated portions into the Distribution Mechanic/Excavator (DMX) and Equipment Operator/Distribution Mechanic (EO/DM) job descriptions.

LETTER OF UNDERSTANDING NO. 56A

Re: Letter of interpretation regarding use of alternate (mini) excavation equipment

1. ~~C&M~~ Crew Leaders (DM1) may volunteer for training on ‘mini-ex’ equipment.

2. Subject to #3 below, regular Crew Leaders who are trained on this equipment, and DMXs who are relieving Crew Leaders on a temporary basis, may operate this equipment from time to time, but only if a DMX is also on the crew. This addresses the issue of maintaining experience in operation of the equipment, and is not a mandatory requirement of the regular or temporary Crew Leader position.

3. If a DMX is upgraded to Crew Leader due to an unscheduled absence of a Crew Leader, and the second person on the crew is a DM or DA who is not trained to operate the mini-ex equipment, the manager can direct the temporary Crew Leader to operate the equipment, but only for the first day of the unexpected absence.

4. BC Gas will ensure that a sufficient number of DMs and DMXs are trained to meet forecast requirements.

5. DMX positions will not be curtailed by Crew Leaders volunteering to operate mini-excavators in accordance with #2, above.

LETTER OF UNDERSTANDING NO. 57

Regarding the new job classifications of System Operations Technicians, and System Operations Apprentice

Deleted in 2006. Incorporated portion into the Job Descriptions

LETTER OF UNDERSTANDING NO. 58

Deleted in 2006. Incorporated into Article 30.

LETTER OF UNDERSTANDING NO. 59 NEED TO DISCUSS

Re: Compression & Controls Technicians (CCT)

Respecting the he trades qualifications of the Compression & Controls Technicians (CCT) within the Transmission Operations Department, their market adjusted wage rates, and the day-to-day organization of their work.

Part 1 – Trades Qualifications: MOVED To Article 38.05

Part 2 – Attraction/Retention Premium (ARP): *NEED TO DISCUSS THIS*

			ARP**		
	Interior	~~Coastal~~	Interior	~~Coastal~~	Base Rate

CCT 1	~~$31.11~~	~~$29.16~~	**$2.18**	~~**$2.04**~~	~~$ 29.16~~
CCT 2	~~$28.00~~	~~$26.24~~	**$1.96**	~~**$1.84**~~	~~$ 26.24~~
CCT 3	~~$26.44~~	~~$24.78~~	**$1.84**	~~**$1.73**~~	~~$ 24.78~~
CCT 4	~~$24.88~~	~~$23.32~~	**$1.74**	~~**$1.63**~~	~~$ 23.32~~

** The ARP is a premium applied only to regular hours worked, annual vacation, supplementary vacation, statutory holidays and SWYL. It does not apply to overtime or stand-by hours or other forms of paid time off. It does not form a base from which other premiums are calculated (e.g. overtime).

The ARP will be jointly reviewed annually relative to our current market comparators, and is subject to full, joint review as required (in any event no less than every five years). The intent is to maintain total cash compensation for CCTs at a level relative to market that will facilitate attraction and retention of qualified CCTs.

Part 3 – Work Leadership: MOVED to Article 8.01.1.5

Part 4 – Miscellaneous: MOVED to Articles 27.04.12 and 27.07.4.8

On behalf of Local 213 of the IBEW: On behalf of Terasen Gas Inc.:

Randy Loski Franz Scherubl

Date Date

LETTER OF UNDERSTANDING NO. 60

Emergency Response & Standby

Deleted in 2006. Incorporated into Article 31

LETTER OF UNDERSTANDING NO. 61

Between

LOCAL 213 OF THE

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS

And

BC GAS UTILITY LTD.

Effective January 1, 2003, in the Metro Unit the”work group” previously defined in LOU 31 1.01 as the “Muster”, will now be considered the “Crew”.

This proposal will create:

- base crews
- construction crews
- DM relief pool

Crew pairing will be determined in the annual headquarters election process

Relief will be provided from within each crew

Construction crews are re-headquartered as a unit

Increased summer time off

Company Plus	Employee Plus
Truck, job/work ownership Better tool inventory control Job continuity More equitable division of relief Improved truck utilization Improved job scheduling	Truck, job/work ownership More consistent tool availability Job continuity More equitable division of relief Increased vacation time during the summer write-up period
	Employee Negative
	Less up time for the senior DMs

For each type of crew the identified pros and cons are:

Base Crew Plus	**Construction Crew Plus**
Preferred location Truck ownership **Increased vacation time during the summer write-up period**	Increased vacation time during the summer write-up period Except where other relief applies, DMs will bonus up when partner DM1 is absent DMs matched up with partner with same location preferences
Base Crew Negative	**Construction Crew Negative**
No concurrent time off with partner	Truck ownership
	No concurrent time off with partner
Relief Pool Plus	**Relief Pool Negative**
More openings for vacation time (no partner restriction) Increased opportunities to fill vacancies in preferred locations	Little opportunity for up time

Crew Selection within the Construction Workforce

In order to establish the crew match up in the construction force a location preference sign up will be issued to all construction personnel. The DM1 and DM/DMX//DA will be matched by selection preference based on seniority. The DM/DMX/DA will maintain the option of opting for the relief pool. The crew will then be assigned as a unit for work in their preferred area based on the seniority of the DM1. Vacancies filled by members of the relief pool will be assigned based on seniority and area preference. Altering temporary headquarter assignments will not be considered if there is a penalty incurred to the Company either with regard to work continuity or travel time expenses. Assignment to areas not to the crews benefit (i.e. not closer to home) will be based on reverse seniority of the DM1 and at no cost to the company in keeping with LOU 39.

DMs Currently Laid Off from DM1 Classification

In order to facilitate the implementation of compound and crew selection (intra crew relief) in Metro, the three DMs who currently hold recall rights to the DM1 classification in Metro: Graeme

Mounce, Mike Cooper and Rob Favaro will, without prejudice, be paid at DM1 rate but remain DMs in every other respect.

Issue Resolution

Issues arising from the implementation of this LOU shall first be discussed between the employee(s) and the appropriate manager(s). Failing satisfactory resolution the issue may be referred to the next regular meeting of the Joint Consultative Committee where the parties shall make every effort to resolve the issue(s) on a mutual gains basis. Such resolution can include agreement to implement an alternative procedure acceptable to both parties.

On behalf of Local 213 of the IBEW:	On behalf of BC Gas Utility:
______________________________	______________________________
Randy Loski	Franz Scherubl
______________________________	______________________________
Date	Date

LETTER OF UNDERSTANDING NO. 62

New Job Classification – Distribution & Service Technician

Deleted in 2006 – CST has replaced both the SST and DST

LETTER OF UNDERSTANDING NO. 62A

CST's In Towns of Four or Less Employees – Layoff/Bumping Rules

Deleted in 2006

LETTER OF UNDERSTANDING NO. 63

Overtime Leave Bank for Employees Subject to Seasonal Layoff

Deleted in 2006. Incorporated into Article 33.01.

LETTER OF UNDERSTANDING NO. 65

Deleted in 2006. Incorporated into Appendix A.

LETTER OF UNDERSTANDING NO. 66

(AMENDED)

(Originally signed by R. Loski, B. Hammond, J. Marwick, and S. Gelinas, and numbered NO.66, then amended February 8, 2007, and numbered NO.66A)

Re: Field Operations Assistant (FOA) - Working Conditions & Wage Rate for Terasen Gas Vancouver Island

The parties agree to establish the new classification of Field Operations Assistant on Vancouver Island. Field Operations Assistant positions will be located in Victoria, Nanaimo, and Courtenay.

The Field Operations Assistant will be a part-time regular position. The following working conditions will be applicable for employees holding the Field Operations Assistant position:

1. The Field Operations Assistant will work according to an assigned regular schedule but will not work less than forty (40) hours bi-weekly. In the event, one of the Field Operations Assistant is absent from work, the other Field Operation Assistant may assume the extra hours to a maximum of forty (40) hours per week**.**

2. An assigned regular schedule will be established by the company at the time of hire and will be for a minimum of 2 weeks. Within an assigned schedule the days worked and the daily/weekly hours may differ due to operational requirements.

3. The normal hours of operation will be Monday to Friday 8:00 a.m. to 4:30 p.m. or 7:30 a.m. to 4:00 p.m., subject to operational requirements.

4. A Manager may change an established schedule but must provide 2 weeks notice of any change. Notice of change is not required where a schedule is varied by mutual agreement between the employee and the manager/supervisor.

Entitlement and Benefit coverage

5. Field Operations Assistants will accumulate service on the basis of regular hours worked.

6. Field Operations Assistants will receive the equivalent dollar amount as pay-in-lieu for Choices days, annual vacation, and statutory holidays on a bi-weekly basis and will have the choice of electing one of the following two options, on an annual basis, for receiving pay-in-lieu:
    1. Each pay period as a bi-weekly payment; or
    2. Transfer the pay-in-lieu each pay period to a time off bank (TOB) to be used as time off and/or lump sum cash payment.

7. Field Operations Assistants will receive pay-in-lieu for Choices days, annual vacation, and statutory holidays at the applicable rates noted below for all regular hours worked and paid absences (medical, sick leave):

Choices Days	4.0%
Annual vacation	6, 8, 10 or 12% per Accredited Service
Statutory holidays	4.4%

8. Field Operations Assistants will pay 50% of the premium for each of the benefit coverage below:
    - Provincial Medical Services Plan
    - Extended Health Care
    - Dental Care
    - Basic Group Life
    - Business Travel Accident Insurance
    - Long Term Disability

9. Sick leave is paid based on regularly scheduled work days.

    The above benefits coverage and sick leave entitlement in 8 & 9 above will be maintained until December 31, 2010. After which time they will be subject to any agreed upon changes to the 'new' flexible benefits design (as they apply to eligible part-time regular employees).

10. Pension Plan entitlement will be applied as follows: If an employee is a pension plan member, they will continue to accrue pensionable service, and the pensionable service will be prorated based on regular hours worked. If they are not pension plan members or are new employees, they will need to meet the eligibility criteria to join the plan. Once they meet the criteria, they will accrue pensionable service prorated on regular hours worked.

11. The hourly wage rate for this position will be as follows:

Jan. 1, 2007	**April 1, 2007**	**April 1, 2008**	**April 1, 2009**	**April 1, 2010**
$23.79/hour	$24.38/hour	$25.11/hour	$25.86/hour	$26.64/hour

12. Additional Compensation entitlement:
    - Employee Savings Plan – As per the Memorandum of Agreement 2006 - 2011
    - Employee Incentive Plan – Corporate Scorecard measure portion only (prorated based on hours of work).

On behalf of Terasen Gas Inc.:

Jeff Marwick

Date

On behalf of IBEW, Local 213:

Gord Van Dyck

Date

LETTER OF UNDERSTANDING NO. 67

Re: Customer Service Technician (Tie-in)

The purpose of this letter of understanding is to clarify and formalize the intent of the 2006 MOA between the Company and the Union with regard to the Customer Service Technician (Tie-in), a subset of the Customer Service Technician (CST) classification.

The parties agree to the following:

Part A - Incumbent CST (Tie-in)'s

1. Incumbent CST (Tie-in)'s shall be kept whole. Their rate shall reflect the CST end rate (CST 1), and their hours of work shall remain on the regular day shift.

2. Bill Friedrick, shall be considered an incumbent CST (Tie-in) and his rate shall be lifted to CST 1, retroactively to the date that he assumed his current CST (Tie-in) position.

3. While the incumbent CST (Tie-in)'s may primarily be focused on tie-in activities, they shall be expected to deliver the full scope of CST work when and as required (to the level of their qualifications and training).

Part B - New CST (Tie-in)'s

1. In recognition of the additional scope of this CST subset; an employee hired as a CST (Tie-in)'s shall be exempt from the CST 2 step in progression provided they hold their Provincial Gasfitter's License Grade B (aka "B" ticket) at the time of selection.

   All new CST (Tie-in)'s shall be subject to a one (1) year probationary period wherein they must demonstrate their ability to deliver the full scope of CST duties.

2. CST (Tie-in)'s that are hired with minimum qualifications (Utility Ticket) shall begin as a CST 2 (Tie-in) and shall advance to a CST1 per the following:

   a) The CST 2 (Tie-in) shall automatically be promoted to CST 1 upon attaining the Provincial Gasfitter's License Grade B;

   b) The CST (Tie-in) 2 shall be required to obtain the Provincial Gasfitter's License Grade B within twelve (12) months of qualifying to write for it (i.e. holding a Provincial Gasfitter's License Utility Grade for 2 years);

   c) Failure to obtain the Provincial Gasfitter's License Grade B within this twelve (12) month period shall result in the employee being returned to their previously-held classification.

3. The CST (Tie-in) shall deliver the full scope of CST duties, including CST shifts, but shall rotate into the Tie-in function on a regular and reasonably equitable basis with others in this subset.

4. The Company has targeted an initial number of six (6) CST (Tie-in)'s and shall eventually post to that level on a transitional basis. Given the limited scope of the incumbent CST (Tie-in)'s in their current configuration this adjustment shall occur when opportunities allow.

5. The Company shall initially post one (1) additional permanent position. This CST (Tie-in) shall provide backfill for the incumbent group and, as transition occurs, shall rotate into tie-in work on a more frequent basis as other new CST (Tie-in)'s positions are posted. This first "new" CST (Tie-in) shall initially be required to focus on other CST work but since he/she may come in as a CST-1 (holding a B Ticket), and may not have the required training to deliver the full scope of the CST

duties, some accommodation by the Company may be required while skills acquired and required training is completed.

Signed this "*6th*" day of December 2007 at Surrey, B.C.

For the Company:	For the Union:
"Jeff Marwick"	*"Randy Loski"*
Jeff Marwick	Randy Loski
Graham Henderson	

LETTER OF UNDERSTANDING NO. 68

Re: TGVI Adjustment Plan – Remaining Items

Respecting the integration of employees form Terasen Gas – Vancouver Island (TGVI) and Terasen Gas – Whistler (TGW) into the TGI collective agreement and bargaining structure.

The parties hereby agree as follows:

1. Employees who transferred between TGVI or TGW and TGI prior to January 1, 2004 are considered external hires and have no seniority prior to their date of transfer.

2. Subject to proceedings before the Labour Relations Board with respect to determination of appropriate bargaining unit jurisdictions, employees in the following classifications as at April 1, 2004 shall remain in the IBEW bargaining unit so long as they continue to be headquartered in the TGVI or TGW service areas:

   Gas Distribution Planner
   Mains & Service Planner
   Planner

3. In the event the company transfers any of these classifications, or any or all of the work performed by these classifications to TGI or to an outside service provider, the incumbent employee(s) (except temps) shall be treated as follows:

4. Regular employees who become redundant due to the operation of the foregoing paragraph shall have the option of transferring with their classification or work (subject to sufficient seniority to hold the job at the new location/employer) as a regular employee, or to terminate with severance in the amount of two weeks per completed year of service, or to be laid off to the recall list in which case the severance payment in the amount originally accrued (i.e. two weeks per year of completed service) shall be made upon the expiry of recall rights if the employee is not recalled or otherwise re-employed prior to the expiry of recall rights.

5. Employees in a classification and location affected by paragraph #3 shall be offered the severance option of paragraph #4 in order of seniority prior to the options of paragraph #4 being made available to the redundant employees. The intent of this paragraph is to allow more senior employees to voluntarily terminate prior to redundant employees being displaced, on a one-for-one basis.

6. Employees made redundant under paragraph #3 who transfer with their classification or work pursuant to paragraph #4 may, for a period of one (1) year from their date of transfer, elect to terminate with

severance in the amount of two (2) weeks per completed year of service, or to be laid off to the recall on the same terms as apply in paragraph #4.

7. Subject to agreement of the COPE, or by order of the Labour Relations Board, the IBEW Union Seniority date of employees who transfer to COPE jurisdiction pursuant to the foregoing, shall be their seniority date for purposes of Article 4.01 of the COPE collective agreement.

8. Employees being reclassified into merged job classifications per the April 24, 2004 Adjustment Plan shall carry forward their classification seniority from their classification to the merged classification.

9. There shall be no job loss among the nine Victoria Utilization Technicians as a direct result of construction crews and/or contract crews hanging residential meters:

Mike Forsyth	Wayne Nason	Richard Carmichael
Lorne Hadley	Dan Ready	Glenn Hamilton
Bob Hammond	Tom Weiss	Dean Pickup

10. Employees whose regular classification is paid above the merged rate per the April 24, 2004 Adjustment plan merged “IBEW Wage Schedule” shall be red circled at their regular rate.

11. The parties shall discuss the organization of the Transmission Operations group in a JCC with the intent of amending, merging and/or creating appropriate province-wide classifications. Until this is completed, the Island and the Mainland will continue with current practices.

12. TGVI and TGW retirees on December 31, 2003 shall continue with substantially the same company-paid post retirement benefits that have been provided by TGVI unless they choose otherwise, individually, should other options be made available to them.

On behalf of Terasen Gas Inc.:

Jeff Marwick

Date

On behalf of IBEW, Local 213:

Gord Van Dyck

Date

LETTER OF UNDERSTANDING NO. 69

(Re-numbered)

(Originally LOU #15 – Victoria Unit dated August 8, 1991, and signed by R. Dowling & D. Bell)

Re: Pension Plan – Victoria Unit

The Company and the Union agree that this Letter of Understanding constitutes the entire agreement, as it relates to pension plan, between the parties and supersedes and replaces all previous agreements, including but not limited to Supplementary Information - Pension Plan and practices both written and oral.

All eligible privatized employees (i.e. all eligible employees hired on or before March 31, 1989 and still in the employ of the company who have cashed out the B.C. Hydro Pension Plan) shall join the pension plan effective January 1, 1990. All other employees are now required to join the plan on the first day of employment. Notwithstanding the preceding in this paragraph, the parties agree and acknowledge that only one (1) employee of the Company, John Muir, did not cash out of the B.C. Hydro Pension Plan, and is therefore not required to join the Company Plan. He will remain on the B.C. Hydro equivalency, pension plan arrangement.

The Company will establish a Pension Plan with the following provisions:
Contributions are fully paid by the Company, and are fully vested after two year's plan membership.
Pension formula is 1.1% of final average earnings up to the final YMPE plus 1.7% of final average earnings in excess of the Final YMPE, multiplied by number of years' of plan membership.

Final average earnings is the highest annual average of earnings in any three consecutive years in the ten years prior to retirement. Final YMPE is the annual average of the year's maximum pensionable earnings under the Canada Pension Plan in the same period used to determine final average earnings.

Normal retirement age is 65 years. Early retirement with Company consent is allowed after age 55 with two years of plan membership. An unreduced pension is payable from age 62, or from age 55 if age plus years of service equals 85 years or more. Otherwise, a reduced pension is payable equal to the accrued pension reduced by 3% per year if retirement age is less than 62. For those employees hired on or before March 31, 1989, service with B.C. Hydro will be recognized when calculating service for early retirement eligibility without reduction, although not calculated as contributory years of plan membership.

Normal form of pension for members with a spouse at retirement is a pension payable for the lifetime of the member, with 60% continuation to the surviving spouse after the member's death.
Normal form of pension for members without a spouse at retirement is a pension payable for life with a guarantee of at least 60 monthly payments.

On behalf of Terasen Gas Inc.:	**On behalf of IBEW, Local 213:**
Jeff Marwick	Gord Van Dyck
Date	Date

INCLUDE LOU #70

LETTERS OF UNDERSTANDING APPLYING TO VICTORIA UNIT ONLY:

LETTER OF UNDERSTANDING #1 – Victoria Unit

EX-OTEU Group

Deleted in 2006

LETTER OF UNDERSTANDING #5– Victoria Unit

Corrosion Control Technologist

Deleted in 2006. Combined with LOU #21 – Victoria Unit, and incorporated into Article 38.04 of the collective agreement

LETTER OF UNDERSTANDING #13 – Victoria Unit

Sales Related Positions

Eliminated in April 2008

LETTER OF UNDERSTANDING #15 – Victoria Unit

Pension Plan

Re-numbered and re-signed as LOU NO. 69

LETTER OF UNDERSTANDING #17 – Victoria Unit
&
LETTER OF INTERPRETATION TO LETTER OF UNDERSTANDING #17, CLAUSE 17

Deleted in 2006.

LETTER OF UNDERSTANDING #18 – Victoria Unit
&
LETTER OF INTERPRETATION TO LETTER OF UNDERSTANDING #18

Deleted in 2006.

LETTER OF UNDERSTANDING #19 – Victoria Unit
(Applicable to both Island Units)

Deleted in 2006.

LETTER OF UNDERSTANDING #21 – Victoria Unit

Measurement Technician Trainee

Deleted in 2006. Combined with LOU #5 – Victoria Unit, and incorporated into Article 38.04 of the collective agreement.

PENSION PLAN (no specified #) – Victoria Unit

Deleted in 2006

LETTER OF UNDERSTANDING (no specified #) – Victoria Unit

Part-Time Position

Deleted in 2006

LETTER OF UNDERSTANDING (no specified #) – Victoria Unit

Job Description – Clerk 2, Communications Centre

Deleted in 2006

LETTERS OF UNDERSTANDING APPLYING TO NORTH ISLAND UNIT ONLY:

LETTER OF UNDERSTANDING NO. 3 – North Island Unit

Deleted in 2006. Amended and incorporated into Article 30.16 of the collective agreement.

LETTER OF UNDERSTANDING NO. 4 - North Island Unit

District Meter Reading Transition Requirements

Deleted in 2006

LETTER OF UNDERSTANDING NO. 5 - North Island Unit

Deleted in 2006

LETTER OF UNDERSTANDING NO. 8 - North Island Unit

Deleted in 2006. Amended and incorporated into Article 30.17 of the Collective Agreement.

LETTER OF UNDERSTANDING NO. 9 - North Island Unit

Article 4.02, Revision

Deleted in 2006

LETTER OF UNDERSTANDING NO. 10 - North Island Unit

Relief Wage Rate – Senior Administration Clerk

Deleted in 2006

APPENDIX A

DEPENDENT BACKHOE CONTRACTOR/OPERATORS

(Coastal Only)

1. General Provisions

1.01 Application

All terms and conditions set out in the Collective Agreement are expressly excluded except those detailed herein. The expiry date of this Appendix will coincide with the expiry date of the Collective Agreement. Terasen Gas will hire an additional dependent backhoe contractor/operator if we employ more than five (5) hourly rubber-tire backhoes who work on a full-time basis simultaneously for a period in excess of 17 weeks in Distribution – Lower Mainland.

The Company may engage the services of a dependent backhoe contractor provided that the dependent backhoe contractor signs a copy of Appendix "B" attached hereto and forming part of this agreement prior to the dependent backhoe contractor performing any services for the Company. A signed copy of Appendix "B" shall be forwarded to the Union.

1.02 Management Rights

The Union recognizes and agrees that except as specifically abridged, delegated, granted or modified by this Appendix, all of the rights, powers and authority which the Company had prior to the signing of this Appendix are retained solely and exclusively by the Company, and remain without limitation within the rights of management.

2. Union Dues

2.01 The Company recognizes the Union and will not discriminate against any dependent backhoe contractor because of his connection with it. The Company agrees that all dependent backhoe contractors shall within one month of engagement become and remain thereafter members of the Union in good standing as a condition precedent to continued engagement with the Company. Properly qualified officers of the Union shall be recognized by the Company for the purpose of discussing any grievance of any dependent backhoe contractor.

2.02 Upon receipt of a written assignment of earnings signed by the dependent backhoe contractors, the Company will deduct from the dependent backhoe contractors pay the amount of the required monthly dues and assessments and transmit that amount to the Union, once per month, together with a list of dependent backhoe contractors from whom such deductions have been made.

2.03 The Union agrees to indemnify the Company for any claims made against it arising out of deductions made under this Article.

2.04 If there are insufficient earnings owing to a dependent backhoe contractor in the period for which dues deduction should be made, the Company is not required to make a deduction or to transmit any payment to the Union in respect of that dependent backhoe contractor.

3. Grievances

3.01 Complaints shall first be discussed with the immediate Manager concerned. Failing settlement at the complaint stage, grievances shall be presented in writing to the immediate Manager with a copy to the Labour Relations Department giving details of the alleged violation and the relevant Collective Agreement Articles(s). Failing settlement at that stage, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Department Head with a copy to the Labour Relations Department. Failing settlement at that level, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Vice-President, and the Vice-President, Human Resources (or delegates). Grievances submitted verbally shall be subject to a one week time limit and grievances submitted in writing shall be subject to a two week time limit for processing through the levels involved.

3.02 Where a difference arises between the parties relating to the dismissal or discipline of a dependent backhoe contractor, or to the interpretation, application, operation, or alleged violation of this Appendix, including any question as to whether a matter is arbitrable, either of the parties, without stoppage of work, may, after exhausting the grievance procedure established by this Appendix, notify the other party in writing of its desire to submit the difference to Arbitration, and the parties shall agree on a single Arbitrator. The Union or the Company shall refer the matter to Arbitration within one (1) month after its rejection by either party or the matter shall be deemed to be withdrawn. The decision of the Arbitrator shall be final and binding on both parties and any dependent backhoe contractor affected by it. Each party shall pay one-half the fees and expenses of the Arbitrator. The dependent backhoe contractors shall continue to work while the above outlined grievance procedure is in progress.

4. Technological Change

4.01 The Company shall provide two month's notice in writing to the Union of its intention to introduce any technological change which will result in a termination of the contract for services for a dependent backhoe contractor.

4.02 In the event there is a dispute relating to this Article, the matter may be submitted as a grievance at the immediate Manager's level of the grievance procedure for resolution.

5. Seniority

5.01 Seniority shall accrue on a departmental basis only, i.e. Metro and Fraser Valley.

5.02 Seniority is established by the date of hire into a department, i.e. the date the dependent backhoe contractor actually reports to work for the department.

5.03 Reduction in the number of dependent backhoe contractors will be in the reverse order of seniority, last on, first off.

The current complement of Dependent Backhoe Operators (DBOs) in the Fraser Valley and Metro Units will be reduced from thirty-two (32) to the following:

(a) Eighteen (18) DBOs classified as full-time regular operators, not subject to the layoff provisions described in 1(b) below;

(b) Five (5) DBOs allocated to the three construction crew hubs (i.e. Abbotsford, Langley, and 2nd/Boundary) who may be subject to layoff upon five (5) days notice, due to shortages of work.

These twenty-three (23) DBOs will not be laid off, or replaced, by the use of hourly or casual backhoe contractors.

This does not guarantee that Terasen will always maintain the complement of 18/5 DBOs.

5.04 A minimum thirty (30) days notice will be required prior to termination of a dependent backhoe contractor. However, the Company retains the right to terminate for cause without notice.

5.04.1 Dependent backhoe contractors shall not be terminated for lack of work while casual backhoe contractors are still working in the department.

5.04.2 Dependent backhoe contractors hired after January 1, 2005 will be subject to layoff upon five (5) days notice, due to shortage of work.

5.05 Short-term layoffs of less than one (1) month duration which are occasioned by force majeure are not termination and do not require notice. The conditions of the force majeure shall be evaluated on a muster-by-muster basis and shall include input from the IBEW safety rep on site. Conditions shall be re-evaluated on a daily basis and contractors recalled when the conditions no longer justify the layoff.

5.05.1 If the contractor has reported to work at the regular starting time and is being laid off pursuant to 5.05, he shall be paid no less than four (4) hours at straight-time rate for the day.

5.05.2 Layoffs of up to five (5) working days shall be in inverse order of departmental seniority within the unit.

5.05.3 Layoffs of greater than five (5) working days shall be in inverse order of seniority within each department.

5.06 A dependent backhoe contractor's department seniority will be placed on a common seniority list at termination for the purpose of determining the order of eligibility for re-engagement except in cases of voluntary termination or termination for cause.

5.07 A former dependent backhoe contractor will be given first consideration for re-engagement in any department for a period of twelve (12) months following termination except in cases of voluntary termination or termination for cause.

5.08 When the company adds a dependent backhoe contractor or fills a vacancy, those contractors already employed shall have the right to transfer to the location of the vacancy on a seniority basis by department. This clause does not negate the company's right to reassign contractors to headquarters based on need.

6. Hours of Work

6.01 Dependent backhoe contractors will normally work between the hours of 0800 and 1630 hours Monday to Friday inclusive. They will be entitled to a one-half (1/2) hour unpaid lunch break and two (2) fifteen (15) minutes paid rest periods each day, which they will take at the same time the crew or employees, with whom they are working, take theirs.

6.02 To compensate for travel to/from Hope, Kent, Mission and Harrison municipalities, dependent backhoe contractors will be paid a travel allowance of one additional hour at straight time pay per round trip. A backhoe contractor mustered in any of these municipalities is not covered by this clause.

6.03 All DBOs will schedule a minimum of two (2) weeks off per year during mutually-agreeable periods. This leave will be without penalty and at a time agreed to between the Company and the DBO and will be subject to workload requirements. Special requests for leave beyond two

(2) weeks per year shall be given due consideration.

6.04 When a dependent backhoe contractor is working with a crew and that crew receives rest time, the dependent backhoe contractor shall, at his option, receive the same rest time off with pay.

7. Schedule of Rates

7.01 Rates as set out herein shall be for the All-Found Rental of Backhoe/Front End Loaders (including hoepack) with operator. The rates will be paid only for the number of hours during which the equipment and operator are ready and able to perform the work for which they were engaged.

	Sept. 4, 2006	**April 1, 2007**	**April 1, 2008**	**April 1, 2009**	**April 1, 2010**
Hourly Rate (including Hoepack)	$67.50	$69.50	$71.00	$73.00	$75.50
Hourly Rate Truck & Trailer	$7.00	$7.00	$7.50	$7.50	$7.50
Total (both) Hourly Rate	$74.50	$76.50	$78.50	$80.50	$83.00
Overtime Rate	$89.00	$89.00	$89.00	$99.00	$99.00

7.02 When the dependent backhoe contractor works in excess of eight (8) hours per day or on a Saturday, Sunday or Statutory Holiday, the overtime rate as per the Article 7.01 table above shall be paid. DBOs will be paid the equivalency of Statutory Holiday Pay (i.e. 4.4%) on their hourly rate schedule.

7.03 Dependent Backhoe Contractors who have been requested by the Company to provide a truck and trailer for transporting their backhoe, shall have an additional truck and trailer hourly amount as per the Article 7.01 table above added to the rate. Overtime rates will not apply to the truck and trailer rate.

7.03.1 Compensation:

The Dependent Backhoe Contractor shall assume complete responsibility for the total cost of the operation and maintenance of the hoepack.

7.03.2 Use of a Grinder Sweeper shall add $25.00 per hour to the rate in Article 7.01, with a minimum of four hours pay on days used.

7.04 Dependent Backhoe Contractors will be required to perform secondary work from time to time. In consideration of this, the Company will pay the Workers' Compensation assessment for Dependent Backhoe Contractors. It is clearly understood that WCB coverage under this provision is valid only while performing work for the Company.

7.04.1 Secondary work includes any tasks which the contractor can safely perform in aid of the crew, and is in addition to operation of the backhoe.

7.04.2 The Company will provide coveralls, safety boots, safety vest, and rain gear, on the same basis as provided for regular members of the crew.

7.05 The dependent backhoe contractor shall assume complete responsibility for the total cost of operation of the backhoe including the insurance on the equipment and all required licenses.

7.06 When a dependent backhoe contractor is working with a crew that is provided with a meal, the dependent contractor shall also receive a meal.

7.07 Dependent backhoe contractors will invoice the Company biweekly and payment will be delivered through the internal Company mail. Any adjustments made by the Company will be shown on a statement accompanying payment.

7.08 The Company will deduct on a biweekly basis, $1.45 per hour from the rates specified in Article 7.01, to provide Health and Welfare coverage for Dependent Backhoe Operators and remit this amount to I.B.E.W., Local 213 Health and Welfare Department by the 10th day of the month following deductions. The amount deducted may be amended by written notification from the Union.

8. Indemnity

8.01 Terasen will indemnify and hold harmless dependent backhoe contractors from legal liabilities imposed upon them arising out of work performed by them directly relating to their contractual relationship with Terasen. However, Terasen shall have no liability with respect to the foregoing where the legal liabilities result from the grossly negligent, reckless or wilful acts or omissions of a dependent backhoe contractor. This clause does not negate the obligation of dependent backhoe contractors to obtain proper vehicle and business insurance.

9. Work Sharing – Dependent Backhoe Contractors (DBC) (Formerly LOU #34)

9.01 **Definition**

Worksharing is defined as dividing all the functions of a full-time DBC position between two current DBCs, each of whom works part-time in a manner that provides full-time coverage for the position. A full-time DBC position can only be work-shared with the approval of the Manager, Regional Business Leader, Human Resources and the Union. The Manager is responsible for communicating the requirements of the work sharing to both DBCs.

It is the intent that the time worked by the two work sharing DBCs will equate to that of a full-time DBC. Neither of the DBC partners in a work-share relationship shall work less than 50% of the normal hours of work of the full-time DBC position unless one of the DBC partners is unable to work because of an illness or disability.

9.02 **General**

(a) The Parties agree that all terms and conditions of Appendix A of the Collective Agreement in force and effect shall apply unless specifically altered herein.

(b) Work sharing partnerships shall be restricted to DBCs between the ages of 55 and <u>beyond</u>, who live within commuting distance of the muster compound where the work-share position exists.

(c) The DBC position left vacant when two DBCs work share may or may not be filled, at the sole discretion of the Company, and if filled, will only be filled on a temporary basis for the six (6) month trial period outlined in Clause #4, and thereafter at the sole discretion of the Company.

(d) Article 6.03 does not apply to work-sharing DBCs.

(e) The Company will only pay WCB assessments for each work sharing DBC on the basis of gross assessable earnings while the DBC partner is working for the company.

(f) The Company may invite the non-working DBC partner to come to work if he is available and willing, in lieu of inviting an independent contractor.

9.03 **Procedure**

(a) DBCs wanting to work share may request the Manager to consider a proposal for a work sharing arrangement. In making a submission it is important that both DBCs realize they are entering partnership. Minimum work sharing blocks must be of two (2) consecutive pay periods in duration. Details which must be considered in the submission included:

(i) Which months or part months will be worked by which DBC partner.

(ii) Contact telephone number or address where non-working DBC partner can be reached within 48 hours.

(iii) Any other information required by the Manager.

(b) Proposed work sharing arrangements will be discussed with the appropriate Human Resources Advisor and for each work sharing arrangement there must be written understanding singed by each DBC partner, the employee's manager, Human Resources and the Union.

9.04 **Registration**

DBCs who wish to work share should submit a proposal to their manager and the Human Resources Department. It is the responsibility of the DBC to arrange for a willing DBC partner.

9.05 **Trial Period**

(a) In order to allow the parties a reasonable time to test the suitability of the individual work sharing arrangement, a six (6) calendar month trial period will be in effect at the beginning of each work sharing arrangements.

(b) During the trial period, either party or either DBC partner may terminate the work share with thirty (30) calendar days written notice.

(c) In the event that the work share is terminated during the trial period, both DBC partners will revert back to their former DBC positions and status in all respects.

9.06 **Seniority**

(a) All matters of seniority will be determined on the basis of the seniority of the senior DBC in the work share.

(b) On the termination or retirement of one DBC, the remaining DBC will return to a full-time position based on his previous seniority and compound selection or,

(c) Enter into another work sharing arrangement in accordance with all the terms of Article 9, if approved pursuant to Article 9.01 of this Appendix.

9.07 **Filling a Work-Share Vacancy**

In the event one of the DBC partners quits, retires or is terminated, the remaining DBC partner must return to the full-time position with seven (7) calendar days. Where the parties and the remaining DBC partner agree a work-share should continue, the vacancy will be dealt with as follows:

The remaining DBC partner has thirty (30) calendar days from the notice date of termination of the original DBC partner to find a replacement DBC partner.

If no suitable DBC partner can be found, the remaining DBC partner will have the option of filling the position on a full-time basis or retiring.

9.08 **Invoicing and Union Dues**

(a) Each DBC partner will invoice only for the time he works, as indicated on the time slips.

(b) Each DBC partner will pay Union Dues based on whether they were working or unemployed as per Union by-laws.

9.09 **Termination of Job Sharing Arrangement**

(a) Individual work sharing arrangements may be terminated by the Manager or either party with thirty (30) days written notice tot he affected DBC partner(s).

(b) If the Manager, or either party terminates the work-share and neither DBC partner voluntarily quits or retires, both DBC partners will be terminated and be subject to Articles 5.06 and 5.07 of this Appendix.

9.10 **Discontinuation of Job Sharing – Article 9**

Either party may discontinue Article 9 of this Appendix on twenty-four hours notice to the other party, following which work-share partnerships in the trial period will be immediately discontinued. Existing work-share partnerships past the trial period will be grandparented.

10. Application for Force Majeure (formerly LOU #35)

10.01 Force majeure is an event or effect that cannot reasonably be anticipated or controlled, like an Act of God. For the purposes of Article 5.05 of Appendix A of our Collective Agreement, a force majeure layoff will be interpreted to be any layoff of Dependent Backhoe Contractors by the Company deemed necessary for any of the following reasons: earthquakes; floods; snow of such a depth or quantity that local authorities are requesting citizens to stay off the roads, except for emergencies**;** severe ice conditions; white-outs; hurricanes; tornados; frost or prolonged sub-zero temperatures when the frost level is of such a depth that backhoe excavation has been suspended by other Utilities and/or Municipalities.

10.02 Any disagreement as to whether or not Dependent Backhoe Contractors have been improperly laid off under Article 5.05 will be dealt with pursuant to Article 3.01. Failing settlement at the Manager or Business Leader level, the disagreement will be resolved pursuant <u>to the procedure outlined in Article 6.03 of the main body of the collective agreement</u>.

MISCELLANEOUS

See DBC Work Sharing Agreement (formerly attached to LOU #34) on next page.

DBC WORK SHARING AGREEMENT

This document records the specific terms and conditions which will be applicable to the work sharing arrangement between:

________________________________ DBC Partner A

______________________________ DBC Partner B

________________________________ Compound/Muster

1. DBC Partner **A** will work from _____________________ (Date) to ___________________ (Date)

   and from _____________________ (Date) to __________________ (Date)

2. DBC Partner **B** will work from _____________________ (Date) to ___________________ (Date)

   and from _____________________ (Date) to __________________ (Date)

3. The work sharing arrangement will commence on __________________________ (Date)

4. The method of termination and other terms and conditions of this work sharing arrangement are as detailed in Article 9 above.

APPENDIX B

DEPENDENT BACKHOE CONTRACTOR/OPERATORS

BETWEEN:

Terasen

AND:

Dependent Backhoe Contractor/Operator____

Address ____

1. The Company agrees to retain the services of the backhoe contractor/operator, named above, with backhoe hereafter described:

MAKE: ____________________________ **MODEL:**_____________________________

LICENCE NUMBER: ____

Hoe Mount Side/Center ____

Aux. Transport Truck/Trailer ____________________________________

SIGNED THIS __________ DAY OF ________________________________, 19 ________

AT ____, B. C.

WITNESS ____

DEPENDENT BACKHOE CONTRACTOR/OPERATOR _____________________________

TERASEN ____

REVISED: 05 SEPT. 1989

APPENDIX C

The Company shall update the list of Dependent Backhoe Contractors by date of hire on January 1 and July 1 of each year. A copy of the list will be forwarded to the Union in a timely manner.

APPENDIX D

DEPENDENT DUMPTRUCK CONTRACTORS
(Coastal Only)

1. General Provisions

1.01 Application

The terms and conditions of this Appendix, (the "Appendix"), apply only to dependent dump-truck contractors. All terms and conditions contained in other sections of the Collective Agreement are expressly excluded except those detailed herein. Specifically, and without limiting the generality of the foregoing, dependent dump-truck contractors are not considered employees in the operation of Article 8.

1.02 **Scope**

Any dump-truck contractor employed by the Company for a period in excess of six (6) months in any twelve (12) month period will become a dependent dump-truck contractor subject to this Appendix.

