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July 31, 2006

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

Attention: Mr. Robert J. Pellatt, Commission Secretary

Dear Sir:

Re: 2006 Resource Plan – Terasen Gas Inc. ("Terasen Gas" or the "Company")

In accordance with the British Columbia Utilities Commission ("BCUC" or the "Commission") Letter No. L-5-04, dated February 6, 2004, Order No. L-30-05, Terasen Gas respectfully submits the attached Resource Plan ("Plan") for the Commission's review. This filing follows an extension to the original submission scheduled for the end of the third quarter of 2005 to the end of second quarter 2006, in order to include information related to BC Hydro's Integrated Energy Plan, Terasen Gas' Conservation Potential Review and updated customer addition forecasts as confirmed in Terasen Gas' letters of November 22, 2005, March 29, 2006 and May 23, 2006.

The attached Resource Plan, covering the Interior and Coastal service areas, was prepared in accordance with the Resource Planning Guidelines released by the Commission in December 2003.

This Resource Plan submission includes the Company's five-year capital plans and statements of facilities expansion, however, the Company is not requesting approval of those capital plans with this submission. Terasen Gas expects to file separate CPCN applications for any projects, as necessary, in accordance with BCUC guidelines.

Following these submissions, the Company will engage in further consultations with stakeholders regarding the action items identified in the Plan.

If there are any questions regarding the content of this letter, please contact Ken Ross at (604) 576-7343 or ken.ross@terasengas.com.

All of which is respectfully submitted.

Yours very truly,

TERASEN GAS (VANCOUVER ISLAND) INC.

Original signed by: Cynthia Des Brisay

For: Scott A. Thomson

Attachment

Terasen
Gas

Terasen Gas Inc.
2006 Resource Plan

TERASEN GAS INC.

2006 RESOURCE PLAN

July 2006

EXECUTIVE SUMMARY

Introduction

Terasen Gas Inc. ("TGI") provides natural gas transmission and distribution services to more than 800,000 residential, commercial, industrial and transportation customers in more than 100 communities in the Province of British Columbia. The company serves most of British Columbia from Vancouver, east to the Kootenays and north to communities including Prince George, Chetwynd & Fort Nelson. The service areas are defined as Lower Mainland (Vancouver to Hope), Inland (Okanagan to Northern B.C.) and Columbia (East Kootenays).

Natural gas for TGI's Lower Mainland region customers is delivered from upstream sources on the Westcoast Energy Inc ("Westcoast") transmission system to the Huntingdon trading point near Abbotsford where it connects with TGI's Coastal Transmission System ("CTS"). The CTS consists of a 265 km network of pipelines ranging in diameter from 6 inch to 42 inch operating at pressures up to 583 pounds per square inch gauge (psig). The CTS is also used to provide natural gas transportation service for BC Hydro to serve Burrard Thermal and Terasen Gas (Vancouver Island) Inc. ("TGVI") to the start of TGVI's transmission system in Coquitlam. As part of this pipeline network, the Langley compressor station is used to maintain transmission pressures during periods of high demand and a LNG storage facility located on Tilbury Island provides additional capacity to meet peak demand requirements.

Natural gas for TGI's Interior region customers is delivered from sources in British Columbia via the Westcoast pipeline system and from sources in Alberta via the TransCanada BC pipeline system. North of Savona and east of Yahk, Terasen Gas uses relatively short pipelines to serve communities adjacent to these major transmission pipelines. The Interior Transmission System ("ITS") serves customers in the Thompson Okanagan and Kootenay regions of the Province and connects to the Duke system at Savona and Kingsvale, and to the TransCanada system at Yahk. The Southern Crossing Pipeline ("SCP") also serves the Okanagan region from the interconnect with TransCanada system at Yahk in addition to transporting gas to the Lower Mainland via the ITS interconnect with the Westcoast system at Kingsvale.

Resource Planning

The Resource Planning process evaluates demand and supply options over a long term planning horizon and considers their economic, environmental, and social characteristics. The British Columbia Utilities Commission's ("BCUC" or the "Commission") description of the planning process is:

> *"Resource Planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run."*

Resource Planning is part of an ongoing planning process at all Terasen Gas utilities (jointly referred to as "Terasen Gas") which includes broader regional planning initiatives. Terasen Gas is a member of the Northwest Gas Association ("NWGA") which represents utilities and pipeline operators in the Pacific Northwest including British Columbia. Working with all its members, NWGA has recently completed an Outlook Study that assesses the natural gas supply and infrastructure serving the I-5 Corridor, which encompasses the B.C. Lower Mainland, Vancouver Island, Western Washington and Western Oregon. The study provides the broader context in which TGI operates and in which this Resource Plan was developed. Furthermore, an integrated regional approach to designing and developing the regional gas delivery infrastructure is required to ensure the secure and reliable supply of energy to consumers throughout the region.

Resource Planning Objectives

TGI's Resource Planning objectives form the basis for evaluating potential resources in the Resource Plan, including major infrastructure projects, gas supply alternatives, and demand side programs. These objectives are set out in the following table.

Table ES-1 Resource Planning Objectives

Objective	Attribute	Measure
Ensure reliable and secure supply.	System reliability Security of supply	Risk of outages Gas supply diversity
Provide service to customers at least delivered cost.	Financial evaluation of supply side and demand side resources	Net Present Value Total Resource Cost (TRC) Ratepayer Impact (RIM)
Reduce rate volatility.	Expected rates	Risk Trade-offs
Balance socio-economic and environmental impacts.	Social costs / benefits including: Local emissions Greenhouse gas Land use impacts Employment/local economic impacts Stakeholder consultation	 Air pollutants Quantity of CO_2 equivalent Area impacted Jobs created Stakeholder input

The objectives reflect the Company's commitment to providing the highest level of quality energy services to its customers. Resource portfolios are assessed by determining the degree to which they meet the criteria of each objective. The most desirable resources will rank high on most or all of the objectives.

Demand Forecast

TGI provides natural gas transmission and distribution services to more than 800,000 customers. TGI provides a bundled service (i.e. both delivery and commodity) to the vast majority of those customers, while approximately 1,500 of these customers, generally representing large volume end-users, receive only transportation service. On the CTS system, TGI also provides transportation service to TGVI to allow it to meet its core market and transportation customer requirements. TGI's single biggest transportation customer is BC Hydro who holds firm CTS capacity to primarily serve Burrard Thermal. A portion of BC Hydro's CTS capacity is also used to serve the Island Cogeneration Project ("ICP") on TGVI's system.

Since 2004, TGI has experienced a significant increase in annual customer additions. This increase reflects the exceptionally strong performance that the Province has been experiencing and is expected to continue for the upcoming years. This has resulted in an increase in forecasted customer additions as compared to the 2004 Resource Plan over the short to medium term. The growth is expected to moderate over the long term, however on average TGI expects just over one percent growth in core market demand over the period as summarised in the following table. Core growth is higher in the Lower Mainland than in the Interior regions.

Table ES-2 TGI Core Market Annual and Design Day Demand

	Lower Mainland	Interior	TGI
2005			
Customers	558,035	241,769	799,804
Annual Demand (TJ)	85,137	28,182	113,319
Design Day Demand (TJ/Day)	907	349	1,256
2021			
Customers	712,728	287,472	1,000,200
Annual Demand (TJ)	105,107	33,694	138,801
Design Day Demand (TJ/Day)	1,117	389	1,507
2031			
Customers	788,338	303,778	1,092,116
Annual Demand (TJ)	113,948	35,645	149,593
Design Day Demand (TJ/Day)	1,194	407	1,600
Average Annual Demand Growth ('05-'21)	1.33%	1.12%	1.28%
Average Annual Demand Growth ('05-'31)	1.13%	0.91%	1.07%

All figures year-end
All figures are for core market customers only as tranporatation demands are assmed to have no net growth for Resource Planning purposes.
Design day figures for TGI do not include Squamish
Squamish 2005 Design Day = 4.0 TJ, 2021 Design Day = 7.0 TJ, 2031 Design Day = 7.8 TJ

Demand Side Management

Demand Side Management ("DSM") refers to "utility activity that modifies or influences the way in which customers utilize energy services". TGI has offered a number of customer programs targeted at improving the energy efficiency of residential and commercial customers since resource planning came to the utility forefront in the mid 1990s. In the past six years, over 100,000 customers have participated in Terasen Gas' DSM programs.

A key strategic objective for Terasen Gas is to ensure that the Province remains attractive to new business from a relative energy cost and supply reliability perspective. This means promoting a level playing field with other regions and avoiding the flight of business driven away by high relative energy costs in the region. Opportunities exist to encourage energy efficient gas appliance choices for residential consumers, while building natural gas load and in turn creating cost and supply efficiencies for all customers. These initiatives can help keep gas prices down for customers. Funding for resources that promote such DSM initiatives is as important as the programs themselves.

Terasen Gas recently completed a Conservation Potential Review (“CPR”) which identified the conservation and fuel substitution potential across all of Terasen Gas’s service areas including the Lower Mainland and the Interior. The potential net energy use reductions that were identified for TGI could provide opportunities to deliver cost saving and environmental benefits to its customers, however are not expected to defer any major capital projects in the near to medium term. TGI is currently reviewing the CPR results and developing a long term DSM plan.

Gas Supply Overview

In planning the gas supply portfolio for TGI, resources must be put in place to manage the varying demand for gas on an annual basis. TGI looks at both the design and expected demand for each day in the year. Supply resources are then assembled to ensure that TGI has sufficient resources to meet the design peak while cost effectively meeting normal demands.

Future gas supply requirements for TGI are driven primarily by Core customer growth. Additional pipeline capacity will be required to meet average day growth, but a majority of additional gas resource needs are for local storage to meet peak demand growth for the winter. As demand increases, relatively scarce local storage is expected to become even more important and costly. TGVI’s proposed Mt Hayes LNG Storage facility is a viable option for TGI to consider for meeting its future peaking gas requirements.

Resource Portfolio Development

One of the primary roles of Resource Planning is to assess system expansion requirements and alternatives over a range of expected demand scenarios to determine the preferred resources required to meet demand over the long term.

For the CTS, TGI has identified that system expansion requirements will principally be driven by BC Hydro’s future decisions regarding the long term operation for Burrard Thermal, which could drive a requirement for additional system capacity by 2011. Of the options available, the proposed Mt. Hayes LNG on Vancouver Island would allow TGI to avoid future CTS expansion as well as provide an on-system gas storage resource for TGI. This would also help TGI to manage the uncertainty associated with future operation of Burrard Thermal and ICP.

On the ITS, future system requirements depend on Core market growth. The Okanagan region is the fastest growing region on the ITS system however current demand forecasts indicate that expansion requirements are likely not to be required before 2013. TGI has identified a number of ITS expansion options and will perform detailed evaluation to determine the most cost effective solution as capacity requirements become more pressing.

Stakeholder Consultation

Stakeholder needs and concerns are critical to Resource Planning. More than simply facilitating open communication, effective stakeholder consultation provides the Utility with insights that can impact the entire planning process, from trends that influence demand forecasting and DSM analysis to the development of an action plan for implementing preferred planning solutions. TGI consultation activities included general stakeholder workshops and focussed meetings with select stakeholders seeking input on a range of system expansion needs and DSM alternatives. Following the filing of the 2006 Resource Plan, TGI will continue discussions with stakeholders regarding the implementation of the recommendations presented by the plan

Action Plan

The Action Plan describes the actions that Terasen Gas intends to pursue over the next four years based on the information and evaluation provided in this Resource Plan.

1. <u>Continue to monitor and evaluate customer demand by</u>:

    a. Monitoring Core customer demand including commercial and industrial transport service trends in both the Coastal and Interior service regions.

    b. Continuing to assess the impact of emerging energy trends and technologies on demand for natural gas.

    c. Continuing to monitor the load demand from natural gas use for vehicles which, due to regional air quality and global GHG concerns, has the potential to increase more quickly then has been seen in the recent past, and contributes to a higher demand forecast scenario.

    d. Continuing to assess Terasen Gas' success rate in penetrating the multi-family dwelling, residential customer sector and incorporating these changes into customer addition rates in the demand forecasts.

2. <u>Continue with existing and implement new Demand Side Management initiatives</u>. TGI will evaluate the potential for an expanded DSM strategy based on the CPR results and will communicate results and recommendations during the fall of 2006 Where increased funding is required to support expanded DSM activities, TGI will submit a request to the Commission outlining the additional funding requirements and the scope of the DSM activities planned.

3. <u>Continue to pursue partnering opportunities regarding energy efficiency measures</u>. TGI will continue to pursue partnering opportunities with NRCan, Industry and BC Hydro and support the Ministry of Energy and Mines and Petroleum Resources in their target to reduce the energy consumption in residential and commercial buildings.

4. <u>Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers</u>. Adding new customers and encouraging existing customers to make high efficiency gas appliance choices will be critical in maintaining competitive energy choices in the region. Marketing programs and materials will be

essential for encouraging new customers to choose natural gas, increasing gas usage per account and reducing the individual's share of fixed costs. Each of these conditions will in turn help to maintain a competitive position for natural gas.

5. Monitor customer growth on the CTS system and continue to investigate options to address future capacity shortfalls. The most significant factor driving potential expansion requirements will be BC Hydro’s future operation of Burrard Thermal and to a smaller degree ICP. TGI will closely monitor developments on this front and bring forward recommendations in a timely fashion when it appears that action is required.

6. Work with TGVI to examine the feasibility of the Mt Hayes LNG facility as an on-system storage resource for both utilities. TGI will work with TGVI to assess the value of storage services based on building a 1.5 BCF facility. Following additional stakeholder consultation, TGVI will then determine the timing and the appropriate course of action to advance the LNG project. Once approvals are obtained, the LNG Storage facility requires 36 months to complete and fill the tank. Therefore, the earliest the facility would be available is November 2010.

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1 INTRODUCTION AND BACKGROUND

1.1 Introduction to Terasen Gas Inc.

Terasen Gas Inc. ("TGI") provides natural gas transmission and distribution services to more than 800,000 residential, commercial, industrial and transportation customers in more than 100 communities in the Province of British Columbia. The company serves most of British Columbia from Vancouver, east to the Kootenays and north to communities including Prince George, Chetwynd & Fort Nelson. The service areas are defined as Lower Mainland (Vancouver to Hope), Inland (Okanagan to Northern B.C.) and Columbia (East Kootenays).

TGI, is one of the Terasen Gas group of subsidiary companies (collectively the "Terasen Gas Utilities" or "Terasen Gas") owned by Kinder Morgan Inc., a private, shareholder-owned company whose shares trade on the New York Stock Exchange under the symbol KMI. KMI is one of the largest energy transportation, storage and distribution companies in North America. It owns an interest in or operates over 69,000 kilometres of transportation pipelines that move primarily natural gas, crude oil, petroleum products and CO_2, and provides natural gas distribution service to over 1.1 million customers.

In British Columbia, KMI also owns and operates the following Terasen Gas utilities:

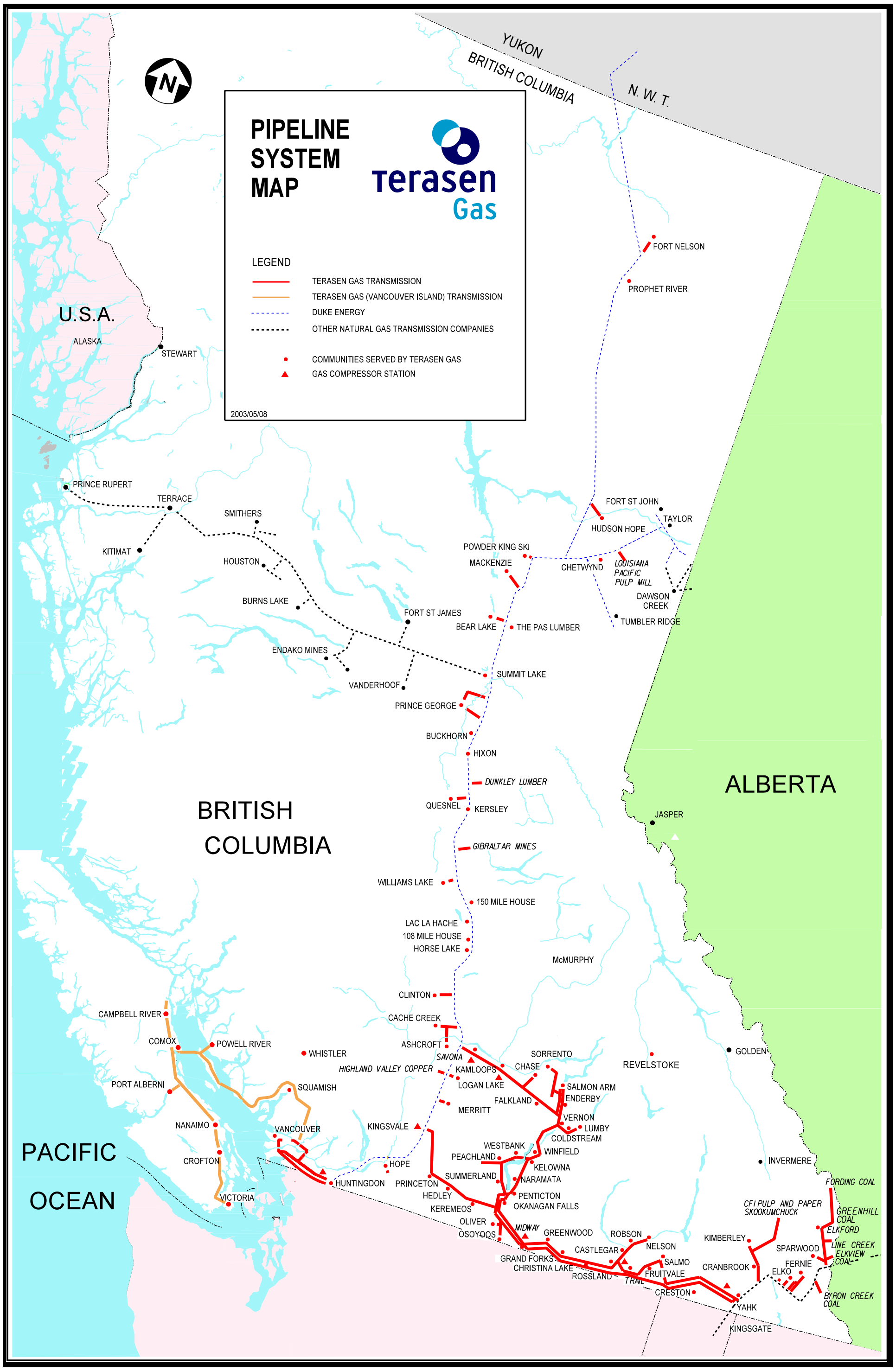
- Terasen Gas (Whistler) Inc. ("TGW"),
- Terasen Gas (Squamish) Inc. ("TGS"), and
- Terasen Gas (Vancouver Island) Inc. ("TGVI"), serving Vancouver Island and the Sunshine Coast.

In total, the Terasen Gas Utilities represent the largest natural gas distribution group in the PNW, serving approximately 900,000 customers in more than 125 communities in British Columbia. Terasen Gas employs approximately 1,400 people and operates more than 43,000 km of natural gas transmission and distribution pipelines. The Terasen Gas Utility operations are regulated by the British Columbia Utilities Commission (the “Commission” or "BCUC").

1.2 Terasen Gas Inc.'s Transmission System

The TGI transmission pressure system is divided into three subsets; the Coastal Transmission system ("CTS"), the Interior Transmission system ("ITS") and the Transmission Pressure laterals from the Westcoast Energy Inc. ("Westcoast") and TransCanada Pipeline systems. Figure 1-1 is a Pipeline System Map of the Province of BC showing the location of Terasen Gas' transmission pipelines including TGI and TGVI.

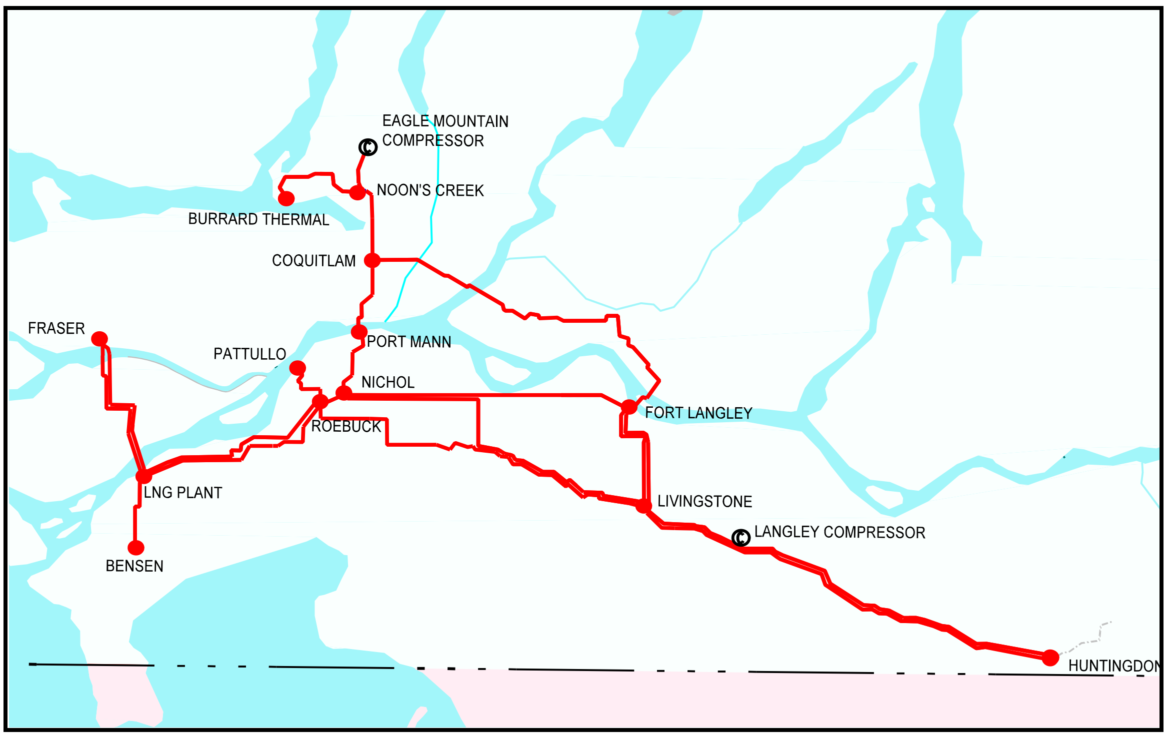
Figure 1-1 Terasen Gas Inc Transmission System



1.2.1 Coastal Transmission System

Natural gas for TGI's Coastal region customers is delivered from upstream sources on the Westcoast pipeline system to the Huntingdon trading point near Abbotsford. The CTS provides transportation from the Huntingdon trading point to various metering and regulating stations in the Fraser Valley and Metro-Vancouver area. The CTS consists of a 265 km network of pipelines and includes the Langley compressor station, used to maintain transmission pressures during periods of high demand, and an existing Liquefied Natural Gas ("LNG") storage facility located on Tilbury Island that provides increased system deliverability also during high demand periods. Figure 1-2 illustrates the TGI CTS.

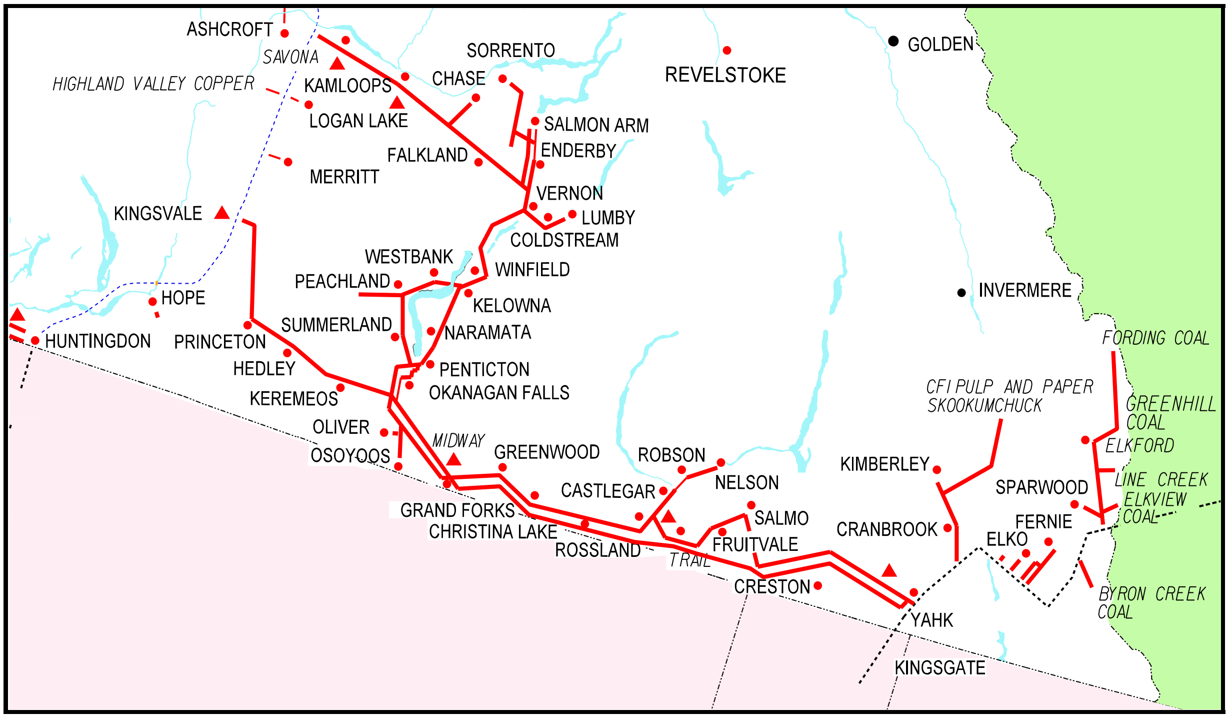
Figure 1-2 Coastal Transmission System



1.2.2 Interior Transmission System

Natural gas for TGI's Interior region customers is delivered from sources in British Columbia via the Westcoast pipeline system and from sources in Alberta via the TransCanada Pipeline system in BC. North of Savona and east of Yahk, TGI uses relatively short pipelines to serve communities adjacent to these major transmission pipelines. The ITS serves customers in the Thompson, Okanagan and Kootenay regions of the Province and connects to the Westcoast system at Savona and Kingsvale, and to the TransCanada Pipeline system at Yahk. The Kingsvale and Yahk interconnects are capable of both receipt and delivery allowing bi-direction flow between these two points. Southern Crossing Pipeline ("SCP") is a 312 kms pipeline from Yahk and Oliver that is used to serve Interior customers in the Okanagan region and also serves Lower Mainland customers via the Westcoast system at Kingsvale. Figure 1-3 illustrates the ITS and SCP.

Figure 1-3 Interior Transmission System Map



1.3 Regulatory Context

Section 45 of the *Utilities Commission Act*, amended in 2003, implements the Provincial government's Energy Policy of November 2002, "Energy for Our Future: A Plan for BC"[1], setting out the requirements under the Act for utilities to complete Resource Plans. In December 2003, the BCUC issued *Resource Planning Guidelines* (Appendix A) to help guide utilities in the submission of Resource Plans under Section 45 of the *Act*.

The Commission's *Resource Planning Guidelines* outline the process, summarized below, to be followed by utilities in developing their Resource Plans.

1. Identify the planning context and objectives of a Resource Plan

2. Develop a range of gross (pre-DSM[2]) demand forecasts.

[1] Energy For Our Future: A Plan for BC - http://www.gov.bc.ca/em/popt/energyplan.htm#eof
[2] DSM = Demand Side Management

3. Identify supply & demand resources.
4. Measure supply & demand resources against Resource Plan objectives.
5. Develop a range of multiple-resource portfolios.
6. Evaluate resource portfolios against Resource Plan objectives and select a portfolio.
7. Develop an action plan to implement the selected portfolio.
8. Obtain stakeholder input during the planning process.
9. Consider government policy and seek regulatory input during the Resource Plan preparation.
10. Submit the Resource Plan for regulatory review.

The Commission's guidelines form the basis of the Resource Planning processes undertaken by TGI as described in this document.

1.4 Planning Context and Objectives

The Resource Planning process evaluates demand and supply options and considers their economic, environmental and social characteristics. The Commission's description of the planning process is:

> *"Resource Planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run."*

Resource Planning is part of an ongoing planning process at Terasen Gas which includes project-specific planning, service territory planning (the Resource Plan) and broader regional planning initiatives. For planning in the broader Pacific Northwest ("PNW") Region, Terasen Gas participates with other gas industry companies in the development of the Northwest Gas Association's ("NWGA") regional Outlook study. The Outlook study assesses the natural gas infrastructure serving the I-5 Corridor, which encompasses the B.C. Mainland, Vancouver Island, Western Washington and Western Oregon, for the purpose of determining supply options and the ability of the infrastructure to reliably serve the needs of the market. This study forms the broader context in which Terasen Gas operates and in which this Resource Plan was developed. A summary of the current NWGA Outlook Study is included in Appendix B.

The key activities which encompass the Resource Planning process are embedded in the overall planning processes which the Company undertakes in providing the highest standards of service to our customers. In keeping with the Provincial government's Energy Policy, effective Resource Planning requires that consumers have access to the information needed to make the best choices among all available energy sources. The delivery of an effective marketing strategy and programs to assist consumers in making appropriate energy choices is an important component of the Resource Planning process.

The product of the Resource Planning process is a long-term plan for the acquisition of resources to meet forecasted customer needs for natural gas over the long term. TGI examines planning periods of both 15 and 25 years to ensure that optimal solutions are identified. The Resource Plan includes a detailed four-year action plan for acquiring resources to meet customer requirements in the near term. The TGI Resource Plan analyzes financial, environmental and social impacts and incorporates stakeholder input. The last formal Integrated Resource Plan for TGI, titled Terasen Gas Inc. 2004 Resource Plan, was filed in April, 2005.

1.4.1 Overview of the Resource Planning Process

The Resource Planning process at TGI consists of the following activities:

1. Establish Objectives

The first step in the Resource Planning process is to develop the objectives. The objectives form the basis for deciding which resources will be acquired to provide service to customers both in the near term and over the planning period. The TGI objectives are described in Section 1.4.3 and are consistent with the objectives for resource planning at all Terasen Gas companies.

2. Review the Regional Context

TGI operates in a greater regional area from which the Company derives its gas supplies and which influences the availability, reliability, security and cost of those supplies. Key considerations related to the greater regional context and to the North American gas market as a whole are embedded in the process of identifying possible resource options for inclusion in alternative resource portfolios. In developing this Resource Plan, TGI has also been monitoring BC Hydro's Integrated Resource Planning process including the *2006 Integrated Electricity Plan* ("2006 IEP") and Long Term Acquisition Plan ("LTAP") submitted by BC Hydro to the Commission in March 2006.

3. Develop a Range of Possible Demand Forecasts

For its core customers, TGI develops base, high and low forecast scenarios that encompass the expected demand forecast with upper and lower bounds to account for potential changes in market conditions. TGI also considers the needs of its transportation (including other Terasen Gas utility transportation customers) and interruptible customers. For electricity generation customer, BC Hydro, TGI examines alternative potential demand scenarios based on publicly available, BC Hydro planning information.

4. Identify Potential Supply and Demand Side Resources

The TGI system is connected to potential supply sources throughout North America. TGI must consider access to sufficient supplies of gas at this regional level as well as capacity requirements on its own system due to increasing demand for gas service. Providing sufficient capacity to meet future customer demand can be accomplished through combinations of additional piping, compression and natural gas storage. On the demand side, programs which encourage customers to modify their energy consumption volumes or patterns or to substitute gas for alternative energy sources have an impact on overall demand requirements.

5. Group Resources into Resource Portfolios to meet the Demand Forecasts

Once the possible supply resources have been identified, they are grouped into distinct portfolios which are capable of delivering the required service to customers for one or more of the demand forecasts. The most effective portfolios will be scalable allowing flexibility in meeting changes in demand over time, thereby reducing the risk of over or under supply for the market.

6. Review the Process and Alternative Portfolios with Interested Stakeholders

A key part of Resource Planning is communication with interested stakeholders on the process undertaken by the Company. This is accomplished through meetings and information sessions with stakeholders such as customers and municipalities.

7. Recommend a Preferred Portfolio

The final part of the Resource Planning process is the selection of a Preferred Portfolio of Resources which satisfies the requirements of the demand forecasts while ranking high against the Resource Planning objectives. The recommendation of a Preferred Portfolio leads to a four year Action Plan for resource acquisition over the near term portion of the long term planning period addressed by the Resource Plan.

1.4.2 Status Update on the 2004 TGI Action Plan

In its 2004 Resource Plan, TGI presented six actions to implement the recommendations outlined throughout the Plan. The following discussion provides an update on the 4-year action plan described in that document.

1. Continue to monitor customer demand and trends.

Section 3, of this Resource Plan describes the inputs to the demand forecast resulting from TGI's monitoring of core customer demand, gas utility customer demand and TGI's understanding of resource options presented by BC Hydro for gas fired electrical generation. Section 2 provides an updated discussion of emerging energy industry trends. Many of the trends discussed are still emerging and continue to have too much uncertainty to impact TGI's demand forecast at this time.

2. Continue to investigate the options available to Terasen Gas to address the future capacity shortfall in the CTS north of Nichol Station.

TGI has continued to monitor demand growth on the CTS and examine resource options to address possible capacity shortfalls north of Nichol Station in the Coquitlam area. Section 6.3 discusses CTS capacity issues, the potential for a system constraint in this area and the resource options available to TGI.

3. *Investigate LNG storage as a regional resource.*

In March 2005, TGI entered into an agreement with TGVI for storage services from the Mt Hayes LNG project beginning in 2008. The project was put on hold following the cancellation of the Duke Point Power project; however TGI is continuing to work with TGVI to evaluate the feasibility of the project to serve as an on-system peaking gas resource for both utilities. As part of this assessment, the Companies are continuing to examine the availability and cost of other regional storage resources.

4. *Conduct ongoing consultation and education on the Resource Plan and on energy efficiency.*

TGI has continued to conduct consultation and education activities with TGI stakeholders and other energy industry participants. A discussion of these activities is presented in Section 7, Stakeholder Consultation.

5. *Report back on the outcomes and recommendations of the Conservation Potential Review ("CPR").*

The CPR, completed in Spring 2006, examined the conservation potential for both TGI and TGVI service areas. The results of the CPR, implications for TGI and recommended next steps are reported in Section 4, Energy Efficiency and Optimization.

6. *Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers.*

Energy efficiency programs and limited fuel choice promotions developed and implemented for TGI are also discussed in Section 4. TGI continues to explore broader marketing and communication programming and related funding opportunities.

1.4.3 Terasen Gas Resource Planning Objectives

TGI's Resource Planning objectives form the basis for evaluating all potential resources in the Resource Plan including major infrastructure projects, gas supply alternatives and demand side programs. The objectives reflect the Company's commitment to providing the highest level of quality energy services to its customers. TGI's Resource Planning objectives are outlined below.

Ensure reliable and secure gas supply.

A secure energy supply is essential for all of TGI customers. Ensuring a sufficient supply of gas and the capacity to deliver gas to customers during anticipated peak demand periods is an ongoing objective for the Utility.

Provide service to customers at least delivered cost.

Customers and regulators expect the Utility to procure and deliver energy in the most cost-effective and efficient manner possible. The most desirable resource options will provide cost effective service solutions both in the near term and into the future in the context of reliability and security. Demand Side Management strategies which are cost-effective can add value to customers through more effective use of the gas delivery infrastructure and more efficient use at the burner tip.

Reduce rate volatility.

Another important objective of the Company is to dampen rate volatility and allow gas to remain competitive with other energy sources. Customers value consistent, predictable rates which allow them to budget for their energy service requirements.

Balance socio-economic and environmental impacts.

It is important to incorporate environmental and socio-economic considerations into the selection process for demand and supply resources by examining the impact of resource selection alternatives on land-use, air emissions, the local economy, and First Nations and communities served.

The Resource Plan objectives form the basis for evaluating potential resource portfolios. Resource portfolios are assessed by determining the degree to which they meet the criteria of each objective. The most desirable resources will rank high on most or all of the objectives. The relative ranking of resource portfolios against the objectives is determined using both quantitative and qualitative techniques. To be meaningful, objectives must be measurable and differentiate between resources.[3] Table 1.1 provides a summary of the objectives, associated attributes and measures used to assess alternative resource portfolios against those objectives.

[3] An example for Terasen Gas is the objective "*ensuring adequate returns for our shareholders*". It was determined that, while key to the viability of our business, it was not possible to unambiguously differentiate between resource portfolios using this objective.

Table 1-1 Resource Planning Objectives – Terasen Gas Inc.

Objective	Attribute	Measure
Ensure reliable and secure supply.	System reliability Security of supply	Risk of outages Gas supply diversity
Provide service to customers at least delivered cost.	Financial evaluation of supply side and demand side resources	Net Present Value Total Resource Cost (TRC) Ratepayer Impact (RIM)
Reduce rate volatility.	Expected rates	Risk Trade-offs
Balance socio-economic and environmental impacts.	Social costs/benefits including: - Local emissions - Greenhouse gas (GHG) - Land use impacts - Employment/local economic impacts - Stakeholder consultation	 - Air pollutants - Quantity of CO_2 equivalent - Area impacted - Jobs created - Stakeholder input

The resource portfolio selection process involves ranking each portfolio for each of the four (4) Resource Planning objectives. The relative ranking of each of the resource portfolios forms the basis for selection of a preferred portfolio. As indicated in the objectives table, Table 1-1, the measures attached to attributes associated with each objective include both quantitative and qualitative measures.

The objective *Ensure Reliable and Secure Supply* is measured qualitatively by ranking the alternative resource portfolios according to their relative susceptibility to upstream outages and the overall diversity of their respective supply resources.

Provide Service to Customers at Least Delivered Cost is evaluated for supply side resources based on the Net Present Value (NPV) of the costs of those resources in each portfolio. For demand side resources, the standard DSM measures are used to evaluate programs: the Total Resource Cost[4] (TRC) is used for conservation and efficiency programs; the Ratepayer Impact Measure[5] (RIM) test is used for load addition programs.

The objective *Reduce Rate Volatility* is evaluated qualitatively by ranking the resource portfolios according to their expected impact on customer rates.

The objective *Balance Socio-Economic and Environmental Impacts* is measured using three quantitative measures: expected impacts of air emissions (local and global); land area affected;

4 Total Resource Cost (TRC) Test – a test used to evaluate the economic benefits and costs of utility DSM program from the perspective of all utility customers. The test can be expressed as a ratio or dollars of net benefits.

5 Ratepayer Impact Measure (RIM) Test – a measure of the distribution of equity impacts of DSM programs on non-participating rate-payers. From this perspective, a program is cost effective if it reduces a utility's rates. This can be expressed as a ratio or in dollars of net benefits

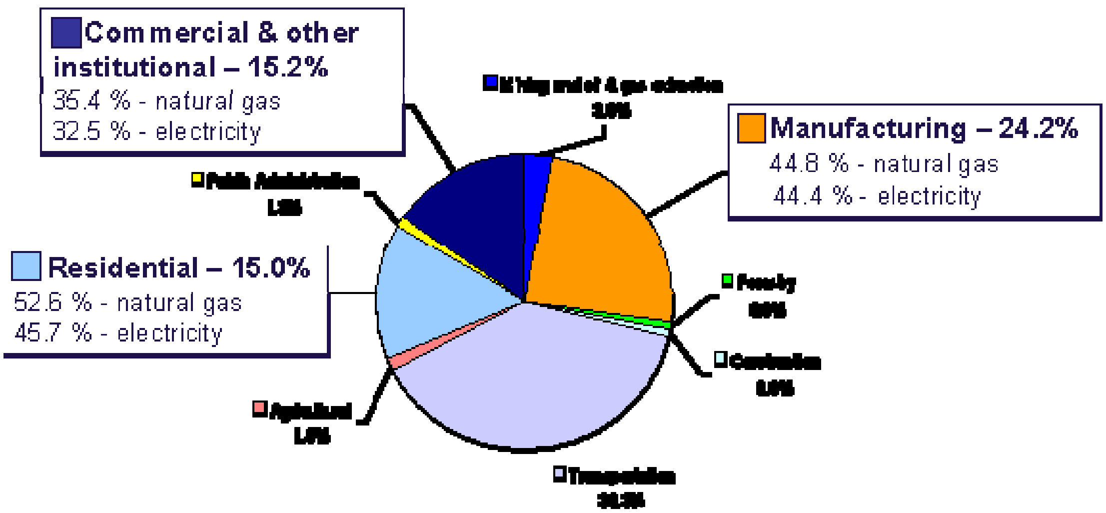
and employment created. Stakeholder input, discussed in Section 7, is also considered within the context of this objective.

Using these criteria in the portfolio selection process involves consideration of both inter-relationships between attributes and judgements on the relative weightings assigned to each attribute.

2 ENERGY MARKET OUTLOOK

Figure 2-1 shows the importance of natural gas in BC's Provincial energy mix. Excluding transportation, the sectors that consume the greatest amount of energy are the residential, commercial/institutional and the manufacturing sectors, together consuming over half of the Province's energy. In each of these sectors, natural gas edges out electricity as the largest source of energy used. With demand for energy in BC continuing to rise, with significant natural gas supplies remaining and new sources being developed, and with a looming gap between existing electrical generating resource capacity and peak demand, natural gas will continue to play a major role in the wise use of energy in the Province.

Figure 2-1 Energy Use in B.C. in 2004 by Sector



Source: Ministry of Energy, Mines and Petroleum Resources[6]

This section discusses the energy landscape in BC - issues that impact planning at TGI and energy planning in the Province in general. Some of the topics in this section, such as the natural gas price forecasts and BC Hydro's 2006 IEP, are discussed here because of their impact on the forecast of demand for natural gas discussed in Section 3 and TGI resource needs and options discussed in Sections 5 and 6.

Other issues presented in this section are only now emerging as potential future considerations in demand forecasting and resource planning for all of the Terasen Gas Utilities. These issues could in the future, begin to act to move Terasen Gas' future demand away from the base forecast scenario. There remain too many uncertainties for all of the issues herein to be accounted for in Terasen Gas' demand forecast, yet they are emerging as important energy issues for BC and therefore warrant discussion and continued monitoring.

[6] Ministry of Energy, Mines and Petroleum Resources – January 2006. Peter Ostergaard, Assistant Deputy Minister, Presentation to the 2006 BC Energy Forum.

2.1 Pacific Northwest Gas Market Overview

2.1.1 Supply Update

A key component of resource planning is the availability of supply to serve both short and long term needs in the region. TGI reviews the latest forecasts for gas reserves from a variety of sources and is satisfied that ample supply exists to serve the TGI market over the planning period. Table 2-1 provides proven and total or ultimate potential of reserves in the local market of British Columbia, in Canada, North America and world wide.

Table 2-1 Proven and Total (Ultimate Potential) Natural Gas Reserves in B.C., Canada, North America and the World

Source	Publication Date	Region	Proven Reserves (Tcf)[7]	Ultimate Potential (Tcf)
Centre International d'Information sur le Gaz Naturel et tous Hydrocarbures Gazeux (CEDIGAZ), Natural Gas in the World, Major Trends for the Gas Industry	July 2005	Canada	55.8	
		North America	263.12	
		World	6,362.04	
BP Statistical Review	June 2005	Canada	56.6	
		North America	263.96	
		World	6,343.03	
Oil & Gas Journal	January 2006	Canada	56.58	
		North America	263.96	
		World	6,112.14	
National Energy Board and the BC Ministry of Energy, Mines and Petroleum Resources, "Northeast BC's Ultimate Potential for Conventional Natural Gas"	March 2006	British Columbia	26.4[8]	51.9
CIA Publication, "The World Factbook"	2004	Canada	59.06	
EIA, "Country Analysis Briefs - Canada"	January 2005	Canada	56.1	
National Petroleum Council	2003	North America	272	1,970

[7] Proven or discovered reserves are those that have been confirmed by wells already drilled and can be economically produced with current technology, whereas unproven or undiscovered resources include resources that are estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but have not been shown to exist by drilling, testing or production. Total or ultimate potential is an estimate of all the resources that may become recoverable or marketable, including proven and unproven resources.

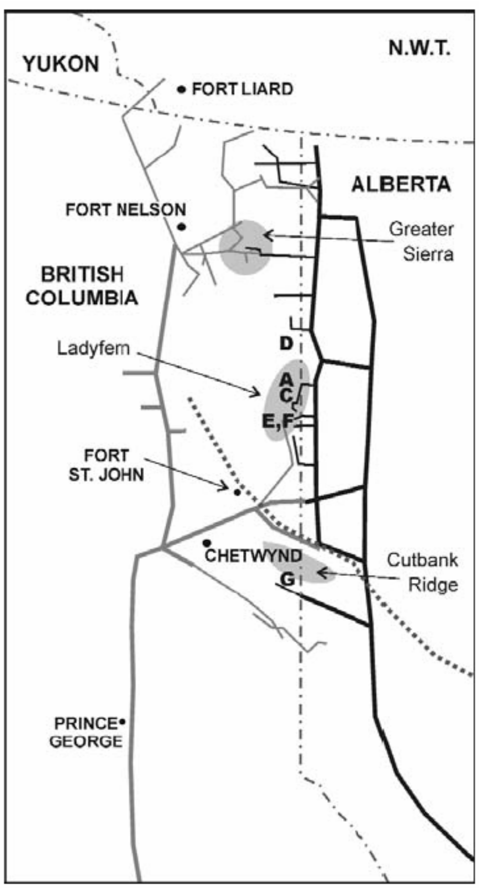
[8] Medium Case

The above table indicates that there are significant reserves in BC, North America and worldwide. Based on current technology and the reserves that have already been drilled; proven or discovered reserves in BC alone are 26.4 Tcf, whereas the ultimate potential of reserves is 51.9 Tcf. In Canada, the ultimate potential for natural gas reserves is 501 Tcf supply, equating to approximately 100 years of supply. North American proven supply is approximately 10 years; whereas the ultimate potential is indicated at over 70 years. Proven world estimated supply is between 60-70 years across the various sources listed.

2.1.2 Northern British Columbia Production and Infrastructure

Since 1995, approximately 2.6 Bcf/d of incremental take-away capacity has been added from Northeast BC into Eastern markets with new pipeline infrastructure. Some of the most significant gas discoveries in BC in the past five years, such as Lady Fern and Ekwan, were connected by producer built pipelines to TransCanada's Alberta system. Production increases in BC from the Greater Sierra and Cutbank Ridge areas are both flowing out of the province into Alberta via Encana's Ekwan Pipeline (418 MMcf/d) and the South Tupper Line (155 MMcf/d), respectively. Figure 2-2 below provides a summary of pipeline infrastructure additions by producers from Northeast BC in the last 7 years.

Figure 2-2 Producer Built Pipelines from Northeast BC to Alberta Since 1999

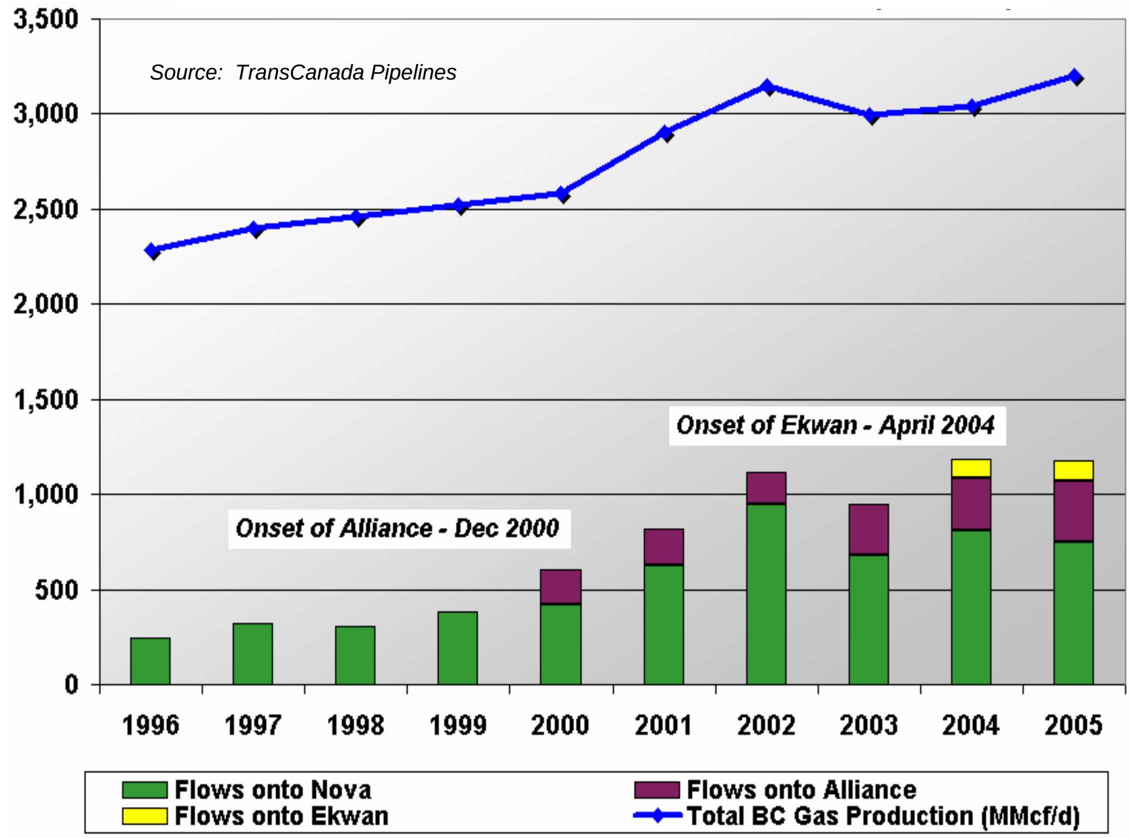


Legend			
		Capacity	
Location on Map	Pipeline	$10^6m^3/d$	MMcf/d
A	Pioneer Chinchaga	1.1	40
B	PennWest Wildboy	2.4	85
C.1	Murphy Chinchaga	1.7	60
C.2	Murphy Chinchaga Loop (Ladyfern)	6.5	230
D	Canadian Hunter	1.0	35
E	EnCana Ladyfern	4.8	170
F	CNRL Ladyfern	19.2	680
G	EnCana Tupper	1.2	45
H	EnCana Ekwan	11.8	418

Source: National Energy Board

The Alliance Pipeline commenced operations in 2000 with take-away capacity of 300 MMcf/d from the Fort St. John area into Eastern markets. Excess transmission take-away capacity from the Western Canadian Sedimentary Basin has resulted in significant competition between the pipelines for available gas supply thereby tightening the pricing dynamics within the region. Consequently, production increases in BC since 1996 have been equally matched by higher gas flows out of the province into Alberta, as illustrated in Figure 2-3.