1.03 Term of Agreement

The expiry date of this Appendix will coincide with the expiry date of the Collective Agreement.

2. Recognition

2.01 Management Rights

The Union recognizes and agrees that except as specifically abridged, delegated, granted or modified by this Appendix, all of the rights, powers and authority which the Company had prior to the signing of this Appendix are retained solely and exclusively by the Company, and remain without limitation within the rights of management.

2.02 Union Recognition

The Company recognizes the Union as the bargaining agent for dependent dump-truck contractors and, without limiting the generality of the foregoing, for the persons named in Clause 5.02 of this Appendix. Such persons are, for purposes of this Appendix and for purposes of the Labour Relations Code as amended, deemed to be, "dependent contractors", as defined in Section 1 of the Code, and properly qualified officers of the Union are recognized by the Company for the purpose of discussing any grievance of any dependent dump-truck contractor.

2.03 Union Membership

The Company agrees that dependent dump-truck contractors will become and remain members in good standing of the Union as a condition precedent to continued employment by the Company.

2.04 Dues Deductions

Upon receipt of a written assignment of earnings, the Company will deduct an amount equal to the prevailing Union dues and assessments from dependent dump-truck contractors' pay as long as such persons remain in the bargaining unit. The Company will deduct such amounts from payments to contractors in respect of the last full pay period in each calendar month and remit the same, with a list naming each contractor so deducted and the amount deducted from each contractor's pay, to the Business Manager of the Union before the 15th day of the following month.

The Union agrees to indemnify the Company for any claims made against the Company arising out of deductions made pursuant to this clause and, if there are insufficient earnings owing to a contractor in the period for which dues deductions should be made, the Company is not required to make a deduction or to transmit any payment to the Union in respect of that contractor and period.

3. Grievances

3.01 Complaints shall first be discussed with the immediate Manager concerned. Failing settlement at the complaint stage, grievances shall be presented in writing to the immediate Manager with a copy to the Labour Relations Department giving details of the alleged violation and the relevant Collective Agreement Articles(s). Failing settlement at that stage, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Department Head with a copy to the Labour Relations Department. Failing settlement at that level, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Vice-President, and the Vice-President, Human Resources (or delegates). Grievances submitted verbally shall be subject to a one week time limit and grievances submitted in writing shall be subject to a two week time limit for processing through the respective levels.

3.02 Where a difference arises between the parties relating to the dismissal or discipline of a dependent dump-truck contractor, or to the interpretation, application, operation, or alleged violation of this Appendix, including any question as to whether a matter is arbitrable, either of the parties, without stoppage of work, may, after exhausting the grievance procedure established by this Appendix, notify the other party in writing of its desire to submit the difference to Arbitration, and the parties shall agree on a single Arbitrator. The Union or the Employer shall refer the matter to Arbitration within one (1) month after its rejection by either party or the matter shall be deemed to be withdrawn. The decision of the Arbitrator shall be final and binding on both parties and any dependent dump-truck contractor affected by it. Each party shall pay one-half (1/2) the fees and expenses of the Arbitrator. The dependent dump-truck contractors shall continue to work while the above outlined grievance procedure is in progress.

4. Technological Change

4.01 The Company shall provide two (2) month's notice in writing to the Union of its intention to introduce any technological change which will result in a termination of the contract for services for a dependent dump-truck contractor. A decision to replace dependent dump-truck operators with employee-operators shall be considered a technological change.

4.02 In the event there is a dispute relating to this Article, the matter may be submitted as a grievance at the Division Manager's level of the grievance procedure for resolution.

5. Seniority and Job Security

5.01 Seniority is established by a contractor's "date of hire", which is defined as the date a contractor first reports for work as a dependent dump-truck contractor, and shall accrue on a departmental basis only, ie. Metro and Fraser Valley.

5.02 Seniority is established for the incumbent contractors, as follows, with the most senior contractor appearing first and the least senior appearing last:

Metro
1. Roger Gladwell
2. Tim MacLeod

The above contractors will not be displaced by the hiring of employee dump-truck operators, or terminated for shortage of work while employee dump-truck/cleanup truck operators hired after July 10, 1989 remain employed as dump-truck operators.

5.03 Reduction in the number of dependent dump-truck contractors will be in reverse order of seniority. The last dependent dump-truck contractor hired will be the first contractor terminated.

5.04 A minimum of thirty (30) days of notice will be required prior to termination of a dependent dump-truck contractor. However, the Employer retains the right to terminate for cause, without notice.

5.04.1 Short-term layoffs of less than one month duration which are occasioned by force majeure are not terminations and do not require notice. The conditions of the force majeure shall be evaluated on a muster-by-muster basis and shall include input from the IBEW safety rep on site. Conditions shall be re-evaluated on a daily basis and contractors recalled when the conditions no longer justify the layoff.

5.04.2 If the contractor has reported to work at the regular starting time and is being laid off pursuant to 5.04.1, he shall be paid no less than four (4) hours at straight-time rate for the day.

5.04.3 Layoffs of up to five working days shall be in inverse order of departmental seniority within each muster.

5.04.4 Layoffs of greater than five working days shall be in inverse order of seniority within each department.

5.05 A dependent dump-truck contractor's seniority will be placed on a common seniority list on termination for the purpose of determining the order of eligibility for re-engagement except in cases of voluntary termination or termination for cause.

5.06 A terminated dependent dump-truck contractor will be given first consideration for re-engagement for a period of twelve (12) months following termination except in cases of voluntary termination or termination for cause.

5.07 Re-engagement of dependent dump-truck contractors will occur in reverse order of reduction.

6. Hours of Work, Overtime and Headquarters

6.01 Dependent dump-truck contractors will normally work between the hours of 0800 and 1630 hours, Monday to Friday inclusive. They will receive a one-half (1/2) hour unpaid lunch break and two (2), paid, fifteen (15) minute rest periods each day.

6.02 When a dependent dump-truck contractor works in excess of eight (8) hours per day or on a Saturday, Sunday or Statutory Holiday, the overtime rate will be paid.

6.03 Each dependent dump-truck contractor will be entitled up to four (4) weeks of unpaid leave of absence in lieu of annual vacation during each twelve (12) month period of engagement. Special requests for leave beyond four weeks per year shall be given due consideration.

This leave will be without penalty and at a time agreed to by both the individual contractor and the Company. Such leave will be subject to workload requirements.

6.04 When the contractor is working with a crew and that crew receives rest time, the contractor shall, at his option, receive the same rest time with pay.

6.05 Dependent dump-truck contractors shall not be assigned a permanent headquarters. They shall report for work to any headquarters within the department as required, and shall be given notice on the previous day of a change in headquarters.

7. Rate Schedule and Equipment Specification

7.01 The rates set out herein are for the All-Found Rental of single axle dump trucks with a minimum load capacity of 4,082 kg., minimum box capacities of 3.83 cubic meters, (box to be equipped with dump chute) and designated, owner-operated contractors. The rates will be paid only for the number of hours during which the equipment and contractor are ready and able to perform the work for which they were engaged.

Effective April 1, 1995 dependent dump-truck contractors straight-time rate shall be increased by $1.45 per hour which shall be deducted by the company and remitted to the IBEW Local 213 Health and Welfare Department on a bi-weekly basis for the purpose of providing health and welfare coverage to the dependent dump-truck operators. The amount deducted may be amended by written notification from the union to the company's accounts payable department.

	Sept. 4, 2006	**April 1, 2007**	**April 1, 2008**	**April 1, 2009**	**April 1, 2010**
Hourly Rate (2006 rate re-based to $45.00)	$46.28	$47.44	$48.86	$50.33	$51.84
Overtime Rate	$67.50	$67.50	$73.29	$73.29	$77.76

7.02 The dependent dump-truck contractor shall assume complete responsibility for the total cost of operation of the dump truck including the insurance on the equipment and all required licenses. Dependent dump-truck contractors are not responsible for cargo related costs such as dumping fees charged by dump site operators.

7.03 Special Attachments

If requested by the Company, special attachments may be installed on the dump trucks. Such attachments will meet normal industry standards and the installation of such equipment will not reduce the resale value of the dump trucks. The cost of these attachments and their installation, shall be borne by the Company, and their use shall not exceed the normal working capability of the dump truck.

7.04 The provisions in Article 32.03 apply to dependent dump-truck contractors.

7.05 Dependent dump-truck contractors will invoice the Company bi-weekly and payment will be made by the Company within two (2) weeks of the date invoices are received. Any adjustments made by the Company will be shown on a statement accompanying the payment.

7.06 The Company will pay the Workers' Compensation Board assessments for dependent dump-truck contractors, however the Workers' Compensation Board coverage is valid only while performing work for the Company.

7.07 At the request of a Supervisor or crew leader, dependent dump-truck contractors will be required to perform secondary work from time to time.

7.07.1 Secondary work includes any task which the contractor can safely perform in aid of the crew, and is in addition to operation of the truck.

7.07.2 In recognition of secondary work, the Company will provide coveralls, safety boots, safety vest, hearing protection and rain gear, on the same basis as provided for regular employees in the department.

8. Indemnity

8.01 Terasen will indemnify and hold harmless dependent dump-truck contractors from legal liabilities imposed upon them arising out of work performed by them directly relating to their contractual relationship with Terasen. However, Terasen shall have no liability with respect to the foregoing where the legal liabilities result from the grossly negligent, reckless or willful acts or omissions of a dependent dump-truck contractor. This clause does not negate the obligation of dependent dump-truck contractors to obtain proper vehicle and business insurance.

MISCELLANEOUS

Dependent dump-truck contractors, may add $4,000 to their first invoice following the implementation date (September 2, 2006).

APPENDIX E

BACKHOE CONTRACTORS

(Applies only to Victoria)

ARTICLE 1 GENERAL PROVISIONS

1.01 APPLICATION

All terms and conditions set out in the Collective Agreement are expressly excluded except those detailed herein. The expiry date of this Appendix will coincide with the expiry date of the Collective Agreement. Any backhoe contractors employed by the Company's Gas Operations during the term of this agreement for a period in excess of six months in any twelve month period will become a dependent backhoe contractor subject to this Appendix.

The Company may engage the services of a dependent backhoe contractor provided that the dependent backhoe contractor signs a copy of Appendix "G" attached hereto and forming part of this agreement prior to the dependent backhoe contractor performing any services for the Company. A signed copy of Appendix "G" shall be forwarded to the Union.

1.02 MANAGEMENT RIGHTS

The Union recognizes and agrees that except as specifically abridged, delegated, granted or modified by this Appendix, all the rights, powers and authority which the Company had prior to the signing of this Appendix are retained solely and exclusively by the Company, and remain without limitation within the rights of management.

ARTICLE 2 UNION DUES

2.01 The Company recognizes the Union and will not discriminate against any dependent backhoe contractor because of their connection with it. The Company agrees that all dependent backhoe contractors shall within one month of engagement become and remain thereafter members of the union in good standing as a condition precedent to continued engagement with the Company. Properly qualified officers of the Union shall be recognized by the Company for the purpose of discussing any grievance of any dependent backhoe operator. For the purpose of Union Dues calculation, the Distribution Mechanic 2 wage rate will be used for Dependent Backhoe Contractors.

2.02 Upon receipt of a written assignment of earnings signed by the dependent backhoe contractors, the Company will deduct from the dependent backhoe contractor's pay the amount of the required monthly dues and assessments and transmit that amount to the Union, once per month, together with a list of dependent backhoe contractors from whom such deductions have been made.

2.03 The Union agrees to indemnify the Company for any claims made against it arising out of deductions made under this Article.

2.04 If there are insufficient earnings owing to a dependent backhoe contractor in the period for which dues deduction should be made, the Company is not required to make a deduction or to transmit any payment to the Union in respect of that dependent backhoe contractor.

ARTICLE 3 GRIEVANCES

3.01 Complaints shall first be discussed with the immediate Manager concerned. Failing settlement at the complaint stage, grievances shall be presented in writing to the immediate Manager with a copy to the Labour Relations Department giving details of the alleged violation and the relevant Collective Agreement Articles(s). Failing settlement at that stage, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Department Head with a copy to the Labour Relations Department. Failing settlement at that level, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Vice-President, and the Vice-President, Human Resources (or delegates). Grievances submitted verbally shall be subject to a one week time limit and grievances submitted in writing shall be subject to a two week time limit for processing through the levels involved.

30.11 Where a difference arises between the parties relating to the dismissal or discipline of a dependent backhoe contractor, or to the interpretation, application, operation, or alleged violation of this Appendix, including any question as to whether a matter is arbitrable, either of the parties, without stoppage of work, may, after exhausting the grievance procedure established by this Appendix, notify the other party in writing of its desire to submit the difference to Arbitration, and the parties shall agree on a single Arbitrator. The Union or the Company shall refer the matter to Arbitration within one month after its rejection by either party or the matter shall be deemed to be withdrawn. The decision of the Arbitrator shall be final and binding on both parties and any dependent backhoe contractor affected by it. Each party shall pay one-half the fees and expenses of the Arbitrator. The dependent backhoe contractors shall continue to work while the above outlined grievance procedure is in progress.

ARTICLE 4 TECHNOLOGICAL CHANGE

4.01 The Company shall provide two month's notice in writing to the Union of its intention to introduce any technological change which will result in a termination of the contract for services for a dependent backhoe contractor.

4.02 In the event there is a dispute relating to this Article, the matter may be submitted as a grievance to the immediate supervisor concerned.

ARTICLE 5 SENIORITY

5.01 Seniority shall accrue on a departmental basis only.

5.02 Seniority is established by the date of hire into a department, i.e. the date the dependent backhoe contractor actually reports to work for the department.

5.03 Reduction in the number of dependent backhoe contractors will be in the reverse order of seniority, last on, first off.

5.04 A minimum thirty (30) days notice will be required prior to termination of a dependent backhoe contractor. However, the Company retains the right to terminate for cause without notice.

5.05 A dependent backhoe contractor's department seniority will be placed on a common seniority list at termination for the purpose of determining the order of eligibility for re-engagement except in cases of voluntary termination or termination for cause.

5.06 A former dependent backhoe contractor will be given first consideration for re-engagement in any department for a period of twelve months following termination except in cases of voluntary termination or termination for cause.

ARTICLE 6 HOURS OF WORK

6.01 Dependent backhoe contractors will normally work between the hours of 0800 and 1630 hours Monday to Friday inclusive. They will be entitled to one half (1/2) hour unpaid lunch break and two (2) ten (10) minutes paid rest periods each day, which they will take at the same time the crew or employees, with whom they are working, take theirs.

6.02 Each dependent backhoe contractor will be entitled to three weeks leave without pay in lieu of annual vacation during each twelve-month period of engagement. This leave will be without penalty and at a time agreed to between the Company and the dependent backhoe contractor and will be subject to workload requirements.

6.03 When a dependent backhoe contractor is working with a crew and that crew receives rest time, the dependent backhoe contractor shall, at their option, receive the same 8 hours rest time off without pay.

ARTICLE 7 SCHEDULE OF RATES

7.01 Rates as set out herein shall be for the All-found Rental of Backhoe/Front End Loaders with operator. The rates will be paid only for the number of hours during which the equipment and operator are ready and able to perform the work for which they were engaged.

	Sept. 4, 2006	April 1, 2007	April 1, 2008	April 1, 2009	April 1, 2010
Hourly Rate* (Including Dumptruck & Equipment)	$77.00	$78.75	$81.50	$84.00	$86.50
Overtime Rate (Including Dumptruck & Equipment)	$89.00	$89.00	$89.00	$99.00	$99.00

*Note: The hourly rate for Rikkmen Excavating Co. is red-circled at $86.85 pending the outcome of a JCC convened to review the use of ancillary equipment for CRD Dependent Backhoe Contractors and to seek standardization with the Lower Mainland.

7.02 When the dependent backhoe contractor works in excess of eight (8) hours per day or on a Saturday, Sunday or Statutory Holiday, they shall be paid as per the Article 7.01 table above.

7.03 The dependent backhoe contractor shall assume complete responsibility for the total cost of operation of the backhoe including the insurance on the equipment and all required licenses.

7.03.1 The Company will provide coveralls, safety boots, safety vest, and rain gear, on the same basis as provided for regular members of the crew.

7.04 When a dependent backhoe contractor is working with a crew that is provided with a meal, the dependent contractor shall also receive a meal.

7.05 Dependent backhoe contractors will invoice the Company bimonthly and payment will be delivered through internal Company mail.

ARTICLE 8 BENEFITS

8.01 Unless specifically outlined in Appendix "A", dependent backhoe contractors are not covered under the Company's benefit plans.

APPENDIX F

DEPENDENT CONTRACTOR/ROUTER
(Applies only to Victoria)

ARTICLE 1 GENERAL PROVISIONS

1.01 **APPLICATION**

All items and conditions set out in the Collective Agreement are expressly excluded except those detailed herein. The commencement date shall be the date of ratification and the expiry date of this Appendix will coincide with the expiry date of the Collective Agreement. Any single individual inspector

or router contractors working under their own name or for a Company which they are a major shareholder, employed by the Company's Gas Operations within the Capital Regional District, except those excluded by Code employed at 320 Garbally Road, Victoria, during the time of this agreement for a period of continuous work in excess of six (6) months in any twelve (12) month period will become a dependent inspector or router contractor (hereinafter called "dependent contractor") subject to this Appendix.

The Company may engage the services of a dependent contractor provided that the dependent contractor signs a copy of Appendix "G" attached hereto and forming part of this agreement prior to the dependent contractor performing any services for the Company. A signed copy of Appendix "G" shall be forwarded to the Union.

1.02 **MANAGEMENT RIGHTS**

The Union recognizes and agrees that except as specifically abridged, delegated, granted or modified by this Appendix, all the rights, powers and authority which the Company had prior to the signing of this Appendix are retained solely and exclusively by the Company, and remain without limitation within the rights of management.

ARTICLE 2 UNION DUES

2.01 The Company recognizes the Union will not discriminate against any dependent contractor because of his connection with it. The Company agrees that all dependent contractors shall, within one month of engagement as a dependent contractor, become and remain thereafter members of the union in good standing as a condition precedent to continued engagement with the Company. Properly qualified officers of the Union shall be recognized by the Company for the purpose of discussing any grievance of any Dependent Contractor. For the purpose of Union Dues calculation, the Mains & Service Planner wage rate will be used for Dependent Contractors.

2.02 Upon receipt of a written assignment of earnings signed by the dependent contractors, the Company will deduct from the dependent contractor's pay the amount of the required monthly dues and assessments and transmit this amount to the Union, once per month, together with a list of dependent contractors from whom such deductions have been made.

2.03 The Union agrees to indemnify the Company for any claims made against it arising out of deductions made under this Article.

2.04 If there are insufficient earnings owing to a dependent contractor in the period for which dues deduction should be made, the Company is not required to make a deduction or to transmit any payment to the Union in respect of that dependent contractor.

ARTICLE 3 GRIEVANCES

3.02 Complaints shall first be discussed with the immediate Manager concerned. Failing settlement at the complaint stage, grievances shall be presented in writing to the immediate Manager with a copy to the Labour Relations Department giving details of the alleged violation and the relevant Collective Agreement Articles(s). Failing settlement at that stage, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Department Head with a copy to the Labour Relations Department. Failing settlement at that level, the Business Agent of the Union or delegate shall submit the grievance in writing to the appropriate Vice-President, and the Vice-President, Human Resources (or delegates). Grievances submitted verbally shall be subject to a one week time limit and grievances submitted in writing shall be subject to a two week time limit for processing through the levels involved.

30.12 Where a difference arises between the parties relating to the dismissal or discipline of a dependent backhoe contractor, or to the interpretation, application, operation, or alleged violation of this Appendix, including any question as to whether a matter is arbitrable, either of the parties, without stoppage of work, may, after exhausting the grievance procedure established by this Appendix, notify the other party in writing of its desire to submit the difference to Arbitration, and the parties shall agree on a single Arbitrator. The Union or the Company shall refer the matter to Arbitration within one month after its rejection by either party or the matter shall be deemed to be withdrawn. The decision of the Arbitrator shall be final and binding on both parties and any dependent backhoe contractor affected by it. Each party shall pay one-half the fees and expenses of the Arbitrator. The dependent backhoe contractors shall continue to work while the above outlined grievance procedure is in progress.

3.03 The Company shall not dismiss or discipline a dependent contractor bound by this Appendix except for just and reasonable cause.

ARTICLE 4 TECHNOLOGICAL CHANGE

4.01 The Company shall provide one month's notice in writing to the Union of its intention to introduce any technological change which will result in a termination of the contract for services for the dependent contractor.

4.02 In the event there is a dispute relating to this Article, the matter may be submitted as a grievance at the next level of management of the grievance procedure for resolution.

ARTICLE 5 SENIORITY

5.01 Seniority shall accrue on a classification basis only and is retroactive to the date of hire.

5.02 Seniority is established by the date of hire into a classification.

5.03 Reduction in the number of dependent contractors will be in the reverse order of seniority, last on, first off.

5.04 A minimum thirty (30) days notice will be required prior to lay-off of a dependent contractor. However, the Company retains the right to terminate for cause without notice.

5.05 A dependent contractor's classification seniority will be placed on a separate seniority list, by classification, at termination for the purpose of determining the order of eligibility for re-engagement except in cases of voluntary termination or termination for cause.

5.06 A former dependent contractor will be given first consideration for re-engagement in any department for a period of twelve months following termination except in cases of voluntary termination and termination for cause.

ARTICLE 6 HOURS OF WORK

6.01 Dependent contractors will normally work between the hours of 0800 and 1630 hours Monday to Friday inclusive. They will be entitled to one half (1/2) hour unpaid lunch break and two (2) ten (10) minutes paid rest periods each day, which they will take at the same time the crew or employees, with whom they are working, take theirs.

6.02 Each dependent contractor will be entitled to vacation pay as outlined in the Employment Standards Act. In addition, dependent contractors will be entitled to three (3) weeks leave without pay during each twelve (12) month period of engagement. This leave will be without penalty and at a time agreed to between the Company and the dependent contractor and will be subject to workload requirements.

ARTICLE 7 SCHEDULE OF RATES

7.01 Rates as set out herein shall be for the dependent contractor including their vehicle and all associated operating and maintenance costs. The rates will be paid only for the number of hours during which the vehicle and dependent contractor are performing the work for which they were engaged. The Mains & Service Planner rate will be used as the base rate and the remainder will be considered the Vehicle Rate.

	Sept. 4, 2006	**April 1, 2007**	**April 1, 2008**	**April 1, 2009**	**April 1, 2010**
Labour (Base Rate) Portion	$29.42	$30.16	$31.06	$31.99	$32.95
Vehicle (Rate) Portion	$5.69	$5.69	$5.69	$5.69	$5.69
Router Rate	$35.11	$35.85	$36.75	$37.68	$38.64

7.02 When the dependent contractor works in excess of eight (8) hours per day or on a Saturday, Sunday or Statutory Holiday, they shall be paid the equivalent of time and one half for such hours.

7.03 The dependent contractor shall assume complete responsibility for the total cost of operation of the vehicle including the insurance on the vehicle and all required licenses.

7.03.1 The dependent contractor shall, at its own expense, obtain and maintain during the duration of the Work, insurance for liability imposed by law upon the dependent contractor for loss or damage including personal injuries and death arising from the ownership, use or operation of any motor vehicle used or to be used in connection with the Work to be performed by the dependent contractor, for not less than a $1,000,000.00 inclusive, bodily injury and Property Damage limit each loss. The dependent contractor will produce to the Company, on request, satisfactory evidence of such insurance.

7.03.2 The Company will provide coveralls, safety boots, safety vest, and rain gear, on the same basis as provided for regular members of the crew.

7.04 Dependent contractors will invoice the Company bimonthly and payment will be delivered through internal Company mail.

ARTICLE 8 BENEFITS

8.01 Unless specifically outlined in this Appendix, Dependent Contractors are not covered under the Company's benefit plans.

ARTICLE 9 MISCELLANEOUS

9.01 Either party may request that the parties meet on a regular basis, as mutually agreed to by both parties, during the term of this Appendix to discuss issues relating to the workplace that affect both parties.

9.02 Unless otherwise indicated, all days referred to in this Appendix will be considered calendar days.

ARTICLE 10 DESCRIPTION OF WORK

ROUTER

Duties and Responsibilities:

1. Plans gas mains and services, renewals, replacements, alterations and upgrading by:
    a) researching appropriate Government, Company and other records to determine locations of utilities, rail crossings, easements and rights of way to running line planning; line location of Company underground plant,
    b) surveying and inspecting area conditions of running line locations,
    c) determining most effective route and location of gas mains and services,
    d) coordinating planning work with both in-house and with municipalities, other utilities and contractors,
    e) ensuring proper standards are maintained,
    f) preparing associated paperwork, including sketches, and specifications,
    g) preparing project cost estimates.
2. Perform other related duties.

Qualifications:

Must have:

1. Grade 12 or equivalent.
2. A valid B.C. Class 5 Driver's License.
3. Able to operate total station survey equipment.
4. Effective oral and written skills.
5. Knowledge of gas distribution systems and installation practices, utilization and installation codes. Knowledge of design and lay-out of municipal services, including water, sewer, telephone and power.
6. Vehicle capable of performing the work and insured as noted in Article.

<u>APPENDIX G</u>

Dependent Contractor ____

Address

____

____

____

1. The Company agrees to retain the services of the Dependent Contractor commencing on the _________ day of ___________________, 20____ as a ____________________________.

SIGNED THIS ________ DAY OF _______________________ 20 __________

AT ____B.C.

Dependent Contractor ____

Witness____

The Company____

Attachment 82.1

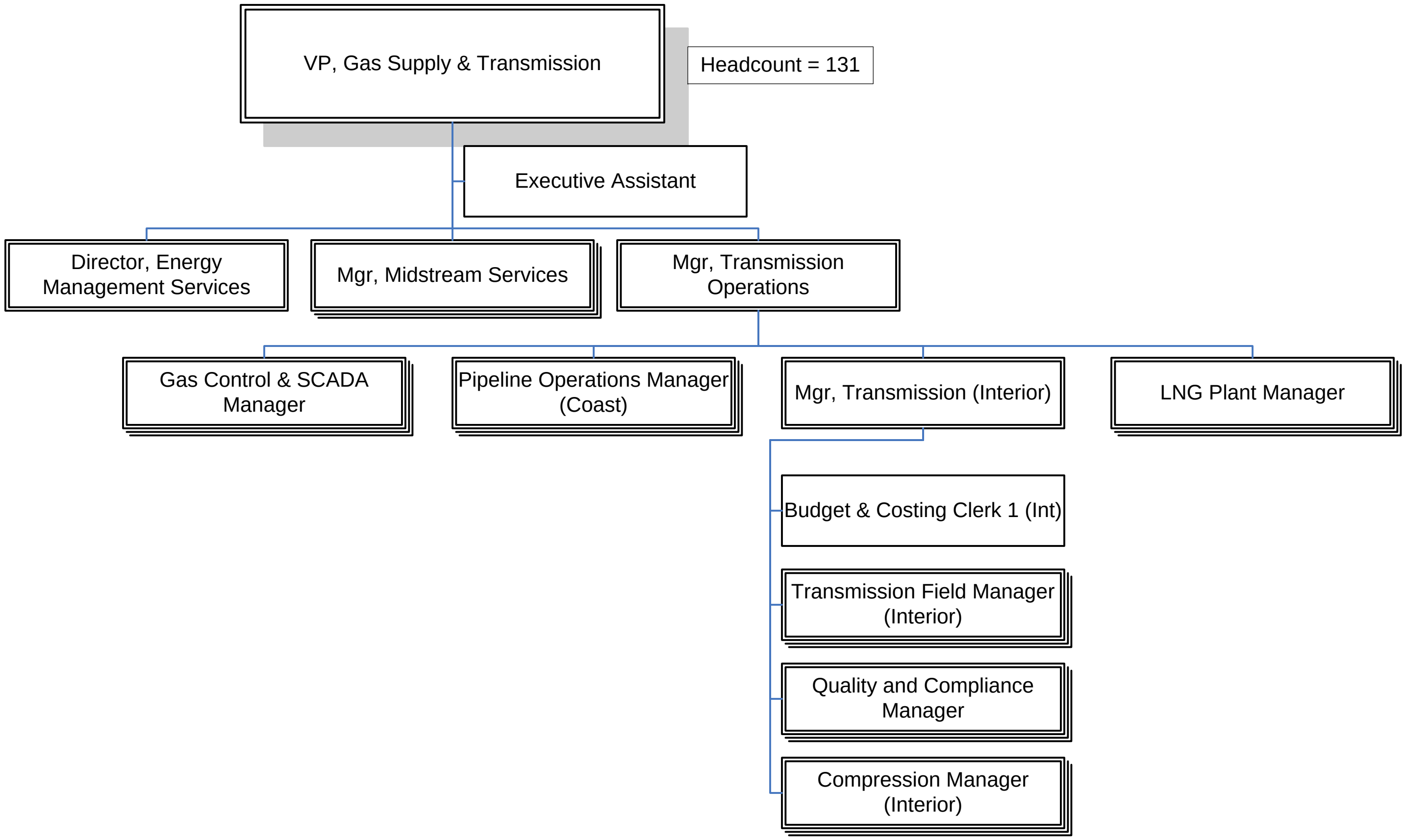
TERASEN GAS INC.

As at December 31, 2006

- President, Terasen Gas Inc. — Total Headcount = 1083
  - Executive Assistant
  - VP, Gas Supply & Transmission — Headcount = 131, See page 2
  - VP, Marketing & Business Development — Headcount = 77, See page 3
  - VP, Human Resources & Ops Governance — Headcount = 97, See page 4
  - VP, Finance & Regulatory Affairs — Headcount =55, See page 5
  - VP, Business Services & CIO — Headcount = 260, See page 6
  - VP, Distribution — Headcount = 463, See page 7

TERASEN GAS INC.

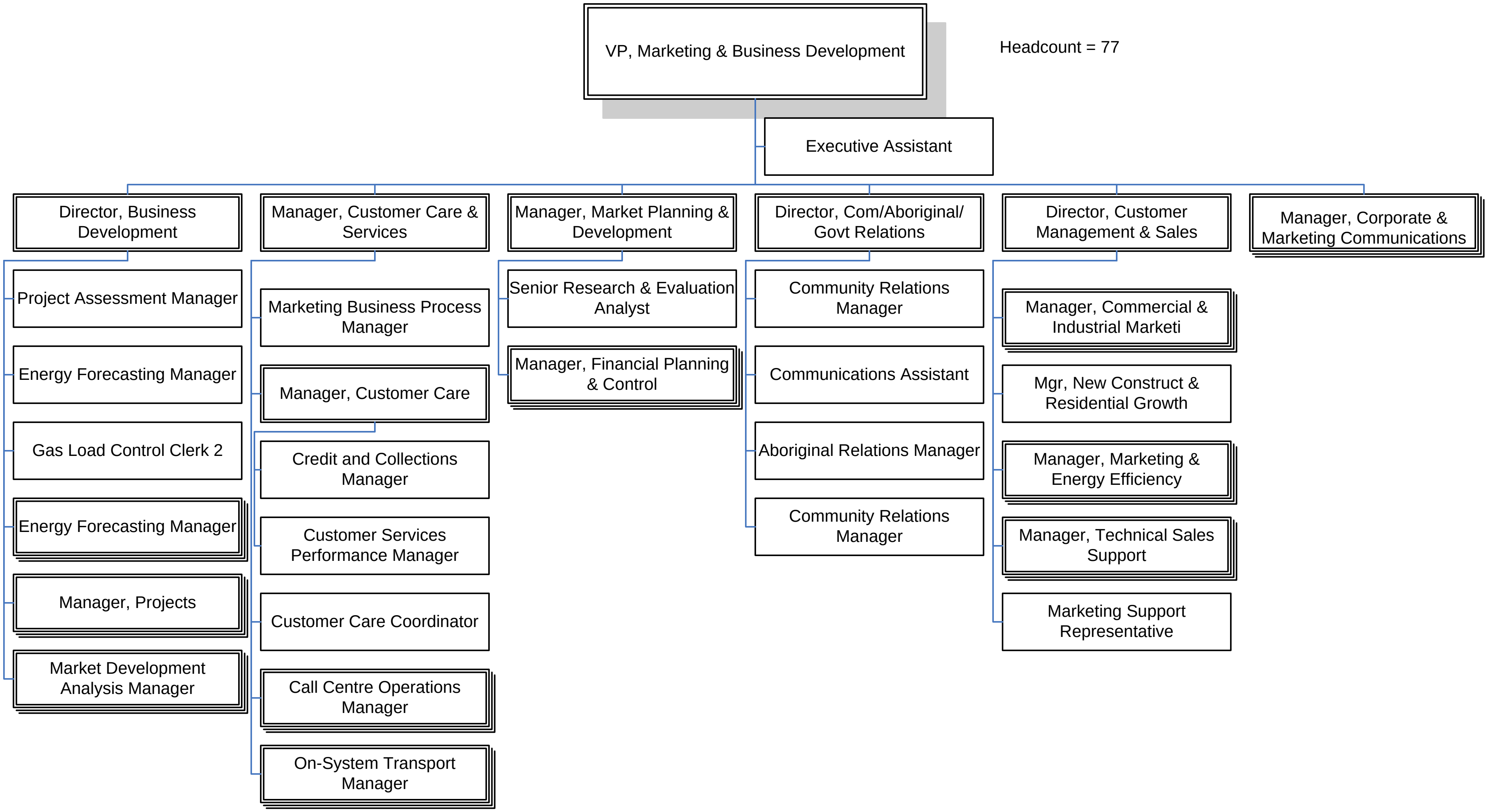
GAS SUPPLY & TRANSMISSION
As at December 31, 2006



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

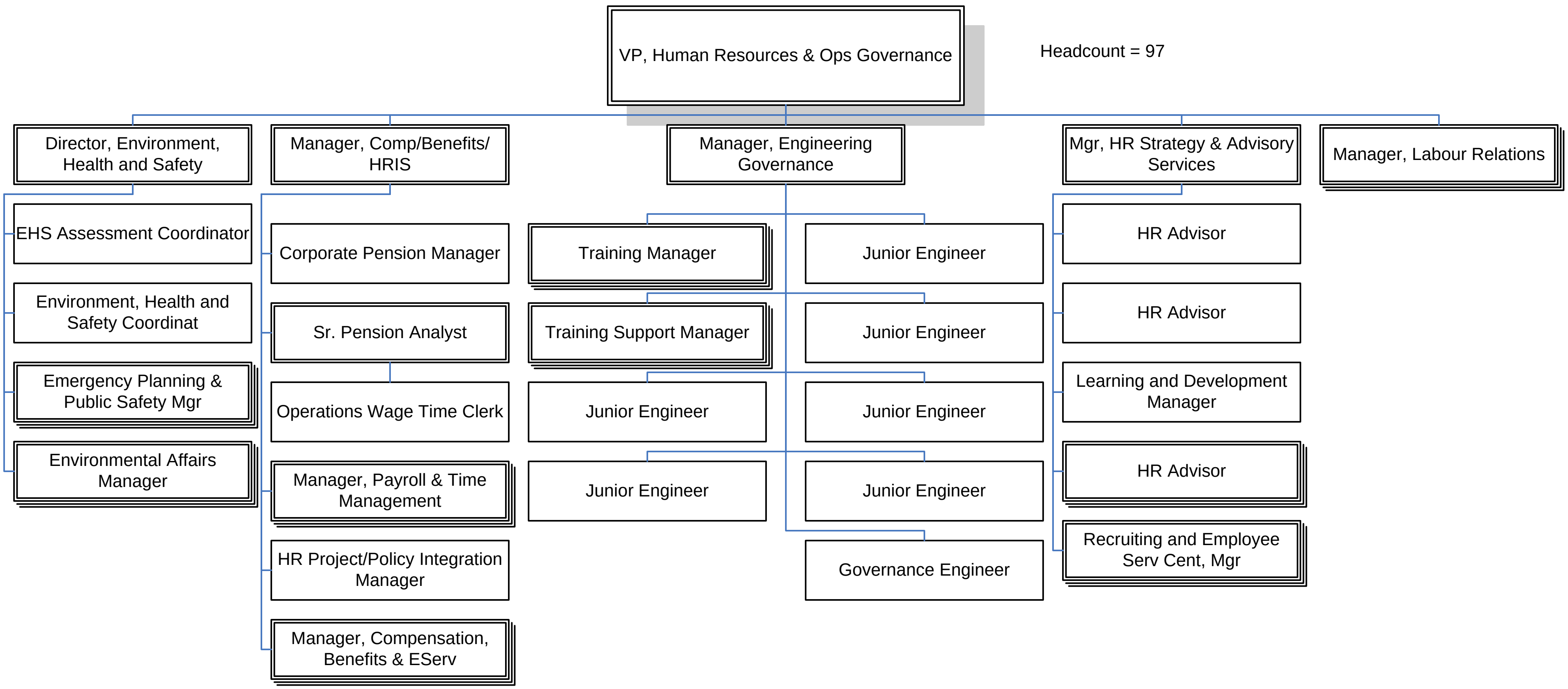
As at December 31, 2006



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

As at December 31, 2006



TERASEN GAS INC.

FINANCE & REGULATORY AFFAIRS

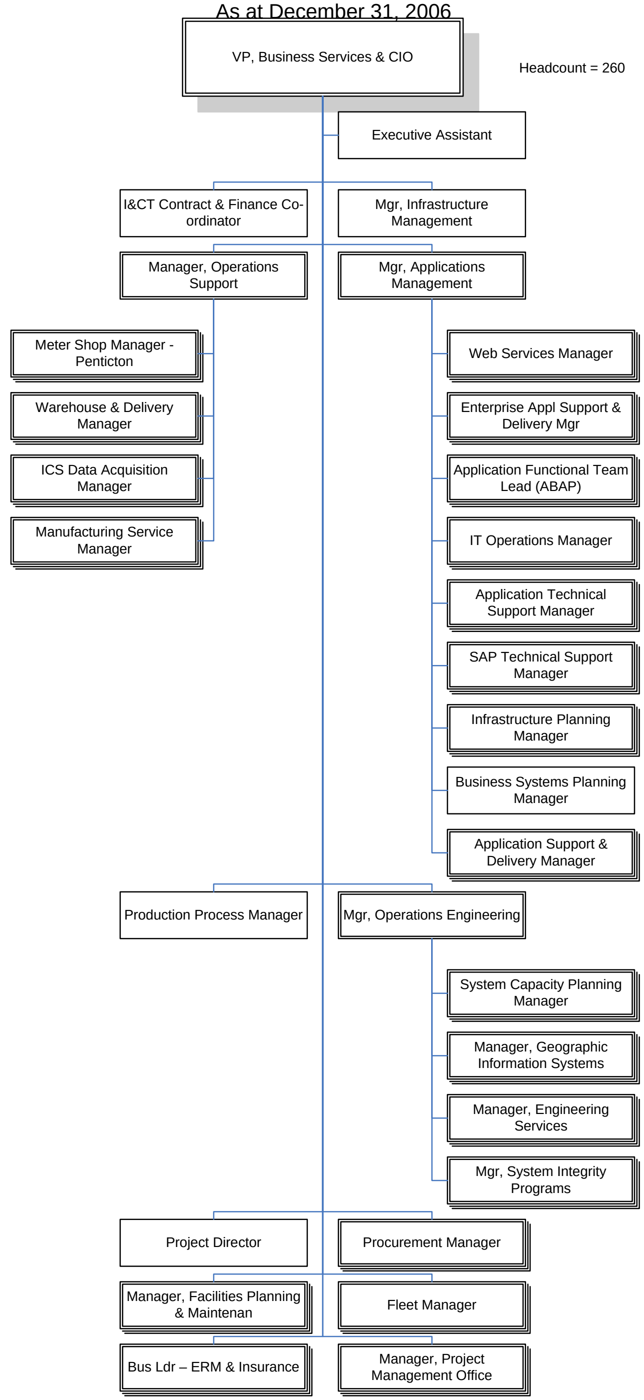
As at December 31, 2006

Headcount = 55

- VP, Finance & Regulatory Affairs
  - Executive Assistant
  - Inc Position
  - Director, Regulatory Affairs
    - Regulatory Affairs Assistant
    - Regulatory Governance Advisor
    - Rate Design & Projects Manager
    - Regulatory Reporting Manager
    - Mgr,Regulatory Strategy & Business Analy
    - Tariff and Special Contract Manager
  - Mgr, Financial & Regulatory Reporting
    - Financial Accounting & Reporting Manager
      - Financial Accounting Analyst
      - Finance Planning & Support Manager
      - Senior Rates Analyst
      - Financial Processes & Control Manager
      - Financial Accounting Analyst
      - Financial Reporting Manager
    - Revenue Requirements Manager
      - Regulatory Reporting Specialist
  - CMO Manager
  - Inc Position

TERASEN GAS INC.

BUSINESS & IT SERVICES
As at December 31, 2006



TERASEN GAS INC.

DISTRIBUTION

As at December 31, 2006

Headcount = 463

- VP, Distribution
  - Executive Assistant
  - Regional Mgr, Dist Ops - Van Isl
    - Quality and Compliance Manager
    - Mgr, Transmission (Interior)
    - Gas Control & SCADA Manager
    - Pipeline Operations Manager (Coast)
    - LNG Plant Manager
  - Regional Mgr, Dist Ops - Interior South
    - Installation Manager - Kelowna
    - Operations Manager - Trail
    - Install/Operate Manager
    - Installation Manager - Trail
    - Install/Operate Manager - Vernon
    - Operations Manager - Kelowna
    - Install/Operate Manager - Penticton
  - Manager, Business Performance - Dist Ops
  - Mgr, Capital Installations
  - Regional Mgr, Dist Ops - Interior North
    - Operations Manager - Kamloops
    - Install/Operate Manager - Ft Nelson
    - Installation Manager - Kamloops
    - Installation Manager - Prince George
    - Operations Manager - Prince George
    - Install/Operate Manager - Revelstoke
  - Manager, Operations Centre
    - Resource Planning & Scheduling Manager
    - Resource Planning andScheduling Manager
    - Installation Centre Mgr - IC2 & Pre Req
    - Installation Center Manager - IC1
    - IRM Manager, Install Work
  - Regional Manager Distribution
    - Damage Prev & Emerg Serv Manager
    - Operations Manager - Burnaby
    - Operations Manager - Squ/Whi
    - Installation Manager
    - Operations Manager - Vancouver
    - Installation Manager - Vancouver
    - Dist Assets & Improvements Manager
    - Operations & Maintenance Manager
    - Installation Manager - Vancouver
  - Regional Mgr, Dist Ops - Fraser Valley
    - Install Manager - Zone 3
    - Operations Manager - Surrey
    - Installation Manager - Coquitlam
    - Operations Manager - Surrey
    - Installation Manager - Langley
    - Installation Manager - Surrey
  - Mgr, Distribution Asset Management
  - Manager, Distribution Integration
    - Process Support Manager
    - Operations Service Manager
    - Special Assignment Manager
    - Special Assignment Manager
    - Operations Service Manager

TERASEN GAS INC.

As at December 31, 2007

- President, Terasen Gas Inc. — Total Headcount = 1114
  - Executive Assistant
  - VP, Marketing & Business Development — See page 6 # of ees 84
  - VP, Human Resources & Ops Governance — See page 2 # of ees 86
  - VP, Regulatory Affairs & CFO — See page 4 # of ee 64
  - VP, Gas Supply & Transmission — See page 7 # of ees 81
  - VP, Business Services & CIO — See page 15 # of ees 307
  - VP, Distribution — See page 3 # of ee 492

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

As at December 31, 2007

- VP, Human Resources & Ops Governance
  - Manager, Comp/Benefits/ HRIS
    - Sr. Pension Analyst
    - Manager, Compensation, Benefits & EServ
    - HR Project/Policy Integration Manager
    - Manager, Payroll & Time Management
    - Corporate Pension Manager
    - HR Representative, Employee Services
  - Manager, Labour Relations
    - Labour Relations Assistant
    - Labour Relations Assistant
  - Director, Environment, Health and Safety
    - OH&S & Corporate Security Manager
    - Emergency Planning & Public Safety Mgr
    - Administrator, Environment Health Safety
    - Environmental Affairs Manager
  - Mgr, HR Strategy & Advisory Services
    - HR Advisor
    - HR Advisor
    - Recruiting Manager
    - Associate Human Resources Advisor
    - HR Advisor
  - Manager, Engineering Governance
    - Governance Engineer
    - Training Manager
    - Learning and Development Specialist
    - Junior Engineer

TERASEN GAS INC.

DISTRIBUTION

As at December 31, 2007

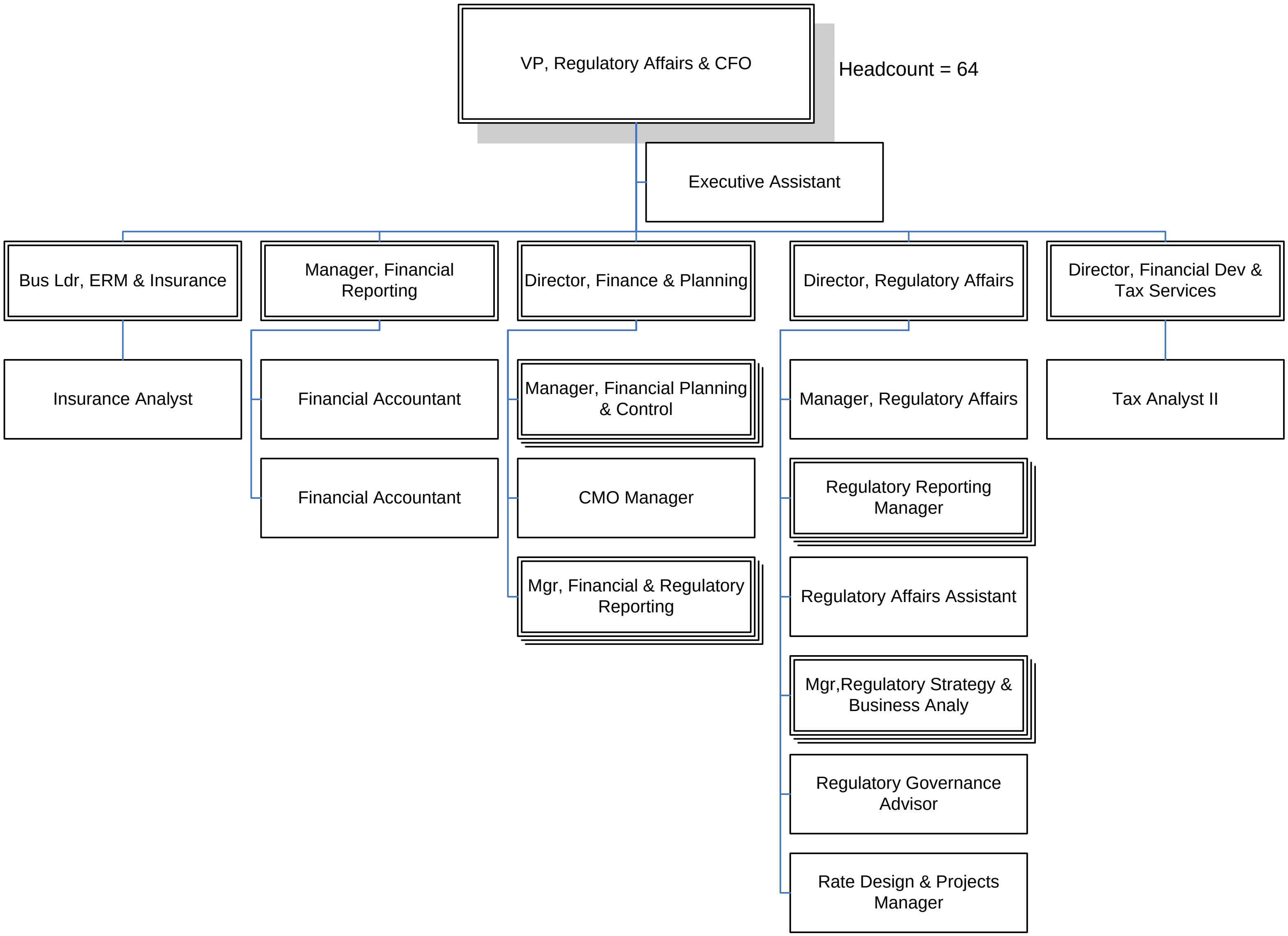
Headcount = 492

- VP, Distribution
  - Executive Assistant
  - Regional Manager, Dist - Vancouver Island
  - Manager, Business Performance - Dist Ops
    - Distribution Operations Analyst
  - Manager, Distribution Integration
    - Process Manager
    - Process Support Manager
    - Operations Service Manager
    - Special Assignment Manager
    - Operations Service Manager
    - Special Assignment Manager
  - Regional Manager, Dist - Interior North
    - Operations Manager - Kamloops
    - Installation Manager - Kamloops
    - Customer Service Technician 2
    - Install/Operate Manager - Revelstoke
    - Customer Service Technician 1
    - Install/Operate Manager - Ft Nelson
    - Installation Manager - Prince George
  - Regional Manager Distribution, Vancouver
    - Operations Manager - Squ/Whi
    - Installation Manager
    - Operations Manager
    - Installation Manager - Vancouver
    - Operations Manager - Vancouver
    - Installation Manager - Vancouver
  - Mgr, Distribution Asset Management
    - Damage Prev & Emerg Serv Manager
    - Dist Assets & Improvements Manager
    - Asset Optimization Manager
    - Operations & Maintenance Manager
  - Mgr, Capital Installations
    - Project Manager
    - Project Management Administrative Assist
    - Project Manager
    - Project Manager
    - Construction Contracts Manager
    - Project Manager
    - Install Coordinator 2
    - Install Coordinator 2
  - Regional Manager Dist - Fraser Valley
    - Installation Manager - Langley
    - Installation Manager - Abbotsford
    - Installation Manager - Coquitlam
    - Operations Manager - Surrey
    - Installation Manager - Surrey
    - Operations Manager - Surrey
  - Regional Manager, Dist Interior South
    - Operations Manager - Trail
    - Install/Operate Manager - Cranbrook
    - Installation Manager - Trail
    - Install/Operate Manager - Vernon
    - Operations Manager - Kelowna
    - Install/Operate Manager - Penticton
    - Installation Manager - Kelowna
  - Manager, Operations Centre
    - Resource Planning & Scheduling Manager
    - IRM Manager, Install Work
    - Installation Centre Manager - IC2
    - Resource Planning & Dispatch Manager
    - Closing Manager
    - Installation Center Manager - IC1

TERASEN GAS INC.

FINANCE & REGULATORY

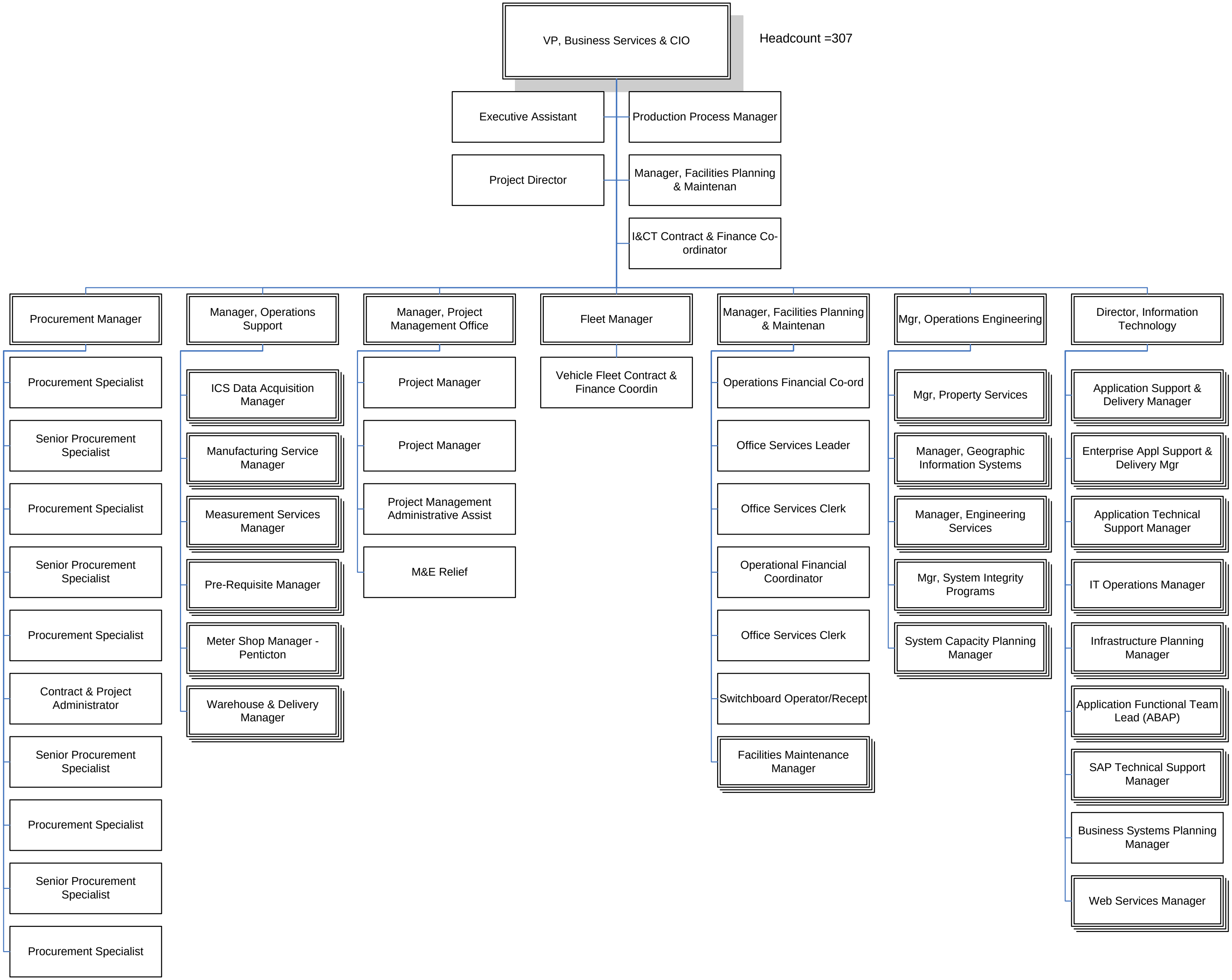
As at December 31, 2007



TERASEN GAS INC.

BUSINESS & IT SERVICES

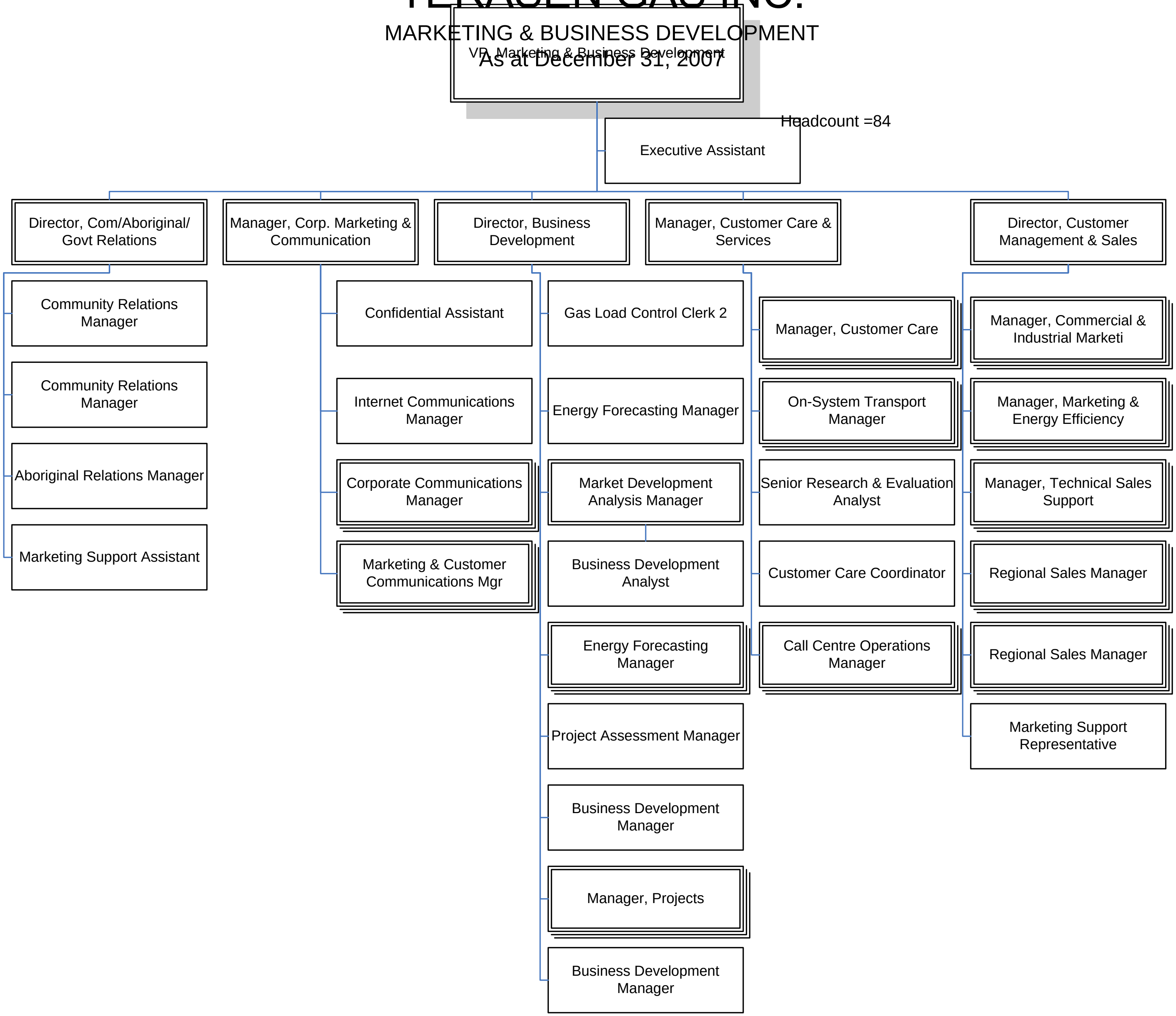
As at December 31, 2007



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

As at December 31, 2007



TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION
As at December 31, 2007

Headcount = 81

- VP, Gas Supply & Transmission
  - Executive Assistant
  - Manager, Midstream Services (Shared (Core))
    - Resource Manager
    - Market Analyst, Midstream
    - Market Analyst, Midstream
    - Operations Manager, Midstream
    - Operations Manager, Midstream
  - Mgr, Transmission Operations
    - Quality and Compliance Manager
    - Pipeline Operations Manager (Coast)
    - LNG Plant Manager
    - Gas Control & SCADA Manager
    - Mgr, Transmission (Interior)
  - Director, Energy Management Services
    - EMS Account Manager
    - Resource Planning Analyst
    - Price Risk Analyst
    - Market Analyst
    - Price Risk Manager

TERASEN GAS INC.

As at December 31, 2008

President, Terasen Gas Inc.

Total Headcount = 1155

- Executive Assistant
- VP, Regulatory Affairs & CFO
  See page 5
  # of ees 66
- VP, Distribution
  See page 4
  # of ees 510
- VP, Gas Supply & Transmission
  See page 3
  # of ees 82
- VP, Marketing & Business Development
  See page 7
  # of ees 80
- VP, Human Resources & Ops Governance
  See page 2
  # of ees 100
- VP, Business Services & CIO
  See page 6
  # of ees 317

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

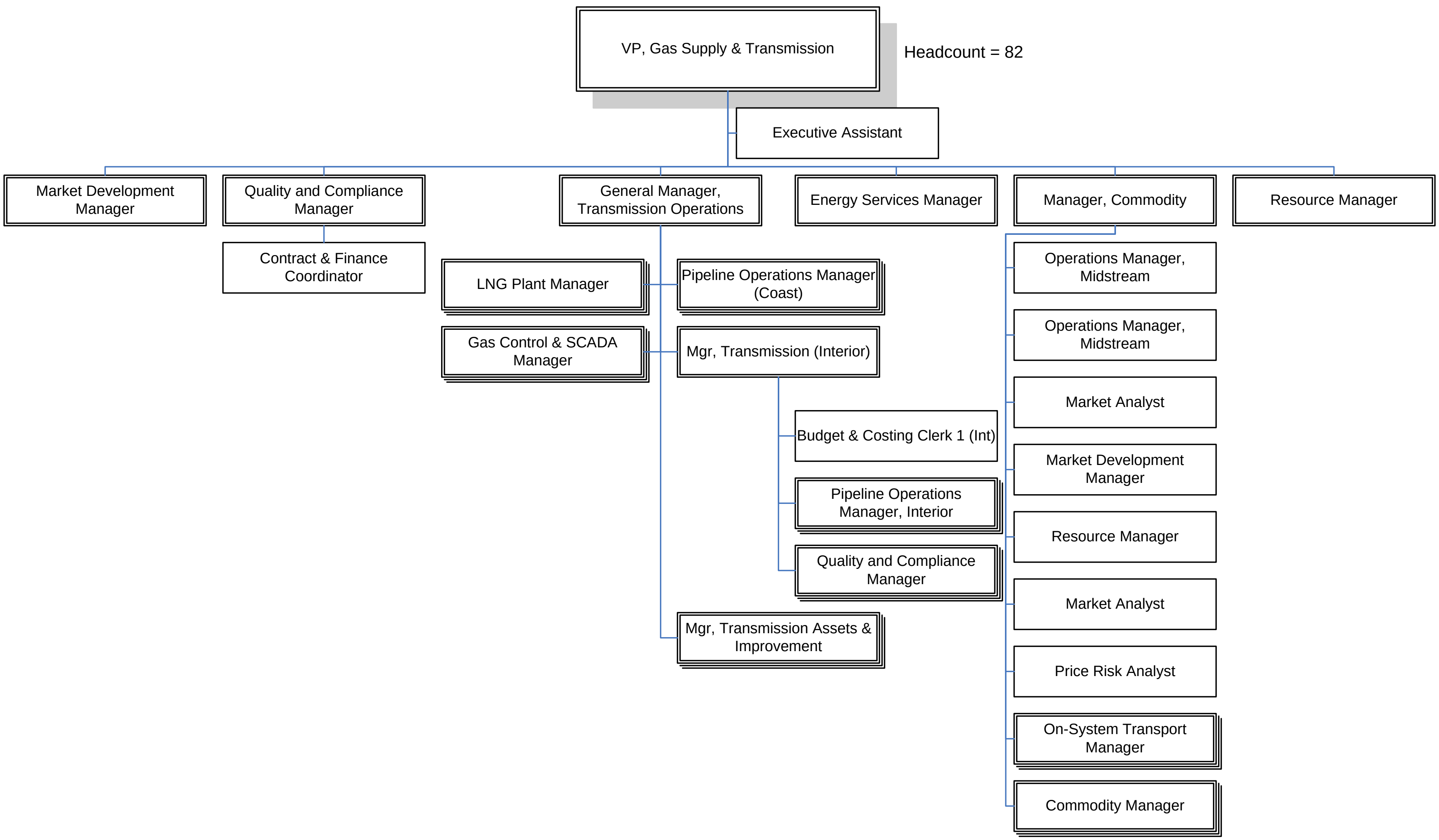
As at December 31, 2008

- VP, Human Resources & Ops Governance — Headcount = 100
  - Executive Assistant
  - Manager, Labour Relations
    - Labour Relations Coordinator
    - Labour Relations Coordinator
  - Director, Environment, Health and Safety
    - Emergency Planning & Public Safety Mgr
    - Operations Compliance Auditor
    - Administrator, Environment Health Safety
    - Environmental Affairs Manager
    - OH&S & Corporate Security Manager
  - Manager, Engineering Governance
    - Manager-In-Training
    - Junior Engineer
    - Manager-In-Training
    - Junior Engineer
    - Training Manager
    - Training Manager
    - Learning and Development Specialist
    - Junior Engineer
  - Director, Total Compensation & HRIS
    - Manager, Compensation, Benefits & EServ
    - Sr. Pension Analyst
    - Payroll & Time Administration Manager
    - Corporate Pension Manager
  - Director, HR Strategy & Advisory Srvcs
    - HR Advisor
    - HR Advisor
    - Recruiting Manager
    - HR Advisor

TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

As at December 31, 2008



Prepared by: Judy Forshner

TERASEN GAS INC.

DISTRIBUTION

As at December 31, 2008

Headcount = 510

- VP, Distribution
  - Executive Assistant
  - Regional Manager, Dist - Vancouver Island
  - Manager, Distribution Integration
    - Operations Service Manager
    - Special Assignment Manager
    - Business Support Manager
    - Special Assignment Manager
    - Special Assignment Manager
  - Mgr, Distribution Asset Management
    - Operations & Maintenance Manager
    - Dist Assets & Improvements Manager
    - Asset Optimization Manager
    - Damage Prev & Emerg Serv Manager
  - Regional Manager Dist - Fraser Valley
    - Installation Manager - Coquitlam
    - Operations Manager - Surrey
    - Installation Manager - Surrey
    - Installation Manager - Langley
    - Distribution Manager
    - Distribution Manager
  - Mgr, Capital Installations
    - Project Manager
    - Project Manager
    - Project Manager
    - Project Management Administrative Assist
    - Project Manager
    - Project Manager
    - Project Manager
    - Project Manager
    - Construction Contracts Manager
    - Project Manager
  - Regional Manager, Dist Interior South
    - Installation Manager - Trail
    - Install/Operate Manager - Vernon
    - Install/Operate Manager - Penticton
    - Install/Operate Manager - Cranbrook
    - Installation Manager - Kelowna
    - Distribution Manager
  - Manager, Business Performance - Dist Ops
    - Distribution Operations Analyst
  - Regional Manager, Dist - Interior North
    - Install/Operate Manager - Revelstoke
    - Installation Manager - Kamloops
    - Installation Manager - Prince George
    - Install/Operate Manager - Ft Nelson
    - Operations Manager - Kamloops
    - Distribution Manager
  - Regional Manager Distribution, Vancouver
    - Distribution Manager
    - Distribution Manager
    - Operations Manager - Vancouver
    - Operations Manager - Squ/ Whi
    - Installation Manager
    - Operations Manager
  - Director, Operations Centre
    - Pre-Requisite Manager
    - Resource Planning Manager
    - Closing Manager
    - Emergency Support Manager
    - Dispatch Manager
    - Installation Centre Manager - IC2

TERASEN GAS INC.

FINANCE & REGULATORY

As at December 31, 2008

Headcount = 66

- VP, Regulatory Affairs & CFO
  - Executive Assistant
  - Financial Reporting INC Position
  - Director, Finance & Planning
    - Financial Accounting & Reporting Manager
    - Manager, Financial Planning & Control
      - Management Reporting Manager
      - Financial Planning Manager
      - Financial Planning Manager
      - Operations Financial Planning Manager
    - CMO Manager
  - Chief Regulatory Officer
    - Regulatory Governance Advisor
    - Regulatory Affairs Assistant
    - Director, Reg Strategy & Bus Analysis
    - Rate Design & Projects Manager
    - Tariff and Special Contract Manager
      - Rates Design Coordinator
    - Manager, Regulatory Affairs
      - Regulatory Policy Manager
    - Regulatory Reporting Manager
  - Dir, , Fin Dev & Tax Services Inc Position
    - Tax Analyst II

TERASEN GAS INC.

BUSINESS & IT SERVICES

As at December 31, 2008

Headcount = 317

- VP, Business Services & CIO
  - Executive Assistant
  - Production Process Manager
  - I&CT Contract & Finance Co-ordinator
  - Project Director
  - Manager, Facilities Planning & Maintenance
    - Office Services Leader
    - Facilities Coordinator
    - Operations Financial Co-ord
    - Switchboard Operator/Recept
    - Office Services Clerk
    - Facilities Maintenance Manager
  - Director, Information Technology
    - Application Technical Support Manager
    - Infrastructure Planning Manager
    - Application Support & Delivery Manager
    - IT Operations Manager
    - Business Systems Planning Manager
    - Enterprise Appl Support & Delivery Mgr
  - Director, Operations Support
    - Meter Shop Manager - Penticton
    - Manufacturing Service Manager
    - ICS Data Acquisition Manager
    - Measurement Services Manager
  - Project Director
    - Project Clerk
    - Project Manager
  - Director, Operations Engineering
    - Manager, Geographic Information Systems
    - Manager, Engineering Services
    - System Capacity Planning Manager
    - Mgr, Property Services
    - Mgr, System Integrity Programs
  - Manager, Project Management Office
    - Project Management Administrative Assist
    - Project Manager
    - Project Manager
  - Procurement Manager
    - Procurement Specialist
    - Senior Procurement Specialist
    - Senior Procurement Specialist
    - Procurement Specialist
    - Procurement Work Leader
    - Procurement Specialist
    - Contract & Project Administrator
    - Senior Procurement Specialist
    - Senior Procurement Specialist
    - Procurement Specialist
  - Bus Ldr, ERM & Insurance INC Position
    - Fleet Manager
      - Vehicle Fleet Contract & Finance Coordin
    - Tax Analyst II

TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

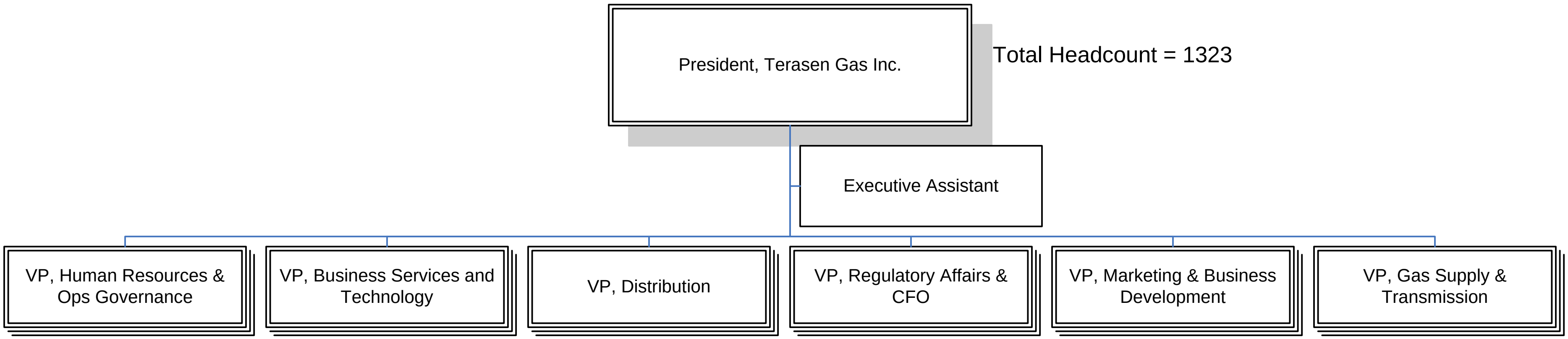
As at December 31, 2008

- VP, Marketing & Business Development — Headcount = 80
  - Executive Assistant
  - Director, Resource Planning & Market Dev
    - Gas Load Control Clerk 2
    - Manager, Marketing & Energy Efficiency
    - Business Development Manager
    - Business Development Manager
    - Market Development Analysis Manager
    - Customer & Energy Forecasting Manager
    - Manager, Project Development
    - Resource Planning Analyst
  - Director, Corp & Marketing Communication
    - Confidential Assistant
    - Corporate Communications Manager
    - Marketing & Customer Communications Mgr
  - Director, Customer Management & Sales
    - Manager, Technical Sales Support
    - Manager, Commercial & Industrial Marketi
    - Regional Sales Manager
    - Regional Sales Manager
  - Director, Com/Aboriginal/ Govt Relations
    - Community Relations Manager
    - Community Relations Manager
    - Government Relations Manager
    - Aboriginal Relations Manager
    - Comm, Aboriginal & Gov't Relations Assis
  - Director, Customer Care & Services
    - Call Centre Operations Manager
    - Manager, Customer Care
    - Manager, Customer Programs & Research
    - OSR 2 (M&E Relief)

Attachment 82.2

TERASEN GAS INC.

2010 (Proposed)

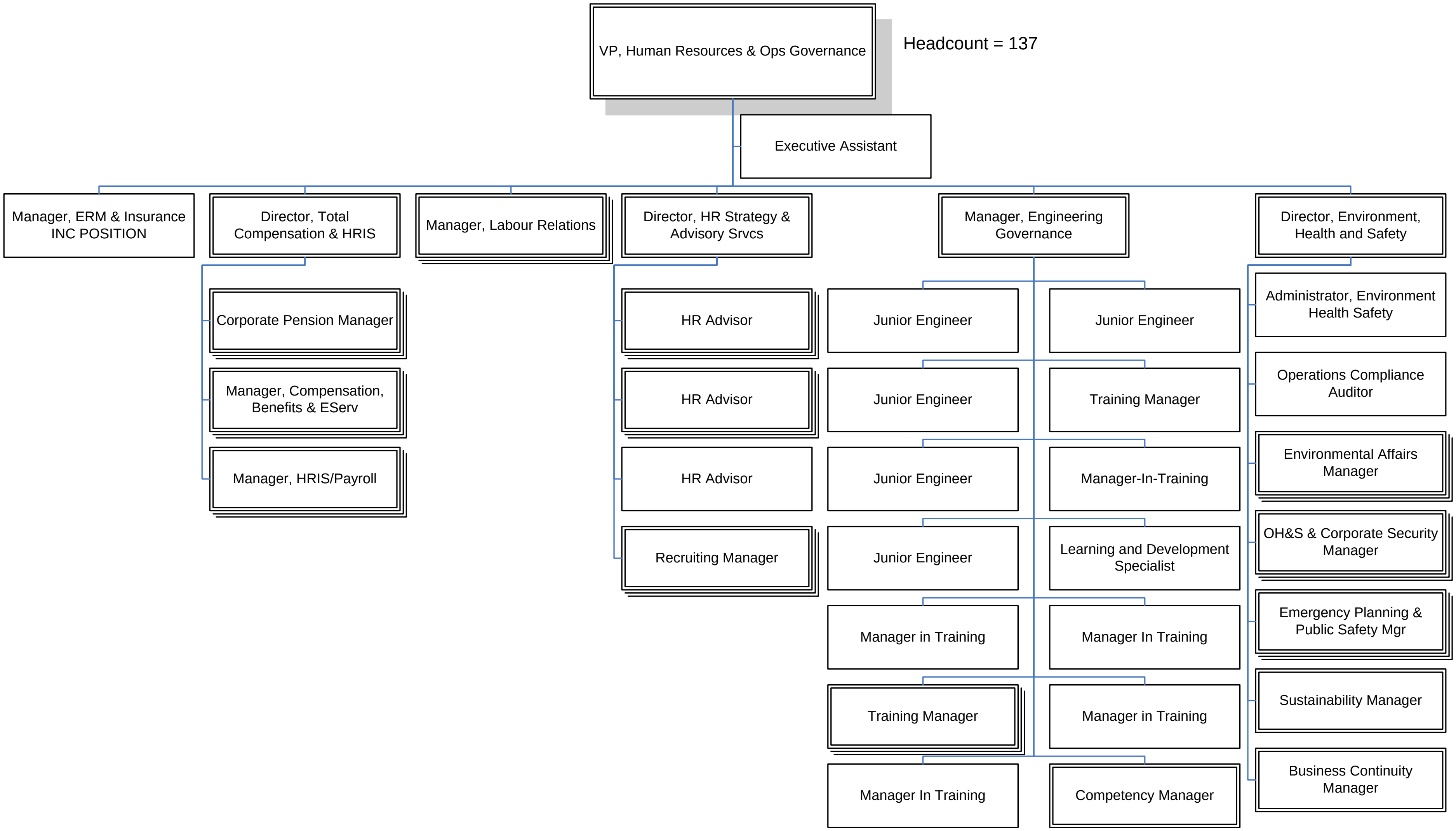


See page 2 See page 3 See page 4 See page 5 See page 6 See page 7

TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

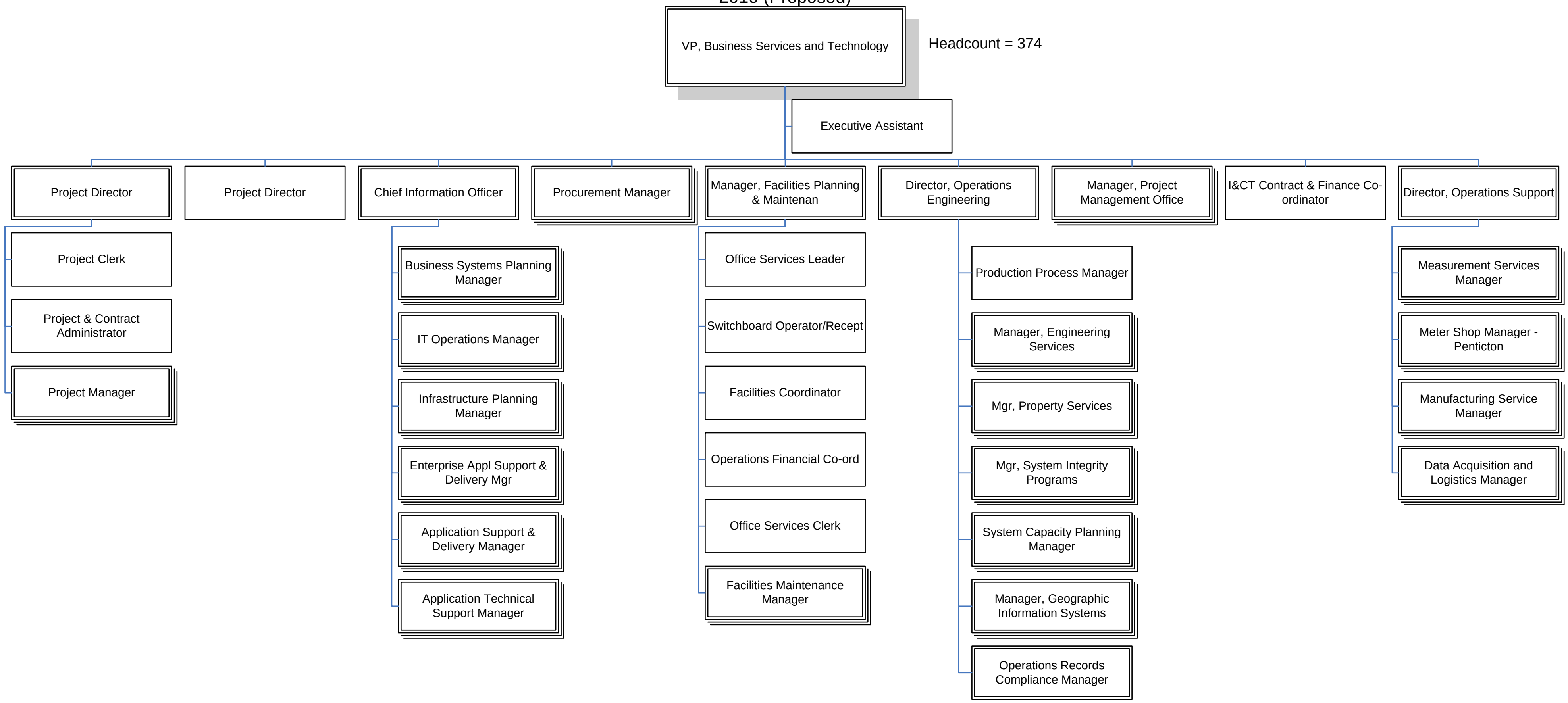
2010 (Proposed)



TERASEN GAS INC.

BUSINESS & IT SERVICES

2010 (Proposed)



TERASEN GAS INC.