Figure 2-3 BC Production and Flows into Alberta (MMcf/d)

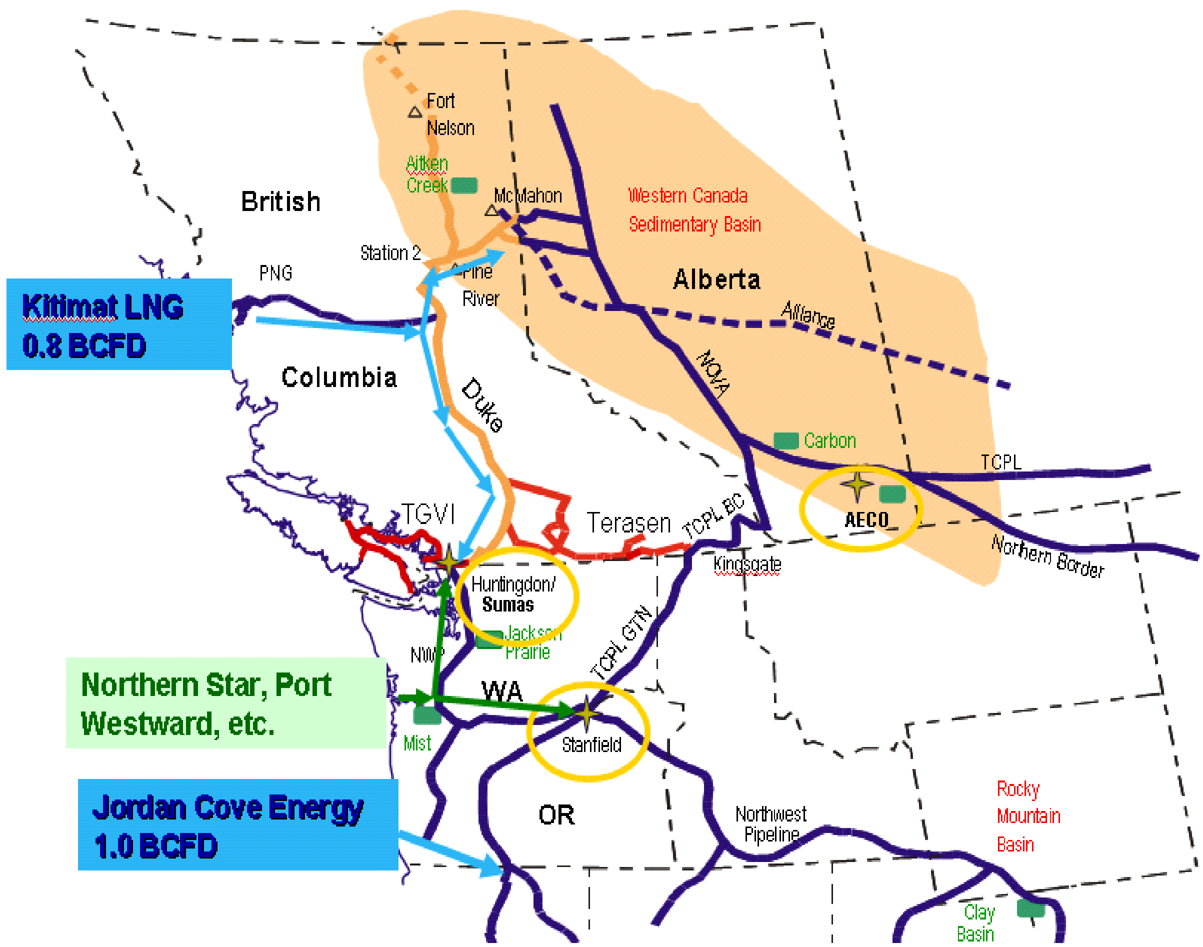


Since the addition of new pipeline infrastructure, producers in BC have greater opportunities and flexibility to move their gas to those markets offering the highest returns. In addition, more gas is currently flowing north into the PNW than in the past as a result of depressed pricing in the Rockies producing area, which is further compounding the reduction of flows on the Westcoast system. As a result an increasing and substantial amount of capacity has become de-contracted on the Westcoast system over the past couple of years which is leading to greater price volatility at Station 2 based on demand conditions.

2.1.3 Proposed LNG Import Terminals

A major expectation for new supplies to meet North American demand growth is the development of LNG import terminals. Several locations have been proposed for LNG import terminals in the PNW, including two in British Columbia (Kitimat and Prince Rupert), and five in Oregon (Bradwood Landing, Port Westward, Skipanon Natural Gas Facility, Tansy Point, and Jordan Cove). The LNG import terminals are supply options for the region not storage options. Figure 2-4 identifies 3 of the more advanced import LNG terminal proposals. Kitimat and Prince Rupert LNG facilities would compete with Station 2 supply sources in the PNW market. Although these projects are currently in preliminary planning and approval stages, they represent possible supply options for 2009 and beyond and would provide access to the vast reserves available worldwide.

Figure 2-4 BC Pacific Northwest Infrastructure & Import LNG Proposals



2.2 British Columbia Energy Outlook

2.2.1 Natural Gas and Electricity Prices

Trends in natural gas and electricity prices send signals to consumers making buying decisions on energy system equipment and fuel choices. Since these are the two primary energy choices for consumers in BC, expectations by consumers of future price increases in the supply of either energy type relative to the other can impact customer additions and load forecasts. This section presents a discussion of natural gas price forecasts prepared by independent sources, as well as a discussion on recent trends and price pressures in electricity and comments on Energy Pricing made by the BC Progress Board in their review of energy opportunities and imperatives in BC. Information reviewed by TGI in preparing this Resource Plan points toward the continued competitiveness of natural gas prices as upward pressures on electric rates continue.

2.2.1.1 Natural Gas Price Forecasts

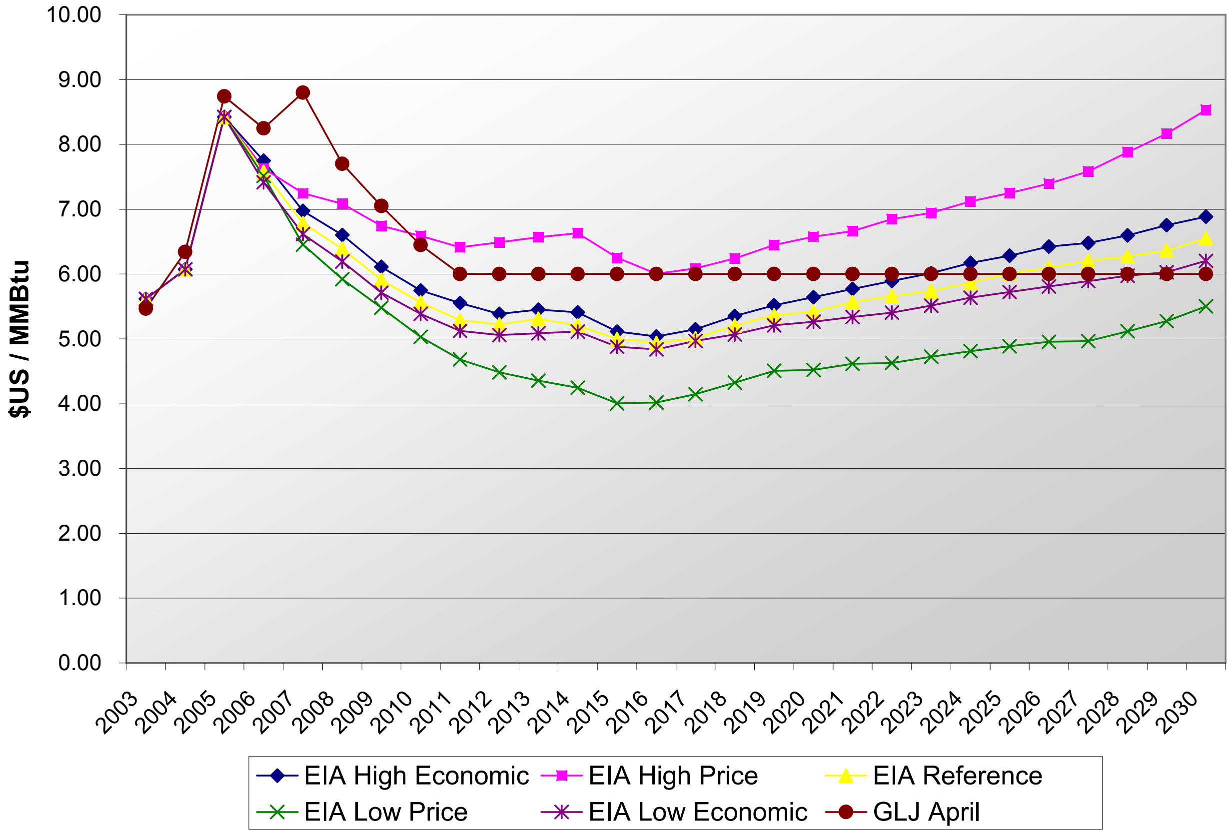
TGI generally utilizes price forecasts generated by other industry experts when analyzing likely future gas consumption for its own customers. GLJ Petroleum Consultants Ltd. ("GLJ") is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis. GLJ prepares commodity price and market forecasts after a comprehensive review of information available to the reported quarter. Information sources include numerous government agencies, industry publications, Canadian oil refiners and natural gas marketers. GLJ's forecasts reflect tracking recent trends in oil and gas supply, demand and transportation issues as well as other trends in the natural gas industry and the cost of competing fuels.

As shown below in Figure 2-5 below, GLJ's April 2006 price forecast is compared with 5 forecasts released in January 2006 from the US Energy Information Administration ("EIA"). The EIA forecasts were taken from its 2006 Annual Energy Outlook report. The EIA uses the last 30 years of data, including normal weather and storage inventories to generate the price forecasts. The reference case is based on an optimistic future with the assumption that natural gas supplies will enter the market to soften prices, from sources such as LNG Imports, Alaska and the Mackenzie Delta. Prices are shown as softening significantly in the short term with the arrival and impact of anticipated new supplies. Following which the EIA predicts a tightening of the supply and demand balance causing prices rise gradually from 2016-2017 and rising steadily to $6.50 US/MMBtu in 2030 (Real or 2006 Constant dollars). EIA's high and low price and high and low economic forecasts as compared to the reference case are generated to provide a balance and sensitivity of reasonableness to the reference case assumptions.

The reference location for the EIA price forecasts is for the US Wellhead. In order to extend the price to an actual trading location for comparison, prices were adjusted to account for the differential between the Wellhead and the Henry Hub, through assistance and analysis provided by EIA staff.[9]

[9] U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices and U.S. Wellhead Prices, Philip Budzk. (http://www.eia.doe.gov/oiaf/analysispaper/henryhub/index.html)

Figure 2-5 Natural Gas Price Forecast Comparison at Henry Hub (Real Constant Dollars)



2.2.1.2 Electricity Prices

In June 2006, the Commission granted BC Hydro's request for an interim rate increase of 4.65% effective July 1st, 2006. BC Hydro has requested an additional increase 2.71% to be made effective in April of 2007. BC Hydro's F07/F08 Revenue Requirement Application ("RRA") is currently under review by the Commission and a decision is expected by the year end. If the July interim rate and the additional 2.71% in April of 2007 are ultimately approved by the Commission, the total rate increase will be approximately 7.5% by April 2007 over previous rates across the Province and for almost all rate classes.

These increases highlight the growing costs for generating and delivering electricity in BC, even though electricity prices in BC are not driven by fully open market conditions. Recent developments in BC have highlighted that electricity is in short supply and marginal costs of new capacity greatly exceeds the costs the costs of existing resources. With both demand and costs for electricity expected to continue to rise in today's healthy BC economy, natural gas will continue to be a favourable alternative to electricity for many uses, and can play an important role in relieving some of the growing cost pressures driven by increasing demand for electricity.

2.2.1.3 BC Progress Board Comments on Electricity Pricing

In November of 2005, the BC Progress Board, appointed by the Premier of BC[10], commissioned a report titled "Strategic Imperatives for British Columbia's Energy Future". In that report, the BC Progress Board recognizes the advantage afforded BC by its vast and relatively inexpensive heritage hydro-electricity resources. They advise, however, that this advantage creates a false sense of security and warn of the higher cost of new sources of electricity. In times of high gas prices, the perceived low cost of electricity may prompt customers to choose electricity over natural gas, adding to the current export/import deficit in electricity in this province.

The BC Progress Board encourages the Province to continue pursuing its electricity self-sufficiency policy but advises that rates need to reflect the marginal cost of electricity generation. Such appropriate pricing, they argue, will encourage wise energy choices and efficient use of electricity among energy customers. Pricing that reflects the cost of new sources of supply will also encourage more private sector investment in the pursuit of energy self-sufficiency. One of the strategic energy imperatives outlined by the BC Progress Board is summarized as follows:

> "Sensible electricity pricing is key to self-sufficiency. Prices should reflect – to the greatest extent possible – the real cost of new electricity supply in order to promote conservation and efficient use, and the development of new sources."[11]

2.2.2 Provincial Energy Policy

The Provincial Energy Policy titled "Energy for Our Future: A Plan for BC" was published in November, 2002 as 'a long term plan to harness the potential of B.C.'s energy resources'[12]. In its policy document, the BC government espoused four cornerstones for BC's energy future. The following discussion reviews how natural gas continues to play a vital role and highlights relevant policy issues that have been raised more recently.

<u>Low Electricity Rates</u>

BC's low electricity rates are a result of vast heritage hydro-electric generating resources that until recently have been able to supply the Province's hungry appetite for electricity. With electricity rates on the rise and concern about the Province's electricity supply/demand balance,

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[10] The BC Progress Board (Visit: http://www.bcprogressboard.com/about.php), established by the Premier in July 2001, is an independent panel of 18 senior business executives and academic leaders with two primary objectives:

1. To provide advice on whether the province is achieving its goal of improving British Columbia's competitive position by establishing an ongoing means to measure and benchmark British Columbia's progress over time and relative to other jurisdictions; and,
2. To identify issues of importance to the future economic prosperity of British Columbia and to advise the Premier on strategies, policies and actions necessary to improve the performance of the provincial economy and its social policy supports.

[11] www.bcprogressboard.com/Nov9_05.html

[12] Energy for Our Future: A Plan for BC created by the BC Government, can be found at: http://www.gov.bc.ca/empr/down/energy_for_our_future_sept_27.pdf

natural gas continues to provide a price competitive alternative to electricity for many end-use applications in the residential, commercial, institutional and industrial sectors. Key examples are space and water heating and household appliances such as dryers, ranges, and fireplaces.

Electricity rates should be structured to send proper purchase signals to energy consumers so that the best choice can be made for incremental energy needs and for the conservation of the Province's low-cost heritage electricity resources. This does not mean that electricity must or should move to market based rates, but rather that appropriate mechanisms be put in place to encourage efficient investment and conserve existing investment for the benefit of all BC consumers. Together, Figure 2-6 and Figure 2-7 illustrate new electricity supply is much higher cost than heritage resources and is therefore not always the appropriate choice for all end uses – a principle Terasen Gas calls ***Choice and Consequences***.

Proper pricing signals will encourage the most efficient and cost effective energy source to be chosen for the right use and will help to optimise overall energy costs in BC. Improper pricing signals will lead to the ineffective selection of fuel and energy alternatives and thus compromise BC's energy future. Natural gas and other fuels offer a more efficient and cost effective choice for space heating, hot water, and appliances, conserving heritage electricity and expensive new electricity resources for uses where alternatives are few, such as lighting and powering electronic equipment.

Terasen Gas Utilities CEO, Randy Jesperson, addressed the Vancouver Board of Trade on Choice and Consequences. His speaking notes, contained in Appendix C, provide additional insights into the energy choices facing BC's residents and businesses.

Figure 2-6 Choice and Consequences - Cost Considerations for Incremental New Sources of Electricity

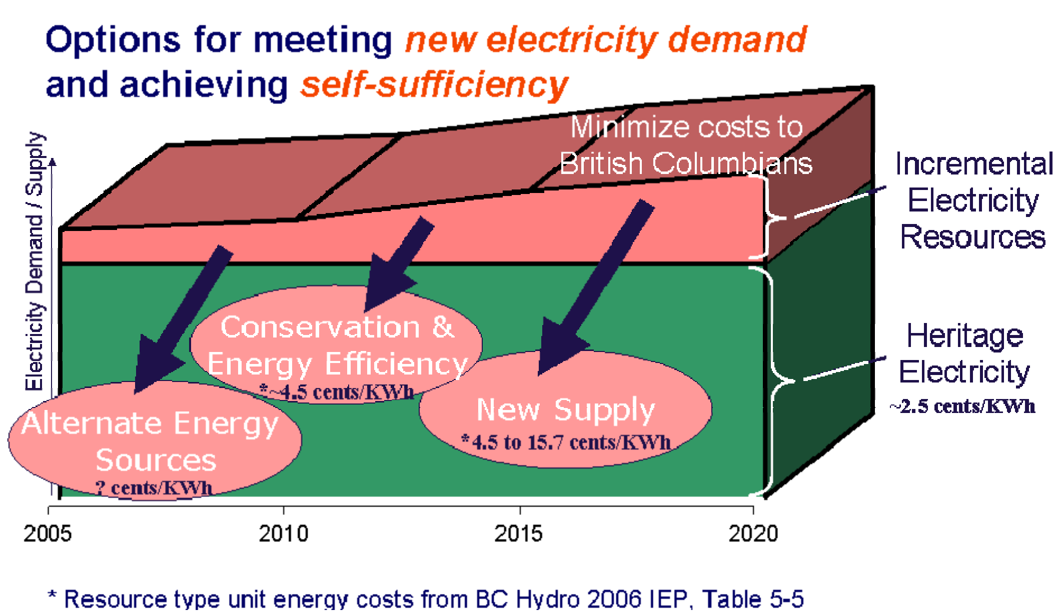
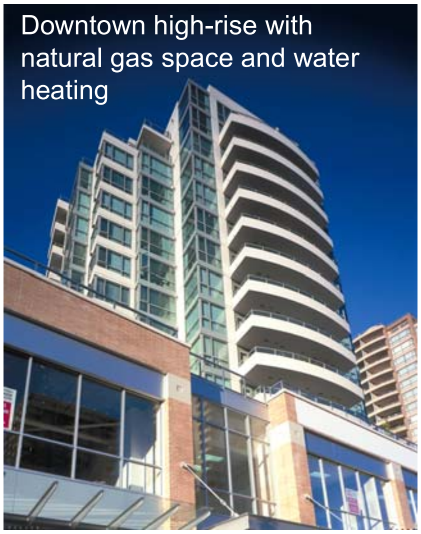


Figure 2-7 Challenges in Meeting British Columbia's Energy Needs

The Right Fuel for the Right Use



Electric baseboard systems
- low potential to convert to future technologies
- increase demand for new electrical supply

Natural gas hydronic systems
- limit future dependence on electrical supply
- easily convertible to future technologies
- may have higher capital cost but lower overall lifecycle cost

The BC Progress Board's Strategic Imperatives for BC's Energy Future include the public's need for more information about the reality of BC's energy supply and demand for more informed decision making. Among the recommendations are BC Hydro increasing public communication to educate consumers on BC's electric supply shortage and the choices faced in increasing supply, and the need for natural gas companies to communicate the advantages of natural gas in displacing other fossil fuels and in being more energy efficient than electricity for many uses[13].

Secure, Reliable Supply

Secure and reliable energy supply is one of the key planning objectives of the TGI Resource Plan. This plan examines the reliability and costs of resource alternatives for both TGI's delivery system and for the acquisition of midstream transport and storage resources and alternatives. In this way, the recommendations of this Resource Plan address the security and reliability of supply objective of the Provincial Energy Plan.

More Private Sector Opportunities

Natural gas is vital to BC's economy and is an integral part of a healthy and diverse energy outlook in BC. Gas industry employment in BC included 11,400 direct jobs among approximately 250 oil and gas companies working in the Province in 2004[14] and has continued to grow. The oil and gas sector contributes approximately $1.9 billion in provincial revenue.

[13] BC Progress Board Report – Strategic Imperatives for British Columbia's Energy Future. 2005. p34-35.

[14] Canadian Energy Research Institute, November 2004: http://www.em.gov.bc.ca/subwebs/oilandgas/pub/CERI.htm

At approximately 1,400 employees, the Terasen Gas Utilities account for more than 10% of the direct oil and gas jobs in BC – an essential private sector interest in BC's energy industry. TGI seeks to continue to make investments in the Province that are sound and make the most sense for its customers and shareholders. The objectives against which TGI measures major investment capital alternatives are both a comprehensive and balanced set of planning objectives. The recommended resource options, therefore, represent sound private sector investment opportunities, in keeping with the Province's energy policy. With continued investment, TGI will continue to add strength and diversity to BC's energy future.

Environmental Responsibility

Natural gas is the cleanest of the conventional energy fuels in use today and as such will continue to play an important role for the foreseeable future and beyond. As the simplest hydrocarbon, it satisfies environmental requirements by reducing emissions over most other fuels. The important role that natural gas can play in a sustainable energy framework for the Province is discussed further in Section 2.2.4. Considering its environmental advantages, the BC Progress Board also recommends in their 2005 strategic imperatives that public agencies should adopt the use of natural gas in public transit. Using natural gas instead of diesel in a transit bus produces 6 – 16% less greenhouse gas, 35 – 50% less NO_x and 95% less particulate[15]. Natural gas as a transportation fuel has significant advantages in reduced emissions over conventional fuels.

Natural Gas in an expanded 2006 Energy Plan for BC.

The Ministry of Energy Mines and Petroleum Resources ("MEMPR") has indicated that a renewed and expanded Energy Plan for BC from the Province is expected in the fall of 2006[16]. TGI believes that natural gas has an even greater role to play in meeting the objectives of BC's Energy Plan:

- Increasing the focus within the province on the right fuel for the right use at the right time will help to preserve the lower cost heritage electricity resources BC now enjoys. Encouraging the use of natural gas instead of electricity for space, hot water heating and other appliances, particularly in multi family dwellings is needed.

- Increasing the efforts to ensure that competitive, well functioning energy markets exist in BC will help consumers and businesses choose the right fuel for the right use at the right time, by sending proper price signals to customers. This knowledge will allow customers to assess the consequences of their energy choices. Current electric rate design does not provide proper pricing signals or reflect the true cost of new incremental electricity supply. The BC Progress Board recommends that the "The Provincial Government, through the BC Utilities Commission should direct BC Hydro to introduce electricity

[15] Whistler Alternative Fuel and Energy Technology Study. April 2004. Levelton Consultants Limited

[16] Hon. Richard Neufeld, Ministry of Energy, Mines and Petroleum Resources. BC Chamber of Commerce Energy Summit Speech. Victoria BC, February 23rd, 2006. http://www.gov.bc.ca/empr/down/feb23_neufeld_speech_energy_summit.pdf

pricing that send the correct signals to all consumers for their energy decisions, mindful of the government's pricing policy with respect to heritage assets."[17]

- Through technologies like hydronics, district energy systems, high efficiency equipment and new metering systems, natural gas creates an excellent platform for integrating other, renewable energy sources. As emerging energy technologies are implemented, they can be combined with existing natural gas systems to improve energy savings and environmental performance, and encourage greater private sector investment. Actions should be taken to discourage the installation of energy systems, such as electric baseboards, that have low conversion potential and exacerbate the need for new electrical supply. These actions and technologies will also help to improve the security of supply by developing an energy platform for communities that is based on a broad spectrum of energy choices – keeping costs competitive and reducing dependence on any one fuel.

Terasen Gas Utilities continue to work with governments and energy stakeholders to bring these opportunities and more to the forefront of BC's Energy Policies. Communicating the advantages of natural gas over electricity for certain uses and promoting energy efficiency and conservation will continue to be priority issues for TGI.

2.2.3 BC Hydro's 2006 Integrated Electricity Plan

BC Hydro submitted its 2006 IEP to the Commission in March, 2006. The IEP is BC Hydro's Resource Plan, filed pursuant to Section 45 of the *Utilities Commission Act*. The 2006 IEP contains BC Hydro's LTAP, which identifies the preferred resources, both supply and demand, that the utility intends to acquire over the long-term to serve the growing demand for electricity in BC. BC Hydro also submitted its RRA for F2007/F2008 in May, 2006. At the time of submission of this Resource Plan, the regulatory processes for review of the IEP, approval of the LTAP, and review and approval process of the RRA, are in progress. A decision from the Commission on either submission is not expected for a number of months.

As the Province's largest electric utility, serving most of the BC and all of Vancouver Island, BC Hydro's plans for generating and delivering electricity have an impact on TGI's service requirements and planning outlook. In addition, BC Hydro is TGI and TGVI's largest single customer for transportation service to Burrard Thermal in the Lower Mainland and the Island Cogeneration Project (ICP) on Vancouver Island. The key issues drawn from the 2006 IEP that are relevant to planning at TGI are discussed below.