DISTRIBUTION

2010 (Proposed)

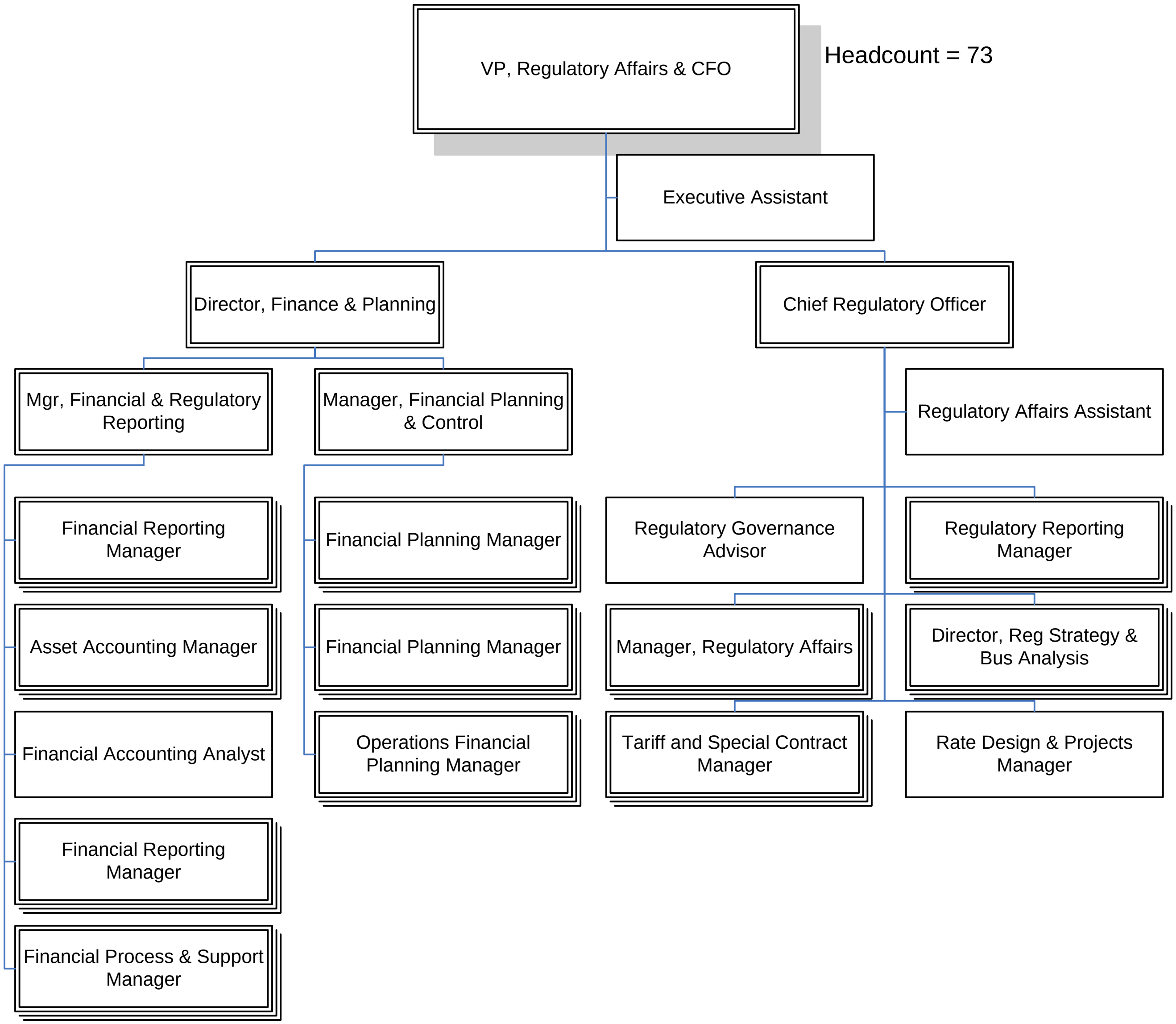
Headcount = 514

- VP, Distribution
  - Executive Assistant
  - Mgr, Distribution Asset Management
    - Asset Optimization Manager
    - Operations & Maintenance Manager
    - Dist Assets & Improvements Manager
    - Damage Prev & Emerg Serv Manager
  - Manager, Business Performance - Dist Ops
  - Regional Manager, Dist Interior South
    - Install/Operate Manager - Penticton
    - Distribution Manager
    - Install/Operate Manager - Cranbrook
    - Installation Manager - Trail
    - Installation Manager - Kelowna
    - Install/Operate Manager - Vernon
  - Regional Manager Dist - Fraser Valley
    - Installation Manager - Langley
    - Installation Manager - Coquitlam
    - Distribution Manager
    - Operations Manager - Surrey
    - Installation Manager - Surrey
    - Distribution Manager
  - Manager, Distribution Integration
    - Business Support Manager
    - Special Assignment Manager
    - Special Assignment Manager
    - Process Manager
    - Operations Service Manager
    - Operations Service Manager
    - Process Support Manager
  - Director, Operations Centre
    - Resource Planning Manager
    - Closing Manager
    - Dispatch Manager
    - Planning & Design Workleader (M&ERelief)
    - Pre-Requisite Manager
    - Emergency Support Manager
    - Installation Centre Manager - IC2
  - Mgr, Capital Installations
  - Regional Manager, Metro Vancouver
    - Distribution Manager
    - Operations Manager - Squ/Whi
    - Operations Manager
    - Distribution Manager
    - Distribution Manager
    - Operations Manager - Vancouver
    - Installation Manager
  - Regional Manager, Dist - Interior North
    - Install/Operate Manager - Ft Nelson
    - Installation Manager - Prince George
    - Operations Manager - Kamloops
    - Installation Manager - Kamloops
    - Install/Operate Manager - Revelstoke
    - Special Assignment Manager
    - Distribution Manager
  - Regional Manager, Dist - Vancouver Island

TERASEN GAS INC.

FINANCE & REGULATORY AFFAIRS

2010 (Proposed)



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

2010 (Proposed)

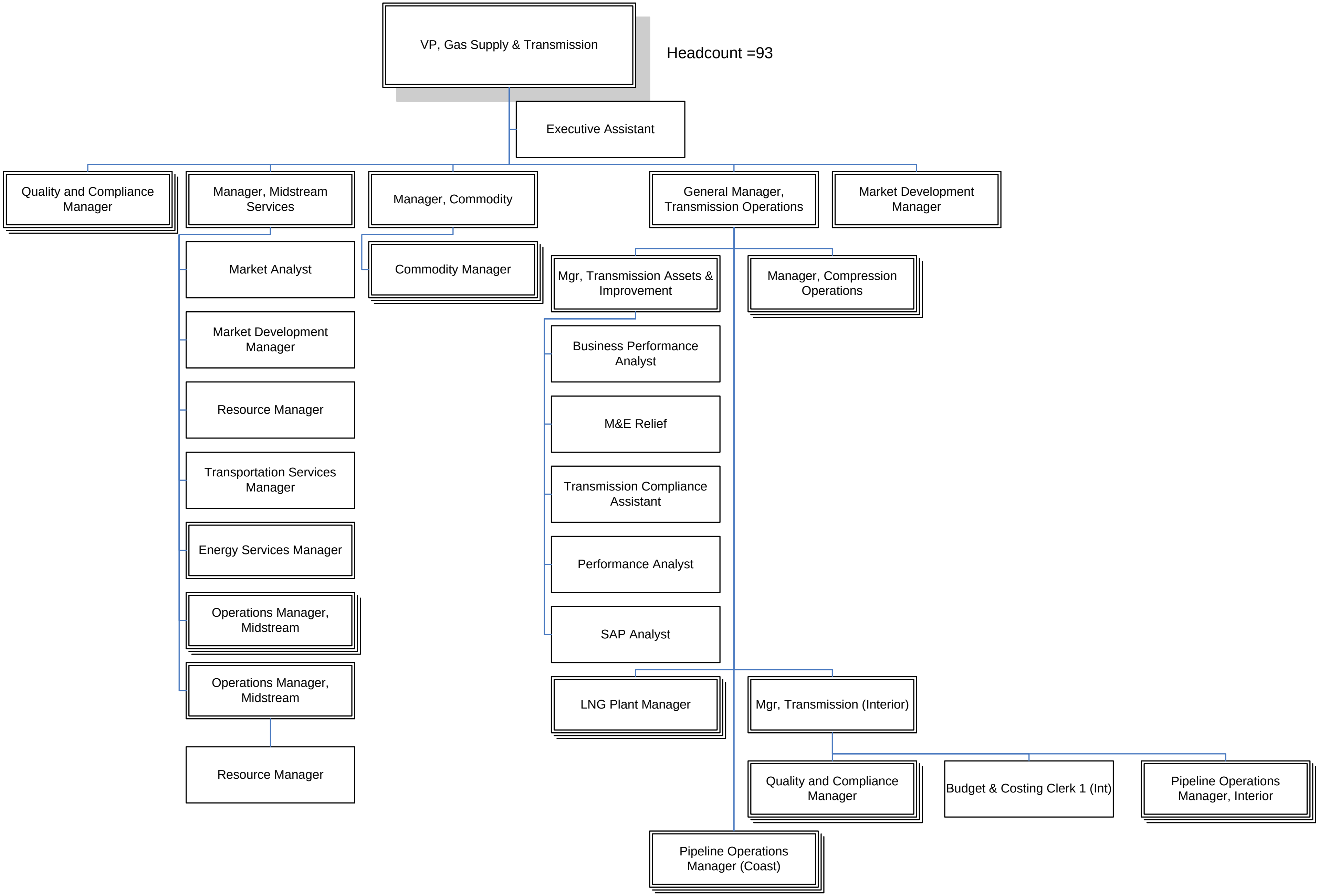
Headcount = 132

- VP, Marketing & Business Development
  - Executive Assistant
  - Director, Corp & Marketing Communication
    - Confidential Assistant
    - Marketing & Customer Communications Mgr
    - Corporate Communications Manager
    - Corporate Communications Manager
  - Director, Com/Aboriginal/ Govt Relations
    - Comm, Aboriginal & Gov't Relations Assis
    - Community Relations Manager
    - Aboriginal Relations Manager
    - Policy Analyst
    - Community Relations Manager
    - First Nations Manager
  - Director, Customer Management & Sales
    - Mgr, Commercial & Residential Energy Sol
    - Regional Sales Manager
      - Customer Account Manager
      - Interior Customer Account Manager
      - Field Operations Assistant
    - Manager, Commercial & Industrial Marketi
    - Regional Sales Manager
  - Director, Customer Care & Services
    - Customer Care & Services Assistant
    - Call Centre Operations Manager
    - Manager, Customer Care
    - Manager, Customer Programs & Research
  - Director, Resource Planning & Market Dev
    - Marketing Specialist
    - Business Development Manager
    - Manager, Operations & Project Assessment
    - Project Assessment Manager
    - Manager, Business Development
    - Business Development Manager
    - Integrated Resource Planning Manager
    - Business Development Manager
    - Project Manager
    - Customer & Energy Forecasting Manager
    - Manager, Technical Sales Support
    - Market Development Analysis Manager
    - Manager, Marketing & Energy Efficiency
      - Co-Op Student
      - EEC Assistant
      - EEC Administrator
      - Marketing Co-op Student
      - DSM Program Development Lead
      - DSM Program Development Lead
      - EEC Program Manager Industrial
      - EEC Program Manager Qualified Dealer
      - EEC Communications & Outreach Manager
      - Marketing Program Specialist
        - Marketing Summer Student
      - EEC Program Manager Commericall
        - Marketing Program Specialist Commercial
      - EEC Program Manager Residential
        - Marketing Program Specialist Residential
      - EEC Communications, Education & Outreach Manager
        - Marketing Program Specialist Communications Education & Outreach
      - EEC Program Manager Low Income Housing
        - Marketing Program Specialist Low Income Housing

TERASEN GAS INC.

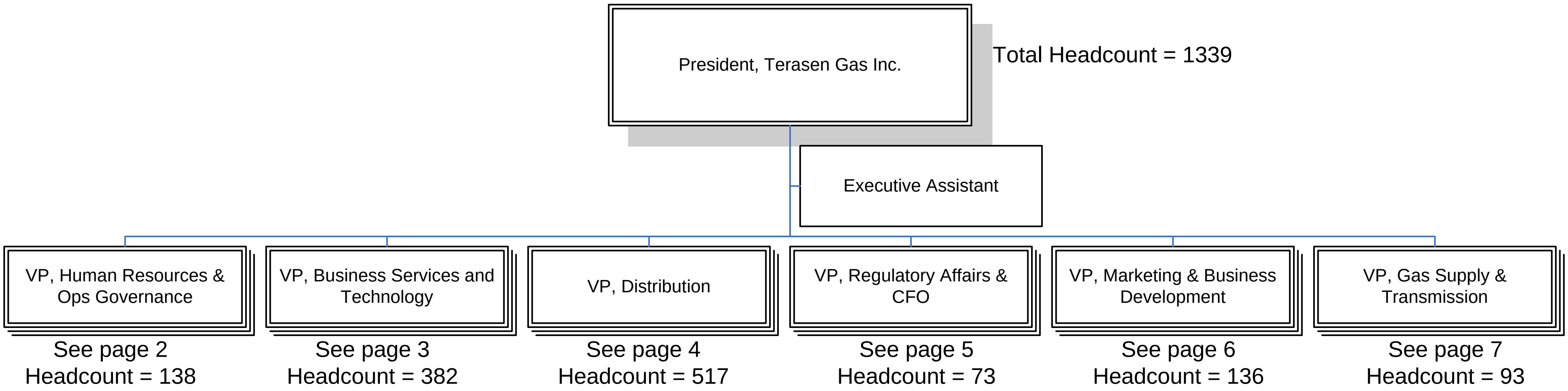
GAS SUPPLY & TRANSMISSION

2010 (Proposed)



TERASEN GAS INC.

2011 (Proposed)



TERASEN GAS INC.

HUMAN RESOURCES & OPERATIONS GOVERNANCE

2011 (Proposed)

Headcount = 138

- VP, Human Resources & Ops Governance
  - Executive Assistant
  - Manager, ERM & Insurance INC POSITION
  - Director, Total Compensation & HRIS
    - Corporate Pension Manager
    - Manager, Compensation, Benefits & EServ
    - Manager, HRIS/Payroll
  - Manager, Labour Relations
  - Director, HR Strategy & Advisory Srvcs
    - HR Advisor
    - HR Advisor
    - HR Advisor
    - Recruiting Manager
  - Manager, Engineering Governance
    - Junior Engineer
    - Junior Engineer
    - Junior Engineer
    - Training Manager
    - Junior Engineer
    - Manager-In-Training
    - Junior Engineer
    - Learning and Development Specialist
    - Manager in Training
    - Manager In Training
    - Training Manager
      - Instructional Design Manager
    - Manager in Training
    - Manager In Training
    - Competency Manager
  - Director, Environment, Health and Safety
    - Administrator, Environment Health Safety
    - Operations Compliance Auditor
    - Environmental Affairs Manager
    - OH&S & Corporate Security Manager
    - Emergency Planning & Public Safety Mgr
    - Sustainability Manager
    - Business Continuity Manager

TERASEN GAS INC.

BUSINESS & IT SERVICES

2011 (Proposed)

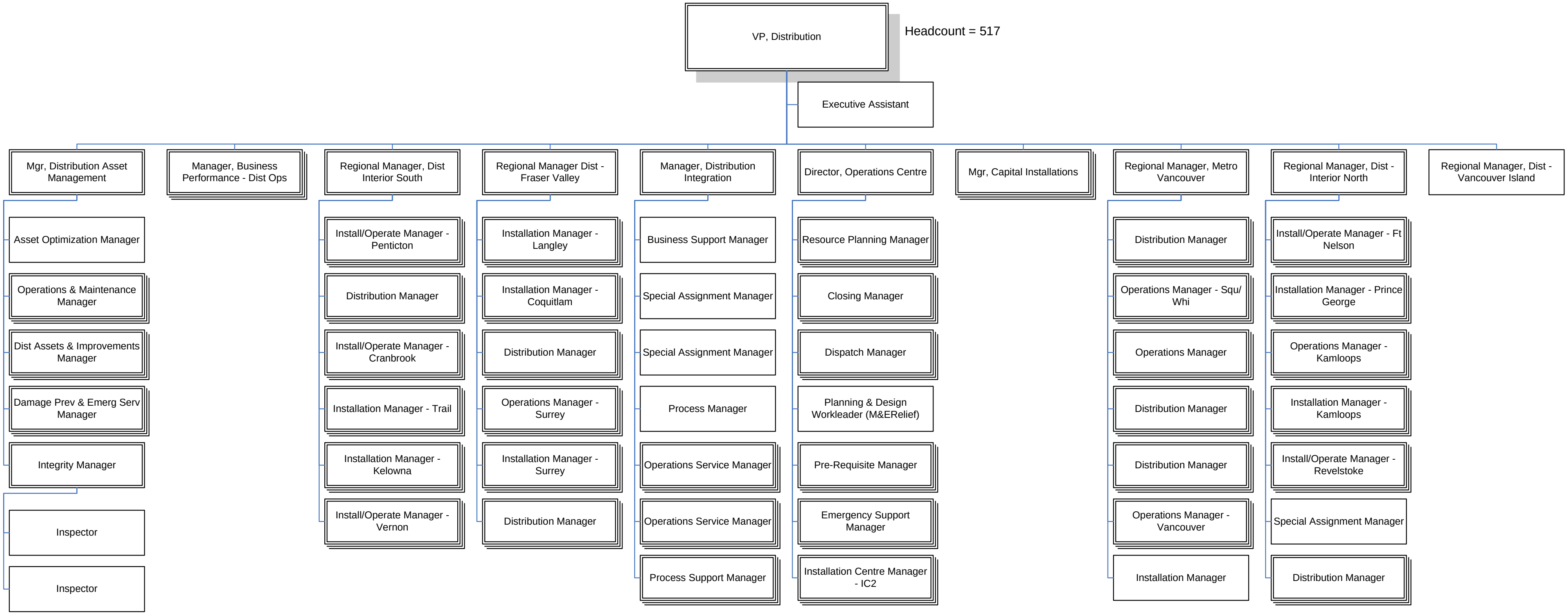
Headcount = 382

- VP, Business Services and Technology
  - Executive Assistant
  - Project Director
  - I&CT Contract & Finance Co-ordinator
  - Project Director
    - Project Clerk
    - Project & Contract Administrator
    - Project Manager
  - Chief Information Officer
    - Business Systems Planning Manager
    - IT Operations Manager
    - Infrastructure Planning Manager
    - Enterprise Appl Support & Delivery Mgr
    - Application Support & Delivery Manager
    - Application Technical Support Manager
  - Procurement Manager
    - Procurement Specialist
    - Senior Procurement Specialist
    - Procurement Work Leader
    - Procurement Specialist
    - Contract & Project Administrator
    - Procurement Specialist
    - Procurement Specialist
    - Senior Procurement Specialist
    - Senior Procurement Specialist
    - Senior Procurement Specialist
  - Manager, Facilities Planning & Maintenan
    - Office Services Leader
    - Switchboard Operator/Recept
    - Facilities Coordinator
    - Operations Financial Co-ord
    - Office Services Clerk
    - Facilities Maintenance Manager
  - Director, Operations Engineering
    - Production Process Manager
    - Manager, Engineering Services
    - Mgr, Property Services
    - Mgr, System Integrity Programs
    - System Capacity Planning Manager
    - Manager, Geographic Information Systems
    - Operations Records Compliance Manager
  - Manager, Project Management Office
    - Project Manager
    - Project Management Administrative Assist
    - Project Manager
    - Project Manager (LNG Plant)
  - Director, Operations Support
    - Measurement Services Manager
    - Meter Shop Manager - Penticton
    - Manufacturing Service Manager
    - Data Acquisition and Logistics Manager

TERASEN GAS INC.

DISTRIBUTION

2011 (Proposed)

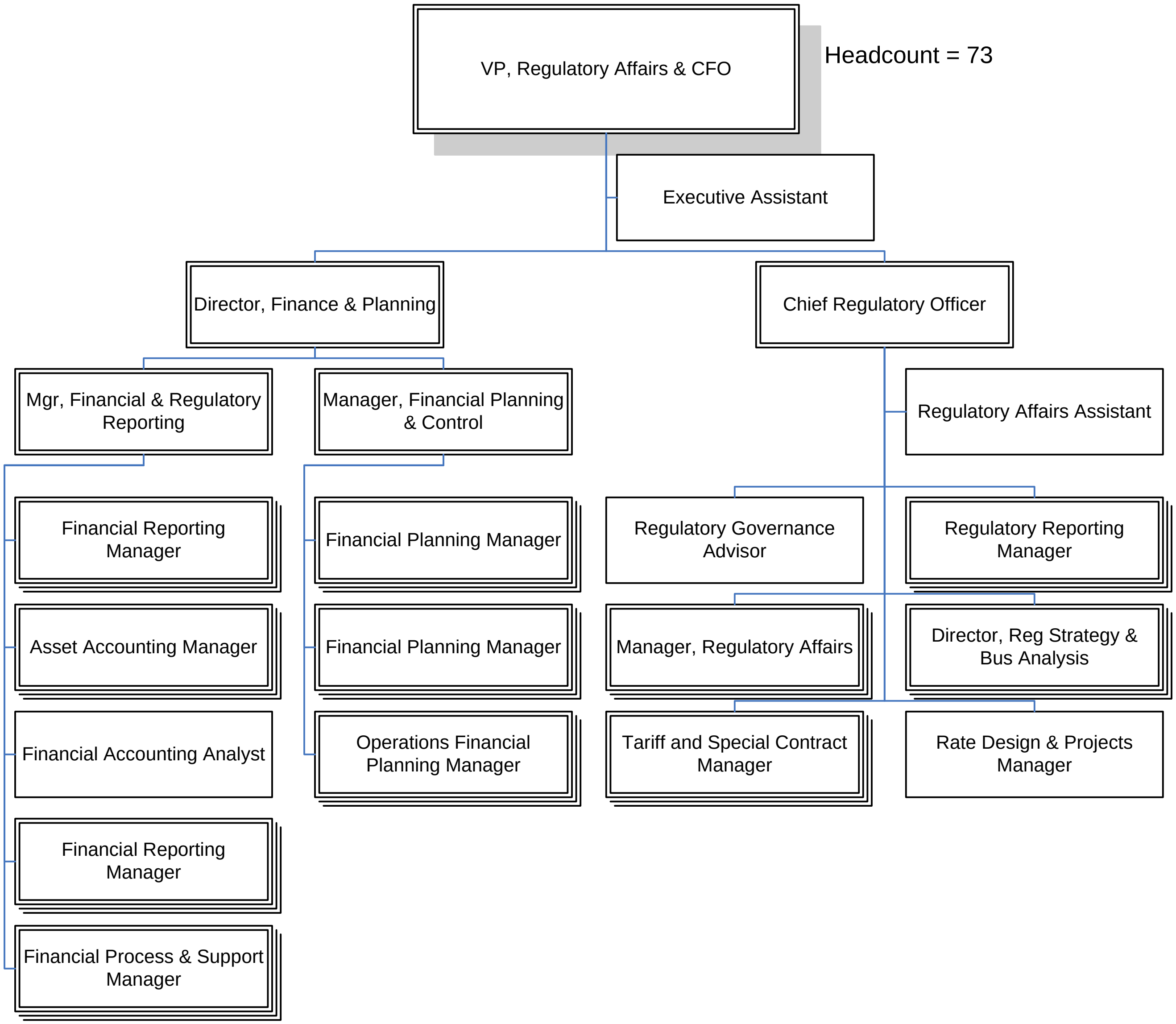


TERASEN GAS INC.

FINANCE & REGULATORY AFFAIRS

2011 (Proposed)

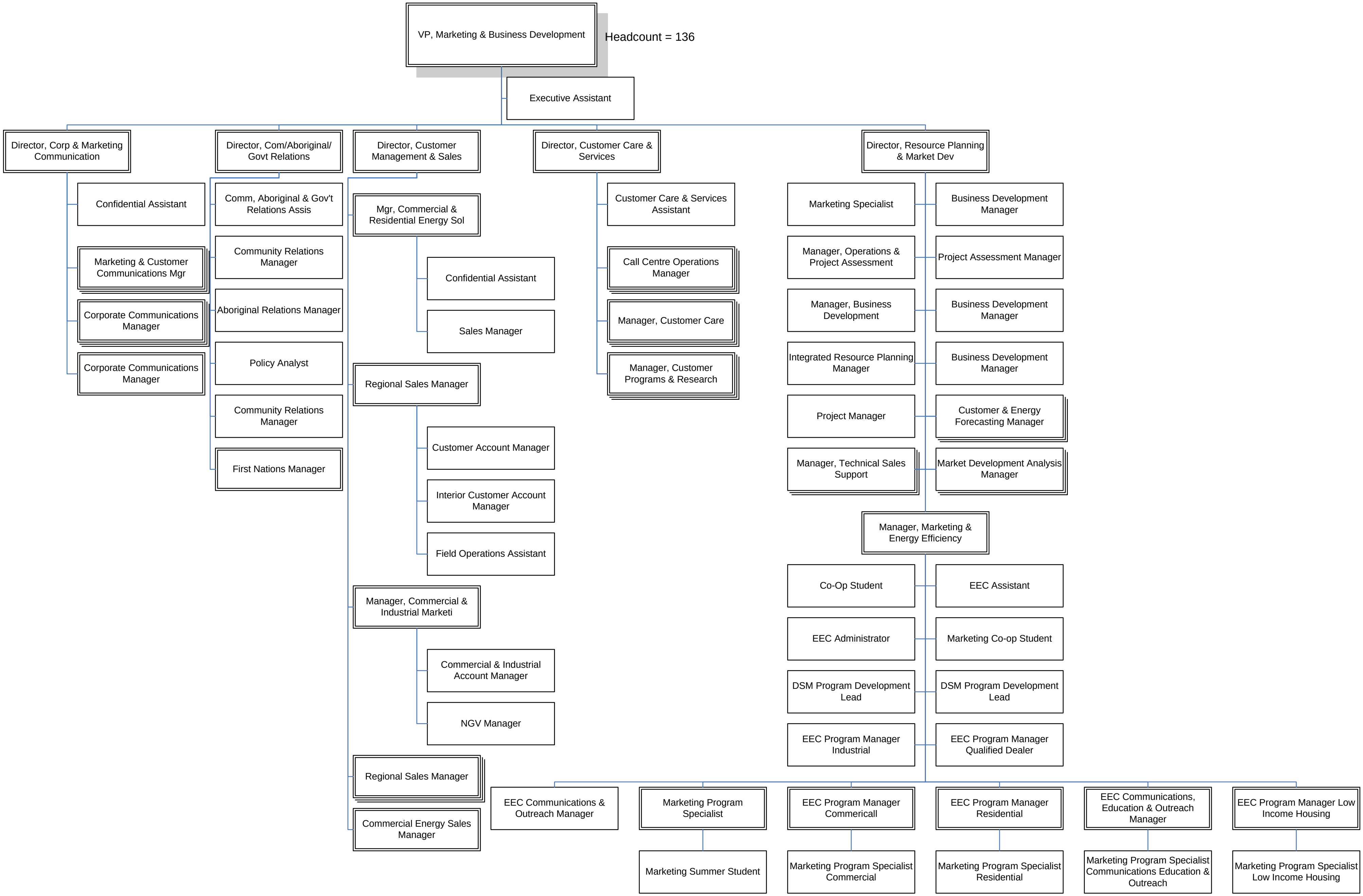
Headcount = 73



TERASEN GAS INC.

MARKETING & BUSINESS DEVELOPMENT

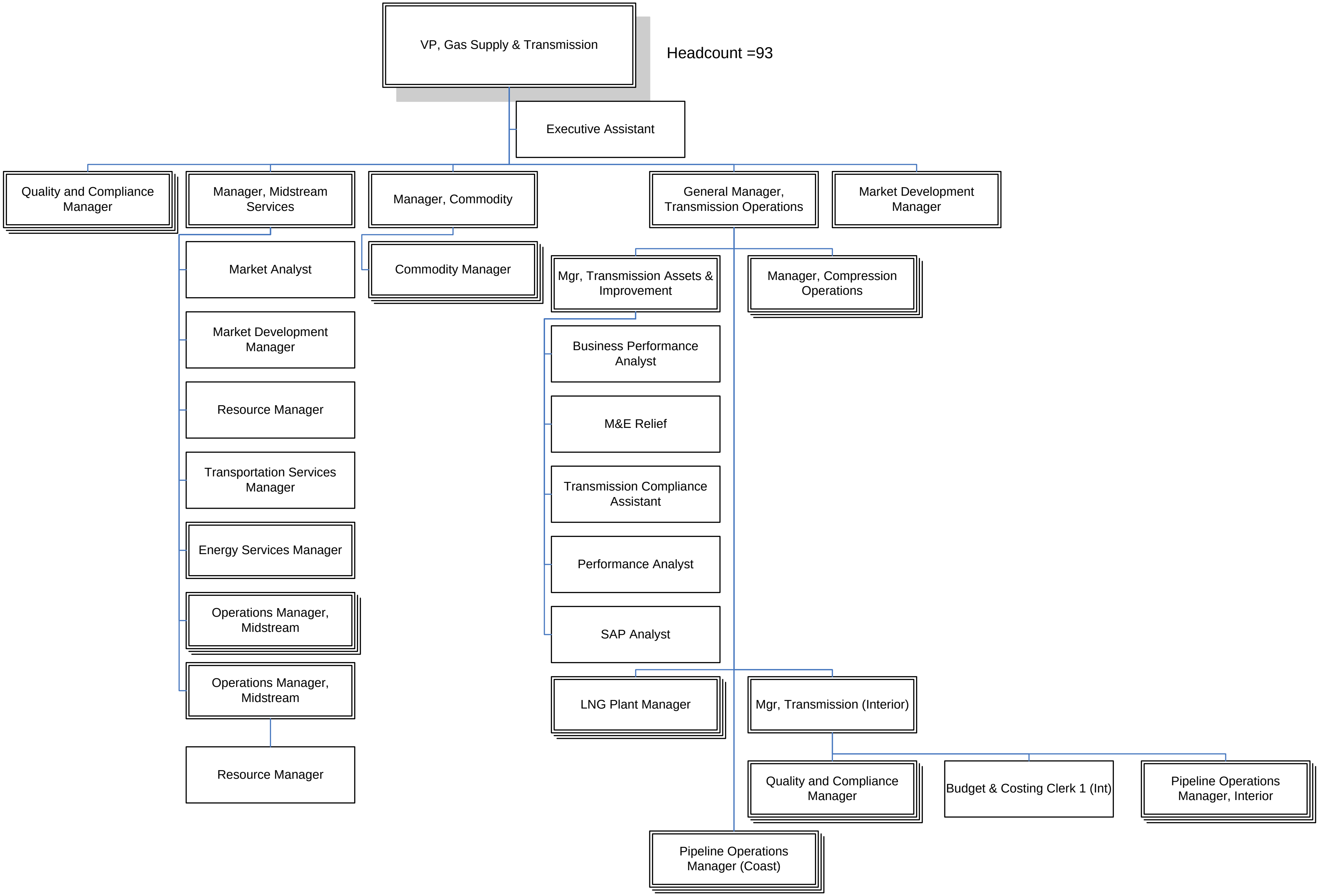
2011 (Proposed)



TERASEN GAS INC.

GAS SUPPLY & TRANSMISSION

2011 (Proposed)



Attachment 91.1

REFER TO LIVE SPREADSHEET

(accessible by opening the Attachments Tab in Adobe)

Attachment 104.2

Terasen Gas

Tel: 604.592.7646
Fax: 604.592.7522
www.terasengas.com

MEMO

To	All employees	Date	June 15, 2006
	Expression of Interest	From	XX
Re	Community Relations Manager	CC	XX

An exciting opportunity exists within the Community, Aboriginal and Government Relations group located at our Kelowna Operations Centre. Reporting to the Director, Community, Aboriginal and Government Relations, this position will appeal to a community relations, communications and stakeholder relationship professional with experience in developing strategic communication plans and delivering community relations business objectives.

The incumbent will be required to establish contact and manage strategic stakeholder engagement in the Okanagan, Kootenay and Northern Region specific to corporate issues and project development support. In addition, the successful candidate will maintain an awareness of all activities that affect business development potential and will advise senior management on strategic issues related to our customer growth and facility development objectives. The incumbent will develop strategic communication plans and deliver our community relations business objectives including management of the company's existing municipal operating and franchise agreements. Unique opportunities will allow the employee to work with Distribution and Transmission on large capital projects in the coming months.

Competency / Skill Requirements:

- Superior municipal relations experience, contacts and issues management
- Superior demonstrated negotiating skills
- Team building capacity
- Established contacts in the community
- Ability to establish and manage a multi-department team (project management skills)
- Superior communication and writing skills
- Accounting and budget experience
- Strong understanding of the regulated utility industry and its needs regarding construction of underground, linear infrastructure and Terasen Energy Services product offerings
- Strong capacity to link customer development opportunities back to our Sales and Account Managers
- First nations cultural and business awareness supporting our corporate growth objectives and statement of Aboriginal Principals in addition to supporting Transmission and Lands pertaining to First Nation land access
- Demonstrated capacity to deliver short-term business objectives with long-term planning around the subject matter expertise and geographic focus
- Extensive travel is required

Terasen Gas Inc.

Manager Position Description

Position: Director, Community, Aboriginal and Government Relations
Incumbent: David Bodnar
Reports to: Doug Stout, Vice President Marketing and Business Development
Date: December 2007

General Accountability/Position Mandate:

Leads the company in all external communications, public consultation (with elected officials, agencies, regulators, community opinion leaders),corporate advocacy and project communications supporting the annual and long term goals of Terasen Gas. Government interactions include Municipal, Regional, Provincial and Federal levels. Is responsible for delivering our business objectives, relationship development with Aboriginal communities and in renewing all operating and franchise agreements with municipalities in our service territory.

Leads all strategic Community Investment on behalf of the company and represents the enterprise on issues relating to corporate sustainability with our customers and peer energy companies across Canada (CGA Committee member). All personal and staff rely on establishing strategic relations with key stakeholders holding the capacity to influence our business objectives.

Ensures the seamless interaction of our subsidiary operating companies in areas of geographic overlap.

Nature and Scope:

Reports to the VP, Marketing and Business Development.

All of my current 6 member staff are assigned geographic areas of responsibility and carry specific and unique subject matter expertise.

I have 4 Community Relations Manager positions, 1 Aboriginal Relations Manager and a Community Relations Assistant reporting to me at present.

All staff are responsible for managing our corporate image within their designated service territories and managing issues and business development opportunities.

Dimensions:

Responsible for annual department budget of approximately $1.5 million and for any capital project funds allocated to external communication and public consultation.

As indicated above, there are currently 6 staff reporting to me.

Specific Accountabilities:

- involved in the development of all corporate communications that are externally focused
- provides input for the corporate annual report
- manages all capital project communication and consultation processes
- manages the communication of all issues impacting stakeholders, customers and advocacy groups:
- Issues management relating to franchise fee payment and distribution, customer rate changes, operating agreement challenges, unbundling, customer accounts, capital project specific issues
- upholding our corporate Aboriginal Statement of principles
- supports the the corporate EHS governance policy
- ensures appropriate coordination of external relations at the Terasen Inc level
- represents the company on numerous and varied organizations including the Vancouver Board of Trade and strategic Chambers of Commerce, all Municipal Association organizations, municipal and provincial energy and sustainability organizations, GVRD, Business Council of BC, energy related organizations of the Pacific Northwest, 2010 Energy Committees, CGA-Subcommittees for Sustainable Growth and Public Affairs
- fulfills the corporate advocacy role for the Gas Utility

Desired Capabilities

- *energy industry knowledge, with particular focus on sustainability issues*
- *communication, negotiation, and consultation skillsets*
- *people management skills*
- *public consultation management experience*
- *personable*
- *standard business management experience*
- *priority setting capacity*
- *capacity to mange complex and varied subject matter files*
- *ability to manage cultural diversity*

Terasen Gas Inc.
Job Description

Position	**Aboriginal Relations Manager**		
Band		**Location**	**Surrey Operations**

Responsibilities:

- Reporting to the Director, Community, Aboriginal and Government Relations, this position is responsible for the following:
  - Develop/maintain strategic relationships with aboriginal governments throughout the Company's combined operating area.
  - Develop/maintain relationships with aboriginal community organizations that may impact the Company or its customers.
  - Identify opportunities for revenue growth within aboriginal communities.
  - Maintain an awareness of national, regional and local aboriginal issues that could affect Company operations and growth opportunities
  - Prepare annual plans for aboriginal relations activities throughout British Columbia that contribute towards Company initiatives of project development and/or customer growth.
  - Develop training programs for Terasen employees to ensure an understanding of aboriginal issues and their impact on Company operations.
  - Contribute towards long-term public consultation processes on major projects working with other Terasen Gas Departments and consultants
  - Deliver corporate communications to contacts within the aboriginal governments and communities regarding company initiatives.
  - Work with Distribution Operations and other staff to ensure coordinated communication with all levels of aboriginal government (staff and elected Chief and Council)
  - Provide input to Company forecasts prepared by Forecasting/Business Analysis department regarding community level issues
  - Use relationship management tools such as Commence software to track contacts
- This position will require evening work and travel away from Surrey Operations to attend meetings and deliver presentations etc. within the Company's geographic area of operations

Competencies:

- University degree in Aboriginal Relations or other suitable discipline or a combination of education and work experience

- Ability to develop and maintain productive working relationships with elected officials and staff within aboriginal government.
- Clear understanding of issues that affect aboriginal communities and the long-term relationship between aboriginal governments and land use for TG projects
- Excellent written and verbal communications skills
- Ability to manage and balance a number of projects simultaneously
- Ability to meet firm deadlines with minimal supervision

M&E Position

Terasen Gas

JOB TITLE:	Policy Analyst
DEPARTMENT	Marketing and Business Development
REPORTS TO	Director, Community, Aboriginal and Government Relations
CAREER BAND	D
LEVEL	1
EVALUATION COMPLETED	February 13, 2009

Job Summary

The position is to provide a high level of research capacity of the external government, business and public affairs environment so as to assess in a timely manner opportunities, threats and stated positions of the Company. The research activities include government publications, legislation and regulatory reviews, public comment opportunities, etc. The incumbent has the demonstrated capacity to prepare presentations and position paper development in support of varying disciplines in Terasen Gas Inc. Information generated will be suitable for integration into corporate public statements and policy opinion.

Relationships

(Please use titles, names of departments, groups, etc.)

Reports to:	Director, Community, Aboriginal an Government Relations
Supervises:	0
Works with: *(internal/external)*	Internal: The incumbent will principally work with M and BD business leaders and where necessary, support the operating business units and corporate governance External: Liaise as appropriate with industry peers, advocacy organizations and government officials as a function of determining policy activity and implications

Key Responsibilities

Policy research
Paper presentation
Speech writing

1. Responsible for analyzing and researching policy legislative proposals and industry trends that effect natural gas.
2. Evaluate and communicate best practices for policies that encourage the development of sustainable energy options
3. Evaluate potential policy and legislative scenarios and provide insights regarding different regulatory options and their impact.
4. Interact with appropriate industry associations, business partners, and governmental agencies in an effort to gather industry insight and data.
5. Develop and present clearly written analyses and interpretations of regulations and policies.

Required Qualifications

Education:	Graduate degree with preferred exposure in the fields of Political Science, Public Affairs or related field
Work experience:	• Applied research experience • Policy development experience an asset • Industry experience desirable (energy, public policy, government affairs related) • Public policy and/or strategic public communications • Demonstrated interest in community affairs and involvement

Technical requirements:	
Certifications or licensing:	
Physical requirements:	
Other:	• Applied research experience • Policy development experience an asset • Industry experience desirable (energy, public policy, government affairs related) • Public policy and/or strategic public communications • Demonstrated interest in community affairs and involvement

Preferred Experience, Skills & Knowledge
(Above the minimum requirements)

- Preferred but not limited to applied research experience directed towards public policy review and energy industry related issues

Responsible for:

No. of staff	0
Budget	

Working Conditions

Location:	Surrey Operations
Travel:	some
Other:	

Terasen Gas

COPE JOB DESCRIPTION						Job Code OCB09X
Job Title: Community, Aboriginal & Government Relations Assistant						Job Family: Clerical
Business Unit: Marketing	Effective Date: Nov 17, 2008			Job Level: 6		
Department: Community & Aboriginal Relations	S	'S' - Supersedes 'D' - Derived From		S	'S' - Supersedes 'D' - Derived From	
Section: Community & Aboriginal Relations	Job Title: Communications Assistant			Job Title: Comm Asst – Advertising		
	Job Code: Same	Level: 5	Dated: Mar 5, 2007	Job Code: Same	Level: 5	Dated: Oct 5, 2004

DUTIES & RESPONSIBILITIES

Job Descriptions are intended to describe only the principal duties and responsibilities of a position. They are not meant to be either an inclusive or exclusive list of all work, tasks and functions of any particular job.

1. Provide administrative support to the group (ie electronic scheduling, calendaring, database, spreadsheet, word processing, presentations and communication) by
   - Reviewing incoming correspondence, acts on when appropriate or redirects to appropriate place/person
   - Providing support with local purchases, invoices and tracking of receipts, payments and expenses
   - Prepares and/or composes a variety of correspondence, reports, presentation materials, charts and forms
   - Organizing department and strategic planning meeting agendas and logistics
   - Coordinates CAGR events and logistical requirements
2. Builds and maintains an extensive Government (Federal, Provincial & Municipal), community and opinion leader database (requires research and some analysis)
3. Monitors Federal Gazette, Orders in Council and Ministerial Order Resumes and reports on any issues that may affect Terasen Gas regarding environment, energy and pipeline infrastructure (research required on a monthly basis)
4. Liaises with Government officials as required on behalf of the Director of Government Relations
5. Administers the Employee Giving Community Investment program and other program (e.g. Warm Hearts) by
   - Tracking external community investment requests and produces letters/e-mails for decline
6. Develops and administers office procedures with manager(s) to ensure efficiency and effectiveness

Terasen Gas

COPE JOB DESCRIPTION	Job Code OCB09X
Job Title Community, Aboriginal & Government Relations Assistant	Effective Date Nov 17, 2008

QUALIFICATIONS:

1) Completion of Grade 12 with Office Practices and Business Communications and work related technical courses
2) Eighteen (18) months relevant & related experience, including previous experience in program administration
3) Demonstrated sound verbal communication skills, including telephone call-handling skills, and the ability to respond to difficult or demanding situations with tact and diplomacy
4) Demonstrated excellent customer relations skills
5) Demonstrated excellent verbal and written communications skills
6) Demonstrated excellent analytical skill and organizational skills, including the ability to multi-task and prioritize
7) Demonstrated sound working knowledge of applications software in use in the department (e.g. MS Office, customer management systems) and office environment peripherals
8) Demonstrated strong keyboarding skills
9) Demonstrated excellent organizational and time management skills

Recruiting Manager

This position is responsible for directly managing HR functions related to recruiting including management of the relief services pool. The individual is expected to work in partnership with other HR professionals and client groups to ensure the staffing needs of the business are being met.

Duties & Responsibilities:

Ensures corporate recruiting and staffing services meet operational and business requirements in a timely manner:
• Manages recruiting staff and relief services pool including assignments, coaching, orientation and performance management • Manages and provides direction to support team on planning, problem solving, productivity, personal development and performance • Analyzes the efficiency of functional processes including the design and implementation of improvement initiatives to ensure effective and efficient service is provided to HR customers and client groups • Ensures compliance with collective agreements and company policies in administering postings and hiring practices • Oversees the Employee Orientation Program • Meets regularly with HR functional leaders to ensure consistency with all HR practices; identifies any impacts to existing processes or compliance issues when planning process, system or policy changes • Liaises with and manages external service providers • Conducts research on related programs and best practices • Implement recruitment strategies • Manages all tools, systems and vendors utilized by the company for recruitment and selection purposes

Ensures hiring processes are efficient and conducted in a timely manner that meets business and operational needs:
• Processing job bulletin requests • Posting internal and external job bulletins • Coordination with internal and external service providers • Coordinates participation in job and career fairs • Effective use of web-based applicant tracking system • Regular updating and maintenance of HR information of Pipeline and Company's Careers web-site • Pre-screening and interviewing support • Development and delivery of new employee orientation program

Maintains an adequate supply of employees in the relief services pool to meet business requirements:
• Receive and monitor requests from assignment managers • Coordinate recruiting of relief clerks to meet demand • Screen and interview candidates, conduct reference checks and pre-employment testing • Manage and track assignment of relief clerks

- Conducts probationary reviews
- Performance management and coaching of relief clerks

Required Qualifications:

- Thorough knowledge of HR business processes including Pension, Benefit, and collective agreement administration.
- University degree or college diploma in Business Administration, Human Resource Management or equivalent.
- Excellent analytical, organizational and decision making skills.
- Excellent communication skills, both oral and written.
- Ability to exercise professional judgement in the handling of sensitive and confidential information
- Customer service oriented with strong interpersonal skills and the ability to resolve issues with a wide cross section of employees.
- Demonstrated ability to lead and coach staff in a fast paced, service oriented environment
- Able to build effective and trusting working relationships throughout the organization
- Ability to work independently and as part of a team.
- Demonstrated ability to balance a heavy workload, tight timelines and changing priorities
- Demonstrated strong working knowledge of SAP along with proficient computer skills.
- 2 or more years of supervisory/leadership experience

Position

Terasen Gas

JOB TITLE:	HR Coordinator, Recruiting
JOB FAMILY:	Coordinator
JOB CODE:	
BAND LEVEL:	E
BUSINESS UNIT:	Recruiting
DIVISION:	HR
☐ **DATE CREATED (IF NEW)** ☒ **DATE MODIFIED**	July 16, 2009

Job Summary

Support the recruiting process for internal and external job postings. Recruit for and coordinate Relief Pool staff. Organize and facilitate new employee orientations. Coordinate other events including career fairs.

Relationships

(Please use titles, names of departments, groups, etc.)

Reports to:	Recruiting Manager
Supervises:	
Works with: *(internal/external)*	Other HR Recruiting Coordinators, Recruiting Manager, Advisors, Associate Advisors, job applicants (internal and external), advertising agencies, managers

Key Responsibilities

1. Employee Orientations

- Prepare and distribute schedules to presenters and new employees
- Facilitate orientations

2. Recruiting Support

Update Job Registers with the information from the Job Bulleting Request

- Update lists of employees impacted by collective agreement provisions such as recall, salary treatment, and auto applicants
- Prepare bulletin summaries
- Record and calculate seniority dates
- Update job tracking sheet and list of job descriptions
- Run statistical reports including terminations and new hires
- Process invoices for payment
- Prepare and post bulletins on Pipeline, in the Mailroom, external sites, and in the job bulletin files
- Receive, process, and respond to internal and external applications
- Process bulletin change forms
- Prepare offer letters and letters of rejection
- Arrange and conduct interviews, telephone interviews and reference checks as required

3. Relief Services

- Coordinate Relief Clerk requests from assignment managers
- Relief Clerk prescreening, phone interviews, interviews, testing, and reference checks
- Send confirmation e-mails of assignment extension to relief clerks
- Prepare and send out Relief Clerk offer and contract letters
- Process Relief Clerk change forms
- Send out evaluation forms to managers
- Report on upcoming probationary reviews for Recruiting Manager
- Coordinate layoff option process
- Update Relief Clerk tracking spreadsheet
- Update and distribute Relief Clerk weekly schedule
- Update directory, probationary variant, skill sets and evaluation spreadsheets
- Coordinate agency temps for assignments at Terasen Gas
- Monitor time charged to Relief Services cost center
- Provide backfill and support, as required, to other HR Coordinators, Advisors, and Associate Advisors

4. General Duties

- Process reviews and documentation
- Coordinate Job Fairs
- Collect and distribute mail (shared)
- Filing
- Coordinate "Take Your Kids to Work" day
- Pipeline publishing
- Coordinate employee moves and relocations

Required Qualifications	
Education:	Grade 12 education, plus post-secondary courses in Human Resources.
Work experience:	Minimum of two years' office experience.
Technical requirements:	Demonstrated proficiency in MS Word, Excel and Outlook
Certifications or licensing:	n/a
Physical requirements:	n/a
Other:	• Excellent interpersonal and communication skills. • Strong customer service skills and the ability to deal with people at all levels of the organization in a professional and confidential manner. • Demonstrated ability to make decisions using sound judgment, including the ability to recognize when it is appropriate to defer more complex matters to Recruiting Manager or more senior staff. • Ability to multi-task while meeting strict deadlines in a busy working environment, and be well organized. • Desire and ability to contribute to a team environment.

Preferred Experience, Skills & Knowledge
(Above the minimum requirements)

- HR experience in a unionized environment.
- Experience with Behavioral Interviewing.

Responsible for:	
No. of staff	n/a
Budget	n/a

Working Conditions	
Location:	Surrey Operations
Travel:	some
Other:	

Attachment 162.3

27 FERC ¶61,011

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

(18 C.F.R. Part 35)

(Docket No. RM84-9-000)

Calculation of Cash Working Capital Allowance for Electric Utilities

NOTICE OF PROPOSED RULEMAKING

(Issued April 5, 1984)

AGENCY: Federal Energy Regulatory Commission

ACTION: Notice of Proposed Rulemaking

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations by the addition of a new § 35.24 which would provide that the cash working capital requirements of any public utility that files any electric rate schedule under the Federal Power Act will be presumed to be zero dollars, unless it is demonstrated that the overall time difference between the average date of payment of certain current operating expenses by that utility and the average date of receipt of revenues for services to ratepayers is significant. A significant demonstrated time difference would result either in an addition to rate base to permit a return on working cash required to be kept on hand by the utility or a reduction in rate base to account for revenues received by the utility prior to paying related expenses. Any adjustment to rate base requested by any participant in a rate case must be supported by a fully developed and reliable study.

Proposed § 35.24 would prescribe the expense elements to be considered in calculating cash working capital adjustments to rate base and other criteria applicable to studies submitted in support of any request for an adjustment. The proposed rule would also establish a threshold standard that must be met to support a cash working capital adjustment. Conforming amendments are also proposed for the filing requirements in § 35.13.

The proposed rule is intended to promote accurate, cost-based ratemaking by establishing a presumption of cash working capital requirements generally reflective of utility industry experience. The proposed rule is also intended to reduce the burdens on ratemaking participants, including the Commission, currently caused by litigation of the cash working capital issue.

In a related order, the Commission is also terminating a previous proposed rulemaking on cash working capital (44 Fed. Reg. 33,410, June 11, 1979) that is replaced by this proceeding.

DATES: Written comments on the proposed must be received on or before June 4, 1984.

ADDRESS: Written comments must be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 and should refer to Docket No. RM84-9-000. An original and fourteen copies must be filed.

FOR FURTHER INFORMATION CONTACT:

Jack O. Kendall
Federal Energy Regulatory Commission
825 North Capitol St., N.E.
Washington, D.C. 20426
(202) 357-8033

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

(18 C.F.R. Part 35)

Calculation of Cash Working Capital Allowance for Electric Utilities	)))	Docket No. RM84-9-000

NOTICE OF PROPOSED RULEMAKING

(April 5, 1984)

I. INTRODUCTION

The Federal Energy Regulatory Commission (Commission) is proposing to add a new § 35.24 to its regulations under Part II of the Federal Power Act (FPA). 1/ The new section would provide, first, that the cash working capital requirements of any public utility that files any electric rate schedule under the FPA will be presumed to be zero dollars. As a result, a filing utility will not receive an adjustment to rate base representing the utility's cash working capital requirements, unless it is demonstrated that the overall time difference between the average date of payment of certain current operating expenses by that utility and the average date of receipt of revenues for services to ratepayers is significant. A significant demonstrated "lag" in revenue collection in relation to the lag

---

1/ 16 U.S.C. §§ 791a-828c (1976 and Supp. V 1981).

in the payment of expenses would result in an addition to rate base to provide a return on the working cash required to be kept on hand. Conversely, a significant demonstrated lag in the payment of expenses relative to the lag in receipt of revenues (typically referred to as a revenue "lead") would be subtracted from rate base. Any such adjustment to rate base must be supported by a fully-developed and reliable study, whetner filed by the utility, a wholesale customer, or other participant in the rate case.

Proposed § 35.24 would prescribe the expense elements considered in calculating cash working capital adjustments to rate base, the threshold standard to support a cash working capital adjustment, and the nature of the studies that may be submitted in support of, or in opposition to, any request for a cash working capital adjustment to rate base. Conforming amendments are also proposed for the filing requirements in § 35.13.

The proposed rule is intended to provide a presumption of cash working capital requirements that more closely reflects utility practice. To that end, the objective of the rule is accurate, cost-based ratemaking. The Commission also wishes to remove the cash working capital issue from electric rate litigation in as many cases as possible. It anticipates that the proposed rule could reduce the burdens on the parties and the resources of the Commission that litigation of this issue tends to produce.

Comments are requested on alternatives or modifications to the approach proposed.

In a related order, the Commission is also terminating a previous proposed rulemaking on cash working capital that is replaced by this proceeding.

II. BACKGROUND

A. Commission Practice

Cash working capital, as it relates to wholesale electric rates, is the term that historically has referred to the amount of cash needed on hand by a public utility to pay its day-to-day operating expenses for the time period during which the utility has provided electric service to its customers and has not yet been fully paid for that service. If, on the average, the time difference between the provision of service and the collection of revenue for that service exceeds the time difference between the rendition of service and the payment of expenses incurred to render that service, the utility is experiencing a "net revenue receipt lag" that necessitates having cash on hand. On the other hand, if the lag in the payment of expenses is longer than the lag in collecting revenues, there is a "net expense payment lag," meaning that the collection of revenues occurs in advance of paying expenses.

The Commission historically has allowed a utility to include in rate base the dollar amount of borrowed or investor-supplied working cash required to compensate for net lags in receiving revenue. This permits the utility, and thus its investors, to earn a return on the working cash used by the utility to pay expenses before corresponding revenues have been received from the utility's customers. The term describing the permissible net addition to rate base to reflect borrowed or investor-supplied working cash is the cash working capital allowance. The average amount of unrecovered expenses at any given time can nevertheless be difficult to determine. The difficulty arises because expenses are paid, service rendered, and revenues collected throughout the year, but a company may receive revenues to cover expenses and services before or after paying the expenses.

The Commission historically has permitted the cash working capital allowance to be calculated in accordance with some form of the "45-day convention." 2/ Under this policy, the time that elapses between the expenditure of a borrowed or investor-supplied dollar to pay for current operating expenses and the recovery of that dollar in consumers' payments for services has been presumed to average one-eighth of a year, or 45 days. Accordingly,

---

2/ This method of approximating utility cash working capital needs was first enunciated in Interstate Power Company, 2 F.P.C. 71 (1939).

the convention permits a utility generally to include in rate base a cash working capital allowance equal to one-eighth of its annual operation and maintenance expenses minus purchased power expenses. 3/

This Commission's predecessor, the Federal Power Commission, set forth the rationale for the 45-day convention as follows

> Electric energy furnished by the company during the current month is billed to the customer as of the first of the succeeding month with a fifteen-day discount period. The full period between the dates of rendition of service and the payment has been adopted as the period of lag and the working capital required for this period (exclusive of fuel and other supplies) was determined to be 45/365 of operating costs, ... 4/

Proponents of the 45-day convention argue that when uncontested, it is inexpensive to compute and easy to apply in electric rate cases. This convention may nevertheless be anomalous in certain respects. Although modified since its inception, there exists

---

3/ Purchased power expenses have historically been excluded from the allowance under the assumption that the lag by a utility in paying for purchased power usually was approximately equal to the lag in the receipt by a utility of revenue in turn from its customers. This assumption was based on the two types of transactions, _i.e._, a utility's purchase of power or its wholesale sale of it, being similar and interrelated. However, more recently a utility's payment for purchased power has no longer been assumed in ratemaking proceedings to necessarily coincide with the utility's receipt of compensating revenue. _See_ Opinion 19-A _infra_, note 6.

4/ Interstate, _supra_ note 2, at 85.

considerable doubt whether the 45-day convention reflects the experiences or practices of utilities generally. Consequently, cash working capital allowances determined solely in accord with the convention may exaggerate the actual needs of utilities, to the detriment of utility customers.

If cash working capital allowances do not reflect utility needs, rates may have unintended effects on utility management behavior. For example, if utility stockholders receive an allowance in excess of a utility's actual cash working capital needs, as may result from application of the currently-used 45-day conventions, the utility's incentives to minimize costs are reduced. The return on working cash amounts that may be overstated provides a cushion which reduces the penalty a utility might otherwise suffer for incurring excessive costs, once customer rates have been established. With the excessive return as a cushion, a utility may still be able to earn its allowed return while unnecessarily incurring extra costs, or it may retain the money as extra profit above its allowed return.

As a result of the variations in utility experiences with the payment and recoupment of operating expenses, the Commission has traditionally allowed any participant in a ratemaking proceeding to file a study to establish a cash working capital allowance on the basis of a utility's actual leads and lags in revenue collections for all major operating expenses. 5/ In addition, recognizing several limitations of the 45-day convention, it has been Commission practice to provide for adjustments in applying the 45-day convention, in the absence of a reliable lead-lag study and provided appropriate information is available. 6/ Under this "modified 45-day convention", when actual lags in fossil fuel payments are known, they have been substituted for the results otherwise obtained for that expense item using the 45-day convention. In addition, if such an adjustment is made for fuel cost lags, a further adjustment is performed to reflect the lag in payment of purchased power expenses. In the past, a utility was thought generally to pay for purchased power at about the same that it, in turn, received payment for the

---

5/ Such a study, frequently called a "lead-lag" study, computes the overall net time difference between the time, on average, when a utility pays its expenses of rendering service and the average time when it receives revenues in payment for the same service. This determination as to whether the utility's receipt of revenues, overall, generally leads or lags behind its payment of expenses is determined by netting the lags and leads of the utility's various kinds of day-to-day operating expenses in relation to revenue collection. The number of days of net revenue receipt lag is translated into dollars that are includable in the utility's rate base.

6/ See Opinion 19-A, Carolina Power and Light Co., Docket No. ER76-495, issued February 21, 1979, 6 FERC ¶ 61,154.

resale of the power and purchased-power-related expenses were therefore not included in cash working capital computations under the original 45-day convention. Because of this historic assumption and practice, any actual purchase power lag represents a working cash need in addition to calculations under the 45 convention.

The modified 45-day convention generally results in a somewhat more accurate assessment of cash working capital needs. It nevertheless shares the weaknesses of the original application of the 45-day convention. Cash working capital requirements can still be significantly overstated and several important expense items, notably taxes, are routinely not accounted for. Parties still invest resources in lead-lag studies and, while a fully-developed and reliable lead-lag study is the most accurate method of determining the working cash needs of a particular utility, such a study tends to be a costly use of company, customer, and Commission resources, relative to the dollars typically involved in a decision. Customarily, thousands of vouchers and invoices are reviewed in compiling the expense components of a study. Finally, all refinements of the 45-day convention share the same fundamentmal flaw: it has never been conclusively decided which operating expenses ought to be taken into account in establishing an allowance, although certain expenses have been disallowed in Commission rate opinions.

The Commission believes that any inadequacies and inaccuracies created by the existing convention enhance the likelihood that more lead-lag studies will be prepared in ratemaking proceedings. The Commission would like to avoid the use of these studies when possible because preparation and review of the studies create a significant drain on the resources of those involved in the proceeding.

The commenters on the previous Commission proposal to reform cash working capital ratemaking practices informed the Commission that the cost of developing a complete lead-lag study to ascertain the exact working cash needs of a utility for a specific period, is between $30,000 and $50,000. Because the methods used in these studies are not themselves beyond dispute, there continues to be protracted litigation that costs the parties and the Commission even more time and expense. The costs to a utility of litigating the issue or of developing studies are includable in rates. For customers that develop lead-lag studies to rebut claimed working cash allowances, the related expenses must be absorbed directly.

B. Prior Notice of Proposed Rulemaking

In 1979, the Commission began to reexamine its practices to determine how it might streamline its ratemaking procedures and practices to reduce its backlog of electric rate proceedings and to issue more timely decisions. The Commission issued a

Notice of Proposed Rulemaking (NOPR) 7/ to establish a formula for calculating utilities' cash working capital allowances. Under that proposal, the 45-day convention in all its forms would have been abandoned and lead-lag studies rendered unnecessary.

The Commission's proposal was designed to provide a uniform, binding, and reasonably accurate means of arriving at a cash working capital allowance. Although recognizing that the formula would yield only approximations of actual revenue receipt lags or expense payment lags, the objective was to create a reasonably precise and indisputable working cash amount for each rate case.

The NOPR proposed that the cash working capital allowance be determined by application of a formula accounting for the following six annual expense items: (1) fossil fuel; (2) wages and salaries (labor) expenses; (3) operation and maintenance expenses (other than nuclear or other fuel expenses, purchased power expenses, and labor expenses); (4) ad valorem taxes; (5) revenue taxes (based on projected revenues under proposed rates); and (6) income taxes payable. The total annual expense for each of the six items would have been multiplied by 40/360,

---

7/ Calculation of Cash Working Capital Allowance for Electric Utilities, 44 Fed. Reg. 33,410, June 11, 1979. See also FERC Statutes and Regulations, Proposed Regulations, 1977-1981, Calculation of Cash Working Capital Allowances for Electric Utilities, ¶ 32,026.

corresponding to the fraction of the year (one-ninth) that the Commission, at that time, believed to be fairly representative of the length of time that the revenues needed to compensate a utility for expenses incurred rendering service typically remain uncollected (the "revenue receipt lag").

The formula would have required that the six expense amounts thus obtained be totalled to yield the average amount of cash that is uncollected by a utility between the time it provides service to its customers and the time at which it receives payment for that service. This was to be the first of two steps. The formula also would have required that the total amount of cash associated with the revenue receipt lags of the six expense items be reduced by an amount representing cash which is not needed by a utility during the time between rendering service and paying the expenses attributable to such service (the "expense payment lag"), but which would have been needed if all expenses were paid when incurred. This adjustment recognizes that utilities generally pay expenses incurred in providing service at some time after the service is rendered. As a result of this calculation, the Commission had tentatively concluded that the fraction of the year for which expense payment lags exist for three of the six expense items does not vary significantly from utility to utility. The formula therefore would have multiplied these annual expenses by fixed time coefficients: labor expenses (10/360), other operation and maintenance expenses (25/360), and income taxes payable (90/360). With respect to fossil fuel expenses, ad valorem taxes, and revenue taxes, the Commission proposed that time coefficients be determined on a case-specific basis because the length of time that utilities delay payment of these expenses varies significantly from utility to utility.

The Commission received seventy comments in response to the 1979 NOPR. Many commenters predicted that, rather than reducing litigation in rate proceedings, the previously proposed formula would cause increased litigation because each of the six expense components could be disputed. Many comments objected to the formula because administrative costs of applying it would be greater than the costs of applying the 45-day convention. Many utilities requested that, if the proposed formula were nevertheless adopted, any filing utility be permitted to substitute actual expense lag experience for the fixed coefficients in the formula, when significant differences exist, in order to achieve greater accuracy. Some wholesale customers also suggested that, as an alternative to the application of the proposed formula, a zero cash working capital allowance should be established in lieu of the 45-day convention as the governing presumption about the working cash needs of most utilities.

The comments received pursuant to the prior NOPR have been reviewed and provide a point of departure for the Commission's proposals in this notice. In light of these comments and the Commission's experience, the Commission has developed a rule that uses as its starting point what it believes to be a more accurate presumption of the net working cash needs of utilities. Only in unusual circumstances does the size of net revenue receipt lags or net expense payment lags appear to justify expending time and funds to support a cash working capital adjustment greater or less than zero. As a result of its reexamination of this subject, the Commission has determined to withdraw its earlier proposed generic formula for calculating cash working capital allowances.

D. Recent Developments

The Commission's recent experience suggests that a 45-day cash working capital allowance may be unrepresentative of industry requirements generally. Some utilities are experiencing leads in the collection of revenues, rather than lags. Although cash working capital is an element in nearly all rate filings, reliable lead-lag studies are not commonly developed. For example, studies were filed with the Commission in twelve of the twenty-one electric rate cases in which Commission opinions were issued after a formal hearing and initial decision in fiscal years 1982 and 1983. 8/ Only eight of these studies were accepted by the Commission as "fully-developed" (including all relevant expense and revenue data) and "reliable" (accurately and appropriately computed). Four of the accepted studies show net revenue receipt lags ranging from three to thirty-two days. The other four showed net expense payment lags of one to fourteen days. 9/ The assumptions that underlie the formula-

---

8/ The Commission typically receives more general rate filings than is reflected in formal Commission opinions. At least 80 percent, and perhaps as high as 90 percent, of general rate increase filings are currently settled before a Commission opinion is issued. During fiscal years 1982 and 1983, 165 general rate increase cases were filed with the Commission.

9/ See Opinion No. 145, issued September 10, 1982, Docket No. ER79-150-003 (Southern California Edison Company -- 32-day net revenue receipt lag) 20 FERC ¶ 61,301; Opinion No. 133, issued November 9, 1981, Docket No. ER78-338-000 (Public Service of New Mexico -- 7-day net revenue receipt lag) 17 FERC ¶ 61,123; Opinion No. 141, issued June 23, 1982, Docket No. ER77-347-000 (Wisconsin Power & Light Company -- 19-day net revenue receipt lag) 19 FERC ¶ 61,288; Order on Application for Rate Increase, issued March 29, 1982, Docket No. ER79-478-000 (Public Service Company of New Mexico -- 1-day net expense payment lag) 18 FERC ¶ 61,276 (see also 16 FERC ¶ 63,040); Opinion No. 147, issued September 22, 1982, Docket No. ER80-214-000 (Pacific Gas and Electric Company -- 3-day net revenue receipt lag) 20 FERC ¶ 61,340; Opinion No. 155, issued November 30, 1982, Docket No. ER80-5-000 (Minnesota Power & Light Company -- 14-day net expense payment lag) 21 FERC ¶ 61,233; Opinion No. 164, issued May 12, 1983, Docket No. ER81-187-000 (Public Service Company of New Mexico -- 10-day net expense payment lag) 23 FERC ¶ 61,218; Opinion No. 146, issued September 17, 1982, Docket No. ER80-313-001 (Public Service Company of New Mexico -- 14-day net expense payment lag) 20 FERC ¶ 61,290.

tion of this proposed rule are based on data derived from these eight studies.

The Commission's proposed rule accounts for all typical current expenses that significantly affect a utility's need to maintain cash on hand. While all utilities pay ad valorem taxes (mostly property taxes) and income taxes, the eight accepted studies show that utilities pay these tax expenses infrequently, typically after long delays relative to the stream of services provided in relation to these tax dollars. This long lag in tax payment appears to be the major factor reducing the net revenue receipt lag time. In fact, delays in tax payments may be creating overall net expense payment lags that, on the average, leave some companies with more working cash than needed to meet current cash expenses.

Although taxes are significant cash expenses that must be paid by utilities, they generally have not been taken into account in determining utilities' cash working capital requirements, contributing to the perceived excessive allowances. 10/ The fact that application of the 45-day convention does not take into account all necessary expenses may be responsible for the failure in some cases of the convention to yield allowances

---

10/ See Opinion No. 19, Carolina Power and Light Company, Docket No. ER76-495, issued August 2, 1978, 4 FERC ¶ 61,107 at 61,224.

that reflect utilities' working cash needs with reasonable accuracy. Application of the convention selectively to only certain expenses also skews its results because there may be important timing variations in the payment of the unaccounted-for expenses. Some payments, such as employees' wages and salaries and bills covering train-delivered coal, are made quickly. Other payments, like ad valorem and income tax bills, are typically paid after long delays. The variability of these working elements has led the Commission to reexamine its general rule for affording rate base treatment to cash on hand to cover those expenses.

III. THE PROPOSED RULE

The Commission believes that the interests of greater accuracy, cost-based ratemaking, and reduced administrative delay require a reexamination of cash working capital allowances that are included in rate base.

Clearly, if the Commission can identify and set forth an equitable allowance level that reflects more closely the average utility's actual cash working capital needs, the less incentive there is for a utility, an intervenor, or Commission staff to file a study to justify some other allowance. A rule that more accurately reflects utilities' actual needs and that permits exceptions from the general rule only in unusual circumstances should help reduce litigation time and costs. The result would be to reduce burden for all ratemaking participants, including the Commission, utilities, and ratepayers. The Commission therefore proposes such an approach.

A. Presumption Against Allowance

The Commission acknowledges that on the basis of its observations -- including the eight cases discussed above -- a perfect matching of expense payments with revenue collections, so as to produce a net lag in revenue receipts or expense payments of exactly zero, is uncommon. However, the Commission's experience indicates that actual net lags in revenue receipt or expense payment are generally so small that they have a minor effect on rates and realization of the allowed rate of return. Therefore, the Commission believes that what is, in effect, a working cash allowance of zero dollars more accurately reflects the needs of most utilities. It proposes to establish that allowance as the operable presumption for all utilities filing rate changes with the Commission. 11/ This presumption against

---

11/ Under the proposed rule, the presumption of zero will apply to each rate filing, including any filing by a utility that has submitted a fully-developed and reliable study approved by the Commission in a previous case. Proposed § 35.13(h)(12)(ii)(D) would, it should be noted, allow a utility to use the data concerning the timing of revenue collections and expense payments contained in the

(Footnote continued on next page)

adjustments to rate base as a result of working cash needs is the primary focus of this proposal. Increased accuracy in setting rates based on costs will result from this presumption in most cases. The proposed rule would nevertheless provide for an adjustment other than zero if, absent the adjustment, the impact on a utility's ability to earn its return would be impaired or the utilities' rates to its wholesale customers would be significantly higher.

In conjunction with the zero presumption, the Commission proposes to allow inclusion of cash working capital in the rate base of a filing utility if it is shown that the timing of its expenses and revenues collection is abnormal. 12/ This exception

---

(Footnote 11/ continued)

previous study. This is appropriate because such data tend to be relatively constant. A utility would therefore have little difficulty overcoming the zero presumption in succeeding cases, if circumstances remained unchanged. The Commission asks comment on whether it should alternatively set that utility's cash working capital adjustment presumptively at its previously-determined level, subject to changes in Period II expense levels or rebuttal by other participants.

12/ Commenters to this proposed rule, who believe that some presumption other than zero would more be more respresentative of utilities' cash working capital needs, are encouraged to submit data demonstrating average cash working capital requirements for the industry. Such data, however, should be submitted in such a form as to facilitate comparison with the lead-lag studies that the Commission already has accepted and considered in final orders. The Commission suggests, in this regard, adherence to the format required under the proposed rule.

to the general rule would be provided in recognition that not all factors affecting these revenue and expense payment timing differences are controllable, particularly when taxes are taken into account. For that reason, a utility may find itself with working cash needs, i.e., a net revenue receipt lag, that without rate base treatment, are sufficient to impair the utility's ability to earn its allowed return. Conversely, net expense payment lags, particularly those created by taxes, may put a utility in a position to earn in excess of its allowed return. In both cases, the Commission believes an adjustment to rate base is appropriate and equitable. It therefore proposes a means of obtaining either such adjustment.

B. Filing for an Adjustment: Threshold Criterion

The Commission believes adoption of the zero allowance presumption would significantly reduce the amount of time and money spent on the cash working capital issue in wholesale electric ratemaking proceedings. Despite the perceived viability of this presumption, the Commission recognizes, on one hand, that disputes might still arise, even though the amount of rate base at stake might not justify the costs of resolving the dispute and, on the other hand, that a prohibition against any cash working capital allowance in rate base could work an undue hardship on investors or ratepayers in some cases. These considerations argue for an exception to the general rule.

If a participant adequately demonstrates that a utility's working cash needs vary significantly from the general rule, i.e., a zero allowance, an adjustment to rate base that reflects either the utility's cash needs or its early collection of revenues would be made. In other words, the Commission is proposing that a cash working capital allowance not be changed from zero, unless a utility or other participant in the proceeding, including the Commission, submits a lead-lag study that demonstrates either a significant "net revenue receipt lag," that is, a delay in collecting money from ratepayers for expenses incurred in their behalf, or a significant "net expense payment lag" in relation to revenue collection. The Commission will not accept such a study and request for adjustment, however, unless it is shown that such a lag is greater than 15 days. This proposed exception to the general rule thus would create a 15-day lag threshold standard or, to state it another way, a thirty-day "no-allowance zone" bounded on one end by a net expense payment lag of 15 days and on the other end by a net revenue receipt lag of 15 days.

The primary purpose of the filing threshold, or no-allowance zone, would be to reduce the time and money spent ligitating the cash working capital issue by discouraging parties from conducting lead-lag studies where the amount at stake is not likely to be large. The 15-day revenue or expense lag requirement is sufficiently large to provide some significant relief from litigation costs and thereby reduce the burden on the parties and Commission resources, but not so large as to prevent rate base adjustments that would reflect lags large enough to seriously impact on either a utility's investors or its customers. The Commission believes the 15-day lag requirement would provide a reasonable balancing of these objectives. The Commission invites comment both as to whether such a threshold filing requirement is needed and the appropriateness of the standard selected. In addition, comments are requested regarding how difficult it would be for a participant in a rate case to determine the likelihood of a greater-than-15-day lag and, based on that estimate, whether preparation of a lead-lag study would be justified.

Of the eight lead-lag studies accepted by the Commission in fiscal years 1982 and 1983, two would have been accepted under the rule proposed here for the purpose of adjusting the rate base. A zero allowance would have replaced the other six studies, which produced results that would not meet the 15-day-lag threshold and thus would lie within the proposed thirty-day no-allowance zone. The Commission believes that the filing threshold should also save time and money in many of the large number of ratemaking proceedings that will ultimately be resolved in settlement but which might otherwise involve more extended cash working capital disputes. While participants in rate proceedings still would need to determine when a fully-developed study would be worthwhile, even if the thirty-day no-allowance zone is adopted, the resources devoted to the cash working capital issues generally should be significantly reduced.

The Commission recognizes that a zero cash working capital requirement may not be possible for every utility. To a greater or lesser extent, the timing of the collection of revenues and payment of expenses may be subject to factors beyond a utility's control. The Commission has nevertheless concluded that the proposed standard for filing a study would provide reasonable protection for stockholders and customers, while helping to reduce litigation of this issue. If a reliable study meeting the standard is filed, rate base will be adjusted to reflect fully the demonstrated net lag in expense payments or revenue receipts.

In proposing this ratemaking device, the Commission is cognizant of the impact on the respective parties. Insofar as jurisdictional rates are involved, all costs incurred by a utility for conducting, filing, and litigating a study are borne by wholesale ratepayers, including studies submitted by a utility filing for a rate change. Assuming that such costs can be reasonably anticipated, they can be included in test period estimates. Therefore, there is a theoretical incentive for a utility to file a study showing any lag greater than 15 days.

If rate base adjustments were permitted to account for only that portion of a lead or lag in excess of 15 days, an option on which comments are invited, the effective no-allowance zone would be somewhat greater in practice. Because of who bears the costs, however, the incentive to prepare a study to demonstrate a revenue receipt lag will always be greater than the incentive to customers to show a smaller net revenue receipt lag or a net expense payment lag.

Differences between revenue collection and expense payments tend generally to have what the Commission views as a relatively small impact on customer rates and stockholders' equity, and this would remain true if the proposed rule is adopted, whether or not the first 15 days of net revenue receipt lags or expense payment lags were recognized for rate purposes. For example, if both a utility and a ratepayer submitted lead-lag studies, but the customer's study was the one accepted by the Commission, rates would be, on average, approximately 0.03% lower for each day of lag claimed by the utility but demonstrated not to exist by the customer's study. 13/ If the customer's study showed the lag to be 15 days less than that claimed in the utility's study, rates would be about 0.44% lower than they would be if the utility's

13/ These estimates are for the "average company" in the sense that they are based on the relationship between rate base, total revenue, and operation and maintenance expenses, as measured by annual industry aggregate data for 1981.

findings were accepted. For further illustration, if the utility's unaccepted study shows a 45-day net revenue receipt lag, but the customer's study demonstrates that there is no net lead or lag, there would be no adjustment at all to rate base, and rates would be 1.28% lower than they would be if a 45-day lag was given effect. However, the costs of preparing, filing, and litigating a study would be borne by the customers, so that overall customer savings would depend on how much study costs are exceeded by actual rate reductions. If rate savings realized by a customer as a result of doing a lead-lag study, are less than the customer's cost in preparing the study, the customer would lose money by doing a study even though it demonstrated that the actual lag was less than that stated by the utility.

A filing utility that submits an acceptable lead-lag study under the proposed rule, rather than accept a presumptive zero allowance, would receive similarly small benefits even if its study is deemed reliable. Each additional day of lag shown by a study would raise shareholders' total earned return on investment approximately 0.02 of a percentage point. This, for example, would be equivalent to increasing a 12.50% rate of return on equity to 12.52%. If a 15-day lag is shown, the utility's equity return would be increased by an amount equivalent to increasing the effective rate of return by about 0.30 of a percentage point, while demonstrating a 45-day lag would increase equity return by an amount equivalent to raising the rate of return 0.92 of a percentage point. Unlike the situation with customers, however, filing and litigation costs do not offset these benefits, because they are also borne by the customers of the filing utility, not the shareholders. These costs, to the extent they can be anticipated by the utility, may be included in test period estimates.

The Commission also proposes an alternative method of stating and computing the filing threshold that would represent an impact on utility rates equivalent to the 15-day test. As a substitute for the 15-day lag standard, a percentage of total revenue requirements test could be used. In other words, if a customer or utility requests an adjustment, the study must show that any net expense payment lag or revenue receipt lag, if given effect, would increase or decrease the utility's projected revenue requirements, before taking into account cash working capital, by at least 0.5 of one percent. If a rate base reduction or increase were requested by any participant, the first step in determining whether this threshold standard was met would be to multiply the amount of the requested cash working capital adjustment to be added to, or deducted from, rate base by the claimed overall rate of return, adjusted to reflect income and revenue tax effects. This amount would then be divided by total projected revenue requirements, yielding a percentage of total rates. If this calculation demonstrated, in a qualifying lead-lag study, that 0.5 percent of the projected revenue requirements would be realized or foregone by the utility if the requested adjustment were made, an adjustment to test period rate base estimates would be allowed.

This approach has two advantages. It may be clearer to express the filing threshold in terms of a percentage impact on revenue requirements. Cash working capital requirements are normally expressed in dollars, not time periods. A threshold test that is intended to exclude from consideration those cases that might involve only minimal amounts of working cash is easily expressed as a percent of all rates and such calculations will use the dollar level of cash working capital adjustments as their starting point. Moreover, a threshold expressed as a percent of a utility's revenue requirements will result in proportionately the same impact for each utility insofar as the effect of precluding any adjustment to rate base is concerned. Regardless of which standard it selects, the Commission is proposing fundamentally one threshold test. Comments on the need for and nature of that threshold are solicited.

D. <u>Proposed Elements of Lead-Lag Studies</u>.

Under the proposed rule, the rate base of a filing utility may be adjusted to reflect cash working capital other than zero if a proceeding participant files a fully developed and reliable lead lag study. In order to ensure that cash working capital adjustments to rate base are made in a consistent and justifiable manner, the proposed rule also would set forth general specifications for lead-lag studies.