2.2.3.1 BC Hydro's Demand Forecast and Supply Shortfall

With higher than anticipated electricity demand growth, BC Hydro has identified that a gap exists between electricity generation resources in BC and the forecast for electricity demand[18].

[17] BC Progress Board Report – Strategic Imperatives for British Columbia's Energy Future. 2005. P31.

[18] BC Hydro 2006 Integrated Electricity Plan, Section 4.5, p4-26 to p4-38.

New firm energy and new dependable capacity resources are required in by BC Hydro Fiscal 2009 and F2010 respectively, and downstream benefits from the Canadian portion of the *Columbia River Treaty* with the US[19] are relied on to meet the shortfall in dependable capacity until those resources are in place. Further, there is considerable uncertainty around the capabilities of existing and planned resources to meet that gap over the next 20 years.

BC Hydro's reliance on Burrard Thermal, and hence the need for TGI to be able to provide firm transportation service to BC Hydro, is impacted by the capability of planned electricity resources to serve future demand. The implications for Burrard Thermal and TGI are discussed below. Also, TGI needs to be able to provides sufficient transportation capacity to meet TGVI's requirements at Eagle Mountain, north of Coquitlam, for TGVI to meet core customer and VIGJV demand as well as demand from ICP. Considerations for serving ICP demand are discussed in Section 2.2.3.3, below.

2.2.3.2 Future Plans for Burrard Thermal Generating Station

TGI currently provides firm transportation service to BC Hydro under the Bypass Transportation Agreement ("BTA") whereby TGI transports natural gas from Huntingdon to Burrard Thermal across its Coastal Transmission System. To allow for BC Hydro to rely on Burrard Thermal for dependable capacity, BC Hydro has held firm CTS capacity under a long term firm transportation agreement with TGI since 1999. The agreement is for 30 years, however BC Hydro does have a right to terminate the agreement upon appropriate notice and the payment of a termination fee based on the then depreciated value of the TGI facilities that were put in place to provide firm capacity under the BTA.

As part of the load resource balance discussed in the 2006 IEP, BC Hydro shows that it plans to rely on three units at Burrard Thermal to provide dependable capacity and firm energy until the April 2009, and then all six units until the April 2014[20]. BC Hydro is currently assessing different options beginning in 2014 which include maintaining, replacing or re-powering Burrard. As part of the 2006 IEP review, BC Hydro is requesting approval for a LTAP which could position BC Hydro to replace Burrard contribution of energy and capacity to the system by 2014. BC Hydro has also indicted that this is likely the minimum timeframe to have the proposed Interior to Lower Mainland transmission upgrade in place. It is expected the forthcoming 2006 Provincial Energy Plan Update will provide more direction with regard to the future of Burrard Thermal however TGI is expecting to continue to provide firm transportation under the BTA until 2014 at the earliest.

2.2.3.3 Future Plans for ICP

ICP is an Independent Power Producer ("IPP") owned and operated natural gas fuelled, electricity generating facility in Campbell River on Vancouver Island. BC Hydro has a long term

[19] Under the Columbia River Treaty, Canada is entitled to the return of one-half of the downstream energy and capacity benefits resulting from increased electricity generation on the Columbia River in the US due to the construction of dams in Canada, ending September 2024, to be delivered over existing interties with the US.

[20] BC Hydro 2006 Integrated Electricity Plan. Section 4.4.3.4, page 4-24

Electricity Purchase Agreement with ICP's owner, Calpine Island Cogeneration LP, whereby BC Hydro delivers the gas supply and takes the electricity output at the plant gate. The Electricity Purchase Agreement expires in 2021. TGVI has provided firm transportation service to ICP since the generation facility was put in service in 2001, through one to two year agreements that have been extended from time to time. Currently, TGVI has a short term contract to provide firm transportation service to ICP that expires in 2007 although it can be extended to the end of 2008.

As discussed in the 2006 IEP, the ICP EPA is one of 59 contracts as of April 2006 that BC Hydro has in place with IPPs that contribute to BC Hydro's system wide requirement for firm energy and dependable capacity[21]. The 2006 IEP assumes that each of these IPP contracts are renewed at the end of their contracted terms and therefore form part of BC Hydro long term resource stack. BC Hydro has also confirmed in the 2006 IEP proceeding that for planning purposes ICP's energy capability is 1,900 GWh/y based on 90% availability but that its expected dispatch may be more or less.[22]

Historically, BC Hydro rights to dispatch the facility has been limited to ensure that the facility meets its obligations to the cogeneration steam host, Catalyst Paper's Elk Falls mill. However, in May 2006, BC Hydro, Calpine and Catalyst Paper entered into a short term dispatch agreement which allows BC Hydro to dispatch ICP subject to certain operating restrictions. BC Hydro has indicated that all three parties are currently working toward a long term agreement that would allow BC Hydro to fully dispatch ICP and at the same time, meet the respective objectives of Calpine and Catalyst[23]. These developments cast uncertainty on BC Hydro's long term requirement for firm transportation on TGVI's system.

BC Hydro has assigned a portion of its BTA capacity to TGVI for delivery at Eagle Mountain as part of its arrangements for firm transportation service across TGVI's transmission system to serve ICP. If Burrard is decommissioned in the future and BC Hydro terminates the BTA, it is possible that TGVI will seek to increase its capacity across the CTS in order to continue to provide service to ICP.

2.2.3.4 DSM Programming and Fuel Substitution

BC Hydro's resource analysis shows that new, more aggressive DSM programs are the most cost effective resources available to the Utility. Each of the three new major DSM programs (EE3, EE4 and EE5[24]) identified in the LTAP is planned to begin implementation in BC Hydro's fiscal 2008. The DSM programs outlined in the LTAP are based mainly on energy efficiency improvements and only very limited residential fuel substitution. In its communications with

[21] BC Hydro 2006 Integrated Electricity Plan. Section 4.4.2.1, page 4-21.

[22] BC Hydro 2006 IEP Proceeding, Exhibit B-10, Reply to TGI Information Request 1.2.3

[23] BC Hydro 2006 IEP Proceeding, Exhibit B-10, Reply to JIESC Information Request 1.11.1

[24] EE3, EE4 and EE5 refer to Energy Efficiency refer to incremental new demand side management programs identified in BC Hydro's 2005 Resource Options Report – page 6-4 of Appendix F, BC Hydro 2006 Integrated Electricity Plan.

customers, however, the utility is increasingly encouraging the use of natural gas and other fuels for space and water heating rather than electricity[25].

On the mainland, TGI hopes to build on the success that TGVI has had in working with BC Hydro on fuel substitution initiatives in order to help relieve some of the growing demand for electricity service throughout BC that is already in a load – resource gap situation. TGI believes that this type of fuel substitution program will benefit energy customers across the Province by conserving heritage resources, keeping prices competitive and broadening the energy mix available in BC. TGI will continue to work with BC Hydro wherever practical on energy efficiency programs and will continue to pursue fuel substitution opportunities that make sense for our customers.

2.2.3.5 Rate Design

Although rates for electricity are increasing, the rates being requested by BC Hydro represent a blend of new incremental market-based supply and Heritage resources. The rate structures affecting most of BC Hydro's customers do not distinguish between the higher costs of new incremental electricity supply and the low cost Heritage resources so the price signals of growing electricity consumption are muted. Also, BC Hydro's rates are set on a postage stamp basis across BC even though regional circumstances may mean that system costs are higher in some areas than others. BC Hydro's F07/F08 RRA seeks to recover increasing costs of the utility, but does not address rate design and rate structure issues that would enable customers to see the true impact of their energy choices and consumption practices. TGI looks forward to BC Hydro's upcoming rate design application where these matters can be addressed in order to encourage energy users to choose the right fuel for the right use, at the right time.

2.2.4 Natural Gas in a Sustainable Energy Framework

The most commonly accepted definition of sustainability is that developed by the Brundtland Commission: *"..development that meets the needs of the present without compromising the ability of future generations to meet their own needs"*[26]. It is also commonly accepted that sustainable development must meet three criteria: environmental, social and economic. Among the Terasen Gas Utilities, sustainability reflects that three-pronged approach. It also reflects our underlying belief in "the right fuel for the right use at the right time" depicted previously in Figure 2-7. Terasen Gas Utilities offer a safe, reliable, secure, affordable and efficient energy choice to meet the growing needs of businesses and communities while enabling the pursuit of sustainability over the long run. Fundamental to environmental responsibility at Terasen Gas is a strong belief that this valuable resource must be used in an energy efficient manner. The use of energy efficient natural gas space heating, hot water heating, and commercial and industrial equipment satisfies the three criteria for sustainability.

[25] http://www.bchydro.com/newsletters/connected/connected37228.html

[26] "Our Common Future". Report to the World Commission on Environment and Development. 1987. 374p.

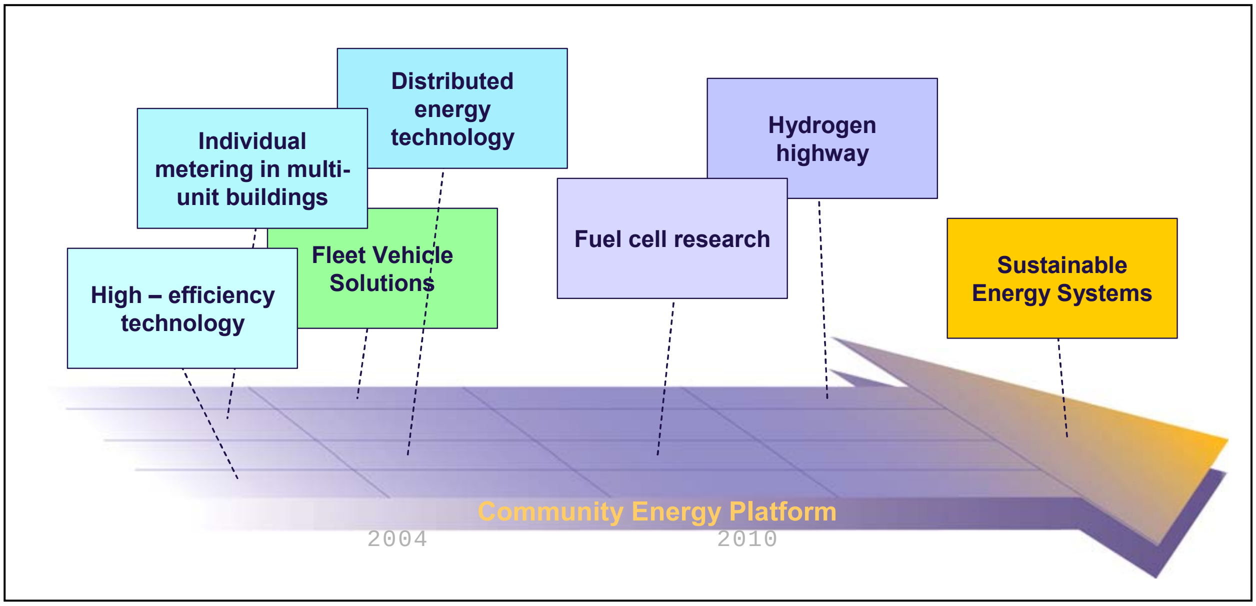
Looking to the future, as the most hydrogen rich fossil fuel available, using natural gas moves us down the carbon chain, closer to the vision of the "hydrogen future". Further satisfying the social criteria for sustainability, many natural gas energy solutions are flexible and can accommodate future technologies when they become more economically attractive. Hydronic technologies discussed in this section provide an example of this interchangeability.

Finally, natural gas satisfies the requirement for sustainable development to be economic. Costs for all sources of energy are increasing, yet natural gas in energy efficient applications continues to remain competitive and affordable. Throughout this Section are examples of how natural gas occupies and important role in a sustainable energy framework.

2.2.4.1 Natural Gas Solutions for Communities

Natural gas is an important part of an efficient, environmentally sensitive and economic energy platform today, and an important bridging fuel for advancements in energy system technology for tomorrow. The energy efficiency of natural gas offers important advantages for both economic health and air quality standards in B.C. Natural gas will also be an important part of developing new, cleaner energy technologies such as hydrogen fuel cells. Identifying and implementing the most energy efficient choices should become integral to Community Energy Planning. Figure 2-8 below describes five ways that natural gas can benefit communities now and going forward.

Figure 2-8 The Role of Natural Gas in Sustainable Energy Planning



High-Efficiency Technology

Condensing furnaces, boilers and hot water heaters are the latest in high efficiency, gas fired energy technology. Using condensing technology, home furnaces and both home and commercial boilers can reach efficiencies in the 87% - 97% range by drawing sufficient heat out of the combustion gases to condense moisture in the gases and release additional, useable heat. This technology is available today and although initial capital costs may be higher, energy efficiency gains over the long run bring life cycle costs down and take advantage of the benefits of improved energy efficiency discussed above.

Individual Metering for Multi-tenant Developments

Terasen Gas Utilities can implement individual metering for multi-unit developments, including high density, residential developments. These processes and systems allow the benefits of high efficiency gas appliances to be more easily brought into apartments, condominiums and multi-tenant, commercial complexes. This technology encourages conservation by linking costs to individual unit rather than overall building use. Implementing these types of solutions into new construction will help reverse the trend toward less efficient energy choices.

High-Efficiency District Energy Systems

The gas boiler technology described earlier can be combined with hydronic heating systems to improve system efficiency, reliability and life cycle costs even further. Hydronic heating systems - the circulating of heated water from a centralized source to facilitate the distribution of space heating and hot water – are a long-established and proven technology. When combined with newer, high efficiency gas boiler technology, these systems can provide reliable and cost-effective distribution of energy for space heating and hot water in multi-unit developments or even multi-use communities, at some of the highest possible efficiencies. The Lonsdale Energy Corporation in North Vancouver provides an example of effectively implementing this type of distributed systems by supplying an entire mixed use, downtown area of the Municipality. New high density residential, community centre and business customers continue to be added to this highly efficient system that is expected to serve 3 million square feet of building space within 10 years.[27]

District energy technology is also one way of combining natural gas with other emerging renewable technologies to create a highly efficient and sustainable, mixed energy platform for growing communities. As new, renewable sources of energy are developed for a community, they can be easily exchanged within the existing district energy infrastructure, making the mixed energy platform flexible to future technologies as well.

Growth in district energy technologies is also creating a need for investment in new metering technologies in the same way that the need for individual metering in multi unit dwellings has driven the need for more refined metering systems. Measuring the flow of heat and other energy to individual users in a district energy system is essential for the fair and efficient distribution of the resource. Continued investment in metering technology improvements will aid in the continued development and implementation of this highly efficient energy distribution technology.

[27] Visit the City of North Vancouver's web site at www.cnv.org for more information on Lonsdale Energy Corporation.

Fleet Vehicle Solutions

Natural Gas Vehicles ("NGV") provide an attractive alternative for the transportation market by offering lower fuel costs and decreased emissions compared to conventional diesel or gasoline engines. NGV continue to gain popularity amongst fleet organizations that are cost and air quality conscious as they can be used in a wide range of light-duty, medium and heavy-duty applications. NGV technology presents one of the biggest opportunities in the Province to reduce GHG and pollutant emissions from automobile transportation and is an important part of an infrastructure that supports future conversion to hydrogen.

The 2004 Resource described successful NGV fleet programs[28] in place in BC, including a pilot fleet vehicle program at the City of Victoria[29], Lordco Auto Parts[30] (boasting 50 NGV among its fleet in 2004) and Novex Courier[31] who call themselves the Clean Courier and count NGV as an essential component of their clean vehicle fleet. Since that time, TransLink has committed to the re-powering of 25 of their existing natural gas buses, as well as a new order of 50 buses, for a total 75 buses that will be running on clean burning, natural gas by fall 2006. The Resort Municipality of Whistler has also adopted a natural gas transportation plan for their municipality which includes light-duty and heavy-duty fleet applications. Efforts continue to be made to promote the use of natural gas and incentives needed to rollout successful programs for a sustainable, alternative fuel infrastructure.

Fuel Cell and Hydrogen Fuel Research

A lot of research is taking place in the development of fuel cells to provide clean energy for a wide range of uses with many different types of fuel cells and alternative fuel sources under development. Hydrogen fuel cells are currently among the leading candidates for implementation and pilot projects. As a fossil fuel with the simplest hydrocarbon, natural gas represents an important feedstock for the production for use in fuel cells and for research in hydrogen technology. The Terasen Gas Utilities continue to monitor hydrogen technology and fuel cell initiatives such as BC's Hydrogen Highway and potential pilot vehicle programs. Where practical, Terasen Gas representatives will consult with appropriate stakeholders to continue to identify and develop the role of natural gas and infrastructure in these initiatives.

2.2.4.2 The 2006 BC Energy Forum

In January 2006, the Terasen Gas co-sponsored a BC Energy Forum with the theme being sustainability and energy choice. The forum brought a wide range of energy industry experts, utility professionals, government representative, community planners and other stakeholders

[28] Terasen Gas Inc. 2004 Resource Plan. Pg 49.

[29] http://www.city.victoria.bc.ca/common/index.shtml

[30] BC Climate Exchange Newsletter, Issue 4, June 2004, Fraser Basin Council: http://www.bcclimateexchange.ca/doc/newsletters/Newsletter_Jun2004.pdf

[31] http://www.novex.ca/default.asp

together to exchange information and views, share ideas, challenge assumptions and plan energy choices for a sustainable future. Appendix D contains an overview of the forum including the purpose, planning and program for the event as well as a participant feedback survey response summary expressing the forum's success. For the Terasen Gas Utilities, the planning and implementation of the 2006 Energy Forum confirmed the importance of the following Sustainable Energy Principles in planning for BC's energy future:

- A sustainable energy system includes a diverse mix of energy options.
- "*Right Energy, Right Use, Right Time*" allows British Columbians to efficiently develop and use its diversified supply of energy to support a growing economy.
- Market based approach to policy and regulation to preserve continued access to low electricity rates.
- Streamlined regulatory, environmental and business framework for energy infrastructure and supply decision making.
- Educating Stakeholders in Energy Choice.

2.2.4.3 The Whistler Example

TGW put this sustainable energy framework to the test in efforts to help the Community of Whistler create an energy platform which, over time, the community could move from its dependence on fossil fuels toward sustainable energy systems. The first stages of Whistler's Sustainable Energy Strategy are under way with the Commission's approval to convert the existing propane distribution system to cleaner burning natural gas, and connect it to TGVI's transmission system. The strategy also envisions a range of energy choices that are now being planned in the community such as waste energy recovery and geo-exchange systems for the Athlete's Village, natural gas fleet vehicle solutions that reduce emissions over conventional vehicle fuels and district energy systems that have interchangeability to adapt new fuel choices and emerging sustainable technologies as they are developed. More information on how TGW is helping Whistler to meet their sustainable energy needs can be found in the TGW 2005 Resource Plan Update[32].

2.2.5 Energy Choice in British Columbia

As described in the Whistler example above, truly integrated energy planning considers a range of energy sources and systems for each end use in the mix of local, regional and provincial energy plans. From the end user and the community planning perspectives, determining the most appropriate source or system for each end use includes evaluating the energy choices against various socio-economic, environmental and reliability criteria. The following discussion presents some historic trends in residential energy choices in British Columbia and explores the implications of these trends in energy planning for the future. Many of the concepts and

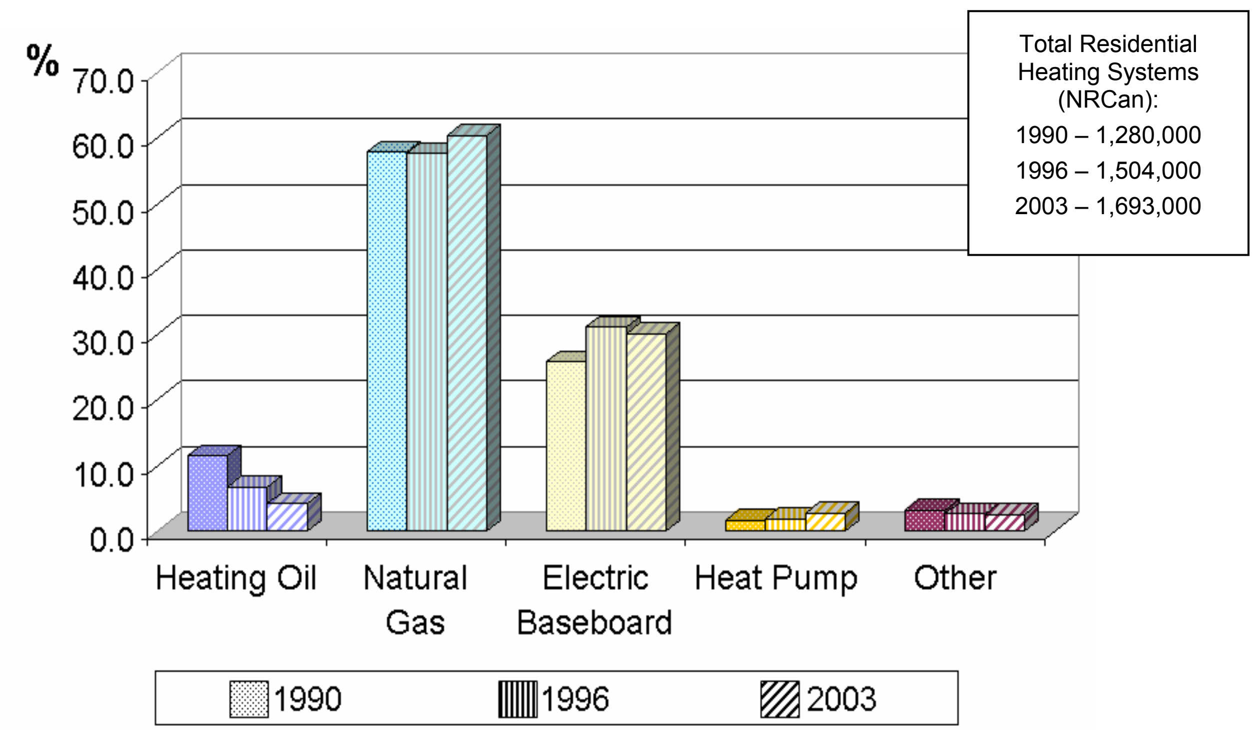
[32] Terasen Gas (Whistler) Inc. 2005 Resource Plan Update. http://www.terasengas.com/_Publications/Regulatory/Submissions/Whistler/default.htm

principles presented elsewhere in this section are also brought together in the discussion below to show how they affect community energy planning for the future.

2.2.5.1 Trends in Residential Energy Choices in British Columbia

Natural Resources Canada ("NRCan") publishes a number of energy use statistics that provide a provincial view on energy use trends since 1990. Figure 2-9 shows the relative mix of residential energy systems in 1990, 1996 and 2003.

Figure 2-9 History of Residential Heating Systems in B.C. by Percentage



Similarly, Figure 2-10 shows the relative mix of energy systems, in this case specifically for apartments in BC. Figure 2-11 shows the energy use trends for domestic hot water in BC apartments.