The Commission is proposing that lead-lag studies be limited to those nine "allowable" expense items which the Commission has determined to have the most significant impact upon working cash needs. These expenses are (1) fossil fuel, (2) leased-nuclear fuel, (3) purchased power, (4) labor, (5) other operation and maintenance (excluding owned-nuclear fuel), (6) payroll taxes, (7) ad valorem taxes, (8) revenue taxes, and (9) income taxes payable. No expenses are permitted any impact on jurisdictional rate base unless they are either allocable or assignable to the wholesale service at issue. For example, fuel expenses not associated with transmission-wheeling services would not be includable in cash working capital calculations. Three of these nine expense items -- purchased power, payroll taxes, and income taxes -- were not included in the June 1979 proposed formula. However, many commenters on that proposal suggested that these additional expenses have a significant impact on a utility's working cash needs and therefore should be accounted for in the formula. 12/

12/ The comments also suggested three capital related items for inclusion in the proposed formula. These items are (1) test period bond interest (based on the weighted cost of long-term debt and test period rate base excluding cash working capital, (2) test period preferred stock dividends (based on the weighted cost of preferred equity and test period rate base excluding cash working capital, and (3) the sum of (a) test period depreciation expenses, (b) test period owned nuclear fuel expenses, and (c) test period provision for deferred income taxes. The Commission does not agree, as discussed below, that any of these three suggested additional elements should be included in calculations of cash working capital adjustments.

The method of computing net revenue receipt lags and net expense payment lags is set forth in proposed § 35.24(c) and the related filing requirement in § 35.13(h)(12)(ii). More specifically, to determine the proper cash working capital allowance for a particular utility, the overall time period between the utility's weighted average date of payment of expenses incurred in the rendition of service and its weighted average date of receipt of payment for the service from its customers must be determined. The expenses considered in arriving at this determination should include only those expenses that are allowable for ratemaking purposes under § 35.13 and are not accounted for elsewhere under one of the other categories of expenses in addition to working cash that are includable in the overall total working capital allowance: the allowance for materials and supplies, including fuel inventories, and the prepayment allowance. Also, calculations of cash working capital adjustments should not include any revenues associated with any portion of a revenue receipt lag period with respect to which a late-payment device has accounted, or will account, for the time-value of those revenues during the period that collection of those revenues lags behind the utility's payments of associated expenses.

The Commission recognizes that data from two different accounting periods is required to be employed in any study rebutting the presumption of a cash working capital adjustment of zero. The timing of revenue collections and expense payments are derived from Period I data or from a previously approved study. Such data must be updated for any known and measurable changes. These coefficients are applied to Period II allowable expenses to develop the appropriate Period II cash working capital allowance. In addition, some of these expense components have asset counterparts 13/ and therefore lead-lag studies must make a distinction between certain of the particular expense components which qualify for rate base treatment as cash working capital and their complementary asset counterparts for which rate base treatment is otherwise provided. The proposal would permit cash working capital calculations to include amounts with respect to costs for components of the nine expense categories that are includable in cost of service statements submitted pursuant to § 35.13 for ratemaking purposes. Cost of service statements filed under § 35.13 must reflect the allocation of expenses to accounts in

13/ For example, fuel stocks that are given separate rate base treatment to cover the time period running from the date of any prepayment to the rendition of utility service.

the Uniform System of Accounts. 14/

To avoid another source of possible confusion, the Commission notes that the derivation of the attendant lead-lag coefficients for each of the qualified expense components may be based upon the actual experience for a time period other than Period I. The coefficients derived from either actual Period I data or data from some other representative period, if Period I is not and cannot be modified to be representative, would be applied to projected Period II counterpart chargeable amounts for each qualifying item that is allocable to the service at issue.

1. Determination of net revenue receipt lags.

The proposed rule presumes that customers generally pay

14/ The Commission's Uniform System of Accounts is set forth at 18. C.F.R. Part 101. This table indicates the Uniform System of Account expense account numbers and the corresponding § 35.13(h) cost of service provision.

Cash Working Capital Component	Uniform System Account Numbers	Section 35.13(h)
Fossil Fuel Expense	501, 547	(8) AH
Purchased Power Expense	555	(8) AH
Leased-Nuclear Fuel	518	(8) AH
Payroll Taxes Charged	408.1	(11) AK
Ad Valorem Taxs Charged	408.1	(11) AK
Revenue Taxes Charged	408.1	(11) AK
Income Taxes Payable	409.1	(36) BK(i)(C)
Labor Expense	500-932	(9) AI
Residual Operation & Maintenance Expenses Excluding Owned-Nuclear Fuel	500-932	(8) AH

for all utility expenses once during a billing cycle. A single fraction of the year during which the revenue to compensate the utility for incurring the expenses is uncollected is therefore developed and applied the same for all expenses. This "revenue receipt lag" is the time period from the midpoint of the service period to the average date of payment by the customer. A "service period" is the period for which the utility customarily measures the service rendered to its customers, typically 30 days.

For purposes of cash working capital analysis, the revenue lag may be broken down into three periods: rendition of service, bill preparation, and bill payment. For example, assuming a continuous rendition of electric service during a 30-day billing cycle, service is provided, on the average, 15 days prior to the end of the service period. The revenue lag, therefore, consists of this 15-day period plus allowances for bill preparation and bill payment less the time frame covered by any late payment penalties. Further, the Commission believes that utilities typically allow about 10 days for meter reading, bill preparation, and mailing, with a 15-day period thereafter for bill payment.

In view of the above considerations, the Commission's 1979 NOPR would have required that the total revenue lag be considered to be 40 days in all cases. However, many commenters on the 1979 proposed rule, predominantly utilities, opposed the establishment of a fixed 40-day revenue lag. Relying upon results of individual revenue lag calculations, utilities claimed that the 40-day period is too short. Utilities indicated that the revenue lag is longer because customers do not or, in some instances, cannot be required to pay their bills within the 15-day payment period used in deriving the proposed 40-day revenue lag. Because the revenue lag was to be multiplied by the total of all expense items included in the formula, utilities claimed that any difference between individually calculated lags and the 40-day lag is critical and should be recognized in the formula. Furthermore, utilities indicated that the revenue lag is relatively easy to calculate. Therefore, many respondents favored calculation of individual revenue receipt lags for each utility.

In response to these comments and due to the fact that the previous proposal and current policy ignore the effect of late payment penalties, the Commission has determined that, in preparing lead-lag studies, utilities and other rate case participants should be required to calculate company-specific revenue lags. This determination has been made also in view of the Commission's belief that the proposed presumptive zero allowance and thirty-day no-allowance zone will substantially diminish the number of instances lead-lag studies will be prepared.

Under the proposed rule, this revenue receipt lag would be netted against the weighted average expense payment lags to yield a cash working capital adjustment that would be added to (CWCA = REV-EXP) or deducted from (CWCA = EXP-REV) rate base.

2. Fossil Fuel and Leased Nuclear Fuel Expense Component.

Payment for fossil fuel purchases is a large part of allowable expenses and therefore has a significant impact upon cash working capital needs. The expense payment lag associated with the fossil fuel expense is dependent upon billing and payment procedures employed by the fuel suppliers, with considerable variation to be anticipated, depending on such factors as quantities purchased, frequency of deliveries, available on-site storage facilities for each type of fuel used, and type of purchase (contract or spot). The expense payment lag is also dependent upon the fuel mix used for generating purposes, which varies from utility to utility. Accordingly, an analysis of fossil fuel purchases and their payment patterns is needed for each utility in order to obtain a reasonably accurate measure of working cash needs resulting from fossil fuel purchases over and above that covered by fuel stock.

A concern raised by many of the comments on the June 1979 proposal pertained to the proper fuel amount to include in the formula. Several comments indicated that the dollar amount of fuel purchased for the test period may not equal the amount of fuel expensed during that period due to inventory fluctuations. This concern appears misplaced, since the dollar amount of fuel paid for prior to service rendition is recognized in the overall working capital allowance on account of fuel inventories.

Another major concern expressed in the comments on the June 1979 proposal that pertains to fossil fuel expense lags is the extent of the calculation which is required to be made. Many commenters contended that the volume of fuel purchases is so great that an analysis of every transaction would be costly, impractical, burdensome, and unnecessary. Two alternative procedures were suggested in the comments as practical means of determining the expense payment lag coefficient for fossil fuel.

The first alternative was to limit the analysis to major fossil fuel suppliers and to terms of delivery and payment specified in contracts and/or purchase orders for spot fossil fuel purchases. Although such procedure may reduce the manhours required to perform the analysis, this would further reduce the validity of the results obtained from the proposed rule, because target contract payment dates, not actual payment dates, would be used.

A second alternative suggested was the use of a sample of fuel purchases with which to calculate the expense lag. Even in cases where many thousands of purchase invoices are involved, analysis of an adequate sample should produce very little deviation. The Commission would be inclined to favor the use of a sampling technique to determine the weighted average expense lag for a fuel type (e.g., coal) if use of the sampling technique would reduce administrative burden and cost while ensuring reasonable accuracy. Therefore, the Commission requests comments as to whether a sampling should be permitted and, if so, how accuracy could be adequately maintained.

3. Purchased Power Expense Component. The 1979 NOPR stated that purchased power was to be excluded from the cash working capital formula because the revenue lag and assigned expense lag associated with purchased power were equal. Many commenters disagreed with the assumption that the billing and payment procedures used in purchased power transacations between utilities conform closely with those associated with the rendition of electric service to wholesale customers. Utilities indicated that they pay other utilities for purchased power before they in turn receive payment from the wholesale customers to whom the purchased power was resold. Utilities suggested that they be permitted the option of using an individually calculated expense payment lag for purchased power if the utility could prove that a significant difference existed between the formula results and actual experience.

Some utilities suggested not only that a review of interchange agreements would provide sufficient support for refuting the assumption of equal revenue receipt and expense payment lags for purchased power but also that interchange transactions should be used in determining the expense payment lag associated with purchased power. The Commission believes that interchange transactions generally involve payments-in-kind, netting out to zero, so that cash working capital is unnecessary with respect to such arrangements. However, since this is apparently not always the case, the Commission is proposing to permit inclusion of purchased power expense, including the net of any interchange reportable under Account No. 555 of the Commission's Uniform System of Accounts. In computing cash working capital requirements, each utility would determine and apply its own, individual appropriate lag coefficient for this expense item.

4. Labor Expense Component.

The 1979 NOPR proposal assigned a fixed expense lag coefficient of 10 days to this expense item. Several commenters questioned the appropriateness of assigning 10 days as the coefficient, voicing concern over the Commission's lack of consideration of biweekly wage payments. This concern should be eliminated by the Commission's decision that all time lag coefficients should be determined individually by utilities.

5. <u>Other operation and maintenance expenses</u>.

Other operation and maintenance expenses includes all operation and maintenance expenses except fuel, purchased power expense, labor expenses, and owned-nuclear fuel expense. Although the other operation and maintenance expense category includes a variety of items, operation and maintenance supply expenses are usually the predominant items.

Because of the variety and diverse nature of the items included within other operation and maintenance expenses, the Commission had concluded in 1979 that performing a detailed payment analysis would cause excessive additional administrative costs. Therefore, the Commission proposed that a 25-day expense lag be assigned to operation and maintenance expenses. However, several commenters that questioned the validity of the rationale for the fixed 25-day expense lag proposed that an option to calculate an individual lag be included in the formula as an alternative to the 25-day expense lag, if the individual result is substantially different. Because the Commission believes its new proposed rule would result in fewer lead-lag studies, it has decided in favor of requiring greater accuracy in those studies that would still be prepared and, therefore, is proposing that each utility be required to calculate and apply its own company-specific expense lag for other operation and maintenance expenses, based on the predominant element, operation and maintenance supplies.

6. Ad Valorem Taxes and Revenue Taxes.

Ad valorem taxes are those taxes which are based upon an assessment or valuation of property (tangible and intangible) owned by a utility (e.g., property taxes). Revenue taxes are those taxes which are based upon the level of revenue earned by a utility (e.g., gross receipts taxes). Ad valorem taxes are typically less than 5% of the total operating expenses. Revenue taxes are applicable only in certain jurisdictions and may not be a large component of operating expenses. Even if these taxes are not a significant consideration in cash working capital evaluations, tax payment schedules frequently involve lengthy lag periods, thereby giving the taxes added importance in determining average cash availability for working capital. They should therefore be taken into account.

The payment lags for ad valorem and revenue taxes fluctuate widely from utility to utility because each company is subject to localized assessments and payment schedules. Some expenses are paid in advance while others are paid at varying lagging intervals. A wide range of payment dates within an individual utility's tax items in these categories may occur due to the difference in the taxes assessed among sectors of the service territory of utility. Therefore, in order that suitable expense payment lags for ad valorem and revenue taxes be calculated, the Commission is proposing a requirement that the expense payment lags for these items be determined on a utility-specific basis.

Almost all of the comments on the earlier proposal addressing the issue supported the provision for individual calculation of expense lags for ad valorem taxes and revenue taxes. Some commenters, however, proposed that all other taxes also be included in the formula. Because of the numerous miscellaneous other taxes reflecting relatively small expense liabilities and the number of these taxes which are incurred in securing rights to provide retail service (e.g., franchise taxes), the June 1979 proposed formula included only those taxes that the Commission at that time believed to generally have a significant impact upon working cash requirements related to wholesale service, i.e., ad valorem taxes and revenue taxes.

Furthermore, revenue taxes would include only those taxes which are based solely upon wholesale revenue collections or gross receipts. Ad valorem taxes would include only those taxes for which the principle underlying basis is an assessed value of that on which the tax is being levied.

7. Payroll Taxes. Payroll tax expenses were not allowable expenses under the 1979 NOPR because the Commission felt at

that time that the expense had an insignificant impact upon working cash needs. However, many commenters argued that payroll taxes expense should be recoverable in the cash working capital allowances. Utilities and other parties indicated that social security taxes, the predominant component of payroll taxes, are paid during the entire year for almost all employees. Based upon information supplied in the comments relating to the payment of taxes, and with the knowledge that these amounts are continuously growing, the Commission proposes now to incorporate this expense element in working capital calculations. Each utility would determine its own expense payment lag time coefficient.

8. Income Taxes. Income taxes payable was included as an expense component in the June 1979 proposed rule. Income tax payable is income tax allowable under § 35.13(h)(36) (Statement BK(i)(C)) less any deferred taxes. Income taxes payable was considered to be the appropriate amount for which working cash requirements should be analyzed, because income tax allowable includes deferred taxes which are capital related and typically do not require a cash outlay during the test period. Income taxes payable would include state as well as federal income taxes, because state income tax payment procedures generally reflect payment patterns for federal income taxes.

The expense lag for income taxes payable in the earlier proposed rule was fixed at 90 days. Although many of the respondents were noncommital or generally supported the figure, some commenters observed that the 90-day expense lag represents the hypothetical bare minimum tax payment by the utility during the taxable year. Such amount, it was contended, can be paid only if a perfect estimate of taxes payable is made. Various commenters also indicated that utilities generally remit more than 90% of their tax liability during the taxable year to provide a cushion in avoiding underpayment penalities.

In order that the rule more accurately reflect tax payment experience, the Commission is proposing that each utility calculate its expense lag coefficient associated with income taxes payable. However, while some commenters proposed separate components for federal income taxes payable and state income taxes payable the Commission believes that the federal tax lag coefficient should be applied to both federal and state income taxes payable to avoid unnecessary complications.

9. <u>Non-Allowable Expenses</u>.

The Commission's proposed resolution in this rulemaking of which expenses should be considered in formulating the cash working capital needs of any utility reflects its analysis of cases and comments on this issue and a determination that various kinds of expenses and expense-related issues are best considered elsewhere in a utility's cost of service.

Questions were raised by the commenters on the 1979 NOPR concerning the inclusiveness of the term "test period fossil fuel expense." One utility proposed that the cost of geothermal energy be considered equivalent to fossil fuel expense and included in the formula calculations. The cost of geothermal energy is an electric power production expense but it is not a fossil fuel expense and therefore is not includable in the fossil fuel expense item category. The cost of geothermal energy and its expense payment lag should be considered as part of the other operation and maintenance expense item category.

A substantial number of the comments on the 1979 proposal dealt with the exclusion from consideration of depreciation and amortization expense relating to nuclear fuel owned, as opposed to leased, by the utility. Although amortization of such "owned-nuclear fuel" in the reactor does not require a cash outlay during the service period, many respondents pointed out that there is a reduction in the rate base upon which utilities are allowed to earn a return. Because the process of rate base averaging implies a reduction in rate base prior to the time that revenues reflecting such adjustments are received from customers, these commenters argued that utilities therefore require working cash for the period between rate base reduction and revenue receipt. Without working cash recognition for this period, some commenters contended, utilities would be deprived of the opportunity to earn a return on all investment necessarily tied up in the utility business but not appearing in the plant accounts (rate base).

The Commission recognizes that depreciation and amortization expenses, including owned nuclear fuel expense, are significant operating expenses. However, such expenses represent recovery of investments and do not require a current outlay of cash. Therefore, the Commission has concluded that such items need not be included in a calculation of cash working capital requirements for purposes of this rule. This decision is consistent with past Commission practice under which it has repeatedly rejected the inclusion in cash working capital calculations of non-cash items such as depreciation, amortizations of various items, insurance premiums, pensions, etc. 17/ The rationale for this policy has been explained:

> * * * The purpose of the cash working allowance is to compensate the investors for the use value of their money where the company is required to pay expenses prior to receiving from the ratepayers the revenues associated with those expenses. Depreciation expense is not a cash expense requiring payment by the Company prior to receipt of revenue from the ratepayers.

17/ See Opinion No. 55, Southern California Edison Company, Docket No. E-8570, issued August 1, 1979, 8 FERC ¶ 61,099 at 61,377.

> Rather, it is in the nature of a bookkeeping expense. . . . 18/

The Commission also recognizes that, although a return on investment is due a utility when service is rendered, the equity and preferred return components of revenue typically are not received until forty days after service is rendered. However, the Commission has concluded that the proposed rule need not address this matter because of the offsetting consideration that neither does the proposed rule require a utility to utilize the interest component of return as working cash, even though the interest may not be paid to the bondholders until after the related revenue is received by the utility. Further, the Commission has taken the position that, since both common and preferred equity return belong to the utility and its shareholders when service is rendered, the utility cannot be expected to use the related revenues subsequently received as working cash without remuneration. 19/

Further, the Commission does not believe that minimum bank balances that a utility may be required to maintain in order to

---

18/ See Initial Decision on Application for Rate Increase, Southern California Edison Company, Docket No. ER76-205, issued June 1, 1978, 3 FERC ¶ 63,033, at 65,209.

19/ See Opinion No. 110, Louisiana Power & Light Company, Docket No. ER77-533, issued January 28, 1981, 14 FERC ¶ 61,075 at 61,122.

secure bank account services are properly considered part of a utility's cash flow requirements for day-to-day operations. In this regard, the Commission notes that, if a utility is required to maintain minimum bank balances under terms of written agreements, the utility may make a separate claim for rate base treatment. As a related matter, the Commission reiterates its position that any need for compensating bank balances required to compensate a lending institution for extending a line of credit necessary to provide for short-term loans is more appropriately considered either in establishing an appropriate rate of return or in fixing the proper accrual rate for allowance for funds used during construction. 20/

10. Calculation of Formula Components.

Many comments on the 1979 NOPR expressed some uncertainty, of continuing relevance to this proposal, regarding the procedure for calculating the fuel expense lag coefficient. Under this new proposed rule, the fuel expense lag coefficient would be determined through analysis of the payment dates for the particular expenses charged to service periods covered by that test period. Payments for fuel received during the

20/ See, Opinion No. 19, Carolina Power and Light Company, Docket No. ER76-495, issued August 2, 1978, 4 FERC ¶ 61,107 at 61,224.

first month of the test period would be analyzed with respect to their relation to the midpoint of the first month (service period). Payments for deliveries during the second month would be compared with the midpoint of that second month, and so on. Since payment dates are entered in cash payment journals when cash is disbursed in settlement of a particular expense obligation, there should be no uncertainty surrounding the determination of when cash is disbursed. The midpoint of a service period does not change, and the lag between the midpoint of the service period and the payment dates for fuel should therefore be readily calculable. Therefore, the comparison of payment dates for fuel deliveries with the midpoint of the service period in which delivery occurs should provide a defined, objective procedure for determining the fuel expense payment lag coefficient for the test period.

Several respondents also raised questions regarding the treatment of payments made before the end of the service period in calculating expense lags. Payments made before the end of a service period should be included, but this does not mean prepayments. Prepayments are a separate working capital component and consequently must not be included in the cash working capital calculations.

Some commenters on the 1979 NOPR expressed confusion regarding the period for which ad valorem taxes and revenue taxes expense payments lags are to be calculated. This uncertainty is reflected by those respondents' concern over the validity of the expense payment lag calculation when the test period does not coincide with the fiscal year of the taxing authority. For cash working capital purposes, the non-coincidence of the tax year and the test year is immaterial to expense payment lag calculation. The purpose of the calculation is not to analyze payments made during the period encompassed by the test year, but rather to determine the lag in payment of tax expense incurred during each service period of Period I.

IV. CERTIFICATION OF NO SIGNIFICANT ECONOMIC IMPACT

The Regulatory Flexibility Act (RFA) 21/ requires certain statements, descriptions and analyses of proposed rules that will have "a significant economic impact on a substantial number of small entities." 22/ Pursuant to section 605(b) of the RFA, the Commission certifies that a proposed rule will not have such an impact and, therefore, that it is not required to make an RFA analysis.

This proposed rule would only affect electric utilities that engage in wholesale activities and their wholesale customers. These companies would be required to develop and file

---

21/ 5 U.S.C. §§ 601-612 (Supp. IV 1980)

22/ *Id.*, § 603(a).

lead-lag studies only if they decided to rebut the presumption of a zero cash working capital adjustment to test period rate base estimates. Virtually all electric utilities that distribute electricity on wholesale level have annual operating levels over $1 million. In addition, this rule, if promulgated should have an insignificant effect on the filing burden on these electric utility companies because they already collect the information needed to analyze cash working capital needs for other purposes. Further, the Commission expects that any filings of lead-lag studies pursuant to this proposed rule would be infrequent because the presumption that zero is the appropriate cash working capital adjustment would not be contested in many instances. Adoption of the proposed filing threshold would even further reduce the number of lead-lag studies prepared. Finally, the substitution of the zero presumption for the 45-day convention would only result in a net reduction in filings by utility customers.

V. PAPERWORK REDUCTION ACT

The information collection provisions in this proposed rule are being submitted to the Office of Management and Budget (OMB) for its approval under the Paperwork Reduction Act 23/ and

23/ 44 U.S.C. §§ 3501-3520 (Supp. I 1980).

OMB's regulations. 24/ Interested persons can obtain information on the proposed information collection provisions by contacting the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426 (Attention: Jack Kendall, (202) 357-8033). Comments on the information collection provisions can be sent to the Office of Information and Regulatory Affairs of OMB (Attention: Desk Officer for the Federal Energy Regulatory Commission).

VI. TERMINATION OF EARLIER DOCKET NUMBER

This notice of proposed rulemaking begins the Commission's reexamination of the cash working capital issues in ratemaking proceedings and has been assigned the new Docket No. RM84-9-000. Comments received in Docket No. RM79-49-000 on the Commission's earlier proposed rulemaking on the same issues have been considered in formulating the new proposed rule. However, in view of the length of period that has passed since those comments were submitted, the Commission does not assume that the commenters' views expressed at that time remain unchanged or applicable to the new proposed rule. Therefore, the Commission will not further consider those comments on the June 1979 proposal in its deliberations as to whether to issue a final rule in this new proceeding.

24/ 5 C.F.R. § 1320.13 (1983).

Any further action by the Commission with respect to cash working capital issues will be taken in Docket No. RM84-9-000. Accordingly, the Commission is issuing in conjunction with this notice of proposed rulemaking a separate order withdrawing the June 1979 notice of proposed rulemaking and terminating Docket No. RM79-49-000, effective on the publication of that order in the Federal Register.

VII. WRITTEN COMMENT PROCEDURES

The Commission invites all interested persons to submit written data, views and other information concerning the matters set out in this notice. All comments in response to this notice should be submitted to the Secretary, Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, and should refer to Docket No. RM84-9-000. An original and 14 copies should be filed. All comments received prior to 4:30 p.m. EST., June 4, 1984, will be considered by the Commission prior to promulgation of the final regulations.

All written submissions will be placed in the public file which has been established in this docket and which is available for public inspection during regular business hours in the Commission's Office of Public Information, Room 1000, 825 North Capitol Street, N.E., Washington, D.C. 20426.

<u>List of Subjects</u>

18 C.F.R. Part 35

Electric Power Rates, Electric Utilities, Reporting Requirements

In consideration of the foregoing, the Commission proposes to amend Part 35, Title 18, Chapter I, Code of Federal Regulations, as set forth below.

By direction of the Commission.

(S E A L)

Lois D. Cashell

Lois D. Cashell,
Acting Secretary.

1. The authority for Part 35 is amended to read as follows:

Authority: Federal Power Act, 16 U.S.C. §§ 791-828c.

2. Part 35 is amended in the table of contents by adding in appropriate numerical order a new § 35.24 to read as follows:

Part 35 -- Filing of Rate Schedules

* * *

§ 35.24 Cash working capital adjustment:

* * * * *

3. Section 35.13(h)(12)(ii) is revised to read as follows:

§ 35.13 Filing of Changes in Rate Schedules.

* * * * *

(h) Cost-of-Service Statements. * * *

(12) Statement AL - Working capital. * * *

(ii) Cash working capital. The filing utility (or other participant in the proceeding, as appropriate under § 35.24) may request a cash working capital adjustment to rate base (CWCA) under this clause by submitting a study of average monthly working cash requirements that reflect the extent to which day-to-day operational utility service revenues are received later or earlier than cash disbursements necessary to provide the service. Such request and study may be filed only if the net revenue receipt lag or net expense payment lag can be shown to exceed a monthly average of 15 days, in accordance with the standards of § 35.24. Statement AL shall contain a summary of such study, which conforms to the following requirements.

(A) Addition to rate base. If the study demonstrates a net revenue receipt lag for Period I, adjusted to reflect changes that affect revenue collections and expense payments during the test period and that are known and measurable with reasonable accuracy, provide the following data in accordance with the general provisions of clause (D).

(1) With respect to the sum of all allowable expenses, the average time during Period I between rendition of service to customers by the utility and when revenue attributable to that service is collected by the utility, measured as the number of days from the midpoint of the service period to the average date of receipt of payment by the wholesale customers and expressed as a fraction of a year (360 days), and the total of allowable expenses for the test period. REV = ?/360 (sum of allowable expenses)

(2) For each allowable expense, the average time during Period I between when the rendition of service to customers by the utility, measured as the number of days from the midpoint of the service period to the average date of payment of the allowable expense and expressed as a fraction of a year (350 days), and the total of each allowable expense for the test period. EXP = Sum of ?/360 (each allowable expense) for all allowable expenses

(3) State the total CWCA requested as an addition to rate base. CWCA = REV - EXP

(B) Deduction from rate base. If the study demonstrates a net expense payment lag for Period I, adjusted to reflect changes that affect revenue collections and expense payments during the test period and that are known and measurable with reasonable accuracy, provide the data described in clause (A) and state the total CWCA requested as a deduction from rate base. CWCA = EXP - REV

(C) As an indication that the party is eligible to file this portion of Statement AL, under § 35.24(c)(2) or (3), state the total net expense payment lag or revenue receipt lag, calculated in days using the weighted average time components presented under clauses (A) or (B).

(D) General provisions.

(1) The definitions and provisions of § 35.24 of this part apply.

(2) To achieve comparability, the amounts stated shall reflect uncollected revenue and unpaid allowable expenses from the same point in time, so that the net effect of uncollected revenue and unpaid allowable expenses are calculated appropriately. The benchmark shall be the rendition of service, expressed as the midpoint of the service period during which service is rendered. For any expenses paid at intervals greater

than a service period, such as quarterly or annual taxes, the point of rendition of service that is the benchmark for measuring all expense payment or revenue receipt lags, shall be the point in the payment cycle that represents the average midpoint of all service periods during that cycle.

(3) For purposes of determining the levels of allowable expenses, the study shall use data for the test period, as defined in paragraph (d) of this section. For purposes of calculating the average length of any revenue receipt lag or expense payment lag, the study shall use data for Period I, adjusted to reflect changes that affect revenue collection and expense payment during the test period and that are known and measurable with reasonable accuracy.

(4) If data other than Period I data, such as data from a previously-approved study, are used for calculating the length of average expense payment or revenue receipt lags, a statement must be supplied explaining the reasons for using the other data and why Period I data are otherwise unnecessary or inadequate.

4. Part 35 is amended further by adding a new § 35.24 to read as follows:

§ 35.24 Cash working capital allowance.

(a) Scope and Applicability. This section:

(1) applies to any initial rate schedule or rate schedule change, other than certain rate increases under § 35.13(a)(2), filed by a public utility under this part; and

(2) governs any cash working capital adjustment to rate base.

(b) <u>Definitions</u>. For purposes of this section and any cash working capital study filed under § 35.13(h)(12)(ii), the following definitions apply.

(1) "Cash working capital" means the total average amount of cash needed by a public utility on a day-to-day basis to pay allowable expenses, if the utility has a net revenue receipt lag.

(2) "Cash working capital adjustment" means:

(i) an addition to a utility's rate base of an amount of cash working capital required on hand, if a net revenue receipt lag is demonstrated under this paragraph; or

(ii) a deduction from a utility's rate base of an amount of cash that is available to the utility as a result of a net expense payment lag demonstrated under this paragraph.

(3) "Allowable expenses" means only the following utility operating expenses chargeable to the test period, as recognized for ratemaking purposes and set forth in the utility's rate schedule filing:

(i) "Fossil fuel expense" reported in § 35.13(h)(8)(i) (Statement AH) of this part, reflecting Accounts 501 or Account 547 of Part 101 of this chapter;

(ii) "Purchased power expense" reported in § 35.13 (h)(8)(i) (Statement AH) of this part, reflecting Account 555 of Part 101 of this chapter;

(iii) "Leased nuclear fuel expense" reported in § 35.13(h)(8)(i) (Statement AH) of this part, reflecting Account 518 of Part 101 of this chapter;

(iv) "Payroll taxes charged" reported in § 35.13(h)(11)(i) (Statement AK) of this part, reflecting Account 408.1 of Part 101 of this chapter;

(v) "Ad valorem taxes charged" reported in § 35.13(h)(11)(i) (Statement AK) of this part, reflecting Account 408.1 of Part 101 of this chapter;

(vi) "Revenue taxes charged" reported in § 35.13(h)(11)(i) (Statement AK) of this part, reflecting Account 408.1 of Part 101 of this chapter;

(vii) "Income taxes payable" reported in § 35.13(h)(36)(i) (Statement BK) of this part, reflecting Account 409.1 of Part 101 of this chapter;

(viii) "Labor expense" reported in § 35.13(h)(9) (Statement AI) of this part, reflecting appropriate accounts of Part 101 of this chapter; and

(ix) "Other operation and maintenance expenses" reported in § 35.13(h)(8) (Statement AH) of this part, not including nuclear fuel expenses for fuel owned by the utility, reflecting appropriate accounts of Part 101 of this chapter.

(4) "Net expense payment lag" means the period between the average time that the utility collects revenues for electric service to wholesale customers and the average time that it later pays the allowable expenses incurred and charged to such service, as calculated under paragraph (c)(3) of this section.

(5) "Net revenue receipt lag" means the period between the average time that the utility pays the allowable expenses incurred and charged to electric service provided to wholesale customers and the average time that it later collects revenues attributable to such service, as calculated under paragraph (c)(2) of this section.

(6) "Service period" means the time interval, such as 30 days for service rendered monthly, used by the utility to measure service rendered to wholesale customers.

(c) General rule. (1) Presumption of Zero Cash Working Capital Needed. Except as provided under subparagraph (2) or (3), a filing utility will receive no cash working capital adjustment to its rate base.

(2) Adjustment permitted. (i) Showing required. A participant may file to provide the filing utility a cash working capital adjustment, as defined in paragraph (b)(2)(i) of this section, only if such adjustment is supported and justified by a study that demonstrates, in accordance with § 35.13(h)(12)(ii) of this part, that the average number of days between the midpoint

of the service period and the receipt of revenues in payment for service provided during that period, not including days accounted for through a customer late payment penalty, is at least 15 days greater than the average number of days between the midpoint of the service period and cash disbursements by the utility for allowable expenses to provide service during the service period.

(ii) Addition to rate base. If a filing utility or other participant demonstrates a qualifying net revenue receipt lag in accordance with this subparagraph, the rate base of the utility will be increased by an amount equal to the utility's total average uncollected revenues for an average service period minus total average allowable expenses that are unpaid for that period, in conformance with the conclusions of an acceptable study under § 35.13(h)(12)(ii) of this part.

(3) Disallowance permitted. (i) Showing required. A participant may file to obtain for the filing utility a cash working capital adjustment, as defined in paragraph (b)(2)(ii) of this section, only if such adjustment is supported and justified by a study that demonstrates, in accordance with § 35.13(h)(12)(ii) of this part, that the average number of days between the midpoint of the service period and cash disbursements by the utility to pay expenses for service during that period is at least 15 days greater than the average number of days between the midpoint of

the service period and receipt of revenues in payment for service rendered during that period.

(ii) Deductions from rate base. If a participant demonstrates that a filing utility has a qualifying net expense payment lag in accordance with this subparagraph, the rate base of the utility will be reduced by an amount equal to the utility's total average allowable expenses that are unpaid for an average service period minus total average uncollected revenues for that period, in conformance with the conclusions of an acceptable study under § 35.13(h)(12)(ii) of this part.

Attachment 197.0

APPENDIX A
to Commission IR No. 1
(See IR 197.0)

Summary of Projected Accounting Changes (based on proposed accounting treatment)
Impact on Financial Reporting and Revenue Requirements: Increase (Decrease) in Millions of $

	Account	Nature of Change	2010 financial statements		2011 financial statements				Comment
			Accounting	Regulatory	Adjustment to 2010 opening retained earnings	Adjustment to restate 2010 financial statements	Change in accounting policy in 2011	Regulatory Variance (if required)	
a	Training costs previously capitalized	Change in Canadian GAAP-2009	2	2					Table C-11-1: 2009 accounting expense deferred and expensed in 2010 for regulatory purposes
b	Feasibility studies previously capitalized	Change in Canadian GAAP-2009	0.5	0.5					Table C-11-1: 2009 accounting expense deferred and expensed in 2010 for regulatory purposes
c	Capitalization of current service portion of pension and OPEB [1]	IFRS	-0.6	-0.6		-0.6	-0.6		Table C-11-1
d	Inspection costs now capitalized [1]	IFRS	-1.2	-1.2		-1.2	-1.9		Table C-11-1
e	Commencement of depreciation [1]	IFRS	2.6	2.6		2.6	2.6		Table C-11-1
f	Reduction in overhead capitalization [1]	IFRS	10.6	10.6		10.6	10.6		Table C-11-1
g	Pension and employee future benefits	IFRS			-0.2		-2		Table C-11-1
h	Shared services with TGVI	Change in estimate by management	-2.9	-2.9			-3.3		Table C-11-1
i	Corporate services with Terasen Inc	Change in estimate by management	0.5	0.5			0.6		Table C-11-1
j	Depreciation study impacts [1]	Change in estimate - IFRS required	28.5	28.5		28.5	29		Table C-11-1: Existing standards allowed regulatory depreciation rates to override actual useful life; IFRS requires depreciation based on actual useful life. Updated study indicates that previously approved regulatory depreciation rates do not match up with remaining useful lives. This variance is a result of the accelerated depreciation.
k	Initial IFRS adoption impact - Unfunded pension plan [2]	IFRS			57.9				Application, page 482, section 9.1
l	Initial IFRS adoption impact - Past service costs [2]	IFRS							Application, page 482, section 9.3
m	Initial IFRS adoption impact - Return on pension plan assets [2]	IFRS							Application, page 482, section 9.4
n	Initial IFRS adoption impact - Pension and employee future benefit changes [2]	IFRS							Application, page 482, section 9.5
o	Initial IFRS adoption impact - Leases	IFRS							Application, page 482, section 10
	Accounts dependant upon changes to existing IFRS								
p	Anticipated IFRS change - Regulatory accounts	IFRS			-40	-5.1	25.9	25.9	Application, page 478, section 2
q	Anticipated IFRS change - Opening cost of property, plant and equipment [3]	IFRS						0	Application, page 478, section 3.1
r	Anticipated IFRS change - Capitalization of borrowing costs [4]	IFRS						0	Application, page 479, section 4.2
s	Anticipated IFRS change - Gains and losses on disposal of assets [5]	IFRS						0	Application, page 480, section 5.1
t	Anticipated IFRS change - Income tax	IFRS			278	284.5	292.2	292.2	Application, page 482, section 10
	Total		**40**	**40**	**295.7**	**319.3**	**353.1**		

[1] Provided that regulatory treatment is aligned with IFRS for 2010 as requested in the Application, these amounts would be recorded in 2010 for both regulatory and accounting purposes, and there would be no 2011 comparative financial statement impact
[2] The unfunded pension plan initial adoption impact includes all adjustments related to past service costs, return on pension plan assets and pension & employee future benefit changes - the components have not been separated
[3] This is unknown and expected to be zero regardless of whether the use of historical cost or fair market value is eventually adopted
[4] This is expected to be zero as the difference between AFUDC and IDC is expected to be immaterial and not require adjustment
[5] The amount of gains and losses embedded in the opening balance of PP&E in 2010 would be included in (q). TGI has not forecasted gains and losses for 2010 and 2011.

Attachment 198.3

July 2009

Exposure Draft ED/2009/8

Rate-regulated Activities

Comments to be received by 20 November 2009

International
Accounting Standards
Board®

Exposure Draft

RATE-REGULATED ACTIVITIES

Comments to be received by 20 November 2009

ED/2009/8

This exposure draft *Rate-regulated Activities* is published by the International Accounting Standards Board (IASB) for comment only. The proposals may be modified in the light of the comments received before being issued as an International Financial Reporting Standard (IFRS). Comments on the draft IFRS and its accompanying documents (see separate booklets) should be submitted in writing so as to be received by **20 November 2009.** Respondents are asked to send their comments electronically to the IASB website (www.iasb.org), using the 'Open to Comment' page.

All responses will be put on the public record unless the respondent requests confidentiality. However, such requests will not normally be granted unless supported by good reason, such as commercial confidence.

ISBN for this part: 978-1-907026-26-3

ISBN for complete publication (set of three parts): 978-1-907026-25-6

International
Accounting Standards
Board®

Additional copies of this publication may be obtained from:
IASC Foundation Publications Department,
1st Floor, 30 Cannon Street, London EC4M 6XH, United Kingdom.
Tel: +44 (0)20 7332 2730 Fax: +44 (0)20 7332 2749
Email: publications@iasb.org Web: www.iasb.org

CONTENTS

Introduction and invitation to comment

Reasons for publishing the exposure draft

The International Accounting Standards Board has developed the proposed IFRS to define regulatory assets and regulatory liabilities, set out criteria for their recognition, specify how they should be measured and require disclosures about their financial effects.

The Board added this project to its agenda in December 2008 because of differences of views in practice about whether it was appropriate for entities to recognise assets and liabilities arising from rate regulation and ongoing requests for guidance on this issue. IFRSs do not currently provide guidance on the recognition and measurement of such assets and liabilities. Consequently, preparers of financial statements must develop accounting policies in accordance with the hierarchy in IAS 8 *Accounting Policies*, *Changes in Accounting Estimates and Errors*, considering the definitions in the *Framework*.

Rate regulation is a restriction on the setting of prices that can be charged to customers for services or products. A number of regulatory methodologies exist and, for each, application can vary by regulator, the entity being regulated and the particular circumstances.

The Board's objectives for the proposed IFRS are:

(a) to establish criteria for the recognition of assets and liabilities arising from rate regulation

(b) to clarify that regulated entities follow the requirements of all other IFRSs in addition to the proposed IFRS

(c) to require disclosures to enable users to understand the nature and financial effects of rate regulation on an entity's activities.

Main features of the draft IFRS

The draft IFRS specifically addresses rate-regulated activities that meet the following two criteria:

(a) an authorised body is empowered to establish rates that bind customers.

(b) the price established by regulation (the rate) is designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a specified return (cost-of-service regulation).

When the scope criteria are met, the entity recognises regulatory assets and regulatory liabilities in addition to the assets and liabilities recognised in accordance with other IFRSs. The effect of this requirement is initially to recognise as an asset (liability) an amount that would otherwise be recognised in that period in the statement of comprehensive income as an expense (income).

On initial recognition and at the end of each subsequent reporting period regulatory assets and regulatory liabilities are measured at their expected present value. Regulatory assets are assessed for impairment when the entity concludes that it is not reasonable to assume that it will be able to collect sufficient revenues from its customers to recover its costs.

Invitation to comment

The Board invites comments on any aspect of the exposure draft of its proposed IFRS *Rate-regulated Activities*. It would particularly welcome answers to the questions set out below. Comments are most helpful if they:

(a) respond to the questions as stated,

(b) indicate the specific paragraph or paragraphs to which the comments relate,

(c) contain a clear rationale, and

(d) describe any other approaches the Board should consider, if applicable.

Respondents need not comment on all of the questions and are encouraged to comment on any additional issues.

The Board will consider all comments received in writing by **20 November 2009**. In considering the comments, the Board will base its conclusions on the merits of the arguments for and against each approach, not on the number of responses supporting each approach.

Scope

Question 1

The exposure draft proposes two criteria that must be met for rate-regulated activities to be within the scope of the proposed IFRS (see paragraphs 3–7 of the draft IFRS and paragraphs BC13–BC39 of the Basis for Conclusions).

Is the scope definition appropriate? Why or why not?

Recognition and measurement

Question 2

The exposure draft proposes no additional recognition criteria. Once an activity is within the scope of the proposed IFRS, regulatory assets and regulatory liabilities should be recognised in the entity's financial statements (see paragraphs BC40–BC42 of the Basis for Conclusions).

Is this approach appropriate? Why or why not?

Question 3

The exposure draft proposes that an entity should measure regulatory assets and regulatory liabilities on initial recognition and subsequently at their expected present value, which is the estimated probability-weighted average of the present value of the expected cash flows (see paragraphs 12–16 of the draft IFRS and paragraphs BC44–BC46 of the Basis for Conclusions).

Is this measurement approach appropriate? Why or why not?

Question 4

The exposure draft proposes that an entity should include in the cost of self-constructed property, plant and equipment or internally generated intangible assets used in regulated activities all the amounts included by the regulator even if those amounts would not be included in the assets' cost in accordance with other IFRSs (see paragraph 16 of the draft IFRS and paragraphs BC49–BC52 of the Basis for Conclusions). The Board concluded that this exception to the requirements of the proposed IFRS was justified on cost-benefit grounds.

Is this exception justified? Why or why not?

Question 5

The exposure draft proposes that at each reporting date an entity should consider the effect on its rates of its net regulatory assets and regulatory liabilities arising from the actions of each different regulator. If the entity concludes that it is not reasonable to assume that it will be able to collect sufficient revenues from its customers to recover its costs, it tests the cash-generating unit in which the regulatory assets and regulatory liabilities are included for impairment in accordance with IAS 36 *Impairment of Assets*. Any impairment determined in accordance with IAS 36 is recognised and allocated to the assets of the cash-generating unit in accordance with that standard (see paragraphs 17–20 of the draft IFRS and paragraphs BC53 and BC54 of the Basis for Conclusions).

Is this approach to recoverability appropriate? Why or why not?

Disclosures

Question 6

The exposure draft proposes disclosure requirements to enable users of financial statements to understand the nature and the financial effects of rate regulation on the entity's activities and to identify and explain the amounts of regulatory assets and regulatory liabilities recognised in the financial statements (see paragraphs 24–30 of the draft IFRS and paragraphs BC59 and BC60 of the Basis for Conclusions).

Do the proposed disclosure requirements provide decision-useful information? Why or why not? Please identify any disclosure requirements that you think should be removed from, or added to, the draft IFRS.

Transition

Question 7

The exposure draft proposes that an entity should apply its requirements to regulatory assets and regulatory liabilities existing at the beginning of the earliest comparative period presented in the period in which it is adopted (see paragraph 32 of the draft IFRS and paragraphs BC62 and BC63 of the Basis for Conclusions). Any adjustments arising from the application of the draft IFRS are recognised in the opening balance of retained earnings.

Is this approach appropriate? Why or why not?

First-time adoption

The exposure draft includes proposed amendments to IFRS 1 *First-time Adoption of International Financial Reporting Standards* (see paragraph C1 of the draft IFRS). These amendments are the result of the Board's exposure draft *Additional Exemptions for First-time Adopters* published in September 2008. These amendments reflect the comments received on that exposure draft and the Board's redeliberations.

Other comments

Question 8

Do you have any other comments on the proposals in the exposure draft?

[Draft] International Financial Reporting Standard X *Rate-regulated Activities* ([draft] IFRS X) is set out in paragraphs 1—32 and Appendices A–C. All the paragraphs have equal authority. Paragraphs in **bold type** state the main principles. Terms defined in Appendix A are in *italics* the first time they appear in the [draft] IFRS. Definitions of other terms are given in the Glossary for International Financial Reporting Standards. [Draft] IFRS X should be read in the context of its core principle and the Basis for Conclusions, the *Preface to International Financial Reporting Standards* and the *Framework for the Preparation and Presentation of Financial Statements*. IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* provides a basis for selecting and applying accounting policies in the absence of explicit guidance.

[Draft] International Financial Reporting Standard X *Rate-regulated Activities*

Core principle

1 **An entity shall recognise the effects on its financial statements of its operating activities that provide goods or services whose prices are subject to *cost-of-service regulation*.**

2 In particular, this [draft] IFRS requires an entity:

(a) to recognise a *regulatory asset* or *regulatory liability* if the *regulator* permits the entity to recover specific previously incurred costs or requires it to refund previously collected amounts and to earn a specified return on its regulated activities by adjusting the prices it charges its customers.

(b) to measure a regulatory asset or regulatory liability at the *expected present value* of the cash flows to be recovered or refunded as a result of regulation, both on initial recognition and at the end of each subsequent reporting period.

(c) to provide disclosures that identify and explain the amounts recognised in the entity's financial statements arising from a regulatory asset or regulatory liability and assist users of those financial statements to understand the nature and financial effects of its rate-regulated activities.

Scope

3 **An entity shall apply this [draft] IFRS to its operating activities that meet the following criteria:**

(a) an authorised body (the regulator) establishes the price the entity must charge its customers for the goods or services the entity provides, and that price binds the customers; and

(b) the price established by regulation (the rate) is designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a specified return (cost-of-service regulation). The specified return could be a minimum or range and need not be a fixed or guaranteed return.

4 If regulation establishes different rates for different categories, such as different classes of customers or volumes purchased, the related operating activities of an entity are within the scope of this [draft] IFRS provided that the regulator approves the definition and the rate for each of those categories and that all customers of the same category are bound by the same rate.

5 An entity shall determine at the end of each reporting period whether its operating activities meet the criteria in paragraph 3.

6 Some regulation determines rates based on targeted or assumed costs, for example industry averages, rather than the actual costs incurred or expected to be incurred by the entity. Activities regulated in this way are not within the scope of this [draft] IFRS.

7 This [draft] IFRS does not apply to financial assets and financial liabilities, as defined in IAS 32 *Financial Instruments*: *Presentation*.

Recognition and measurement

8 An entity shall recognise:

(a) a regulatory asset for its right to recover specific previously incurred costs and to earn a specified return, or

(b) a regulatory liability for its obligation to refund previously collected amounts and to pay a specified return

when it has the right to increase or the obligation to decrease rates in future periods as a result of the actual or expected actions of the regulator.

9 Regulated entities comply with the requirements of IFRSs in the same way as other entities. Although regulators can determine the timing of recovery of costs or settlement of refunds in rates, they cannot change the characteristics of assets and liabilities that would exist in accordance with IFRSs. Therefore, if the criteria in paragraph 3 are satisfied, the entity shall recognise regulatory assets and regulatory liabilities in addition to the assets and liabilities recognised in accordance with other IFRSs.

10 An effect of applying the requirements in paragraph 8 is to recognise as an asset (liability) initially amounts that would otherwise be recognised in that period in the statement of comprehensive income as an expense (revenue). Consequently, this [draft] IFRS is not applicable when items related to regulated operating activities have been recognised as assets or liabilities in accordance with other IFRSs.

11 When an entity recognises a regulatory asset or regulatory liability, it shall determine whether a temporary difference exists that requires the recognition of a deferred tax asset or a deferred tax liability in accordance with IAS 12 *Income Taxes*.

12 On initial recognition and at the end of each subsequent reporting period, an entity shall measure a regulatory asset or regulatory liability at its expected present value.

Components of an expected present value measurement

13 An entity shall reflect the following elements in the measurement of the expected present value of a regulatory asset or a regulatory liability:

(a) an estimate of the future cash flows that will arise in a range of possible outcomes.

(b) an estimate of the probability of each outcome occurring.

(c) the time value of money, represented by the current market risk-free rate of interest.

(d) the price for bearing the uncertainty inherent in the regulatory asset or regulatory liability.

14 An entity shall determine a range of possible outcomes and estimate the cash flows that it will recover or refund for each outcome. It shall also estimate the probability that each outcome will occur, including the probability that in the entity's future rates the regulator will allow the entity to include the actual costs incurred or require the entity to include amounts collected.

15 Interest rates used to discount the estimated cash flows shall reflect assumptions that are consistent with those inherent in the estimated cash flows. In other words, the discount rates used shall not reflect risks for which the estimated cash flows have been adjusted. However, the fact that the estimated future cash flows have been adjusted for the probability of different outcomes occurring does not eliminate the need

to include in the discount rate the price for bearing the uncertainty inherent in the regulatory asset or regulatory liability. The price for uncertainty relates to the entity's estimates of both the amount and the timing of the cash flows and the probabilities of different outcomes.

16 In some cases, a regulator requires an entity to capitalise, as part of the cost of self-constructed property, plant and equipment or internally generated intangible assets, amounts that would otherwise be recognised as regulatory assets in accordance with this [draft] IFRS. After the construction or generation is completed, the resulting capitalised cost is the basis for depreciation or amortisation and unrecovered investment for rate-making purposes. In such cases, the amounts included in the cost of the asset for rate-making purposes shall also be included in its cost for financial reporting purposes, even if IAS 16 *Property, Plant and Equipment*, IAS 23 *Borrowing Costs* or IAS 38 *Intangible Assets* would not permit the entity to do so. Those amounts shall be included in the cost of the asset only if their inclusion in the cost for rate-making purposes is highly probable. Otherwise, they shall be accounted for as regulatory assets in accordance with this [draft] IFRS.

Recoverability

17 In some cases, regulatory assets recognised individually in accordance with this [draft] IFRS are not partially or fully recoverable when considered in total. A particular regulator may permit a variety of specific costs to be recovered. However, when the entity considers the net effect on its future rates of all the regulatory assets and regulatory liabilities arising from the actions of that regulator, it may conclude that rates set at those levels would affect demand. In particular, significant increases in rates to recover the net regulatory assets may result in customers reducing the number of units consumed either by conservation or by switching to alternative sources.

18 At each reporting date, an entity shall consider the net effect on its rates of its regulatory assets and regulatory liabilities arising from the actions of each regulator for the periods in which the regulation is expected to affect rates. The entity shall determine whether it is reasonable to assume that rates set at levels that will recover the entity's costs can be collected from customers. In making this determination, the entity shall consider estimated changes in the level of demand or competition during the recovery period.

19 If an entity concludes that it is not reasonable to assume that it will be able to collect sufficient revenues from its customers to recover its costs, this is an indication that the cash-generating unit in which the regulatory assets and regulatory liabilities are included may be impaired. Accordingly, the entity shall test that cash-generating unit for impairment in accordance with IAS 36 *Impairment of Assets*.

20 An entity shall recognise any impairment loss determined in accordance with IAS 36 and shall allocate it to the assets of the cash-generating unit in accordance with that standard. An entity shall reflect the impairment loss allocated to each regulatory asset by reducing the entity's estimate of the future cash flows that it will receive from the regulatory asset as required by paragraphs 13(a) and 14 of this [draft] IFRS.

Derecognition

21 An entity shall derecognise the entire carrying amount of regulatory assets and regulatory liabilities when the underlying activities fail to meet the criteria in paragraph 3.

Presentation

22 An entity shall present in the statement of financial position current and non-current regulatory assets and regulatory liabilities, without offsetting, separately from other assets and liabilities.

23 An entity may present a net regulatory asset or a net regulatory liability for each category of asset or liability subject to the same regulator.

Disclosures

24 An entity shall disclose information that:

(a) enables users of the financial statements to understand the nature and the financial effects of rate regulation on its activities; and

(b) identifies and explains the amounts of regulatory assets and regulatory liabilities, and related income and expenses, recognised in its financial statements.

25 An entity shall disclose the fact that some or all of its operating activities are subject to rate regulation, including a description of their nature and extent.

26 For each set of operating activities subject to a different regulator, an entity shall disclose the following information:

(a) if the regulator is a related party (as defined in IAS 24 *Related Party Disclosures*), a statement to that effect, together with an explanation of why the regulator is related to the entity.

(b) an explanation of the approval process for the rate subject to regulation (including the rate of return), including information about how that process affects both the underlying operating activities and the specified rate of return.

(c) the indicators that management considered in concluding that such operating activities are within the scope of this [draft] IFRS, if that conclusion requires significant judgement.

(d) significant assumptions used to measure the expected present value of a recognised regulatory asset or regulatory liability including:

(i) the supporting regulatory action, for example, the issue of a formal approval for costs to be recovered pending a final ruling at a later date and that date, when known, or

(ii) the entity's assessment of the expected future regulatory actions.

(e) the risks and uncertainties affecting the future recovery of the regulatory asset or final settlement of the regulatory liability, including the expected timing.

27 An entity shall disclose the following information for each category of regulatory asset or regulatory liability recognised that is subject to a different regulator:

(a) a reconciliation from the beginning to the end of the period, in tabular format unless another format is more appropriate, of the carrying amount in the statement of financial position of the regulatory asset or regulatory liability, including at least the following elements:

(i) the amount recognised in the statement of comprehensive income relating to balances from prior periods collected or refunded in the current period.

(ii) the amount of costs incurred in the current period that were recognised in the statement of financial position as regulatory assets or regulatory liabilities to be recovered or refunded in future periods.

(iii) other amounts that affected the regulatory asset or regulatory liability, such as items acquired or assumed in business combinations or the effects of changes in foreign exchange rates, discount rates or estimated cash flows. If a single cause has a significant effect on the regulatory asset or regulatory liability, the entity shall disclose it separately.

(b) the remaining period over which the entity expects to recover the carrying amount of the regulatory asset or to settle the regulatory liability.

(c) the amount of financing cost included in the cost of self-constructed property, plant and equipment and internally developed intangible assets in the current period in accordance with paragraph 16 that would not have been capitalised in accordance with IAS 23.

28 When an entity recognises an impairment loss in accordance with paragraph 20, it shall provide the disclosures required by IAS 36.

29 When an entity derecognises regulatory assets and regulatory liabilities in accordance with paragraph 21 because the related operating activities fail to meet the criteria in paragraph 3, it shall disclose a statement to that effect, the reasons for the conclusion that the criteria in paragraph 3 are not met, a description of the operating activities affected and the amount of regulatory assets and regulatory liabilities derecognised.

30 If the disclosures required by paragraphs 25–29 of this [draft] IFRS do not meet the objectives set out in paragraph 24, the entity shall disclose whatever additional information is necessary to meet those objectives.

Effective date and transition

Effective date

31 An entity shall apply this [draft] IFRS for annual periods beginning on or after [date to be inserted after exposure]. Earlier application is permitted. If an entity applies this [draft] IFRS for an earlier period, it shall disclose that fact.

Transition

32 An entity shall apply this [draft] IFRS to regulatory assets and regulatory liabilities that exist at the beginning of the earliest comparative period presented when it applies this [draft] IFRS. The entity shall reflect any adjustments required as a result of applying this [draft] IFRS in the opening balance of retained earnings of that comparative period.

Appendix A
Defined terms

This appendix is an integral part of the [draft] IFRS.

Cost-of-service regulation	A form of regulation for setting an entity's prices (rates) in which there is a cause-and-effect relationship between the entity's specific costs and its revenues.
Expected cash flow approach	A measurement method that weights the expected cash flows of possible outcomes by the probabilities associated with those outcomes.
Expected present value	The estimated probability-weighted average of the present value of the expected cash flows related to an asset or liability.
Regulator	An authorised body empowered by statute or contract to set rates that bind an entity's customers. The regulator may be a third-party body or may be the entity's own governing board if the board is required by statute or contract to set rates both in the interest of the customers and to ensure the overall financial viability of the entity.
Regulatory asset	An entity's right to recover specific previously incurred costs and to earn a specified return by increasing rates in future periods as a result of the actual or expected actions of its **regulator.**
Regulatory liability	An entity's obligation to refund previously collected income and to pay a specified return by decreasing rates in future periods as a result of the actual or expected actions of its **regulator**.

Appendix B
Application guidance

This appendix is an integral part of the [draft] IFRS.

Scope

Prices that bind customers

B1 The first criterion to consider in determining if the regulated operating activities are within the scope of the [draft] IFRS is whether the regulator is empowered to determine prices that bind the entity's customers. The regulator's ability to determine rates is established by statute or by a contract delegating such authority. For example, a public utility commission may be elected or appointed to establish prices that are intended to be fair to both the entity and its customers.

B2 In a co-operative utility, the members of the entity's governing board may be empowered to set its rates in a manner consistent with the purpose and governance of the organisation. This would satisfy the first criterion provided that the board is similarly required by statute or contract to set rates both in the interest of the customers and to ensure the overall financial viability of the entity.

Cost-of-service regulation

B3 The second criterion to consider in determining if the regulated operating activities are within the scope of the [draft] IFRS is whether the rate established by regulation is designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a specified return, ie whether the entity is subject to a cost-of-service form of regulation. This criterion requires a cause-and-effect relationship between an entity's costs and its rate-based revenue stream.

B4 In many cases, determining whether the entity is subject to cost-of-service regulation will be straightforward. In others, significant judgement will be required. The following circumstances are indicators of cost-of-service regulation:

(a) The regulation is designed to provide recovery of the specific entity's costs.

(b) If actual costs are not used to establish rates, the regulation provides for a 'true-up' to actual costs incurred.

(c) In the case of a 'price cap' plan, there is a true-up to actual costs through a rate of return sharing mechanism.

(d) If the entity is required to provide a rate discount, the rate discount is temporary rather than permanent.

(e) If a short moratorium on rate increases is imposed, it will be followed by a return to direct cost-based regulation.

B5 The first three indicators relate to whether the plan is intended to permit the entity to recover its specific costs rather than industry averages, costs based on other indices or targets. The last two indicators relate to whether the entity is permitted to recover its costs (including financing costs) and earn an adequate return on its shareholder's investment.

B6 Concluding that a regulatory plan does not provide a sufficient return for shareholders to justify the application of the [draft] IFRS requires judgement. One or a combination of the following indicators could lead to that conclusion:

(a) Abnormal excess capacity exists.

(b) The rates per unit are currently higher (or are forecast to be higher in the future) than those of entities in neighbouring jurisdictions or alternative competitive sources. This may indicate that the regulator will disallow costs.

(c) The regulatory environment has changed, as indicated by:

  (i) the existence of unrecoverable investments.

  (ii) substantial regulatory disallowances.

  (iii) the establishment of phase-in plans or a trend towards increasing amounts of regulatory assets.

  (iv) proposed or actual rate-making that is designed to stimulate competition or rates set based on other than a pure cost-of-service concept.

  (v) rate freeze periods that extend beyond a reasonable time.

Recognition and measurement

Permitted costs

B7 In the form of regulation described in the scope of the [draft] IFRS, the rates set by the regulator are designed to recover an entity's specific costs of providing the goods and services.

B8 Not all costs that an entity incurs are automatically recoverable from its customers. Regulators typically review entities' costs to ensure that they were appropriately incurred to provide the regulated service and were 'prudent'. Consequently, a cost must be permitted by the regulator to be included in the determination of rates. In cost-of-service regulation, such costs are the actual or estimated costs for which revenue is intended to provide recovery and include costs of debt and a reasonable return on shareholders' investments.

B9 Cost-of-service rate-making does not necessarily equal a one-for-one pass-through of costs. Rate-making involves projections and assumptions; as a result actual costs will differ from estimated amounts assumed in the rate-making process itself, commonly referred to as regulatory lag. Rates should be established to provide that the entity will recover its costs using reasonable assumptions regarding demand as well as normal expenditures.

Probability of cost recovery

B10 Paragraph 14 requires an entity to consider the probability that the regulator will allow or require the entity to include in the entity's future rates the costs incurred or amounts collected. In practice, an entity may incur costs several periods before the regulator formally considers them. Consequently, the entity considers a variety of evidence in determining the probability that the regulator will allow particular costs when it reviews them.

B11 Indicators that an entity shall consider in assessing the probability of recovery include:

(a) statutes or regulations that specifically provide for the recovery of the cost in rates that cannot be overturned by future regulatory decisions;

(b) formal approvals from the regulator specifically authorising recovery of the cost in rates;

(c) previous formal approvals from the regulator allowing recovery for substantially similar costs (precedents) for a specific entity or other entities in the same jurisdiction;

(d) written approval from the regulator (although not a formal approval) approving future recovery in rates;

(e) uniform regulatory accounting guidance providing for the accounting treatment of various costs that the regulator typically follows in setting rates;

(f) written confirmation from the regulator's staff that they will recommend approval of the cost that is not legally binding on the regulatory body that sets rates; and

(g) analysis of recoverability of the cost from internal or external legal counsel on the basis of regulations and past practice.

Expected present value

B12 If the timing of the estimated cash flows is the same for all outcomes, the discount rate can be applied to the probability-weighted estimated cash flows to determine their present value. Otherwise, the present value for each possible outcome must be determined before the probability factor is applied. The results are then accumulated to determine the probability-weighted average of the present value of the cash flows.

B13 In some situations, the rate of return set by the regulator may be a reasonable approximation of the discount rate that would be appropriate to use in the measurement of the regulatory assets and regulatory liabilities in accordance with paragraph 15. However, this cannot always be assumed to be the case. In addition, the entity would have to consider whether the cash flows have already been adjusted for any of the risks included in the regulatory rate of return (see paragraph 15).

Recoverability

B14 In accordance with paragraphs 17–20, an entity considers the net effect on its rates of all the regulatory assets and regulatory liabilities arising from the actions of a particular regulator. For example, an entity might expect that if it were to charge the electricity rates necessary to recover all the costs permitted by the regulator, its customers would have a strong incentive to reduce their consumption of electricity or to switch to less expensive sources of energy. A conclusion that the reduction in demand would result in total revenue not recovering the entity's net regulatory assets and regulatory liabilities is an indication of impairment. The entity shall include the regulatory assets and regulatory liabilities with the other assets and liabilities of the cash-generating unit and test them for impairment in accordance with IAS 36.

B15 Given the characteristics of the regulatory environment within the scope of the [draft] IFRS, entities will be able to determine when the costs of all the assets in the cash-generating unit are expected to affect rates and by how much. Consequently, the entity's estimates will identify the periods in which changes in demand will affect future cash flows to such an extent that the entity will not recover its costs. The entity uses this information to comply with the requirement in paragraph 18 to reflect the impairment loss determined and allocated in accordance with IAS 36 to each regulatory asset.

B16 In accordance with paragraph 105 of IAS 36, in allocating an impairment loss for a cash-generating unit to the assets in that unit, an entity shall not reduce the carrying amount of an asset below the highest of:

(a) its fair value less costs to sell (if determinable);

(b) its value in use (if determinable); and

(c) zero.

B17 Because the entity is able to estimate both the amount and timing of the cash flows of the regulatory asset, the entity is able to estimate the asset's value in use. An entity may determine that the value in use of an individual regulatory asset equals the amount previously determined in accordance with paragraph 12. In this case, the entity shall allocate no impairment loss to the regulatory asset. Conversely, changes in the amount or timing of cash flows to be received may result in the current value in use being less than the amount previously determined in accordance with paragraph 12. In these instances, an impairment loss shall be allocated to the regulatory asset.

B18 If a recognised impairment loss is allocated to a regulatory asset, in subsequent periods the entity shall continue to measure the asset in accordance with paragraph 12 using the amount and timing of the estimated cash flows used in determining the amount of the impairment loss.

B19 If an entity subsequently determines that impairment indicators no longer exist, the entity shall follow the provisions of IAS 36 for reversing an impairment loss for a cash-generating unit.

Regulatory liabilities

B20 Regulation can establish three types of regulatory liabilities:

(a) The regulator requires refunds to be made to customers in the form of reduced future rates. However, if the refunds are to be made in determinable amounts to specific customers, they are financial liabilities and are not within the scope of this [draft] IFRS.

(b) The regulator provides current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred, future rates will be reduced accordingly. A liability is recognised only if the entity will be required to refund amounts collected in advance of expenditure.

(c) The regulator requires a realised gain or other reduction of cost to be refunded to customers in the form of reduced rates over future periods.

B21 In accordance with paragraph 9, a regulator cannot eliminate or change the measurement of a liability that was not created by that regulator.

Appendix C
Amendments to other IFRSs

The amendments in this [draft] appendix shall be applied for annual periods beginning on or after [date to be inserted after exposure]. If an entity applies this [draft] IFRS for an earlier period, these amendments shall be applied for that earlier period. Amended paragraphs are shown with new text underlined and deleted text struck through.

IFRS 1 *First-time Adoption of International Financial Reporting Standards*

C1 Paragraph D1 is amended and paragraph D25 is added.

D1 An entity may elect to use one or more of the following exemptions:

(a) ...

(n) borrowing costs (paragraph D23); ~~and~~

(o) transfers of assets from customers (paragraph D24)~~.~~<u>; and</u>

<u>(p)</u> <u>regulatory assets (paragraph D25).</u>

D25 Entities with rate-regulated activities as defined in [draft] IFRS X *Rate-regulated Activities* may hold, or have previously held, items of property, plant and equipment or intangible assets for use in those activities. The carrying amount of such items sometimes includes amounts that were included in accordance with previous GAAP that would be recognised separately as regulatory assets in accordance with [draft] IFRS X. If this is the case, a first-time adopter may elect to use the carrying amount of such an item at the date of transition to IFRSs as deemed cost. An entity may use this election or that relating to borrowing costs in paragraph D23 but not both.

IAS 36 *Impairment of Assets*

C2 Paragraph 5 is amended as follows.

5 This Standard does not apply to financial assets within the scope of IAS 39, investment property measured at fair value in accordance with IAS 40, ~~or~~ biological assets related to agricultural activity measured at fair value less costs to sell in accordance with IAS 41, <u>or individual regulatory assets measured at their expected present value in accordance with [draft] IFRS X *Rate-regulated Activities*</u>.

However, this Standard applies to assets that are carried at revalued amount (ie fair value) in accordance with other IFRSs, such as the revaluation model in IAS 16 *Property, Plant and Equipment*. Identifying ...

C3 Paragraph 67A is added before paragraph 68.

67A Individual regulatory assets are not subject to impairment testing because they are measured at their expected present value. However, when the conditions in paragraphs 19 and 20 of [draft] IFRS X exist, regulatory assets and regulatory liabilities shall be included in the cash-generating unit containing the assets used to provide the regulated goods and services.

IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*

C4 Paragraph 5 is amended as follows.

5 When another Standard deals with a specific type of provision, contingent liability or contingent asset, an entity applies that Standard instead of this Standard. For example, some types of provisions are addressed in Standards on:

(a) ...

(d) employee benefits (see IAS 19 *Employee Benefits*); ~~and~~

(e) insurance contracts (see IFRS 4 *Insurance Contracts*). However, this Standard applies to provisions, contingent liabilities and contingent assets of an insurer, other than those arising from its contractual obligations and rights under insurance contracts within the scope of IFRS 4~~.~~; and

(f) rate-regulated activities (see [draft] IFRS X *Rate-regulated Activities*).

IAS 38 *Intangible Assets*

C5 Paragraph 2 is amended as follows.

2 This Standard shall be applied in accounting for intangible assets, except:

(a) ...

(c) **the recognition and measurement of exploration and evaluation assets (see IFRS 6** ***Exploration for and Evaluation of Mineral Resources*****);** ~~**and**~~

(d) **expenditure on the development and extraction of minerals, oil, natural gas and similar non-regenerative resources**~~**.**~~**; and**

(e) **the recognition and measurement of regulatory assets (see [draft] IFRS X** ***Rate-regulated Activities*****).**

C6 Paragraph 3 is amended as follows.

3 If another Standard prescribes the accounting for a specific type of intangible asset, an entity applies that Standard instead of this Standard. For example, this Standard does not apply to:

(a) ...

(i) regulatory assets (as defined in [draft] IFRS X).

IFRIC 12 *Service Concession Arrangements*

C7 Paragraph 9A is added.

9A An entity that operates a public-to-private service concession arrangement that is within the scope of this Interpretation should also consider whether its operating activities provided using the infrastructure in accordance with the concession arrangement are within the scope of [draft] IFRS X *Rate-regulated Activities*.

Approval by the Board of *Rate-regulated Activities* published in July 2009

The exposure draft *Rate-regulated Activities* was approved for publication by twelve of the fourteen members of the International Accounting Standards Board. Messrs Cooper and Zhang voted against its publication. Their alternative views are set out after the Basis for Conclusions.

Sir David Tweedie	Chairman
Thomas E Jones	Vice-Chairman
Mary E Barth	
Stephen Cooper	
Philippe Danjou	
Jan Engström	
Robert P Garnett	
Gilbert Gélard	
Prabhakar Kalavacherla	
James J Leisenring	
Warren J McGregor	
John T Smith	
Tatsumi Yamada	
Wei-Guo Zhang	

July 2009

Illustrative Examples
Exposure Draft ED/2009/8

Rate-regulated Activities

Comments to be received by 20 November 2009

International
Accounting Standards
Board®

Draft Illustrative Examples

Exposure Draft

RATE-REGULATED ACTIVITIES

Comments to be received by 20 November 2009

ED/2009/8

These draft Illustrative Examples accompany the proposed International Financial Reporting Standard (IFRS) set out in the exposure draft *Rate-regulated Activities* (see separate booklet). Comments on the draft IFRS and its accompanying documents should be submitted in writing so as to be received by **20 November 2009.** Respondents are asked to send their comments electronically to the IASB website (www.iasb.org), using the 'Open to Comment' page.

All responses will be put on the public record unless the respondent requests confidentiality. However, such requests will not normally be granted unless supported by good reason, such as commercial confidence.

ISBN for this part: 978-1-907026-28-7

ISBN for complete publication (set of three parts): 978-1-907026-25-6

International
Accounting Standards
Board®

Additional copies of this publication may be obtained from:
IASC Foundation Publications Department,
1st Floor, 30 Cannon Street, London EC4M 6XH, United Kingdom.
Tel: +44 (0)20 7332 2730 Fax: +44 (0)20 7332 2749
Email: publications@iasb.org Web: www.iasb.org

CONTENTS

IFRS X *Rate-regulated Activities* [Draft] Illustrative examples

These examples accompany, but are not part of, the draft IFRS.

The Board plans to publish examples 1–6 with the IFRS. Examples 7–9 are included in the exposure draft to help respondents.

Application of the scope

Example 1 – Example of rate-regulated operations

IE1 Company X, the owner of electricity transmission infrastructure and related assets, has been licensed for twenty years to operate a transmission system in a particular jurisdiction. Only one operator is authorised to manage and operate the transmission system.

IE2 Company X charges its customers for access to the network at prices that must be approved by the regulator. Pricing structures are defined in the law and related guidelines, and are determined on a 'cost plus' basis that is based on budget estimates. Once approved, prices are published and apply to all customers. Prices are not negotiable with individual customers.

IE3 Prices are set to allow Company X to achieve a fair return on its invested capital and to recover all reasonable costs incurred. At the end of each year, Company X reports to the regulator deviations between the actual and budgeted results. If the regulator approves the differences as 'reasonable costs', they are included in the determination of rates for future periods.

IE4 Such rate-regulated activities are within the scope of the [draft] IFRS because the regulator establishes the prices Company X charges its customers, those prices bind the customers, and the prices are designed to recover Company X's specific costs and earn a fair return.

Example 2 – Incentive-based regulation in energy transmission and distribution

IE5 Company Y operates in a jurisdiction where revenue rather than rates is regulated for energy distribution. The regulator sets a total 'allowable revenue' for each year. To the extent that Company Y collects more or less than the allowable revenue in any year, it must adjust its prices for the following year.

IE6 The regulator resets allowable revenue every five years after reviewing every entity in the industry and taking into account the differences in their operations and geographical distribution of customers. The regulator then determines for each entity:

(a) an efficient level of operating costs;

(b) an agreed programme of capital expenditure over the next five years; and

(c) a cost of capital.

IE7 Allowable revenue for the first year of the price review is generally determined by adding together a level of operating costs that will be allowed for recovery (based on existing levels of operating costs) and a return on the regulated asset base (based on existing assets, plus the capital expenditure programme at the allowed cost of capital).

IE8 For subsequent years, allowable revenue is adjusted by an efficiency factor related to the reduction of allowable operating costs that the regulator has determined is achievable by Company Y.

IE9 Such regulation is not within the scope of the [draft] IFRS because:

(a) Company Y's allowable total revenue is determined on the basis of industry averages and targeted reductions in operating costs rather than the actual costs Company Y incurs;

(b) the regulator controls Company Y's total revenues rather than the prices it charges customers; and

(c) Company Y is entitled to retain any profits (or suffers any losses) from exceeding or failing to meet the regulator's deemed level of efficient operating costs rather than being entitled to recover excess costs or having to return excess profits to customers through future rates.

Example 3 – Supply of energy in a rate-regulated environment

IE10 In some jurisdictions distributors are allowed to make a profit or loss only on the distribution of energy, not on the energy supplied. Therefore, a company in these jurisdictions charges its customers two rates—one for the cost of energy and another for the cost of distribution. This separation allows customers to obtain their energy from suppliers other than the distributor.

IE11 Company Z determines the difference between the revenue received at the rate charged and the purchase cost of the energy each month. This difference is then recovered from or returned to customers by adjusting the rates charged for energy over the next twelve months, beginning in the month after the energy is supplied. Thus, the rate Company Z charges customers for energy supplied in September will be determined as the estimated cost of energy in September, adjusted by one-twelfth of any profit or loss on energy supplied in the previous twelve months.

IE12 In the absence of rate regulation, Company Z would simply bill each customer the difference between the price it charged and its cost for the energy the customer used in September. Because an identifiable amount, based on that customer's prior usage, would be due from an individual customer, a financial asset or financial liability would exist. However, by regulation Company Z may recover its specific cost of energy supplied to customers only by adjusting future rates. Because the profit or loss from the supply of energy will be recovered over twelve months from the customer base as a whole, Company Z recognises a regulatory asset or regulatory liability within the scope of the [draft] IFRS.

Example 4 – Cost-of-service regulation with a determinable variable return

IE13 Company A operates under a cost-of-service regulation with a determinable variable return. The performance incentive mechanism allows it to retain 25 per cent of the amount by which its actual return exceeds the target return allowed by the regulator (referred to as 'over earnings'). The regulator requires the customers' share of the over earnings (75 per cent) to be returned to them as rate reductions over three years beginning in the year following its approval of the determination of such over earnings. If Company A earns less than the return allowed by the regulator, it is permitted to increase rates in the following three years to recover 50 per cent of the difference. In both cases, the amount is adjusted by interest at the company's cost of capital to compensate the party receiving the payment for the delay in recovery.

IE14 This regulation is within the scope of the [draft] IFRS. The permitted rates of return are based on the entity's specific costs incurred and the entity has a right to recover 50 per cent of the amount by which its actual return is lower than the regulator's target and similarly an obligation to return to its customers 75 per cent of over earnings. However, if Company A consistently fails to recover a reasonable return, it would need to consider the indicators in paragraphs B4–B6 of the [draft] IFRS to determine whether it continues to be within the scope of the [draft] IFRS.

Example 5 – Example of price cap regulation

IE15 Company B operates in a jurisdiction where the prices it charges its customers for the goods or services it provides are regulated according to a 'price cap index'. The regulator sets prices considering various factors such as competition and inflation. Company B cannot charge more than the set prices.

IE16 Under such regulation the buyer is assured of the result while the supplier takes the risk and receives the rewards from additional effort or from the implementation of cost-reducing innovations.

IE17 Though such regulation meets the criterion in paragraph 3(a) of the [draft] IFRS in that prices are regulated and bind customers, it fails the criterion in paragraph 3(b) because prices are not designed to recover Company B's specific costs to provide the goods or services.

Rate-regulated assets and liabilities

Example 6 – Example of a regulatory asset

IE18 Company C, an entity operating rate-regulated activities, received formal approval from the regulator before recognising a regulatory asset. Consequently, Company C did not need to assess the probability of regulatory approval.[*]

[*] The example oversimplifies the calculation as it does not take into account variations such as volume of use or load conditions which would affect the units used and billed to customers in individual periods.

IE19 Following a major storm that destroyed its distribution towers, Company C received a rate order from its regulator that allows it to recover the replacement costs of CU100[*] straight-line over five years with a yearly allowed return of 5 per cent. The 5 per cent return applies to the net carrying amount of the unrecovered costs at the end of each year.

The table below shows the cash flows generated:

	Y1	Y2	Y3	Y4	Y5
Allowed storm costs	20	20	20	20	20
Allowed return	5	4	3	2	1
Total cash inflows	25	24	23	22	21

The regulatory asset is the expected present value of the total cash inflows received from customers generated by the incurrence of the replacement costs and the allowance of the costs and the return by the regulator.

IE20 The regulatory asset arises because the regulator has approved the recovery of costs that would otherwise have been recognised as an expense in the period when the costs were incurred:

(a) if Company C had recognised the original distribution towers as an asset, it would have derecognised their carrying amount as a loss in profit or loss and included the costs of the new towers in property, plant and equipment in accordance with IAS 16.

(b) if Company C had recognised the cost of the original distribution towers as an expense in profit or loss, it would similarly have recognised the cost of their replacements as an expense in profit or loss.

IE21 In either case, recognition of the regulatory asset reduces the amount Company C recognises as expense in profit or loss in the period.

[*] In this guidance monetary amounts are denominated in 'currency units (CU)'.

Other examples

Example 7 – Determination of the regulated rate

IE22 The formula for determining a rate per unit of goods or services provided to customers generally entails the determination of a rate base, a rate of return and operating expenses as follows:

Rate base × rate of return + operating expenses = revenue requirement

IE23 Then, to determine the rate to be charged to customers (the price of each unit of service), the revenue requirement is divided by the total units of service expected to be used by the customers. So:

Revenue requirement/estimated volume = rate per unit

IE24 The following is an example of how the rates are usually determined in a cost-of-service regulation.

An entity operates a rate-regulated activity for which the following items are allowed by the regulator (all amounts are expressed in CU):

Operating costs	
Fuel	10,000
Operations	
(including property, plant and equipment depreciation)	8,000
Maintenance	2,000
Selling, general and administration	1,000
Allowed operating expenses	21,000
Rate base	
Plant in service (carrying amount)	1,000,000
Construction work in progress	300,000
Allowed rate base	1,300,000

Because the intention is to provide for earnings on all balances necessary for utility operations, the allowed costs also include the cost of debt financing for the following items:

continued...

...continued

Other assets/liabilities	
Working capital	3,000
Net regulatory assets	5,000
Net other assets/liabilities	(1,000)
Allowed other assets/liabilities base	7,000

The capital structure of the entity is assumed to include 50 per cent debt and 50 per cent equity. The average borrowing rate is 6 per cent and the allowed return on equity is 10 per cent. The allowed rate of return on the rate base is the average of the debt cost and the equity return, ie 8 per cent.