Figure 2-10 History of Apartment Heating Systems in B.C. by Percentage

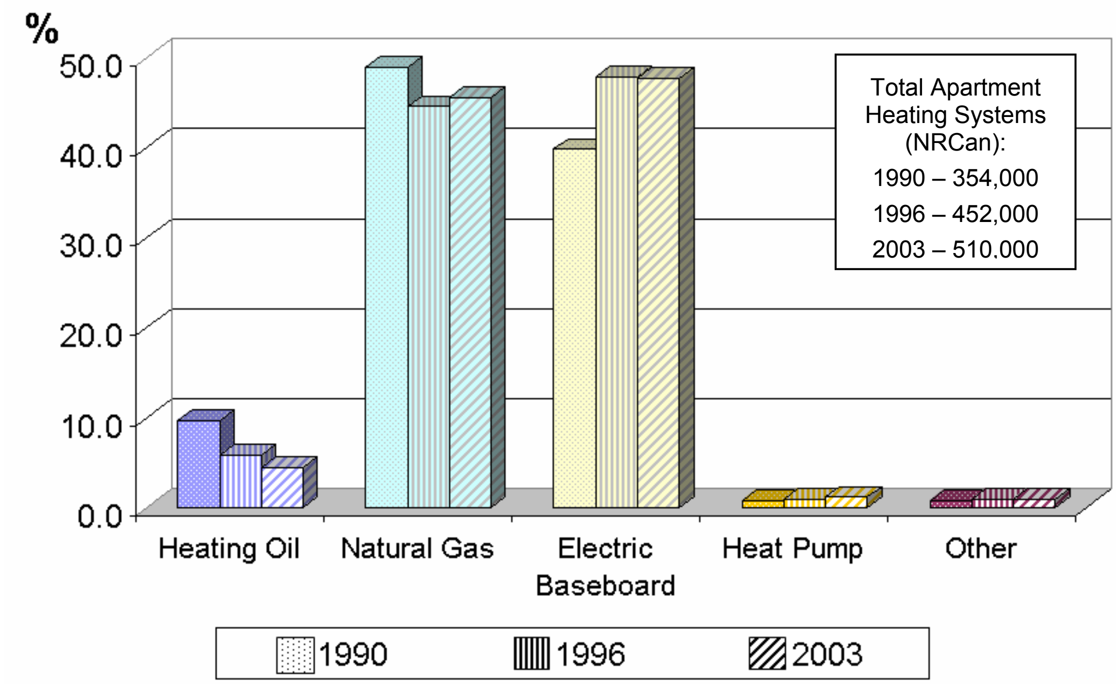
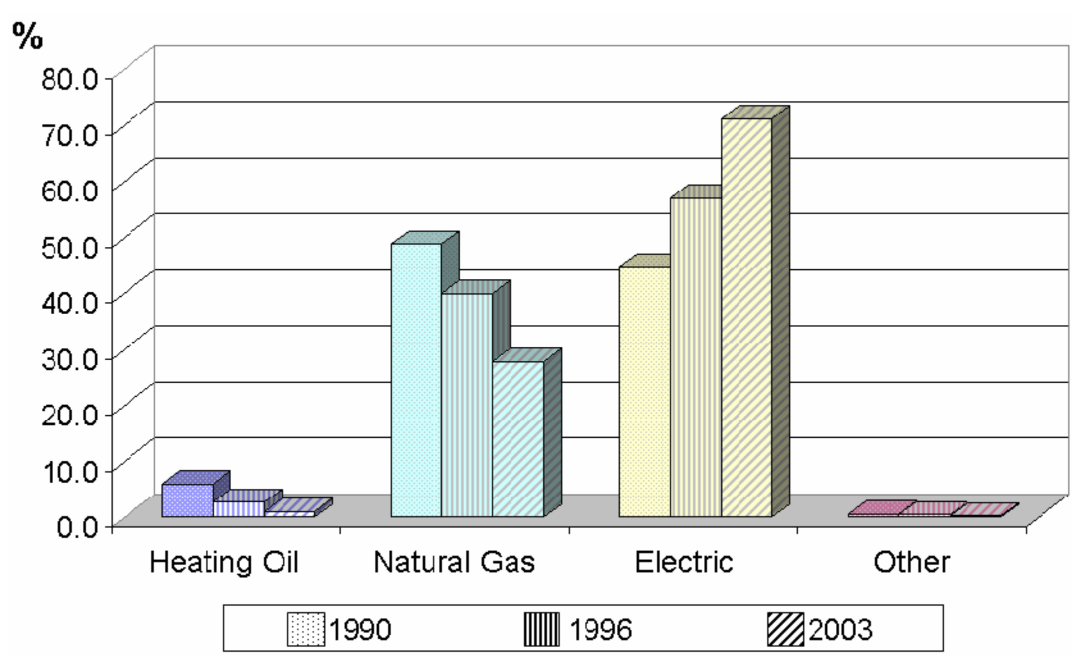


Figure 2-11 History of Energy Use for Domestic Hot Water in B.C. Apartments



Heating Oil (or Fuel Oil)

Since 1990, heating oil has had only a small portion of the market for residential heating and hot water in BC. The cost, convenience, reliability and environmental benefits of natural gas and electricity are among the factors causing the heating oil share of the home energy market to diminish. With world-wide oil prices on the rise, this trend is expected to continue.

Natural Gas

The NRCan data (Figure 2-9) shows that for overall residential home heating, natural gas has enjoyed a slightly growing market share since 1990. This trend is due in large part to growth in the single-family market segment since, as Figure 2-10 indicates, natural gas has lost share in the apartment, or multi-family segment during that same period. This decrease in market share for natural gas in apartments appears more pronounced in the energy choices for hot water heating shown in Figure 2-11.

Electricity

Electricity, on the other hand, has realised a jump in market share over the 1990 to 2003 period. This trend can also be largely attributed to growth in the apartment, or multi-family segment. The reason for this growth in electricity market share appears to be the relative simplicity and lower, up-front capital costs for installing electric baseboard heating in multi-unit buildings, over the initial capital costs of other energy technologies. When combined with a provincial increase in the percentage of new multi-family housing starts reported by CMHC[33], this trend has the potential to place additional and unnecessary burden on the requirement for new electricity generation.

Terasen Gas representatives have observed that this trend toward electric heating systems in higher density residential developments in BC has become more pronounced in new construction than the NRCan data has captured. The NRCan data is based on high level sampling methodologies that appears to be derived from census data. Given the emerging gap between electricity generation capacity in the Province and demand for electricity that has been identified by BC Hydro, this trend continues to place greater, incremental demand on already constrained electricity resources. Finding new sources of generation to meet this additional new demand generally means finding ever more expensive sources of electricity, when natural gas and other energy sources can provide a more efficient and/or cost effective means of meeting new energy demand for space heating and hot water.

Heat Pumps or Geo-exchange Systems

Ground source heat pumps ("GSHP") are a form of geo-exchange system. These can be installed in single family applications, multi-family developments and district energy systems (discussed below). Air source heat pumps are another space heating and cooling technology, typically installed in some single family applications. Both types of systems are often installed

[33] http://www.cmhc-schl.gc.ca/odpub/press/2006/2006_07_11_0815_EBV.pdf

along with a secondary or back-up energy system that is typically either an electric or a natural gas system. These systems appear to have gained slightly in market share in certain areas of the Province. Local ground and weather conditions for successfully implementing heat pumps are very regional and site specific.

As the name implies, geo-exchange or geo-thermal systems use heat pump technology to exchange heat energy between ground, groundwater or surface water resources and the living or working environment in a building or buildings. There also appears to be growing interest in some urban areas for heat pump technology that utilizes waste heat from other municipal systems such as sewers and sewage treatment. Geo-exchange systems are most often used for building heating and cooling and hot water. Many of the conditions for successfully implementing geo-exchange technology are very regional and site specific. As well, the systems are generally more complex, with higher initial capital costs.

Currently, geo-exchange systems are often installed along with a secondary energy system that is typically either an electric or a natural gas system for supplementary or peaking energy needs. More and more, developers and community planners appear to be looking at hybrid systems that combine geo-exchange technology with other forms of both new and traditional energy technologies. These systems can be designed with building use and regional weather characteristics in mind to provide an optimal mix of energy efficiency, reduced emissions, system reliability and life cycle costs.

Communities in BC may begin planning for an energy future consisting of a mixed energy platform – one in which natural gas is expected to play a significant role for the foreseeable future. The Terasen Gas Utilities are pursuing opportunities in its various service regions to combine natural gas with geo-exchange systems in district energy systems (discussed below) to provide an optimal balance of reliability, costs, environmental benefits and customer satisfaction as some communities in BC begin to commit more resources to sustainable energy planning. TGI continues to monitor the development of alternative energy systems for impacts on customer additions and use rates.

2.2.5.2 Commercial and Industrial Energy Choice

While electricity remains the primary alternative to natural gas (see Figure 2-1), other traditional and emerging fuels and technologies also exist. The following discussion examines two other fuel and technology trends within the TGI service region.

Biomass and Biogas

Biomass energy is generated through the combustion of organic matter in plant material. This type of energy production comes from different sources but is commonly found in the pulp, paper, and wood products manufacturing sectors where significant amounts of organic waste material is produced from the industrial operations. Biomass energy is also commonly referred to as "hog fuel" because of the mechanical shredder, called a "hog", used to process the waste. The waste material including bark, sawdust, planer shavings and general waste wood are combusted in a boiler to produce steam for turbines to generate power. Since use of biomass results in no net increase in carbon dioxide emissions to the environment, and provides a way to dispose of waste material, it is perceived as being environmentally neutral.

As of 2004, British Columbia had an installed renewable energy (electricity and thermal) capacity of 16.1 GW[34]. Eighty-nine percent (89%) of the total electrical capacity in the Province is supplied by renewable sources, which consist of naturally regenerating energy resources such as the sun, wind, moving water, earth energy, biomass and biogas. 75% of BC's renewable energy power capacity is standard hydroelectric with about 24% derived from biomass wood residue sources (both electrical and thermal). Biogas currently plays a very small role in BC's energy landscape, accounting for less than one percent of electrical and thermal energy capacity in BC.

Wood biomass energy is used primarily by sawmills and the pulp and paper industry as a means of recycling and augmenting other higher efficiency fuels such as natural gas. Developments in recent years could make biomass fuel more of a threat to natural gas and other fossil fuels in some industrial applications. As natural gas and oil prices rise, the cost of producing biomass fuel becomes more attractive, providing additional incentive to industries to utilize biomass as their primary energy source instead of as a secondary source. Advances in technology in biomass production and emissions control have increased its efficiency making it more attractive economically and environmentally. The third and perhaps more significant development in the short term is an abundance of wood waste supply for biomass energy production as a result of significant increases in wood harvesting in an attempt to control and eliminate the pine beetle infestation.

The availability of this low cost supply may change the energy economics for some industries, particularly the greenhouse industry, making it more feasible to burn wood waste to generate biomass energy for consumption as the primary fuel with natural gas or oil as the supplemental or secondary fuel. Industrial demand forecast methodology, discussed in Section 3, captures fuel choice decisions by this customer group. The long term impact of this effect, however, is less certain. As more industries consider biomass for a greater portion of energy needs, and as more uses for beetle infested lumber are developed, creating higher demand, maintaining low costs for this supply becomes less certain over the long term. In turn, the pay back period for investing capital in new wood burning equipment becomes less certain. Many industries that invest in new wood burning equipment may also maintain their gas systems for operational flexibility or to take advantage of periods of low natural gas prices and maintain their fuel choice alternatives.

Biogas energy is typically methane that is collected as a waste product of other industrial or municipal processes such as landfill gas, gas from sewage treatment plants or industrial digestion process gas. Use of biogas resources is generally opportunistic in that it makes sense only when a ready and sufficient source of the gas is located close to a ready user and where the incremental costs of installing the necessary equipment are reasonable. Limited sources of biogas and cost constraints mean that biogas is expected to play only a small role in BC's energy future. Yet, in some instances of new development, biogas technology can be effectively combined with other traditional fuels such as natural gas to provide cost and

[34] Review of Energy Consumption and Supply in British Columbia 1990 to 2004. February, 2006. Prepared for The British Columbia Ministry of Energy and Mines, June 2004, by the Canadian Industrial Energy End-use Data and Analysis Centre, Simon Fraser University, Burnaby, BC.

environmental benefits in a district energy system that could serve industrial, commercial and residential needs. District energy technology is discussed previously in Section 2.2.4.1.

Distributed Generation

Small scale power generation systems and equipment located at or near the end-use is a growing choice in some regions of North America. Used primarily in commercial, industrial or institutional applications, these systems can provide peak shaving and fuel switching benefits as well as improvements in power quality and reliability for sensitive applications and remote locations. Distributed generation equipment typically relies on traditional fuels such as natural gas at relatively high efficiencies and low emission. However, technology advancements are allowing the use of alternate fuels such as lower quality recovered gas from industrial processes and bio-gas from landfills, wastewater treatment and agricultural operations.

Distributed generation does provide some potentially significant benefits to the regional energy mix in circumstances where the generation facility is close to the electrical distribution network. The company using this technology to generate electricity can use excess generation capacity to supply electricity to the electrical distribution grid. BC Hydro, for example, does enter net metering arrangements with this type of Independent Power Producer, which can use the excess power to further offset energy costs. Where sufficient generation capacity can be supplied in this way, distributed generation has the potential to partially offset the need for new electrical transmission and distribution infrastructure. Where new distributed generation is being built, higher efficiencies in the generation process also have the potential to provide energy and emissions savings over older, fossil fuel burning, legacy generation equipment.

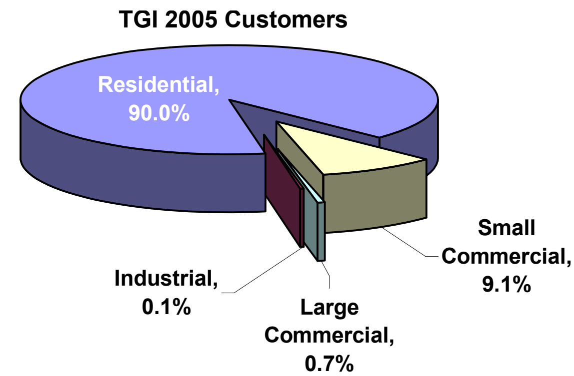
Looking further into the future, improvements in fuel cells and renewable energy technologies such as wind, run-of-river, and solar alternatives could add to the growth in distributed generation in locations where strict emission controls are in place or desired by the community. New systems, small enough and quiet enough to work in the home are being developed in Europe. Incentives from federal, provincial and local municipal governments as well as some utilities for pilot projects and implementing new technologies might speed the growth of distributed generation. With the current gap that exists in electricity supply and demand on the Island, and demand for electricity continuing to grow, TGI does not see distributed generation technology reducing demand for natural gas.

3 DEMAND FORECAST

3.1 Introduction to Demand Forecasts

TGI provides natural gas transmission and distribution services to approximately 800,000 residential, commercial, industrial and transportation customers in more than 100 communities in the Province of British Columbia as of the end of 2005. Figure 3-1 illustrates the number and types of customers on the TGI system. This demand forecast has been prepared with a 25 year planning horizon to provide the basis for the long range system planning and gas supply option analysis conducted in subsequent sections of this resource plan.

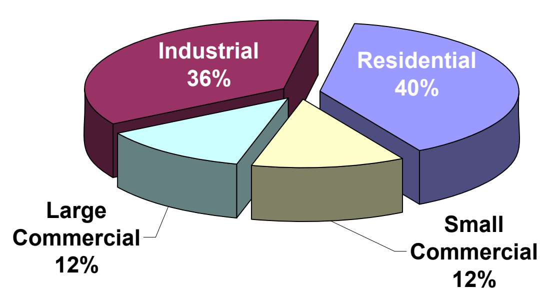
Figure 3-1 TGI Customer Profile - 2005



The two key deliverables of the demand forecast that are important in resource planning are annual demand and peak day demand. Annual demand is the cumulative daily demand for gas over an entire year and captures the general growth trends for energy consumption over the planning period. Annual demand is used to develop the plan for securing an adequate supply of energy and is also use for determining customer rates.

Though the majority of customers are residential, annual demand is more evenly distributed between residential, commercial and industrial as seen in Figure 3-2.

Figure 3-2 TGI Annual Demand[35] - 2005



[35] TGI Annual Demand depicted here includes Burrard Thermal, but does not include TGVI or TGS demand

Design day or hour demand is the maximum demand for natural gas that a utility expects to provide and is a critical input into system planning. This measure of demand sets the parameters around which the supply system must be designed in order to meet customer requirements during the period of highest expected heat load (i.e. coldest expected temperatures) that might occur during any year within the planning period.

3.1.1 Differences between Annual Demand and Peak Demand

Though detailed descriptions of annual demand and design demand methodology follow later in this section, it is important to highlight the different purposes and hence the different approaches used to arrive at each type of demand forecast. Factors such as changing weather patterns, customer mix and customer use rates can have different effects on the annual and design demand forecast.

The role of the annual demand forecast is to predict the most likely consumption in future years assuming typical weather conditions. The pattern of declining use rates among residential customers within the TGI territory is mainly driven by 1) the replacement of less efficient older appliances and 2) the fact that weather data is showing a warming trend. In order to ensure that the annual demand forecast is representative of the recent trend in customer use rates, only the last ten years of weather data is used for analysis purposes.

The purpose of the peak demand forecast is to determine consumption under extreme or unusual weather situations. To ensure that the needs of customers are met, a longer time horizon is necessary for weather analysis so that the current system can meet the need should extreme weather events similar to those experienced in the past manifest themselves again. As will be described in more detail later, the peak demand analysis is based on the five coldest winters experienced since 1961. A report prepared in 2003 by Pacific Meteorology Inc.[36], states that:

> *"In the Lower Mainland area, the latest data – which includes the current global warming now in effect – does not show evidence of a change in frequency of the coldest annual mean daily temperatures. And it was found that the coldest mean daily temperatures occurred just as frequently during El Nino occurrences as during non El Nino events. Since in the Lower Mainland area there has been no evidence yet of a change in frequency of the coldest annual mean daily temperatures, the current return periods are probably the best estimates that can be made at this time."*

Based on this expert's opinion, TGI continues to base its peak demand forecasts on historical weather data beyond the 10 years that is used to arrive at annual demand. The other factor driving changes to the peak demand forecast is the forecasted change in customer mix. For the planning period, residential customers are forecasted to be the fastest growing segment of customer additions. Residential customers have the lowest load factor, that is to say they have the lowest average daily demand as a percentage of design day requirements. Consequently,

[36] Pacific Meteorology. September, 2003. Return Periods of Low Mean Daily Temperature for Lower Fraser Valley. 19p.

the net effect of the customer mix shifting more towards residential customers is that the growth in design day demand is outpacing the growth in annual demand for the overall TGI system. Adding to this is the point made earlier that the warming trend tends to reduce the annual demand (based on the 10 most recent years) for weather sensitive rate class while not affecting the peak demand which is based on the five coldest years over a longer timeframe.

3.2 Customer Type

For the purpose of this Resource Plan, TGI divides its customers into four types.

- Core Customers
    - o residential, commercial and firm industrial sales
- Transportation & Interruptible ("IT") Customers
    - o commercial and industrial transportation
    - o IT sales
- Generation
    - o BC Hydro for Burrard Thermal
- Utility Transportation Customers
    - o TGVI (Including demand for TGW and TGS)

The focus of this demand forecast is on TGI's residential, commercial and industrial customers, comprising the Core and the Transportation & IT customer types. BC Hydro operates under contractual arrangements which are discussed separately at the end of this section. Utility Transportation customers are identified because provisions must be made to carry these volumes on TGI's distribution system, but a discussion of their respective Core demand forecasts are detailed in separate submissions as each of these companies is regulated under separate tariffs.

3.3 Core and Transportation & IT Demand Forecast Components

3.3.1 Forecast Methodology

Consistent with previous years, the forecasting process is comprised of four main components:

- Customer additions forecast
- Use per customer forecast - residential and commercial accounts
- Industrial survey
- Design day or hour demand analysis

Both the annual and design day or hour demand forecasts for residential and commercial customers (rates 1, 2 and 3 of the Core group, and rate 23 of the Transportation & IT types) are driven by the total number of customer accounts and their associated use per customer rate. The customer additions forecast is used to determine the number of new customers that are added to the existing customer base and reflects prevailing macroeconomic circumstances affecting residential and commercial customers. Consistent with the methodology used in prior years, the use per customer rate is estimated for residential and commercial customers and is multiplied by the corresponding forecast of customers in each respective rate class to arrive at annual demand. No customer additions are forecasted for the other Core and Transportation & IT customers unless there is specific market knowledge indicating a change. Use per customer rates are determined through an annual survey.

Changing market conditions can impact customer account additions and use per customer rates producing results that vary from the Base forecast. To address this uncertainty, three forecast scenarios (Base, High and Low) have been developed to represent the expected outcome with upper and lower bounds. Variability due to weather is addressed through the analysis of historical weather data to determine peak day requirements and normal weather conditions for determining annual demand requirements.

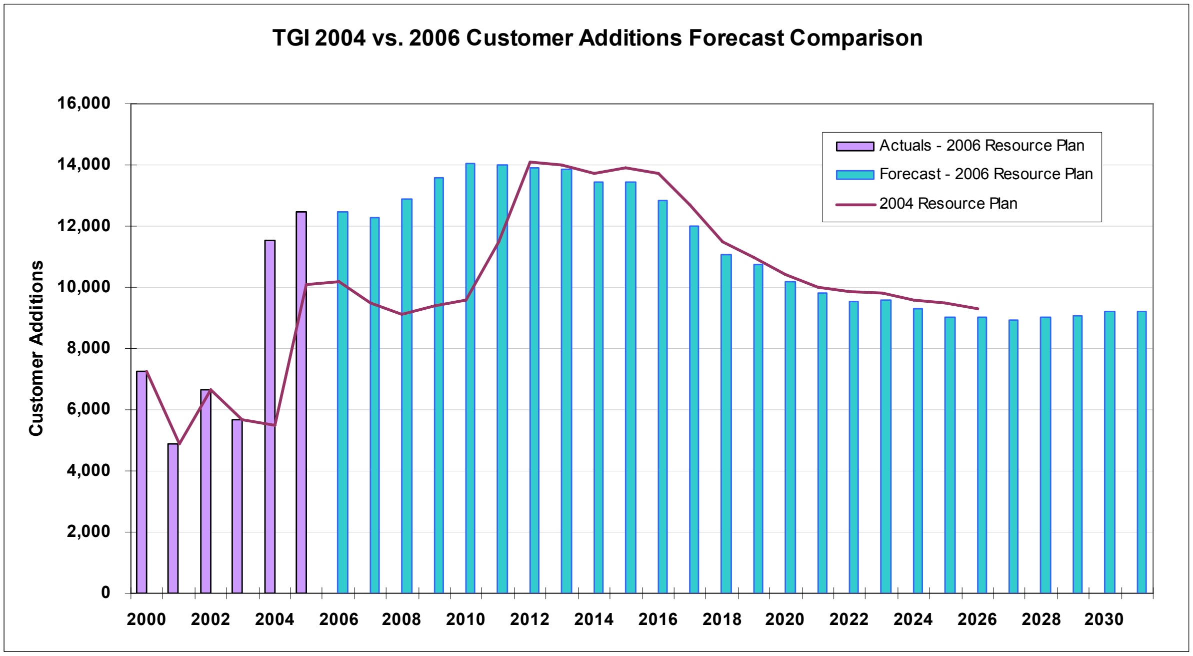
3.3.2 Customer Additions Forecast

The customer additions forecast is derived from broad regional economic forecasts and end-use information for the estimation of account additions for residential and commercial rate classes. Inputs gathered through industrial associations, research institutes, government agencies and periodic surveys provide the basis for relating economic data to account growth. Actual household formation data, estimated market share and historical commodity price are statistically linked with actual account additions to model annual account growth on a service area basis. These factors are then applied to obtain the expected number of customer account additions based on the most recent actual customer counts available. For the forecast produced in support of the 2006 TGI Resource Plan, the BC Statistics 2005 Household Formation Forecast was used as the primary predictor variable to estimate account additions by area over the forecast period, with the near-term forecast validated by current housing start and service request information.

The housing boom driven by low mortgage rates and improving consumer confidence has added new customer accounts at rates higher than those anticipated in the 2004 Resource Plan. Although mortgage rates are expected to slowly rise, a very active resale market together with continued population and employment growth are expected to maintain the current pace for the next few years.

As illustrated in Figure 3-3, the 2006 TGI Resource Plan shows an increase in forecasted customer additions as compared to the 2004 TGI Resource Plan over the period of 2004 to 2011. This increase reflects the exceptionally strong economic performance that the province has experienced over the past two years. The outlook for the upcoming years is still positive and is reflected in the upward revision to the factors that drive the forecast of account additions.

Figure 3-3 Comparison of Customer Additions for 2004 versus 2006



Three forecast scenarios – Base, High and Low were developed to reflect the range of possible outcomes in anticipated Core Market customer growth rates over the forecast horizon. The following is a discussion of the assumptions used to generate the three forecast scenarios.

3.3.3 Base Forecast Description

For the Base forecast scenario, the price of natural gas remains relatively competitive to electricity over the forecast period. Price volatility for natural gas will continue and be similar to that experienced in recent years. The primary predictor variable used in the account additions model is household growth rate by Local Health Authority, which is used to calculate account growth rates for the reasons discussed above. In addition, the effects of economic performance are assumed to be reflected in the household formation forecast e.g. dependency of a community on a single industry. New customer accounts due to conversions from alternate fuels are assumed to be negligible as conversion activity during the past few years has averaged only approximately 300 per year.

3.3.4 High Forecast Description

In the High forecast scenario, factors affecting demand for natural gas are favourable. The provincial economy continues to improve and grow with positive effects on the total number of household formations and housing starts in the province. Business and industry activity are strong as the economy expands. Natural gas remains relatively competitive to electricity over the forecast period. In addition, TGI is able to capture a significantly higher proportion of new housing starts compared to recent experience, particularly in the multi-family dwelling market segment.

The High forecast scenario supports the Terasen Gas Utilities' objective of achieving one million customers for its gas Utility entities by 2010 - primarily through residential customer additions from new construction attachments. Marketing efforts will focus on maximizing the capture of new construction starts by promoting the benefits of piping natural gas ahead of the construction phase when decisions on space and water heating are made. The emphasis will be on proactively managing relationships with builders, developers and communities.

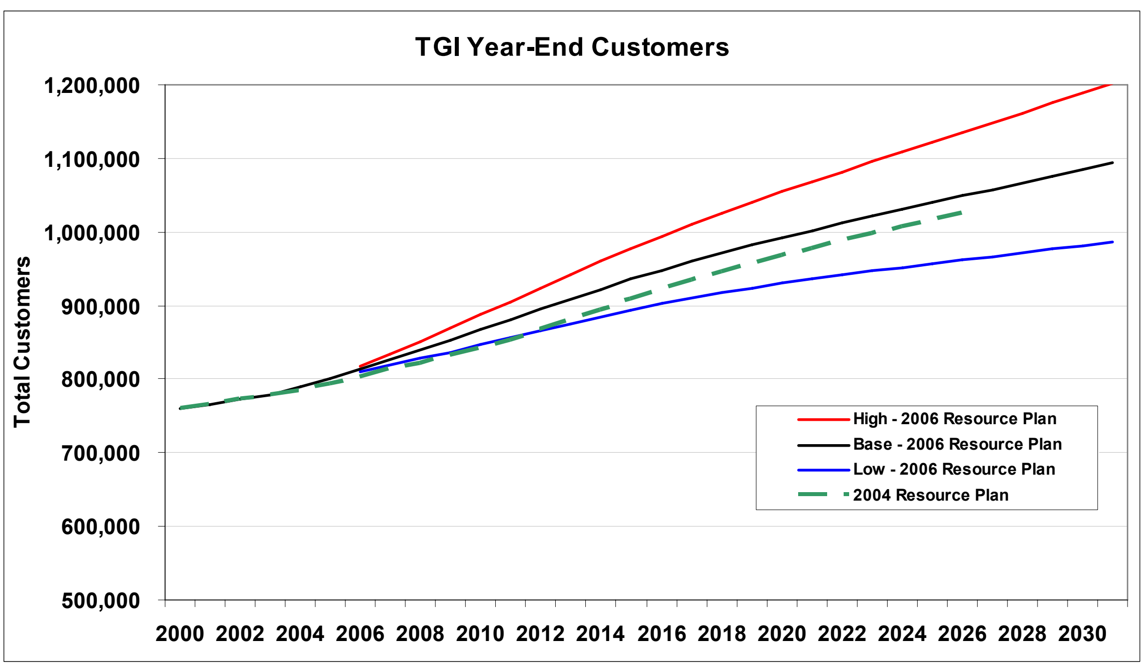
3.3.5 Low Forecast Description

For planning purposes, the Low forecast assumes that customer additions occur at a slower rate than forecasted under the Base scenario. The price of natural gas commodity is less competitive compared to electricity and price volatility for natural gas continues. New housing starts decline and continue to shift towards the multi-family market.

3.3.6 Total TGI Customer Count - Base, High & Low

Figure 3-4 illustrates the effect of the three customer addition scenarios on TGI total customer count. The base forecast from the 2004 TGI Resource Plan is included for comparison purposes. As discussed earlier, strong economic performance over the past two years and a more positive outlook for the future is manifested by an increase in the overall number of TGI customers. Though the number of customers is increased since the 2004 TGI Resource Plan, the forecast provided here is in line with the 2006 TGI Revenue Requirement.

Figure 3-4 Comparison of Total Customers for TGI - 2004 versus 2006 Forecasts



3.3.7 Use per Customer Forecast

For the residential and commercial rate classes, use per customer forecasts are developed for each service area and rate class by considering the following factors:

- recent historical normalized use per account
- customer migration between rates
- forecast use for new customer additions
- appliance conversion or replacement effects where applicable
- estimated impact of demand side management programs over the forecast period
- near term reaction of consumers to recent natural gas rate increases

In response to changes in customer lifestyle and the provincial demographic profile, TGI expects the proportionate share of multi-family housing to increase over the next several years. As homeowner preferences shift toward apartment-style condominiums and townhouses, further downward pressure on residential usage per account is expected. Other factors causing a reduction in use rates include space heating efficiency, improved home insulation and setback thermostats - all of which are in response to higher natural gas commodity prices. The competitive price perception of natural gas has eroded in recent years, notwithstanding that gas continues to be the most cost effective energy alternative for many applications. The forecast assumes that future electricity rate increases will help preserve the relative competitiveness of natural gas as a heating energy source over the next few years. Recent rate increases in 2005 are expected to have an impact on customer use rates in 2006 as customers seek to mitigate the financial impacts of these increases. Customers may undertake some further conservation activities to reduce gas use in the near term, such as turning back thermostats and hot water heater settings and reducing the use of their natural gas fireplaces.

A summary of historical and forecasted use per customer values are set out in Table 3-1. The normalized use rates for 2005 show a material difference from the previous year. This is attributable to customers reacting to significant increases in natural gas commodity prices during that period. The forecasted values show a small rebound for 2006 as commodity prices moderate, but the outlook still calls for use rates to maintain their decline in the near term as less efficient appliances are replaced by newer, more efficient ones.

Table 3-1 TGI Use per Customer Rates

	Normal 2003	Normal 2004	Normal 2005	Forecast 2006	Forecast 2007
Rate 1	103.1	102.6	97.4	100.7	99.5
Rate 2	303.6	313.8	305.8	307.0	303.3
Rate 3	3,292.0	3,500.9	3,387.6	3,391.1	3,334.1
Rate 23	4,883.4	5,112.6	4,714.4	4,978.6	4,902.4

3.3.8 Industrial Forecast

For most industrial customers (rates 7, 22, 25 and 27 of the Transportation and IT group), the demand forecast is driven by results to the annual customer survey. For those industrial customers not surveyed (rates 4, 5 and 6 of the Core group), demand volumes are projected based on historical data and sector analyses. As described earlier, the forecast for industrial customers assumes no net change in the number of customers over the forecast period, except where written requests for change of service have been received by TGI.

3.3.9 Total Annual Demand Forecast

The total annual demand for a region is arrived at by combining the entire forecast activities described to this point. Given the different design characteristics of the CTS and ITS which are explained later in this section, the annual demand forecast is developed for each region separately and is illustrated in Figure 3-5 and Figure 3-6 respectively. In both regions, total demand is forecasted to increase over the planning period with the bulk of the increase in volume coming from the growth in residential accounts.

Figure 3-5 CTS - Forecast Total Annual Demand for 2006 through 2031

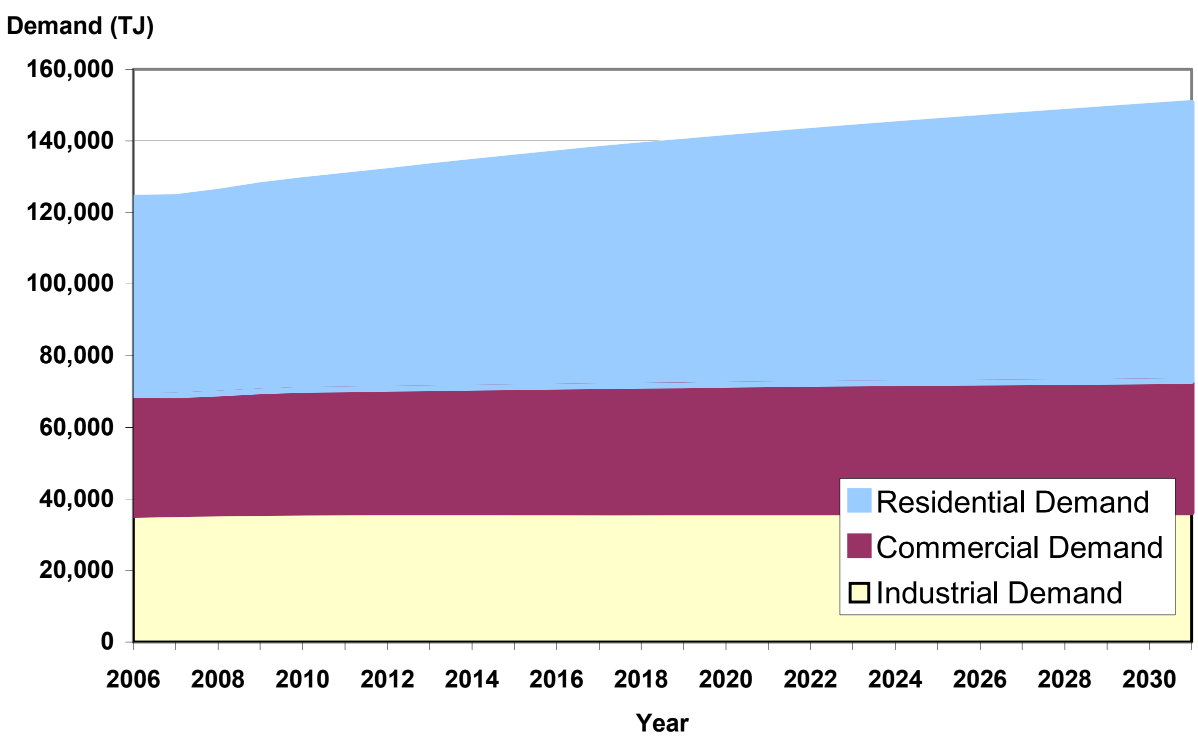
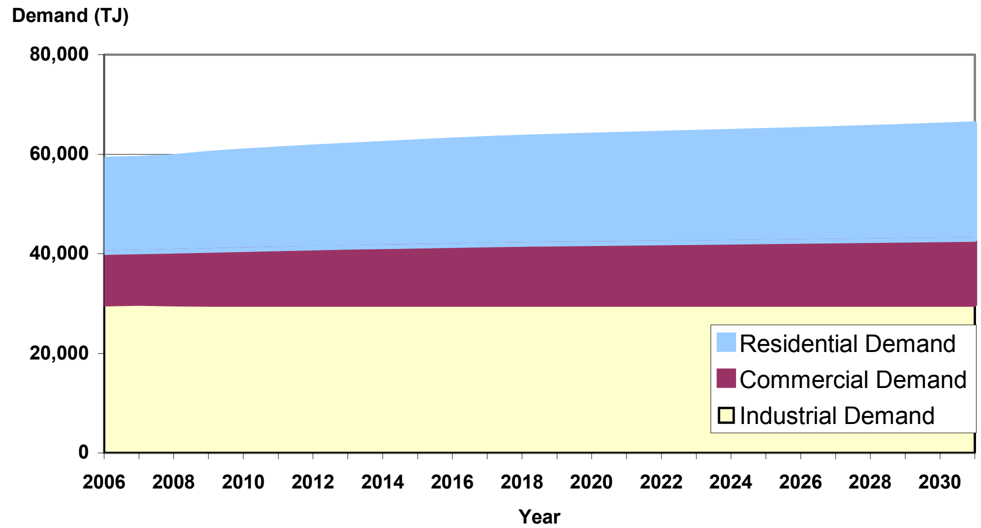


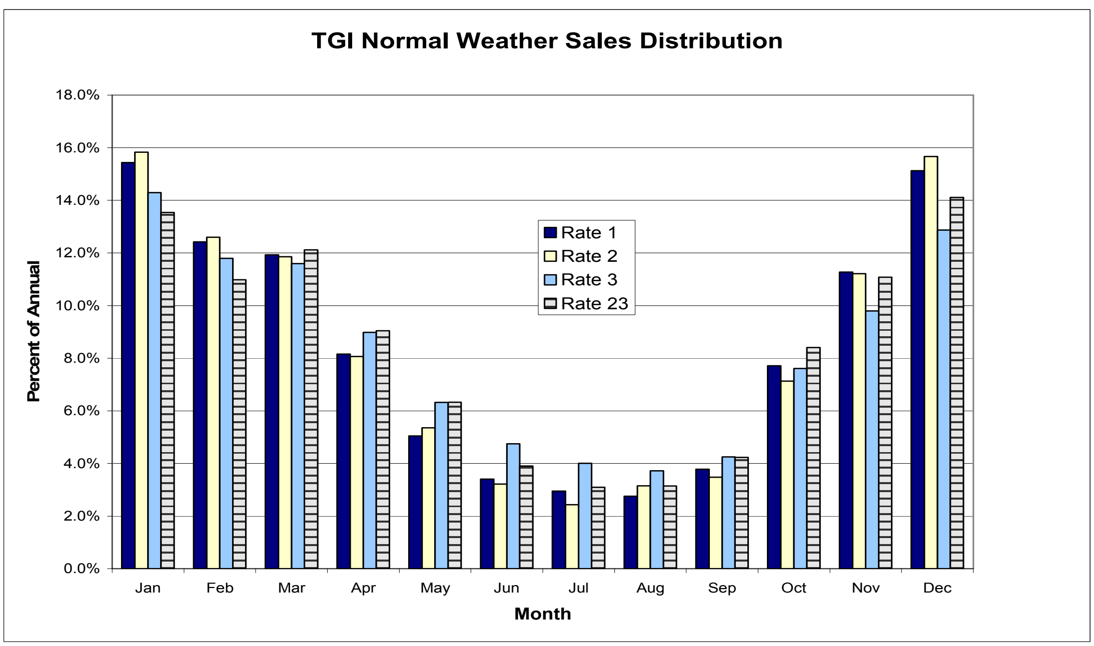
Figure 3-6 ITS - Forecast Annual Demand for 2006 through 2031



3.4 Peak Demand Forecast

As illustrated in Figure 3-7, temperature has a significant impact on natural gas consumption for the weather sensitive customers – residential and commercial (rates 1, 2 and 3 of the Core group, and rate 23 of the Transportation and IT types). This is to be expected as the majority of their consumption is related to space heating. As such, estimations of design day or hour demand are required to ensure adequate system capacity and gas supply.

Figure 3-7 Residential and Commercial Customer Annual Consumption Profile



Design day demand or design hour demand represents the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. This results in a design day temperature of 30.8 heating degree days (HDD)[37] (-12.8 °C) for the Lower Mainland region; 44.1 HDD (-26.1°C) for the Inland region; and 49.4 HDD (-31.4°C) for the Columbia region. To estimate the design day requirements, actual daily send-outs[38] for the past three contract years (November 1 – October 31) are regressed against temperature.

System planning and gas supply options are driven primarily by the design day demand or design hour demand[39]. For the CTS, design hour demand is used since the CTS covers a much smaller geographic area with less climatic diversity and has a higher portion of heat sensitive load. The CTS also has a lower maximum operating pressure. These factors combine to limit the capacity of the system, as linepack is not sufficient to moderate intra-day demand peaks. Because it covers a larger geographic area with lower population density than the Lower Mainland, the ITS uses design day demand rather than design hour demand to determine system requirements.

3.4.1 Weather Influences on Customer Demand

To estimate design day demand, a relationship between weather and demand must be established and then applied to the design day temperature described above. The relationship between weather and demand is established by analyzing daily historical demand as a function of weather (on an HDD basis). This is accomplished through regression analysis by estimating the model: Daily Demand = $\beta0 + \beta1 \times HDD_{13} + \beta2 \times HDD_{18}$, where HDD_{13} = Heating Degree Day based upon a 13 degree Celsius control point, HDD_{18} = Heating Degree Day based upon a 18 degree Celsius control point and Daily Demand = daily natural gas consumption for all core customers. Each of the past three most recently completed contract years (i.e. 2002, 2003 and 2004 contract years as of January 2006) are modelled separately, providing three sets of regression equations. Those equations are converted to a "per customer" basis, averaged over the three contract years and then grown over the forecast period to reflect the number of future customer accounts.

By applying the design day temperature to the averaged regression equation, TGI is able to estimate the design day demand. Figure 3-8 illustrates the historical consumption and weather experienced over the 2002 to 2004 contract years.

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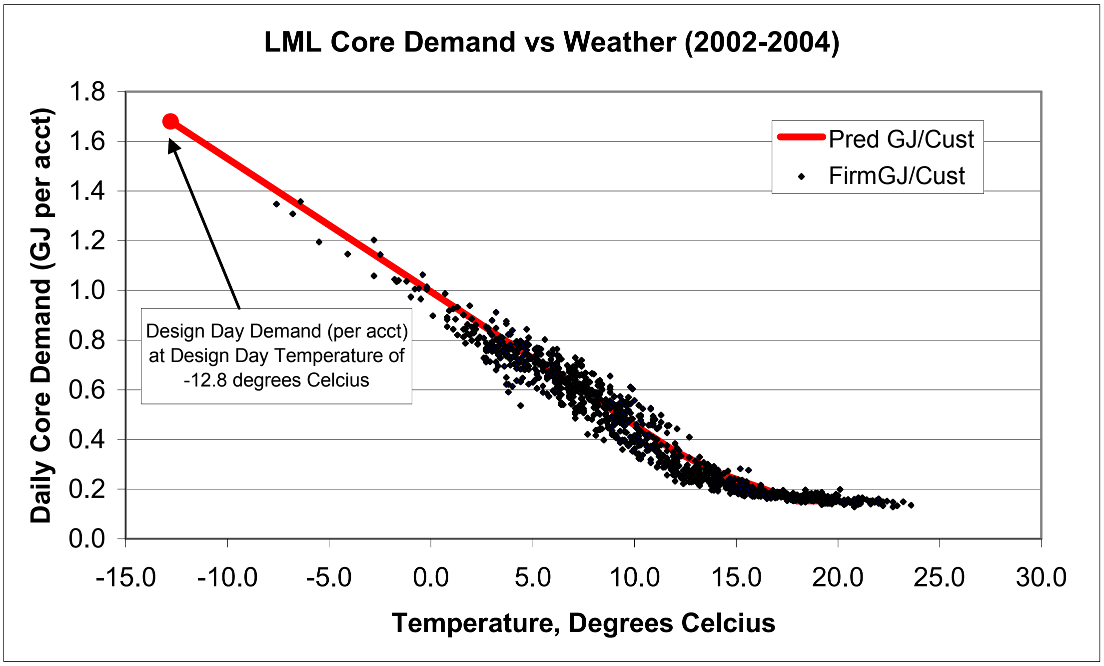
[37] A heating degree day is a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature - typically 18 degrees Celsius.

[38] Daily firm send-out refers to the daily sales made to customers on a bundled rate (rates 1-6), UAF losses, heater and compressor fuel.

[39] Design Day/Design Hour Demand - the maximum demand for natural gas a utility expects it must provide over a single day or hour as the case may be.

Figure 3-8 Relationship between Customer Demand and Weather



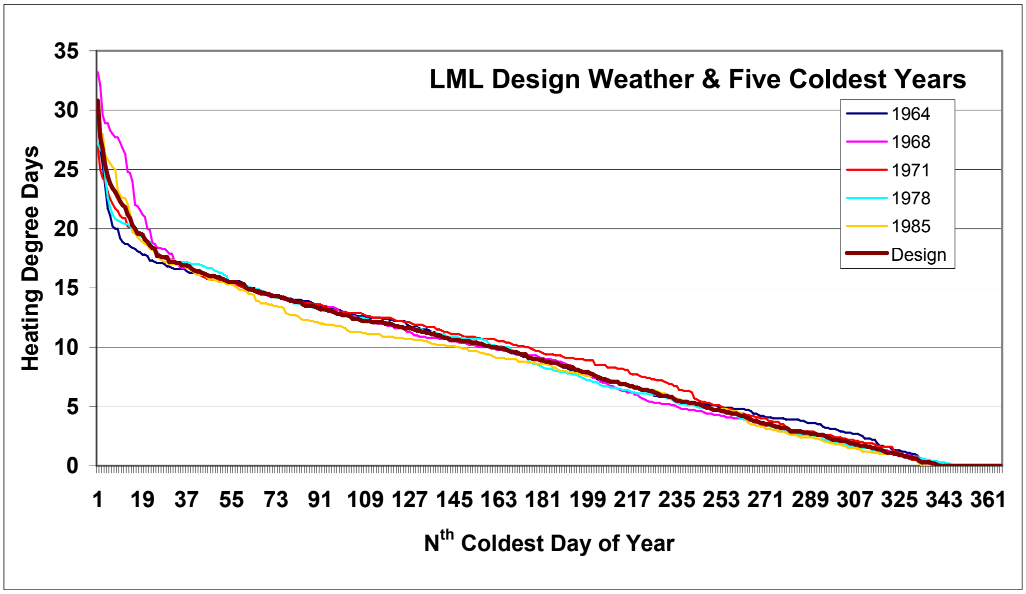
3.4.2 Load Duration Curves

Load duration curves illustrate the daily estimated demand for core customers, typically over a contract year. Load duration curves are established by applying the estimated relationship between weather and demand to an expected daily weather pattern. TGI establishes a normal (average or typical) and design (very cold) weather scenario for use in deriving load duration curves. The design scenario assists in identifying system requirements and to ensure adequate supply resources are in place to serve customers during cold weather events.

The normal weather scenario is derived from the actual weather experienced over the past ten years. The distribution of temperatures within each of the last ten years is analyzed, where each day is represented as a percentage of the coldest (e.g. in 2001, the coldest day was 0.7 degrees Celsius, or HDD_{18} = 17.3, the second coldest day was HDD_{18} = 17.0 or 98.3% of the coldest day, etc.). Once the distribution of temperatures within each of the past ten years has been calculated, they are averaged to provide a 'normal' distribution. To determine the actual temperatures of the normal year, the average of the coldest day in each of the past ten years is taken, and then applied to the 'average' distribution just calculated, resulting in a normal weather year.

The design weather scenario for TGI is a composite of the five coldest contract years (as experienced at the Vancouver airport weather station) since November 1, 1961. To create the design weather scenario, an average of those five weather years is taken, with the resulting coldest day being replaced by the design day temperature (as determined through an Extreme Value Analysis as previously discussed). Figure 3-9 illustrates the design weather scenario for the Lower Mainland region, along with the five coldest years used to create the design weather.

Figure 3-9 TGI Design Weather versus Five Coldest Years



To determine the load duration curve, the regression equation discussed above is applied to the daily weather from the appropriate scenario. As illustrated in Figure 3-10, the Lower Mainland design year load duration curve expresses the estimated daily demand requirements under design weather conditions, with the coldest day representing TGI's design day demand requirements for the upcoming contract year.

Figure 3-10 TGI Design Year Load Duration Curve

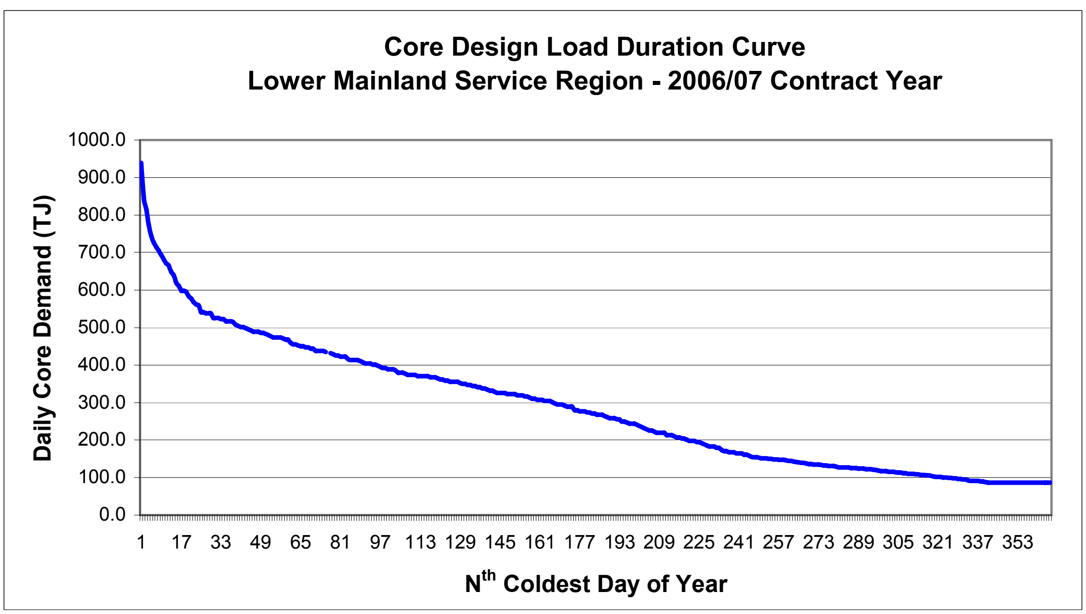
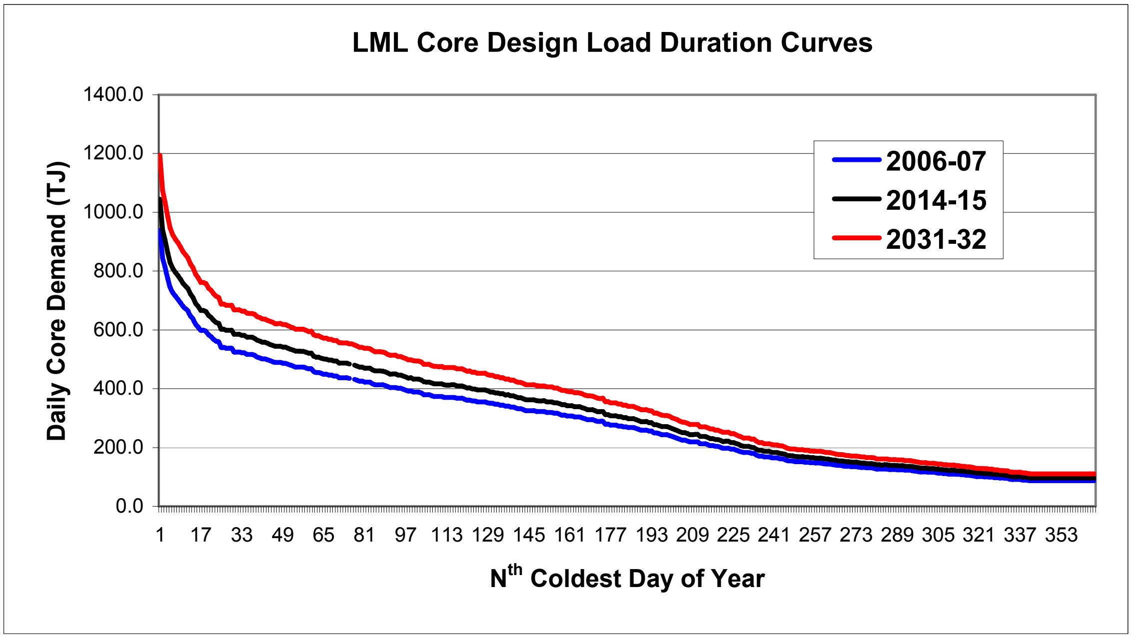


Figure 3-11 illustrates how the design year load duration curve is forecasted to grow over the planning period. It is important to note how, in absolute terms the demand during peaking periods will grown grow faster than the total peak demand over the course of a year as the bulk of new customer additions come from heating load sensitive customers.