The total allowed costs is the sum of the allowed operating expenses and the cost of financing both the rate base, by application of the rate of return, and the other assets and liabilities, by application of the borrowing rate:

Allowed operating expenses		21,000
Cost of financing rate base		
	1,300,000 × 8% =	104,000
Cost of financing other assets		
	7,000 × 6% =	420
		125,420

Expected units to be billed	1,000,000
Regulated rate per unit	0.12542

Example 8 – Balancing account

IE25 In some jurisdictions, regulators have separated the cost of the goods provided to customers from the costs of their distribution. This permits customers to purchase the goods from alternative suppliers, increasing competition. Entities operating in such environments are often prohibited from earning a return on the supply of goods. However, they are permitted to recover their purchase costs on the basis of a one-for-one pass through to retail customers. Such a mechanism may be included in legislation or could take the form of an automatic adjustment clause.

IE26 To reduce volatility in rates charged to customers, regulators generally require differences between actual and estimated costs to be collected or refunded over time. The cumulative adjustments for the under-collection or over-collection of these costs are recognised as a regulatory asset or liability in the statement of financial position, until they affect future billings to customers.

Illustrative example

IE27 The example below illustrates the effect of variations in the cost of gas on an entity's rate-regulated activities over a three year period. In practice, the recovery process for variances in costs would generally be over periods from three to twelve months.

IE28 During 20X1, sales volume was lower than expected and natural gas prices increased as a result of supply shortages in the region.

IE29 The table below shows the entity's actual gas supply costs and the amount collected in rates for each of the three years, taking into account the provision in rates for the effect of volumes and cost variances:

	20X1	20X2	20X3
	CU	CU	CU
Actual gas supply costs	1,034	1,040	978
Amount collected in rates	917	1,085	1,055

IE30 The entity did not recover gas supply costs of CU117 (CU1,034 − CU917) in year 20X1. For this example, assume that as of 1 January 20X1, the entity has a nil balance in its balancing account. The amount not recovered is recognised as a regulatory asset for CU117 in the statement of financial position in 20X1 and reduces gas costs in the statement of comprehensive income for this period.

IE31 In 20X2, the net amount recovered in excess of cost is calculated as follows:

20X2	CU
Amount collected in rates	1,085
Actual gas supply costs	1,040
Difference	45
Amortisation of prior period balance	(39)[(a)]
Net excess recovery in 20X2 refundable over three years	**6** [(b)]

(a) The entity is entitled to recover CU39 during 20X2 (CU117 over three years) related to costs not recovered in 20X1, leaving CU78 to be recovered in the next two years.

(b) The entity decreases the carrying amount of its regulatory asset by CU6 at the end of 20X2, leaving a cumulative net balance of CU72.

IE32 In 20X3, the net amount recovered in excess of cost is calculated as follows:

20X3	CU
Rate collection	1,055
Actual gas supply costs	978
Difference	77
Amortisation of prior period balance (from 20X1)	(39)[(a)]
Amortisation of prior period balance (from 20X2)	2 [(b)]
Net excess recovery in 20X3 refundable over three years	**40** [(c)]

(a) The entity is entitled to recover CU39 during 20X3 (CU117 over three years) related to costs not recovered in 20X1, leaving CU39 to be recovered in the following year.

(b) The entity is required to refund CU2 during 20X3 (CU6 over three years) related to excess recoveries in 20X2, leaving CU4 to be refunded in the next two years.

(c) The entity decreases the carrying amount of its regulatory asset by CU40 at the end of 20X3, leaving a cumulative net balance of CU(5).

IE33 The statement of financial position includes a line for the current regulatory asset showing the balance at the end of each period:

	20X3	20X2	20X1
	CU	CU	CU
Balancing account, net	(5)	72	117

IE34 The statement of comprehensive income shows the following line items related to gas costs and the balancing account:

	20X3	20X2	20X1
	CU	CU	CU
Cost of gas purchased in the period	978	1,040	1,034
Current period net (deferral)/recovery	40	6	(117)
Total amortisation of deferred gas costs	37	39	–
Amount included in profit or loss	1,055	1,085	917

Note: Normally the regulator would permit the entity to recover a return on the outstanding balance to reflect the deferred payment; however, to simplify the example such amounts are not included in the calculations.

Example 9 – Regulatory liability

IE35 An electricity distribution company sells land originally purchased to construct its operations centre for CU20 (carrying amount of the land is CU1). The entity is building two new operations centres at other locations and their cost will be included in the rate base when they are complete.

IE36 The regulator approved the sale of the land but the approving order does not address accounting for the gain on sale. However, in prior property sales, the entity has been required to return gains to customers and amounts returned have ranged from 75 per cent to 100 per cent.

IE37 The entity plans to address the accounting for the gain in its next general rate case. However, on the basis of previous decisions and the facts and circumstances for this particular sale, it expects the regulator to require it to return the entire gain to customers (estimated probability of total refund is 100 per cent). Consequently, it recognises the following amounts when the sale takes place:

Sale of property

	Dr	Cr
Cash (statement of financial position - SFP)	20	
Land (SFP)		1
Gain on sale of property (statement of comprehensive income - SCI)		19

Recognition of the regulatory liability arising from the gain on sale of land

	Dr	Cr
Gain on sale of property (SCI)	19	
Regulatory liability (SFP)		19

IE38 In the following year, the entity files its general rate case. As expected, the regulator orders the entity to refund the entire gain to its customers over the next ten years. The amortisation of this non-cash amount is included in the determination of the entity's revenue requirement. Thus, the amortisation results in reduced customer rates which settle the liability over ten years. Therefore, the entity will record the following entry in each subsequent year:

	Dr	Cr
Regulatory liability (SFP)	1.9	
Other income/expense (SCI)		1.9

Note: Normally the regulator would also require the entity to provide a return on the outstanding balance of the liability to reflect its deferred settlement; however, to simplify the example these amounts are excluded.

July 2009

Basis for Conclusions
Exposure Draft ED/2009/8

Rate-regulated Activities

Comments to be received by 20 November 2009

International
Accounting Standards
Board®

Basis for Conclusions on Exposure Draft

RATE-REGULATED ACTIVITIES

Comments to be received by 20 November 2009

ED/2009/8

This Basis for Conclusions accompanies the proposed International Financial Reporting Standard (IFRS) set out in the exposure draft *Rate-regulated Activities* (see separate booklet). Comments on the draft IFRS and its accompanying documents should be submitted in writing so as to be received by **20 November 2009.** Respondents are asked to send their comments electronically to the IASB website (www.iasb.org), using the 'Open to Comment' page.

All responses will be put on the public record unless the respondent requests confidentiality. However, such requests will not normally be granted unless supported by good reason, such as commercial confidence.

ISBN for this part: 978-1-907026-27-0

ISBN for complete publication (set of three parts): 978-1-907026-25-6

International
Accounting Standards
Board®

Additional copies of this publication may be obtained from:
IASC Foundation Publications Department,
1st Floor, 30 Cannon Street, London EC4M 6XH, United Kingdom.
Tel: +44 (0)20 7332 2730 Fax: +44 (0)20 7332 2749
Email: publications@iasb.org Web: www.iasb.org

CONTENTS

Basis for Conclusions on the exposure draft *Rate-regulated Activities*

This Basis for Conclusions accompanies, but is not part of, the draft IFRS.

Introduction

BC1 This Basis for Conclusions summarises the considerations of the International Accounting Standards Board in reaching the conclusions in the exposure draft *Rate-regulated Activities*. Individual Board members gave greater weight to some factors than to others.

BC2 The Board added this project to its agenda in December 2008 because of ongoing differences of views in practice regarding whether it was appropriate for entities to recognise assets and liabilities arising from rate regulation.

BC3 In June 2005 the International Financial Reporting Interpretations Committee (IFRIC) received a request about the US standard SFAS 71 *Accounting for the Effects of Certain Types of Regulation*. The request asked whether SFAS 71 could be applied in accordance with the hierarchy in IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* to select an accounting policy in the absence of specific guidance in IFRSs.

BC4 US generally accepted accounting principles (GAAP) have recognised the economic effect of rate regulation on US rate-regulated entities since at least 1962. In 1982, SFAS 71 formalised many of those principles. In the absence of specific national guidance, practice in many other jurisdictions followed SFAS 71.

BC5 The IFRIC discussed the possible recognition of regulatory assets as part of its project on service concessions. As a result of its consideration of the issues at that time, the IFRIC concluded 'that entities applying IFRSs should recognise only assets that qualified for recognition in accordance with the IASB's *Framework for the Preparation and Presentation of Financial Statements* and relevant accounting standards, such as IAS 11 *Construction Contracts*, IAS 18 *Revenue*, IAS 16 *Property, Plant and Equipment* and IAS 38 *Intangible Assets*.' In other words, the IFRIC thought that an entity should recognise regulatory assets to the extent that they meet the criteria to be recognised as assets in accordance with existing IFRSs.

BC6 Following this first request, the IFRIC published an agenda decision in August 2005 not to add a project on regulatory assets to its agenda. The IFRIC agenda decision did not preclude the recognition of regulatory assets and regulatory liabilities.

BC7 In January 2008 the IFRIC received a second request to consider whether regulated entities could or should recognise a liability (or an asset) as a result of regulation by regulatory bodies or governments. This indicated that the previous agenda decision had not resolved the practice problems related to this issue. The IFRIC again decided not to add the issue to its agenda for several reasons. Importantly, it concluded that divergence did not seem to be significant in practice for entities that were already applying IFRSs. However, the IFRIC also noted that rate regulation is widespread and significantly affects the economic environment of many entities.

BC8 The Board noted the ongoing requests for guidance on this issue. It also considered the comments received on the IFRIC's tentative agenda decision. Those comments pointed out that although divergence in practice did not currently exist, several jurisdictions whose local accounting principles permitted or required the recognition of regulatory assets and regulatory liabilities would be adopting IFRSs in the near future. This would increase pressure for a definitive conclusion on the question. Consequently, the Board added the project to its agenda.

Background

BC9 Rate regulation is a restriction on the setting of prices that can be charged to customers for services or products. The goal of some forms of rate regulation is to set 'just and reasonable rates', ie rates that charge the customer a reasonable price and allow the entity to earn a fair rate of return.

BC10 Generally, rates are regulated when an entity has a monopoly or a dominant market position that gives it excessive market power. In such situations, there is a lack of effective competition to constrain the prices the entity can charge. To compensate, governments impose rate regulation by setting up a regulatory authority and giving it jurisdiction to approve the rates of a specific entity or categories of entities (for example, electricity distribution utilities). Entities within the jurisdiction of the regulatory authority are not allowed to charge prices for regulated goods or services other than those approved by the regulatory authority. In those circumstances, the regulator acts on behalf of the customers who individually would have no bargaining power with the entity.

BC11 A number of regulatory methodologies exist and, for each, application can vary by regulator, the entity being regulated and the particular circumstances. One regulatory methodology for essential services charged to individual customers is cost-of-service regulation (also referred to as return-on-rate-base regulation). Under this approach, rates are set to give the entity the opportunity to recover its costs of providing the good or service plus a fair return.

BC12 In cost-of-service regulation, the rates are set by working backwards from the desired return on the previously incurred costs (the rate base), to derive a revenue requirement and using an estimate of volume to set the rate. In recent years there has been a trend to incentive-based regulatory methodologies, such as so-called 'price cap' regulation. With price cap regulation, initial rates may reflect the cost of service, but are allowed to increase, or are required to decrease, over time in accordance with a formula. Hybrid methodologies that are combinations of price cap and cost-of-service approaches also exist.

Scope

BC13 The exposure draft does not address an entity's accounting for reporting to regulators (regulatory accounting). Regulators may require a regulated entity to maintain its accounts in a form that permits the regulator to obtain the information needed for regulatory purposes. The exposure draft would neither limit a regulator's actions nor endorse them. Regulators' actions are based on many considerations. The exposure draft specifies how an entity reports the effects of rate regulation in its financial statements prepared in accordance with IFRSs.

BC14 In the past, rate regulation tended to be applied to an entire entity. With acquisitions, diversification and deregulation, rate regulation may now be applied to only a portion of an entity's activities. In some cases, an entity may have both regulated and non-regulated activities. In others, the entity may be permitted to negotiate rates individually with some customers. The exposure draft applies only to the activities of an entity that meet the two criteria set out in paragraph 3 of the draft IFRS.

Can regulation create assets and liabilities?

BC15 The threshold question the Board had to address was whether the effects of rate regulation could result in items that meet the definitions of assets and liabilities in the *Framework*. If the answer to that question was yes, the Board then had to consider the circumstances in which those assets and liabilities could arise. This second question is discussed in paragraphs BC26–BC39. The two issues are interrelated.

Regulatory assets

BC16 The definition of an asset set out in paragraph 49(a) of the *Framework* is 'a resource controlled by an entity as a result of past events and from which future economic benefits are expected to flow to the entity.' The Board concluded that in some forms of regulation, the resource is a promise by the regulator that the costs the entity incurs will result in future cash flows. In such environments, incurring costs creates an enforceable right to set rates at a level that permits the entity to recover those costs, perhaps plus a specified return, from an aggregate customer base. The adjustment of future rates is the mechanism the regulator uses to implement its promise.

BC17 The Board decided that the cause-and-effect relationship between an entity's costs and its rate-based revenue is important to the conclusion that an asset exists. In this case, the entity's right that arises as a result of regulation relates to identifiable future cash flows linked to costs it previously incurred, rather than a general expectation of future cash flows based on the existence of predictable demand. Without a cause-and-effect relationship with previously incurred costs, the Board agreed with those who believe that the effect of rate regulation is just the permission to charge customers a specified price in the future. Such permission does not satisfy the definition of an asset because the regulator provides no assurance that future economic benefits will result.

BC18 Some who do not support the recognition of regulatory assets believe that a rate-regulated entity does not control the recoverability of future economic benefits because it does not control whether the customers will use the good or service. They believe that because the entity cannot force individual customers to purchase goods or services in the future, the entity's right to increase future rates does not create an asset.

BC19 However, in the Board's view, because regulation governs the entity's relationship with its customer base as a whole, rate regulation creates a present right to receive from or a present obligation to pay economic benefits to that aggregate customer base. Although the individual members of that group may change over time, the relationship the regulator oversees is between the entity and the group. The regulator has the authority to permit the entity to set rates at a level that will ensure the entity receives the promised cash flows from the customers as a whole. Therefore, the Board concluded that recognition of regulatory assets and regulatory liabilities should be considered at the aggregate customer level.

BC20 The Board also noted that the *Framework* states that control over the future economic benefits is sufficient for an asset to exist, even in the absence of legal rights. In many examples involving the definition of an asset, an entity will have power, as well as the ability, to obtain cash inflows. For example, in the case of some economic resources an entity owns, the entity has the power to cause cash inflows to arise from those resources either from sale or from use. However, in other examples, the entity need not have the power to cause the cash inflows to arise (ie although the power criterion is a sufficient condition, it is not a necessary condition). The key notion is that the entity has access to a resource and can limit others' access to that resource.

BC21 For example, in the case of established customer relationships, an entity does not have the power to force its existing customers to do business with the entity. But, if they do, the entity will obtain future cash inflows. The entity has an asset resulting from the existing relationship between the entity and its customers that can result in future cash inflows to the entity. This conclusion is reflected in accounting for customer relationship intangible assets in business combinations. Another example is intangible assets recognised by operators in service concession arrangements in accordance with IFRIC 12 *Service Concession Arrangements*. The operator recognises as an intangible asset the right it receives (a licence) to charge users of the public service, even though the amount to be received under the licence is contingent on the public's use of the service.

BC22 In the Board's view, these examples illustrate the general conclusion that an asset exists because the entity has a present right to a resource (the regulator's promise). The fact that the cash flows the right will generate are uncertain because they are subject to risks relating to future demand affects the measurement of the right not its existence or recognition. Any other conclusion would result in a failure to recognise a wide variety of intangible assets, such as royalty and franchise agreements, among others. Moreover, the Board notes that an entity does not control the recoverability of many other types of assets, recoverability being often dependent on the actions of others. For example, even though an entity may have a contractual right to repayment of a loan, recoverability will depend on the counterparty's willingness and ability to pay. That uncertainty does not mean the right is not recognised as an asset. Consequently, the Board believes that those who do not support the recognition of regulatory assets because the rate-regulated entity does not control the recoverability of future economic benefits are confusing the issues of recognition and measurement.

Regulatory liabilities

BC23 Paragraph 49(b) of the *Framework* defines a liability as 'a present obligation of the entity arising from past events, the settlement of which is expected to result in an outflow from the entity of resources embodying economic benefits.' The Board concluded that in some forms of regulation, an obligation arises because of a requirement to refund to customers amounts collected in previous periods. In such environments, collecting amounts in excess of costs and the allowed return creates an obligation to return the payments to the aggregate customer base.

BC24 Some believe that the obligation arising from the arrangement with the regulator is not a present obligation but a possible future obligation because its existence depends on the occurrence of uncertain future events: the future sales. If a sale is made in the future period, the customer's usage will be billed at a decreased rate in that future period because of the regulator's requirement. Once again, the Board concluded that the regulator has the authority to ensure that future cash flows from the customer base as a whole would be reduced to refund amounts previously collected.

BC25 Much of the basis for the Board's conclusion that rate regulation can result in items that meet the definition of liabilities parallels its analysis of the recognition of assets set out in paragraphs BC16–BC22:

(a) The obligation relates to amounts the entity has already collected from customers.

(b) The obligation is owed to the entity's customer base as a whole, not to individual customers.

(c) The obligation exists even though its amount may be uncertain because it depends on the actions of others. In this respect, a regulatory liability is similar to a mortgage with a feature that obliges the borrower to share some portion of the profits from the use of the property with the lender.

The Board also concluded that an economic obligation is something that results in reduced cash inflows, directly or indirectly, as well as something that results in increased cash outflows. A regulator has the ability to enforce the entity's obligation to reduce rates until the specified amount has been returned to the customers.

Circumstances in which assets and liabilities can arise

BC26 Having concluded that regulation can result in items that meet the definitions of assets and liabilities, the Board then considered the circumstances in which those assets or liabilities could arise. The Board identified two criteria that an entity's activities must satisfy to be within the scope of the proposed IFRS. In other words, an entity is not within the scope of the proposed IFRS and therefore would not recognise regulatory assets and regulatory liabilities simply because it was subject to some form of rate regulation.

BC27 The Board concluded that the situation of an entity that satisfies these criteria is not economically similar to the situation of an entity that does not. Therefore, failure to recognise regulatory assets and regulatory liabilities when they exist would make unlike situations look alike. This outcome is just as detrimental to comparability as making like situations look different. The Board also noted that the return an entity reports in its financial statements is the result of the appropriate recognition and measurement of items that meet the *Framework*'s definitions of assets and liabilities, not the application of any type of mechanism.

Criterion 1 – Prices that bind customers

BC28 The first criterion requires an entity to satisfy two conditions:

(a) An identifiable body is authorised to set prices for the regulated goods or services it provides to its customers.

(b) The prices set by that body bind the entity's customers.

BC29 The Board noted that the existence and authority of the price-setting body should be readily determinable because it is established by statute or contract.

BC30 Agreements between a rate-regulated entity and its customers cannot be understood without reference to the regulation. Therefore, some believe that such agreements are different from agreements between an entity and its customers in a non-regulated environment. An alternative view is the one adopted by the Board in its revenue recognition project. In that project the Board concluded that the terms required by relevant regulation did not need to be included in a customer contract for them to affect the accounting for that contract. Thus, customer contracts in rate-regulated environments have the same effect as those in non-regulated environments in that the terms imposed by legislation/regulation have to be considered. Therefore, no matter which view is adopted, the effect of regulation needs to be considered as part of the agreement with the customer.

BC31 Some believe that the ability to charge a higher or lower price is not a differentiating feature. In fact, all entities have this ability and it does not give rise to an asset or a liability. For example, as a result of a new competitor entering the market, an entity may decide to decrease its prices, but such a decision does not give rise to a liability.

BC32 However, rate-regulated entities are not allowed to charge rates for regulated goods or services other than those approved by the regulator. The regulator has the ability to require price reductions until a specified amount has been returned to customers through those decreases. When an entity reduces its prices to match competition, there is no link to previous profits.

BC33 As previously discussed, regulatory assets and regulatory liabilities arise when the regulator acts on behalf of the customers who individually would have no bargaining power with the regulated entity. It is this aggregate customer base that is both represented by the regulator and bound by the regulator's actions.

Criterion 2 – Cost-of-service regulation

BC34 As discussed in paragraphs BC16 and BC17, the Board concluded that a cause-and-effect relationship between the entity's costs and the future revenue cash flows is the principal economic effect of regulation on the accounting for regulated entities. The regulator's action promising the recovery of a cost creates a future economic benefit, which is the critical feature in the definition of an asset. Consequently, the Board concluded that only regulation in which rates are designed to recover the specific costs the entity incurs in providing the regulated goods or services and to earn a return would result in items that meet the definitions of assets and liabilities.

BC35 In many cases, determining whether the entity's regulatory regime qualifies as cost-of-service regulation will be straightforward. In others, significant judgement will be required. The Board included in Appendix B of the draft IFRS indicators to help an entity determine whether its regulatory regime is cost-of-service regulation.

BC36 The Board noted that the definition of cost-of-service regulation, to some extent, is similar to the definition of a cost plus contract in IAS 11: 'a construction contract in which the contractor is reimbursed for allowable or otherwise defined costs, plus a percentage of these costs or a fixed fee.' From the perspective of the regulated entity, contracts with the customers together with the cost-of-service regulation have, in substance, economic effects similar to cost plus contracts directly negotiated with customers in a non-regulated environment. In the case of regulated entities, the regulator acts on behalf of the customers as a group to identify which costs are allowable.

BC37 In considering rate-regulated activities, the Board noted that IFRIC 12 provides guidance on determining the nature of the asset received (an intangible or a financial asset) by the operator in exchange for the acquisition or construction of the infrastructure used in the service concession. Paragraph 17 of IFRIC 12 states that 'the operator shall recognise an intangible asset to the extent that it receives a right (a licence) to charge users of the public service.' Thus, IFRIC 12 requires an entity to recognise an asset for a right to charge customers for use of a public service at a price controlled or regulated by the grantor even though the entity bears the demand risk. The Board concluded that it would be inconsistent not to recognise regulatory assets when an entity has a similar right as a result of regulation rather than a contract.

BC38 Some believe that rate regulation does not give rise to the recognition of an intangible asset because it does not change the nature of the existing licence. First, in most cases, the licence is not recognised as an intangible asset as it is when it is acquired in circumstances such as those covered by IFRIC 12 or a business combination. Second, the nature of the licence or the service provided under it may not have changed but the rates charged for that service have been changed by the regulation. The Board concluded that the value of the licence reflects the general regulatory environment. In other words, the value of the licence reflects the regulator's promise that, in return for the entity providing reliable service, the regulator will set 'just and reasonable rates' permitting the entity to recover its costs and make a fair return. The permission for the entity to recover specific costs that it has incurred creates an intangible asset separate from the licence.

BC39 The Board also noted that an entity with an arrangement within the scope of IFRIC 12 would have to consider whether it has rate-regulated activities that are within the scope of the proposed IFRS. For example, in one service concession arrangement, the grantor may give the operator only the right to charge customers for use of the public service at the price the grantor controls. In another service concession arrangement, the grantor may give the operator the right to recover the operator's costs and earn a specified return as well as the right to charge customers to use the public service. If it does, the entity would apply both IFRIC 12 and the proposed IFRS on rate-regulated activities.

Recognition and measurement

Recognition of regulatory assets and regulatory liabilities

Recognition criterion and probability of recovery

BC40 The Board considered whether the proposed IFRS should include a separate recognition criterion for regulatory assets and regulatory liabilities. Paragraph 83 of the *Framework* indicates that an asset or liability should be recognised if:

(a) it is probable that any future economic benefit associated with the item will flow to or from the entity; and

(b) the item has a cost or value that can be measured reliably.

BC41 Paragraph 85 of the *Framework* explains that this notion of probability is used in the same sense as it is employed in other standards and defined in the Glossary, ie 'more likely than not'. The Board concluded that if rate-regulated activities satisfied the scope criteria in the proposed IFRS, the actions of a regulator provide reasonable assurance that the economic benefit will flow to or from the entity. In addition, because regulatory assets and regulatory liabilities relate to specifically identifiable amounts expended or collected by the entity, the Board concluded that reliable measurement was possible.

BC42 The Board decided that the scope criteria are both necessary and sufficient for the recognition of regulatory assets and regulatory liabilities. Consequently, once the scope criteria have been satisfied, assets and liabilities exist that meet the criteria for recognition. As a result, the Board decided not to propose a separate recognition criterion in the draft IFRS.

Type of assets or liabilities

BC43 Typically, regulatory assets or regulatory liabilities that would be recognised as a result of applying the proposed IFRS are not financial instruments subject to the requirements of IAS 39. The entity does not have the right to request reimbursement from, or the obligation to make payments to, individual customers for fixed or determinable amounts. Rather, rights or obligations created as a result of rate regulation are rights from or obligations to an aggregate customer base. In this respect, regulatory liabilities are similar to some liabilities recognised in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, in which the identity of the party to whom the obligation is owed is not known. In other respects, regulatory liabilities resemble obligations to perform future services recognised in accordance with IAS 18 *Revenue*. In rare circumstances, the regulator may direct that specific amounts should be paid to or recovered from specific customers. In that case, the definition of a financial instrument would be satisfied.

Measurement of regulatory assets and regulatory liabilities

Probability-weighted average of possible outcomes

BC44 The Board decided that measuring regulatory assets and regulatory liabilities at the present value of expected future cash flows is consistent with the current guidance in IAS 37. Moreover, this approach is consistent with the approach to the determination of expected cash flows the Board recently proposed in its exposure draft *Income Tax* published in March 2009.

BC45 The Board concluded that this measurement approach more faithfully reflects the entity's expectations of future cash flows than does an approach in which satisfying a recognition requirement results in the recognition of the entire asset or liability as if it was certain. The Board concluded that a recognition criterion was unnecessary given the scope criteria. In addition, such a recognition criterion would postpone the recognition of assets and liabilities with future cash flows that can be estimated. Consequently, the Board decided that it was preferable to include the probability of the cash flows in the measurement of the regulatory asset or regulatory liability.

BC46 The draft IFRS requires an entity, in estimating future cash flows, to consider the probability that the regulator will allow or require the entity to include a specific item in the determination of future rates. Usually, the rate-making process is initiated by the entity preparing and filing a rate case designed to show the costs of providing service to customers. When a cost has been considered as part of a finalised rate case, the regulator has provided clear evidence of its agreement on costs that are allowable. Such evidence can be in the form of a formal approval (eg a final rate order), setting out findings of fact and of law, issued by the regulator to support its decisions. Appendix B of the draft IFRS describes additional evidence an entity would consider in estimating the probability of regulatory approval to assist entities in applying its requirements.

Discount rate

BC47 In some jurisdictions regulators allow entities to earn a rate of return that is intended to be consistent with their market-based cost of capital. In these situations, the rate of return set by the regulator may be a reasonable approximation of the discount rate appropriate for the measurement of the regulatory assets and regulatory liabilities. However, this cannot be assumed. Therefore, the Board proposes in paragraph B13 of the draft IFRS that the discount rate should be determined in accordance with the draft IFRS independently of the rate allowed for reimbursement by the regulator.

BC48 The Board noted that the general principle for determination of an appropriate discount rate in an expected present value measurement proposed in paragraph 15 of the draft IFRS is consistent with both paragraph 55 of IAS 36 *Impairment of Assets* and paragraph 47 of IAS 37.

Cost of self-constructed or internally generated assets

BC49 The Board noted that in some cases, a regulator requires an entity to include as part of the cost of property, plant and equipment or internally generated intangible assets amounts that would not be included by non-regulated entities. Such amounts may be indirect overheads not permitted in accordance with IAS 16 or IAS 38 or the cost of financing construction or development that is not in accordance with IAS 23 *Borrowing Costs*. The regulator may require a computed interest cost and a designated cost of equity funds to be included in the cost of the asset.

BC50 The Board acknowledged that two alternatives exist for accounting for these costs. Proponents of the first alternative believe that regulatory assets that would be recognised as a result of the proposed IFRS do not have the same characteristics as assets recognised in accordance with other IFRSs. Therefore, proponents of this alternative believe that all regulatory assets should be presented separately from assets recognised in accordance with other IFRSs.

BC51 Proponents of the second alternative believe that some regulatory assets that would be recognised as a result of the proposed IFRS are so closely related to other assets of the entity that accounting for them separately does not provide additional information to users. Proponents of this alternative believe that when regulatory assets are complementary to other assets and have similar useful lives, there is no need to incur the costs of separate accounting. In accordance with this alternative, an entity includes the cost of the regulatory asset in the cost of the asset recognised in accordance with other IFRSs as a single asset.

BC52 The Board concluded that when it is highly probable that the regulator will require amounts to be included in the cost of self-constructed or internally generated assets that would not be permitted in accordance with IFRSs, those amounts should be included in the cost of the assets rather than being accounted for separately in accordance with the proposed IFRS. If it is highly probable that the regulator will require the amount to be included in the cost of the asset, only one possible difference exists between the accounting the Board proposes and the accounting that would otherwise be required by the proposed IFRS. The proposed IFRS would require a regulatory asset recognised separately to be adjusted for changes in interest rates. The Board concluded that an exception to the principles in the proposed IFRS was justified on cost-benefit grounds.

Recoverability

BC53 The Board concluded that an entity may determine that individual regulatory assets and regulatory liabilities exist and that it should recognise them. However, the Board also concluded that there may be situations in which the net effect of the regulatory assets and regulatory liabilities an entity recognises will result in significant increases in future rates to be charged to customers. A significant increase in an entity's future rates may create a strong incentive for customers to reduce their consumption or switch to an alternative good or service. In these cases, even though rates are increased, expected reductions in volume might mean that the entity will not achieve its total revenue requirements.

BC54 The Board concluded that when it is not reasonable to assume that the entity will be able to collect sufficient revenues from its customers to recover its costs and earn a fair return, an indicator of impairment exists. The regulatory assets and regulatory liabilities should then be included with the other assets and liabilities of the cash-generating unit and tested for impairment in accordance with IAS 36. The Board concluded that this treatment is appropriate because regulatory assets and regulatory liabilities do not generate cash inflows that are largely independent from other assets of the entity.

Derecognition

BC55 The exposure draft proposes that all items that meet the scope criteria of the draft IFRS should be recognised. As a consequence, the draft IFRS does not include additional criteria specifying when regulatory assets and regulatory liabilities should be derecognised. Failure to satisfy the scope criteria for some activities would automatically result in the derecognition of all previously recognised regulatory assets and regulatory liabilities related to those activities.

Presentation

BC56 Regulatory assets and regulatory liabilities typically do not meet the definition of financial instruments because the assets and liabilities created as a result of regulation relate to the interaction of the entity with the aggregate customer base and not with individual customers. Consequently, they cannot meet the criteria to be presented net set out in IAS 32 *Financial Instruments: Presentation*.

BC57 IAS 12 *Income Taxes* permits (non-financial) current and deferred tax assets and liabilities to be offset if specified conditions are satisfied. One of those conditions is that the entity must have a legal right to set off the recognised amounts. This condition can be satisfied for income taxes because ultimately payments will be made to or received from a single taxing authority.

BC58 Regulatory assets and regulatory liabilities arise from specific costs to be collected from or amounts to be refunded to the aggregate customer base. The Board noted that all the regulatory assets and regulatory liabilities recognised that are related to a distinct regulatory activity will affect the determination of the same rate, but decided not to permit offsetting them as a single net position. However, the Board concluded that the presentation of a net regulatory asset or net regulatory liability for each category subject to the same regulator would be appropriate.

Disclosures

BC59 The Board is aware that most entities already recognising regulatory assets and regulatory liabilities in accordance with US GAAP or similar requirements in other jurisdictions currently provide virtually all of the information proposed to be disclosed by paragraph 24 of the draft IFRS. However, the Board observed that the information is often disclosed in various places throughout the financial statements in a way that can make it difficult for a user to appreciate the overall effect that rate regulation has had on the amounts recognised in the financial statements.

BC60 In the draft IFRS, the Board proposes that entities should meet the minimum disclosure requirements by providing a table showing a reconciliation, from the beginning to the end of the period, of the carrying amount in the statement of financial position of the various categories of regulatory items. This table will be required unless another format is more appropriate. This reconciliation should show in one place the changes in the amounts recognised in the statement of comprehensive income. The Board noted such a table would be useful in helping users to understand how the entity's reported financial results and position have been affected by rate regulation.

Effective date and transition

BC61 The Board will set the effective date for the proposals in the exposure draft when it approves the IFRS on rate-regulated activities. The Board intends to allow a minimum of one year between the date when wholly new IFRSs or major amendments to IFRSs are issued and the date when implementation is required.

BC62 The Board noted that jurisdictions throughout the world have a variety of types of rate regulation to serve a variety of purposes. The current accounting treatment may vary from one jurisdiction to another depending on the application of IFRSs to the specific regulations. The Board considered whether it should provide an exemption from retrospective application of the proposed IFRS because entities must obtain information necessary to determine the probability-weighted present value of future cash flows. The Board believes that this information may be available in many, but not all, instances given the regulatory environment in which such entities operate. The Board noted that determining the probability-weighted present value of future cash flows in these instances would require the use of hindsight and might not achieve comparability.

BC63 Accordingly, the Board proposes not to require full retrospective application. Instead, the Board proposes to require application of the proposed IFRS to regulatory assets and regulatory liabilities existing at the beginning of the earliest comparative period presented in the period in which the entity applies the proposed IFRS. The Board recognises that this requirement means that it may need to extend the normal period between the date of finalising the IFRS and its effective date.

Costs and benefits

BC64 The objective of financial statements is to provide information about an entity's financial position, financial performance and cash flows that is useful to a wide range of users in making economic decisions. To attain this objective, the Board tries to ensure that a proposed IFRS will meet a significant need and that the overall benefits of the resulting information justify the costs of providing it. Although the costs to implement a new IFRS might not be borne evenly, users of financial statements benefit from improvements in financial reporting, thereby facilitating the functioning of markets for capital and credit and the efficient allocation of resources in the economy.

BC65 The evaluation of costs and benefits is necessarily subjective. In making its judgement, the Board considers the following:

(a) the costs incurred by preparers of financial statements.

(b) the costs incurred by users of financial statements when information is not available.

(c) the comparative advantage that preparers have in developing information, compared with the costs that users would incur to develop surrogate information.

(d) the benefit of better economic decision-making as a result of improved financial reporting.

BC66 The Board concluded that the proposed IFRS would meet a significant need because questions continue to arise on the application of IFRSs to various types of regulated activities. In the Board's view, it is more efficient for the Board to develop an IFRS than to require each entity to reach its own conclusions on the application of the *Framework*.

BC67 The Board decided that particular types of regulation create assets and liabilities. The draft IFRS requires those assets and liabilities to be recognised in the financial statements. The Board believes that consistent recognition of elements that meet the definitions of assets and liabilities improves financial reporting and consequently economic decision-making.

BC68 In the case of regulatory assets and regulatory liabilities, the Board believes that the additional costs that preparers of financial statements need to incur should not be significant because the detailed information is already required in most circumstances for reporting to the regulator. Consequently, preparers have a large advantage in developing information when compared with the costs that users would incur to develop surrogate information.

Alternative views on exposure draft

Alternative views of Stephen Cooper and Wei-Guo Zhang

AV1 Messrs Cooper and Zhang voted against the publication of the exposure draft of the proposed International Financial Reporting Standard *Rate-regulated Activities* for the reasons set out below.

Definition of an asset or a liability

AV2 Messrs Cooper and Zhang do not agree that assets or liabilities should be recognised solely as a result of rate regulation. The definitions of an asset and a liability in the *Framework for the Preparation and Presentation of Financial Statements* are not met for items arising from rate regulation. By requiring them to be treated as assets and liabilities, the exposure draft proposes a departure from the *Framework*.

AV3 Regulators are empowered to establish the price charged for regulated activities or the rate of return allowed on assets used in such activities. In doing so they may approve, for the purposes of computation, accruals or deferrals of related costs to meet that specified rate of return. But in the view of Messrs Cooper and Zhang, those actions do not create an enforceable right to recover cost plus a rate of return. Nor do they assure the level of future demand. As a result, the entity cannot control adequate transactions in the future to enable its recovery of cost plus return.

AV4 The exposure draft uses the concept of 'a group of customers' or 'customer base' to justify the recognition of regulatory assets and regulatory liabilities. Messrs Cooper and Zhang's alternative view is that there is no justification to presume that the customers as a group will use a given level of service at a given price in the future. The rate allowed by regulation is not necessarily the rate the customers will be willing or able to pay for the level of demand envisaged. They acknowledge that the proposed IFRS includes recoverability and impairment tests. However, imposing such tests does not overcome their view that the regulatory asset should not be recognised in the first instance.

AV5 An entity cannot demand payment of any deferred cost until it forms part of an actual transaction in a future period. The reverse is equally true. Reducing the rate and/or the rate of return in the future does not mean that the regulated entity is liable to refund or reimburse any excess past return to the customers.

AV6 Since the regulator cannot ensure the demand, Messrs Cooper and Zhang cannot see how the right or obligation that arises as a result of regulation can be related to identifiable future cash flows. Furthermore, in practice, the pattern of cash flows is often complicated by: using estimated rather than actual cost to establish rates and to approve deferred debits or credits; time lags between the submission and approval; differences between expected and actual transaction volumes; different classes of customers subject to different rates; and activities that are subject to different regulations. These complications make it virtually impossible to establish any direct link between the regulatory right or obligation and the entity's future cash flows. The proposed treatment will confuse users and preparers of financial reports, as well as cause extra time and effort, which in their opinion outweigh any perceived benefits.

Inconsistencies with existing IFRSs and comparability

AV7 The exposure draft would require regulated entities to recognise as assets or liabilities items that unregulated entities are prohibited from recognising as assets or liabilities, for example, research costs, indirect overheads, damaged fixed assets, and the imputed cost of equity capital used in financing the construction of plant and equipment. Messrs Cooper and Zhang find no basis for overriding the principles that other IFRSs would require to be applied in such cases.

AV8 Messrs Cooper and Zhang believe that because of the inconsistent requirements with other IFRSs, this exposure draft will lead to a lack of comparability: economically similar situations will be accounted for differently within a regulatory entity over time, or among different regulatory entities, and between regulated and unregulated entities.

AV9 Furthermore, since jurisdictions may have different approaches to regulated activities with different sizes and different schemes that are evolving over time, Messrs Cooper and Zhang have deep concerns over whether the proposed IFRS will be interpreted and applied consistently.

Objective of financial reporting and the provision of useful information

AV10 The IASB has asserted that the objective of financial reporting is different from that of government regulation, and accounting principles serving the objective of financial reporting should not be the same as the one serving the objective of government regulation.

AV11 Messrs Cooper and Zhang consider the proposed treatment will result in the regulated entity reporting a stabilised rate of return allowed by the regulator in a particular period. They recognise that stability is clearly the objective of the regulator. However, they question whether such a profit-smoothing mechanism is desirable for financial reporting purposes. Actual results will always differ from regulatory decisions or expectations because of deviations in the volume of transactions, the cost of production etc. Financial reports will be more useful if they reflect the actual results of each period rather than the expected or stabilised results permitted by a regulator.

AV12 Messrs Cooper and Zhang do not deny that a regulated entity has some unique features, and the decisions taken by regulators may affect the entity's current or future financial position or operating results. In their judgement, what is called for is appropriate disclosure rather than setting accounting standards inconsistent with the existing *Framework* and IFRSs.

Transparency

AV13 If in due course the Board requires the recognition of regulatory assets and regulatory liabilities Messrs Cooper and Zhang consider it vital that the impact on the financial statements should be transparent so that investors can clearly identify how this accounting has affected profit or loss and financial position. In this regard, they do not believe that regulatory assets should be included as a component of self-constructed assets as proposed.