Figure 3-11 TGI Design Year Load Duration Curve - Forecast



3.5 Utility Transportation Customers – TGVI, TGS and TGW

In addition to its own Core and Transportation customer demand, TGI also provides transportation service to its affiliated utility, TGVI, through a wheeling agreement to deliver gas across the Coastal Transmission System from Huntingdon to the start of the TGVI system at Eagle Mountain. In turn, TGVI provides transportation service from Huntingdon to TGS to serve residential and commercial customers in Squamish and is in the process of extending its system to Whistler to serve TGW beginning in 2008. Demand forecasts for each of these utilities have also been prepared and are included in the TGVI 2006 Resource Plan.

In TGVI's 2006 Resource Plan, the utility has identified that in its baseline demand scenario it also assumes that it continues to provide transportation service to the Vancouver Island Gas Joint Venture ("VIGJV") over the planning period. As TGVI contracts for CTS capacity to service all the loads on its system, for the purposes of this plan, the only aggregate demand for TGVI is considered, including the VIGJV. TGVI is currently also provides transportation service to BC Hydro to serve the Island Cogeneration Project ("ICP"), however that agreement expires in 2007, and BC Hydro's long term requirement is uncertain at this time. As the ICP load represents approximately 30% of TGVI's take away capacity at Eagle Mountain, the impact of this load on the CTS is also examined.

3.6 Generation

BC Hydro holds 275 TJ per day firm CTS transportation capacity under the Bypass Transportation Agreement ("BTA") for the Burrard Thermal in Port Moody. BC Hydro, TGI, and TGVI have also entered into agreement where BC Hydro has assigned 22 TJ/d of the BTA capacity to TGVI to support firm transportation service to ICP on Vancouver Island. The BTA expires in 2030; however BC Hydro has the right to terminate the agreement as early as 2009.

For transmission planning purposes, however, TGI plans to meet the transportation requirements for Burrard Thermal based on information contained in BC Hydro's 2006 IEP[40]. As part of the load resource balance discussed in the 2006 IEP, BC Hydro has indicated that it plans to rely on three units at Burrard Thermal to provide dependable capacity and firm energy until the April 2009, and then all six units until April 2014[41]. This equates to a demand of 120 TJ/day through the winter of 2008/09 followed by 231 TJ/day through the winter of 2013/14. In scenarios where TGVI continues to provide firm transportation service to ICP, TGI also considers any incremental requirement on CTS capacity in its planning.

As discussed in the 2006 IEP, BC Hydro is currently reviewing the future of Burrard Thermal beginning in 2014. It is TGI's understanding that 2014 is the earliest BC Hydro expects that a major transmission reinforcement project to serve the lower mainland can be completed, which would allow it to consider other resources to replace the Burrard Thermal capacity. It is expected that the forthcoming 2006 Provincial Energy Plan Update will provide more direction with regard to the future of Burrard Thermal; however, TGI is expecting to continue to provide firm transportation under the BTA until 2014 at the earliest. If at that time BC Hydro should elect to discontinue operation at Burrard and terminate the BTA, it is also assumed that TGVI would expand its wheeling capacity across the CTS to serve ICP if and as required.

3.7 Forecast Risk

Although the economic fundamentals that underpin the forecast for the 2006 TGI Resource Plan are stronger than they were when the 2004 plan was completed, a number of risks are present that could affect actual performance over the near term. These risks have been growing over the course of 2006 and will be monitored as they develop:

- increasing interest rates and a slow-down in new construction,
- rising construction costs and a shortage of skilled trades workers,
- stronger Canadian dollar and a decrease in the competitiveness of the export market, especially as it affects the forestry industry,
- commodity price increases that impact the competitive position of natural gas, and
- reduced natural gas consumption in light of recent rate increases.

[40] 2006 Integrated Electricity Plan. BC Hydro. p4-24. http://www.bchydro.com/info/epi/epi43498.html

[41] BC Hydro 2006 Integrated Electricity Plan. Section 4.4.3.4, page 4-24

3.8 Summary

Demand for natural gas on both the CTS and ITS continues to grow. Table 3-2 provides a summary of TGI core annual and design day demand growth over the planning period. Transportation and IT customer demand is not shown in this summary table since, for resource planning purposes, little or no growth is assumed for these customers. Demand forecast details for the Coastal (Lower Mainland) region and Interior regions, including Transportation and IT customers, for the base demand scenario are included in Appendix E.

Table 3-2 Summary of TGI Annual and Design Day Demand Forecasts

	Lower Mainland	Interior	TGI
2005			
Customers	558,035	241,769	799,804
Annual Demand (TJ)	85,137	28,182	113,319
Design Day Demand (TJ/Day)	907	349	1,256
2021			
Customers	712,728	287,472	1,000,200
Annual Demand (TJ)	105,107	33,694	138,801
Design Day Demand (TJ/Day)	1,117	389	1,507
2031			
Customers	788,338	303,778	1,092,116
Annual Demand (TJ)	113,948	35,645	149,593
Design Day Demand (TJ/Day)	1,194	407	1,600
Average Annual Demand Growth ('05-'21)	1.33%	1.12%	1.28%
Average Annual Demand Growth ('05-'31)	1.13%	0.91%	1.07%

All figures year-end

All figures are for core market customers only as tranporatation demands are assmed to have no net growth for Resource Planning purposes.

Design day figures for TGI do not include Squamish

Squamish 2005 Design Day = 4.0 TJ, 2021 Design Day = 7.0 TJ, 2031 Design Day = 7.8 TJ

The future of Burrard Thermal remains uncertain, particularly beyond 2013/14. However, TGI assumes that firm capacity will be required to serve BC Hydro's reliance on Burrard Thermal for firm energy and capacity until at least through the winter 2013/14 as considered by BC Hydro's 2006 IEP.

4 ENERGY EFFICIENCY AND OPTIMIZATION

Demand Side Management ("DSM") refers to "utility activity that modifies or influences the way in which customers utilize energy services." TGI has offered a number of customer programs targeted at improving the energy efficiency of residential and commercial customers since resource planning came to the utility forefront in the mid 1990s. In the past six years, over 100,000 customers have participated in TGI's DSM programs. Terasen Gas recently conducted a Conservation Potential Review ("CPR") which identified the total conservation and fuel substitution potential for each region in the province including an analysis of TGI.

The key finding of the CPR is the "achievable potential" which is defined as the most likely GJ reductions possible assuming all identified DSM measures with a positive TRC Net benefit[42] are implemented within a defined timeframe and also assuming appropriate incentives are in place to address market barriers. TGI has evaluated the potential reduction in peak load and annual use identified in the CPR within the various scenarios of this resource plan by considering DSM as one of the resource options. As discussed in Section 6 of this Resource Plan, the achievable potential specific to TGI is not significant enough to defer significantly any of the major capital projects in the Lower Mainland Region; however, the achievable potential specific to TGI could possible defer major capital projects in the Interior Region by as much as 5-6 years although the earliest requirement for a major project in that region is not until 2013. There is a TRC net benefit as well as many other societal and environmental benefits to implementing a DSM strategy.

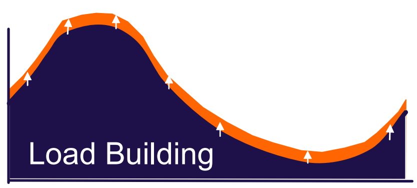
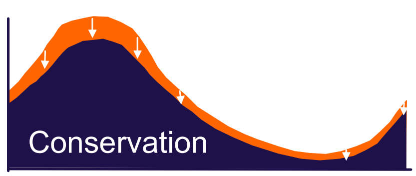
Based on the findings of the CPR, as well as an investigation of the magnitude and nature of DSM activities of other gas utilities in North America, TGI will be establishing a long-term DSM strategy. Please note that the inclusion of the results of the CPR in this Resource Plan is intended to provide readers with a preliminary, high-level understanding of the outcomes of the CPR as they relate to Resource Planning, and that the CPR results and recommendations will be presented in more detail in Fall 2006. The following analysis assumes that no regulatory disincentives to DSM exist.

4.1 Load Management Strategies

There are four primary load shaping strategies that DSM can employ to meet various utility objectives. The diagrams in Figure 4-1 represent the role of DSM in changing customer gas demands throughout the year.

[42] The TRC (Total Resource Cost) is a standard utility cost benefit test that identifies the discounted economic benefit of a specific measure as compared to the “business as usual” or base case.

Figure 4-1 Primary Load Shaping Strategies

	**Peak Shaving** reduces design day load requirements. Customer energy costs are reduced by decreasing demand on the delivery system, thereby reducing the need to expand the system. In addition, the need to purchase the most expensive gas is reduced.
	**Valley filling** is a load building strategy to add load during the summer months when demand is low. The primary effect of valley filling is rate reduction for all customers by increasing the recovery of fixed costs through higher load during periods of low demand.
	**Strategic load building** adds load throughout the year. It increases delivery system utilization and contributes to rate reductions. To maximize the cost effectiveness of this strategy, the energy efficiency of heating loads should be optimized.
	**Strategic conservation** reduces the demand on the delivery system throughout the year. It can be employed to address opportunities to defer capital upgrades where the potential savings impact is meaningful. Otherwise, rates are negatively impacted.

4.2 Potential Role of Demand Side Management

In the context of the changing energy profile of the province—rising fuel prices, electricity capacity concerns and climate change and air quality initiatives—it is appropriate for DSM to take a more prominent role in TGI. The standard utility cost benefit tests used throughout North America (and by Terasen Gas) are appropriate for evaluating the net benefit of measures that affect the avoided costs of both natural gas and electricity. In addition to being economic, DSM programs provide the benefits outlined in ***Table 4-1***.

Table 4-1 Utility and Public Benefits of DSM Programs

• Improve the overall economic efficiency of end use applications • Meet customer expectations by assisting them with managing their energy use • Educate consumers regarding energy efficiency and environmental impact • Maintain competitive position of natural gas relative to other energy sources • Maintain competitive position of British Columbia relative to other provinces and states by keeping customers energy bills competitive with other jurisdictions • Enhance the safety and improve the operating characteristics of energy utilization systems • Support climate change initiatives and improve local air quality • Support local, provincial and federal government objectives • Overcome barriers to market transformation of efficient technology • Support job creation • Defer transmission facility improvements through targeted DSM • Conserve non-renewable resources

4.3 Conservation Potential Review Results

4.3.1 Background and Objectives

In the context of the four potential load management strategies, the CPR provides TGI and TGVI with a comprehensive planning document that the companies can use on an ongoing basis to:

- Develop a long range energy efficiency and fuel choice strategy.
- Design and implement energy efficiency and fuel choice programs.
- Assess the impact of energy efficiency & fuel choice programs on both peak & annual loads.
- Set annual energy efficiency and fuel choice targets and budgets.

4.3.2 Scope

The study was designed to coincide as much as possible with the structure and approach of the BC Hydro CPR, which was completed in 2003. The intent was to ensure that the TGI/TGVI CPR would benefit from the substantial body of information and modeling work prepared for BC Hydro as part of its Conservation Potential Review – Update 2002; and, the results of the study would enable the assessment of not only energy efficiency opportunities, but also opportunities where natural gas could cost effectively replace electricity.

4.3.3 Sector Coverage

The study addresses three sectors: residential (single family and multi-unit buildings) commercial/institutional (non process loads) and manufacturing (process loads).

4.3.4 Geographical Coverage

The study included the total TGI and TGVI service regions with specific results for each of the three service areas: Lower Mainland, Interior and Vancouver Island. This DSM section will focus on CPR findings specific to the TGI service territory.

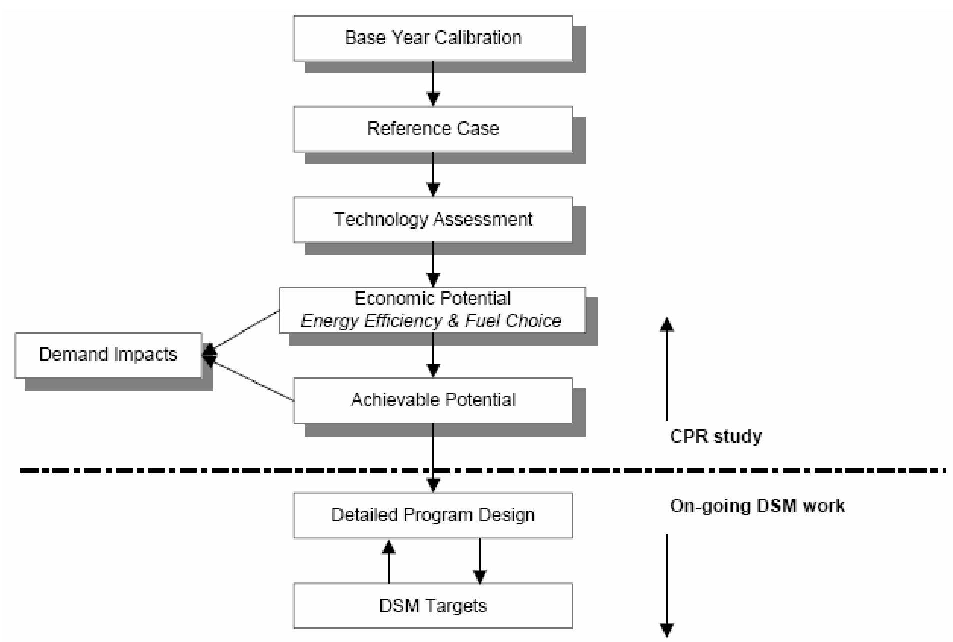
4.3.5 Study Period

The base year for the study corresponds with the BC Hydro fiscal year 2003/04. This corresponds with the Terasen Gas winter 2003/04 gas planning period. The time period covered by the study is to BC Hydro fiscal year 2015/16, with milestones at the intervening years of 2005/06 and 2010/11.

4.3.6 Approach

The major steps involved in the analysis are shown in Figure 4-2 As illustrated, the results of the CPR study, and in particular the estimation of Achievable Potential, support on-going DSM planning work. However, it should be emphasized that the estimation of Achievable Potential is not synonymous with either the setting of specific program targets or with program design.

Figure 4-2 CPR Study Approach - Major Analytical Steps



4.3.7 Customer Segments

The CPR used the allocation of rate class annual use for the three sectors—residential, commercial and manufacturing as shown in Table 4-2 and Table 4-3, respectively, for the Lower Mainland and Interior.

Table 4-2 Sector Allocation for Annual Gas Use for the Lower Mainland

Service Area:	*% of Sales*	*Lower Mainland*		Sector Allocation (GJ) FY 2003/04			
Rate Class		**# of Customers**	**Consumption (GJ/Yr)**	**Residential (incl High-Rise Apts)**	**Commercial (inc Institutional)**	**Manufacturing**	**Beyond Study Scope**
1	44%	494,843	52,844,936	52,844,936	0	0	0
2	14%	51,841	16,667,241	5,266,848	9,366,990	2,033,403	0
3	12%	4,079	14,234,817	7,387,870	5,053,360	1,793,587	0
23	3%	732	3,352,708	855,352	1,586,477	885,995	24,884
5	3%	372	3,646,499	2,251,633	785,252	609,614	0
25	7%	469	8,761,471	1,188,612	2,226,146	5,346,713	0
7	0%	4	63,619				63,619
22	12%	32	14,692,785				14,692,785
27	4%	90	4,856,841				4,856,841
Total GJ		552,462	119,120,916	69,795,251	19,018,225	10,669,312	19,638,129
% Total		100%	100%	59%	16%	9%	16%

Table 4-3 Sector Allocation for Annual Gas Use for the Interior

Service Area:	*% of Sales*	*Interior*		Sector Allocation (GJ) FY 2003/04			
Rate Class		**# of Customers**	**Consumption (GJ/Yr)**	**Residential (incl High-Rise Apts)**	**Commercial (inc Institutional)**	**Manufacturing**	**Beyond Study Scope**
1	30%	213,032	18,714,253	18,714,253	0	0	0
2	10%	21,703	6,431,661	1,865,182	3,858,996	707,483	0
3	5%	819	2,893,920	1,030,235	1,446,960	416,724	0
23	1%	130	699,445	15,822	430,280	247,314	6,029
5	1%	50	774,046	48,911	441,992	283,143	0
25	11%	165	6,563,106	43,820	864,233	5,655,054	0
7	0%	2	21,384				21,384
22	40%	27	25,019,059				25,019,059
27	1%	9	778,860				778,860
Total GJ		235,937	61,895,733	21,718,223	7,042,461	7,309,718	25,825,332
% Total		100%	100%	35%	11%	12%	42%

4.3.7.1 Residential Sector – analysis of end use

The sector model used in the CPR, allocated the total sector consumption to the end uses as shown in Table 4-4 and Table 4-5, respectively, for the Lower Mainland and Interior. Space and water heating consumed 83% of the total use.

Table 4-4 Natural Gas Consumption Modelled by End Use and Segment (Base Year) for the Lower Mainland (thousand GJ/yr)

Segment	Heat	DHW	Cooking	Dryer	Pool Heater	Fireplace	Other Gas	Total
SFD/Duplex	31,612	7,981	697	96	601	5,324	600	46,913
Row Unit	2,572	1,010	80	12	16	693	96	4,479
Lowrise	6,826	2,794	66	6	11	1,244	192	11,139
Highrise	3,671	1,401	33	3	1	623	96	5,828
Mobile/Other	834	331	26	4	6	231	27	1,459
Total	**45,515**	**13,517**	**901**	**123**	**636**	**8,114**	**1,012**	**69,818**

* Totals may vary slightly due to rounding

Table 4-5 Natural Gas Consumption Modelled by End Use and Segment (Base Year) for the Interior (thousand GJ/yr)

Segment	Heat	DHW	Cooking	Dryer	Pool Heater	Fireplace	Other Gas	Total
SFD/Duplex	8,392	3,392	337	42	347	2,225	363	15,099
Row Unit	255	129	11	2	3	87	17	504
Lowrise	1,145	800	3	2	6	307	69	2,332
Highrise	302	254	1	-	-	88	22	667
Mobile/Other	1,553	854	67	10	19	535	77	3,115
Total	**11,646**	**5,429**	**419**	**56**	**375**	**3,242**	**548**	**21,716**

* Totals may vary slightly due to rounding

Based on the existing and new customer end use forecast, the CPR identified ten conservation measures (R1 through R10) that could provide a reduction of 7,144,000 GJ/yr by winter 2015/16 under the most likely achievable scenario. These measures are listed in Table 4-6 and Table 4-7, respectively, for the Lower Mainland and Interior.

Table 4-6 Ten Residential Conservation Measures Identified in the CPR for the Lower Mainland

Lower Mainland Region	Annual Savings (thousand GJ/yr)	
	2010/11	2015/16
R1 - Furnaces	728	1,868
R2 - Fireplaces	88	597
R3 - Efficient DHW Equip	5	34
R4 - DHW Load Reduction	96	178
R5 - DHW Heat Rec & Traps	16	15
R6 - Appliances	816	1,615
R7 - Efficient Windows	309	745
R8 - Air Sealing	35	140
R9 - Integrated Design	19	78
R10 - Building Operations	21	28
Lower Mainland Total	**2,135**	**5,298**

Table 4-7 Ten Residential Conservation Measures Identified in the CPR for the Interior

Interior Region	Annual Savings (thousand GJ/yr)	
	2010/11	2015/16
R1 - Furnaces	204	528
R2 - Fireplaces	37	266
R3 - Efficient DHW Equip	2	14
R4 - DHW Load Reduction	40	74
R5 - DHW Heat Rec & Traps	7	6
R6 - Appliances	338	672
R7 - Efficient Windows	87	211
R8 - Air Sealing	10	40
R9 - Integrated Design	6	26
R10 - Building Operations	7	9
Interior Total	**738**	**1,846**

The CPR also identified 1,453,000 GJ/yr in incremental fuel choice load across all regions including the Mainland which could be obtained under the most likely scenario by promoting three measures intended to encourage the selection of natural gas over electricity as the fuel of choice to the residential single family new construction market: ENERGY STAR natural gas heating, natural gas dryers and natural gas ranges (see Table 4-8).

Table 4-8 CPR Summary of Fuel Choice Natural Gas Impacts by Action and Segment

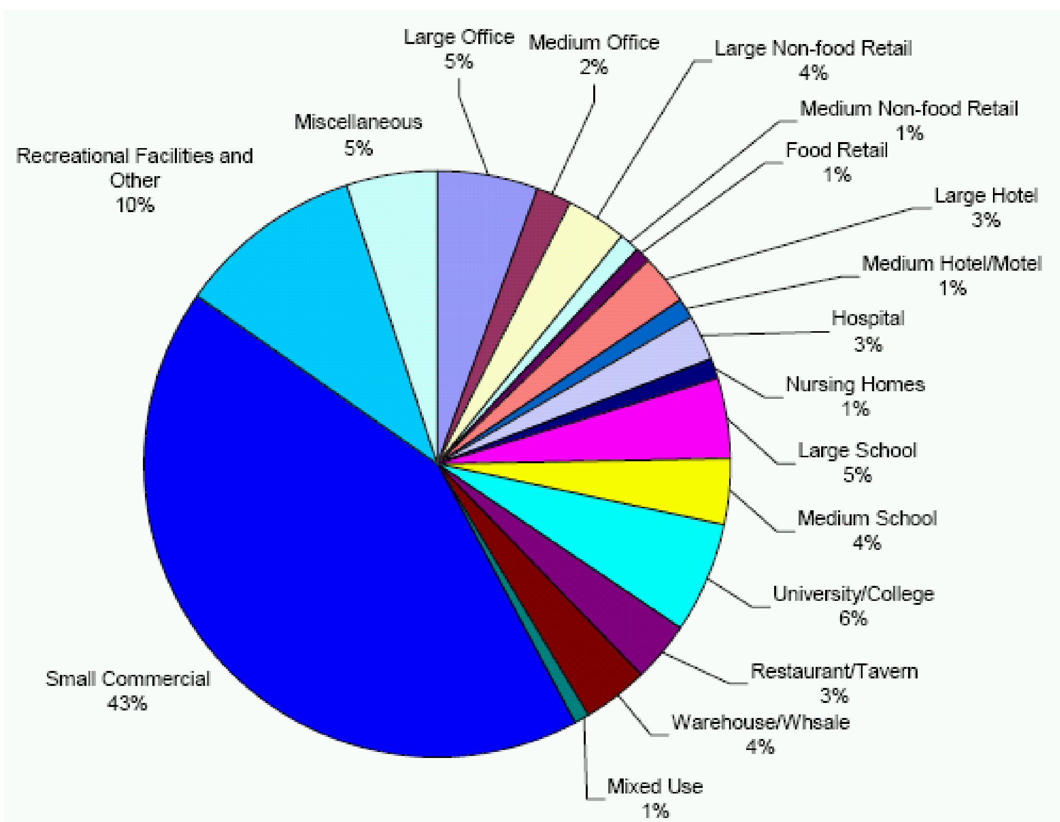
(All TGI and TGVI regions)			
Action	**Annual Gas Increase (thousand GJ/yr)**		**% Total of 2015/16**
	2010/11	**2015/16**	
RFC1 - Heating	491	868	60%
RFC3 - Range	62	195	13%
RFC3 - Dryer	117	389	27%
Total* - All Regions	**670**	**1,453**	**100%**

* Totals may vary slightly due to rounding

4.3.7.2 Commercial Sector – analysis of end use

For the commercial sector, Figure 4-3 shows the end use profile that was used to derive the commercial sector conservation potential.

Figure 4-3 CPR Commercial End Use Profile



Based on the existing and new commercial end use forecast, the CPR identified nine conservation measures (C1 through C9 - Table 4-9 and Table 4-10, respectively, for the Lower Mainland and Interior) that could provide a reduction of 1,827,000 GJ/yr by the winter 2015/16 under the most likely achievable scenario.

Table 4-9 Nine Commercial Conservation Measures Identified in the CPR for the Lower Mainland

Lower Mainland Region	Annual Savings (thousand GJ/yr)	
	2010/11	2015/16
C1 - Energy Efficient New Construction	125	312
C2 - Improved Boilers, New	87	132
C3 - Improved Boilers, Existing	205	379
C4 - Next Gen BAS, Existing	26	51
C5 - Recommissioning, Existing	32	62
C6 - EE Food Prep, New	2	8
C6 - EE Food Prep, Existing	5	42
C7 - DHW Reduction for Food Prep, Existing	15	30
C8 - Small Commercial Efficiency Initiative	112	295
C9 - Recreational & Other Efficiency Initiative	36	85
Lower Mainland Total*	**645**	**1,396**

* Totals may vary slightly due to rounding

Table 4-10 Nine Commercial Conservation Measures Identified in the CPR for the Interior

Interior Region	Annual Savings (thousand GJ/yr)	
	2010/11	2015/16
C1 - Energy Efficient New Construction	35	88
C2 - Improved Boilers, New	25	38
C3 - Improved Boilers, Existing	59	108
C4 - Next Gen BAS, Existing	7	14
C5 - Recommissioning, Existing	9	18
C6 - EE Food Prep, New	1	3
C6 - EE Food Prep, Existing	2	13
C7 - DHW Reduction for Food Prep, Existing	5	9
C8 - Small Commercial Efficiency Initiative	49	123
C9 - Recreational & Other Efficiency Initiative	7	17
Interior Total*	**199**	**431**

* Totals may vary slightly due to rounding

4.3.7.3 *Manufacturing Sector – analysis of end use*

Figure 4-4 and Figure 4-5, respectively, for the Lower Mainland and Interior, show the end use profile used in the CPR to derive the manufacturing sector conservation potential.

Figure 4-4 CPR Manufacturing Sector End Use Profile – Lower Mainland

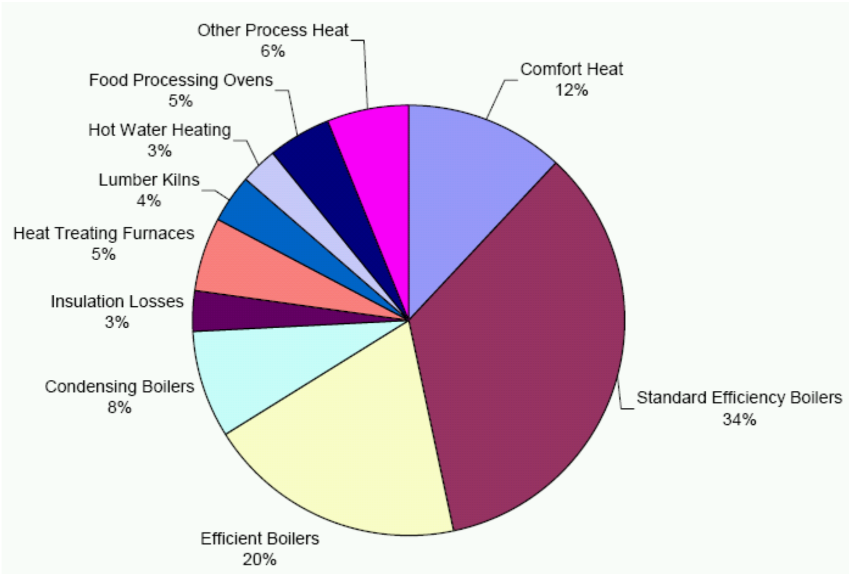
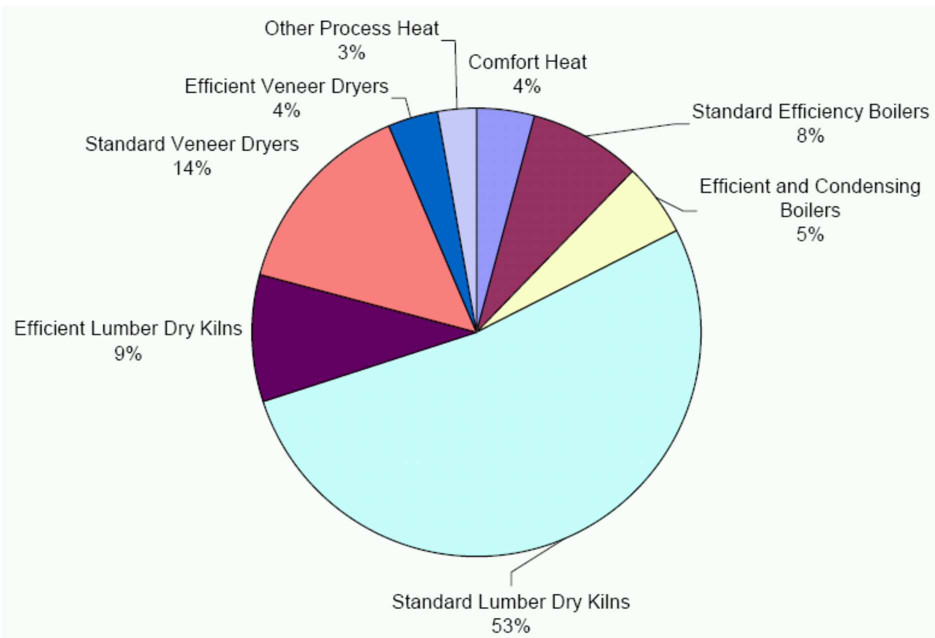


Figure 4-5 CPR Manufacturing Sector End Use Profile – Interior



Based on the existing and new manufacturing end use forecast, the CPR identified four primary conservation measures (M1 through M4 - Table 4-11 and Table 4-12, respectively, for the Lower Mainland and Interior) that could provide a reduction of 1,857,000 GJ/yr by the winter 2015/16 under the most likely achievable scenario.

Table 4-11 Four Primary Manufacturing Conservation Measures Identified by the CPR for the Lower Mainland

Lower Mainland	Annual Savings (thousand GJ/yr)	
	2010/11	**2015/16**
M1 - Efficient Lumber Dry Kilns	22	28
M2 - Efficient Veener Dryers	-	-
M3 - Efficient Boilers	551	631
M4 - Fully Insulated Process Heat Dist Systems	174	181
Other	76	93
Lower Mainland Total*	**822**	**933**

* Totals may vary slightly due to rounding

Table 4-12 Four Primary Manufacturing Conservation Measures Identified by the CPR for the Interior

Interior Region	Annual Savings (thousand GJ/yr)	
	2010/11	**2015/16**
M1 - Efficient Lumber Dry Kilns	564	735
M2 - Efficient Veener Dryers	38	44
M3 - Efficient Boilers	94	112
M4 - Fully Insulated Process Heat Dist Systems	16	17
Other	15	17
Interior Total	**727**	**924**

4.3.7.4 Cumulative Most Likely Achievable Potential (Annual Consumption)

Table 4-13 below outlines the potential cumulative change in natural gas consumption for the TGI service region, in annual GJ, by winter 2015/16, ***if*** all of the most likely achievable potential in conservation measures described in the CPR was to be achieved. There are a number of conditions on actually attaining all the most likely achievable potential, namely an enhanced regulatory environment for TGI DSM programs, and the continuation of the success that TGI has enjoyed in attracting partner funding for DSM initiatives from other utilities, and from the provincial and federal governments. At the time of writing, considerable uncertainty exists about the nature of federal and provincial funding for continued participation in utility DSM programs.

Table 4-13 Potential Cumulative Change in Consumption

By 2015/2016, GJ per year	Lower Mainland	Interior	Total
Residential EE	-5,298,000	-1,847,000	-7,145,000
Commercial EE	-1,396,000	-431,000	-1,827,000
Industrial EE	-933,064	-924,210	-1,857,274
Potential Annual Impact			**-10,829,274**

4.3.7.5 Cumulative Potential Design Day Reduction

Table 4-14 outlines the potential net design day reductions expressed in GJ of consumption per day ***if*** all the most likely achievable potential in both conservation measures and fuel choice measures described in the CPR was to be achieved. As stated above, there are a number of conditions on actually attaining all the most likely achievable potential, not least of which are an enhanced regulatory environment for TGI DSM programs, and the continuation of the success that TGI has enjoyed in attracting partner funding for DSM initiatives from other utilities, and from the provincial and federal governments.

Table 4-14 Potential Cumulative Design Day Impacts

POTENTIAL DESIGN DAY IMPACTS

Based on CPR Results (Most Likely Scenario)

LOWER MAINLAND			
Gas Supply Year	Conservation Most Likely Savings GJ (Peak Day Reduction)	Fuel Choice Most Likely Growth GJ (Peak Day Increase)	Net Decrease in Peak Day Use (GJ)
2010/11	29,816	3,094	26,722
2015/16	67,751	5,878	61,873

INTERIOR			
Gas Supply Year	Conservation Most Likely Savings GJ (Peak Day Reduction)	Fuel Choice Most Likely Growth GJ (Peak Day Increase)	Net Decrease in Peak Day Use (GJ)
2010/11	12,662	1,030	11,632
2015/16	25,639	3,327	22,300

4.3.8 Interpretation of CPR Results

4.3.8.1 Identified Savings

The study findings confirm the existence of significant potential cost-effective natural gas efficiency improvements for TGI. In the Most Likely achievable scenario those energy efficiency improvements could provide 10,829,000 GJ/yr of savings by winter 2015/16 as well as potential design day load reductions of approximately 93,390 GJ/d. The reference case for total annual consumption by 2015/16 for TGI was 164,251,576 GJ, so conservation represents a 6.6% potential reduction in total annual consumption by 2015/16.

The study also identified 1,453,000 GJ/yr in province-wide fuel substitution opportunities through the increased use of natural gas instead of electricity for space heating in new homes and for cooking and clothes drying. For the Residential Sector, the load growth opportunities are likely to be greater than that identified with CPR primarily as a result of the propensity of builders to select electric baseboard due to the lower capital cost and the perceived lower operating costs; programs targeting builders could provide a significant load growth opportunity, and are being explored with BC Hydro.

4.3.8.2 Other Considerations

- The Achievable Potential was derived assuming significant partner funding. NRCan, at the time, had $2 billion earmarked for the climate change action plan which, in part, could have supported DSM programs in the Province. However, the future of federal climate change funding is less certain with the recent cancelling of many of the federal programs and with no specific clarity on the future funding.

- Annual DSM targets and spending levels were set by a collaborative stakeholder working group in 1997. Since that time, there have been significant increases in energy prices and evolving energy needs in the province which suggest it is appropriate to review with stakeholders the desired level of utility DSM investment to meet the broad spectrum of stakeholder objectives. The CPR has defined the conservation potential; however, the impact of an expanded level of DSM has not been quantified. Therefore TGI is currently conducting an analysis of the appropriate DSM strategy.

- The MEMPR launched the "Energy Efficient Buildings: A Plan for BC" in 2005. The plan identified six provincial objectives as shown in Table 4-15.

Table 4-15 Six Objectives of MEMPR for Energy Efficient Buildings

Sector	Targets
New detached single-family and row houses	*Achieve an EnerGuide for houses rating of 80 by 2010, reducing the average energy consumption in new homes by 32%.*
New multi-unit residential buildings	*Achieve energy performance of 25% better than Model National Energy Code for Buildings by 2010, reducing the average energy consumption by 37%.*
New commercial, institutional and industrial buildings.	*Achieve energy performance 25% better than Model National Energy Code for Building by 2010 reducing the average energy consumption by 20%.*
Existing single-family and row houses	*Reduce the energy consumption in 12% of existing buildings by an average of 17% by 2010.*
Existing multi-unit residential buildings	*Reduce the energy consumption in 16% of existing buildings by an average of 9% by 2010.*
Existing industrial, commercial, and institutional buildings	*Reduce the energy consumption in 20% of existing buildings by an average of 14% by 2010.*

The plan is supported by $11 million in Opportunities Envelope funding through NRCan which the province will administer. Terasen Gas recently signed a $2.4 million contribution agreement to deliver DSM programs in partnership with the province In additional, BC Hydro and NRCan are also providing nearly $1 million in additional funding to directly support DSM programs in the province in addition to BC Hydro's investment in conservation through Power Smart. BC Hydro and TGI both endorse using natural gas as the best source of energy for space and water heating and encourage the use the natural gas for cooking and clothes drying through programs such as the New Home program described below.

TGI endorses the provincial targets and will look for continued opportunities to partner with other utilities, industry organisations and all levels of government to support MEMPR in improving the energy efficiency in buildings—particularly in new construction where energy efficiency measures are often the most cost effective.

4.3.8.3 *Existing Programs*

The following programs summarized in Table 4-16 are currently being offered by TGI in 2006.

Table 4-16 2006 DSM Portfolio for TGI

Rate Class	Program Title and Timing	Projected Participants – Life of Program	Terasen Program Costs	Terasen Incentive Costs	Measure TRC	Program Savings (GJ)
Residential	ENERGY STAR Heating Upgrade Sept 1/05 to Dec 31/06	8,000	$250,000	$1,200,000	1.77	2,760,000
Residential	New Construction Heating Upgrade Jan 1/05 to Dec 31/06	2,500	$75,000	$625,000	1.32	455,000
Residential	New Home Program July/06 to Mar 31/07	1,000	0	$1,000,000	1.76	750,000
Residential	New Home Program – Appliances only July/06 to Mar 31/07	500	0	$50,000	2.18	40,000
Commercial	Utilisation Advisory ongoing	120	$110,000	0	2.45	1,125,000
Commercial	Efficient Boiler Program April 4/05 to Dec 31/06	130	$200,000	$1,820,000*	3.03	4,225,000
Commercial	Destination Conservation ongoing	30	$45,000	0	2.77	18,000
	Total for current programs	**11,780**	**$680,000**	**$4,695,000**	**2.18**	**9,373,000**

* Please note that projected incentive costs for the Efficient Boiler Program are based on average incentive paid of $14,000. Incentives paid will vary by applicant.

Residential Programs

- ENERGY STAR Heating System Upgrade

Similar to the upgrade program offered during 2001-2004, a utility incentive would be paid to residential customers who upgrade their existing natural gas furnace or boiler to an ENERGY STAR model. This program runs from September 2005 through to December 2006. Partners include NRCan, MEM, manufacturers, BC Hydro and FortisBC. The total incentive available is $350, with TGI contributing $150, and the remainder coming from BC Hydro, Fortis BC, MEMPR and NR Can. The forecast for this program for 2006 is approximately 3,000 incentives paid through the calendar year.

- <u>New Construction ENERGY STAR Heating Systems</u>

This program targets the installation of ENERGY STAR qualified natural gas furnaces and boilers in new construction with an incentive payable to residential builders. The intent of the program is to alter the existing market where only 20% of new homes currently have high-efficiency equipment installed. The total incentive available is $500, with TGI contributing $250 to the incentive, and the remainder coming from MEMPR. The forecast for this program for 2006 is approximately 600 paid incentives through the calendar year.

- <u>New Home Program</u>

The New Home Program, launched in July 2006, provides up to $3000 for a new home with an EnerGuide 80 rating, natural gas heating, natural gas hot water, ENERGY STAR appliances and windows, natural gas range and dryer, 40% CFL[43] lighting, and an ENERGY STAR ventilation fan. On average, these homes will consume one third less energy than a standard home while encouraging the use of high efficient natural gas equipment. Program partners include BC Hydro, MEMPR, NRCan and possibly FortisBC and CHBA-BC. The province-wide program incorporates the three primary fuel substitution opportunities addressed in the CPR—natural gas heating, ranges and dryers. TGI contribution to this program is $1,000 of the total incentive amount available. There is also an option for the builder to participate only in the natural gas and Energy Star appliance bundle, in which case the builder is eligible for an incentive of $600, to which TGI contributes $100. The forecast overall for this program for 2006 is approximately 400 incentives paid through the calendar year.

Commercial Programs

- <u>Commercial Utilization Advisory</u>

This program provides energy assessments to large commercial customers upon request. Over 100 assessments are conducted each year with approximately one-half of the participants acting on most or all of the recommendations.

- <u>Efficient Boiler Program</u>

The Efficient Boiler Program, launched in March 2005, provides incentives to purchasers of condensing and "near-condensing" natural gas boilers. The program supports both the new construction and the retrofit commercial boiler markets and was launched in partnership with NRCan, MEM and boiler suppliers. Applications need to be received by December 31, 2006; however, participants have up to two years to install the equipment. TGI contributes 50% of the incentives available under this program, with the remainder coming from NRCan. The incentives vary based on a number of factors including the size of boiler installed, the annual gas savings, need for venting etc., but are expected to average $14,000 per applicant. The forecast for this program is approximately 40 incentives paid through the calendar year.

[43] CFL=Compact Florescent Light bulbs

- <u>Destination Conservation</u>

Destination Conservation ("DC") is a K-12 school program involving students, teachers and school facilities management staff. The program is organized by the Pacific Resource Conservation Society, a B.C. based not-for-profit group and is offered to school districts.

4.4 Recommendations

While the CPR is an important step in developing DSM plans, TGI is not yet in a position to seek approval for such plans. Therefore, TGI's recommendations for DSM planning are as follows:

1. In the short term, TGI will continue to support existing and new programs and look for opportunities to add economic customers.

2. The results of the CPR will be presented in more detail in the fall of 2006. TGI will evaluate the potential for an expanded DSM strategy based on the CPR results. Where increased funding is required to support expanded DSM activities, TGI will submit a request to the Commission this fall seeking outlining the additional funding requirements and the scope of the DSM activities planned.

3. TGI will also continue to pursue partnering opportunities with NRCan, Industry and BC Hydro and support the MEMPR in their target to reduce the energy consumption in residential and commercial buildings.

5 TGI GAS SUPPLY PORTFOLIO PLANNING

5.1 Introduction

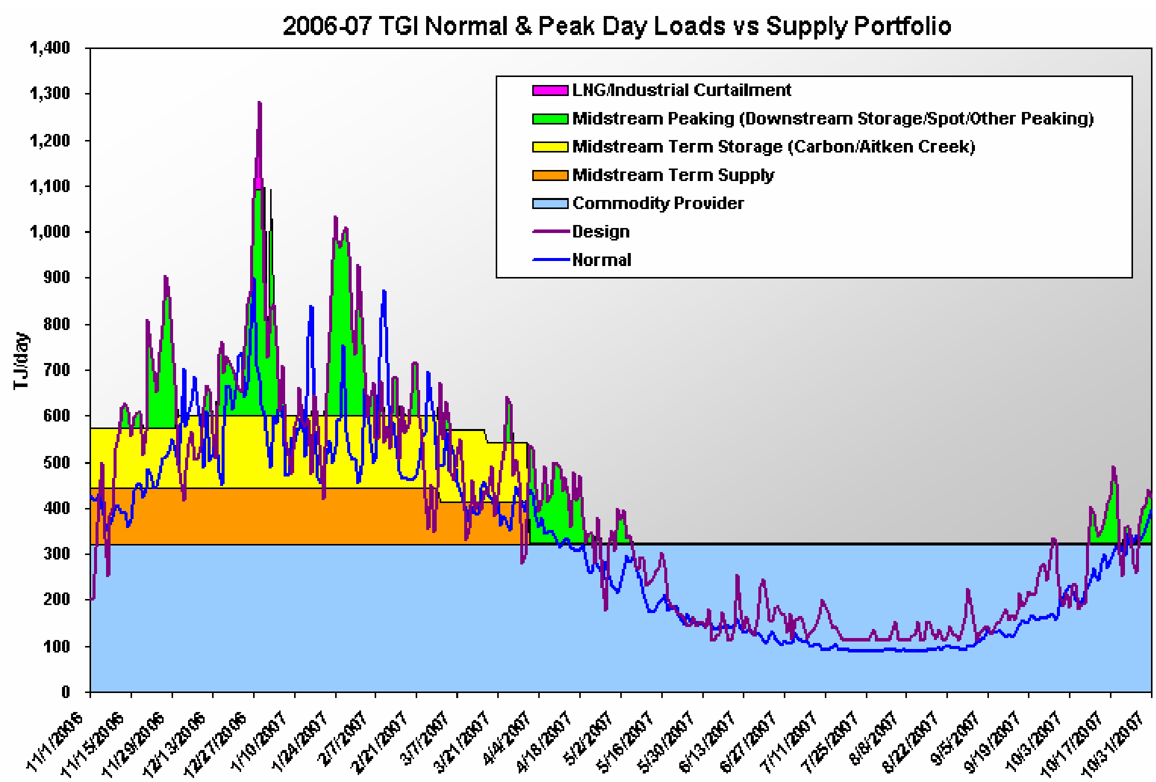
An integral part of the planning process to meet TGI's future gas demand requirements is an assessment of available gas supply resources in the region. This section of the Resource Plan outlines TGI's gas supply obligations as well as the market and planning environment in which TGI operates to secure future resources. A review of gas price risk management is also included.

5.2 TGI Gas Supply Obligations

5.2.1 2006/07 Gas Supply Portfolio Planning and Utilization

TGI considers critical factors such as security of supply, reliability, delivered cost of gas, and availability of alternative incremental resources as the fundamental drivers in determining the most viable options to meet peak and normal day demand. Figure 5-1 provides a visual illustration of TGI's stack of resources against normal and peak day load requirements forecast for 2006/07:

Figure 5-1 2006/07 TGI normal & Peak Day Load vs Recommended Portfolio



TGI generates a priority schedule of all contracted resources which are stacked by contract type. Typically supply with 100% load factor[44] are drawn first with more flexible resources, such as storage, placed further down the resource stack. Generally, the contracts are grouped under the following categories and utilized in the priority sequence outlined below:

1. 100% Load Factor Contracts: Include baseload supply from Commodity Providers, seasonal and long-term supply at Huntingdon, Station 2, Alberta, Stanfield and Kingsgate.

2. Seasonal Storage: Aitken Creek (151-day).

3. Shaped Storage Contracts & Spot Supply: Includes Carbon storage (106-day) and spot supply from Alberta. Spot gas is purchased at Huntingdon or at Station 2 to meet forecast load requirements when day prices are less than other contracted resources, for mitigation purposes, or to allow for downstream storage to be held in reserve for a prolonged cold weather event.

4. Peaking Resources: Includes downstream storage such as Jackson Prairie Storage, ("JPS") and Mist Storage ("Mist"), SCP, spot and other peaking supply (Huntingdon/Kingsgate/Stanfield). These resources are typically essential in meeting the coldest 20-25 days of the winter. Availability of supply from downstream storage facilities can become depleted during prolonged cold weather events as deliverability declines once inventory levels reach below 60% of capacity for JPS and 50% of capacity for Mist. TGI maintains deliverability levels of downstream storage facilities by recycling gas and purchasing spot supply when economic to substitute for downstream storage.

5. LNG & Industrial Curtailment: Referred to as needle peaking reserves for shorter-interval weather events. LNG supply is available for 4 days at maximum deliverability of 166 TJ/d. Industrial curtailment of up to 26 TJ/d is the last resource on the supply stack and can be used for up to 5 days during the winter months.

5.2.2 Gas Supply – Price Risk Management

TGI employs a Price Risk Management Plan to manage the market risk inherent in its procurement of natural gas to serve customer load and the subsequent impact on customer rates. The focus of the Price Risk Management Plan is to manage commodity price risk.

Through an annual submission to the BCUC, TGI re-examines the price risk management objectives, strategies and implementation activities in order to take into consideration on-going discussions with the BCUC about special topics of interest and changing pricing and contracting environments.

The primary objectives of the plan are to improve the likelihood that natural gas remains competitive with electricity over the plan's term and to moderate the volatility of market gas

[44] 100% load factor contracts are “take or pay” agreements, and are therefore, utilized first.

prices and resultant rates for customers. TGI believes that the primary focus for load retention and economic load growth is to ensure gas rates stay competitive with electricity rates in the Province. The objectives of the Price Risk Management Plan are to:

1. Focus price risk management activities on remaining competitive with other energy sources, primarily electricity.
2. Dampen impacts of price volatility on customer rates.
3. Reduce the risk of regional price disconnects.

TGI diversifies its portfolio by reducing exposure at any one pricing point, especially at illiquid trading hubs, and managing overall price volatility. TGI continues to manage associated price risks and optimize its resource portfolio by:

- Purchasing physical supply using different pricing indices – Huntingdon, AECO and Station #2.
- Purchasing physical supply using different pricing structures - daily, monthly and fixed prices.
- Injecting supply into storage during the summer months to meet load requirements in the winter, and in the winter during warmer weather to maintain deliverability. Storage provides a natural physical winter hedge by locking in the value of summer gas to be used during the heating season. Storage also increases security of supply and reliability by removing the risk of gas well or plant upsets and by providing operational flexibility for load balancing to meet unexpected changes in anticipated supply or demand.
- Securing transportation capacity using contracts with varying expiry dates. This gives TGI the ability to retain firm service capacity as required, or the option to terminate an agreement upon expiry if market conditions or options do not favour holding certain fixed cost assets in the portfolio.
- Contracting for storage with varying expiry dates. TGI storage agreements consist of varying terms which help to reduce the risk of negotiating all storage agreements at the same time.

The TGI service region is essentially at the end at the supply line that is part of the PNW regional market including BC, Alberta and the north western states. As such, supply and storage resources available to TGI to help manage supply security and price volatility are limited. The National Energy Board ("NEB") in its April 2004 study of the BC Market[45] has found that a lack of storage resources in the region could contribute to price volatility during periods of high natural gas demand. The preliminary findings of the NWGA 2006 Outlook Study[46] also show that while regional storage and transmission capacity is adequate at present, the ability to meet peak day demand the region is becoming increasingly constrained. In order to maintain a well-balanced market, new capacity and supply requirements need to be implemented in a timely manner.

[45] The British Columbia Natural Gas Market: An Overview and Assessment, NEB, April 2004

[46] www.nwga.org

5.3 Long Term Planning Strategy

Longer-term planning is conducted as a regional effort to ensure sustainability of resources in the PNW. When contracting for resources to meet the requirements of its service area, TGI must consider not only local market factors affecting the Utility in the Lower Mainland, Interior, on Vancouver Island and the Sunshine Coast, but also the regional dynamics of the industry in British Columbia, the US Pacific Northwest and in North America.

5.3.1 Regional Planning Efforts

Terasen Gas has been actively working in partnership with the NWGA to develop a consensus industry study giving perspective of the region's current and projected natural gas supply and delivery capabilities as well as customer demand projections and drivers for the PNW. Produced in June 2005, the NWGA Outlook Study[47] addresses the PNW's current and projected natural gas supply and delivery capabilities, as well as the status of customer demand and associated market drivers. According to this study, regional natural gas demand is projected to grow at an annual average rate of 2.5% between 2005 and 2010, primarily driven by an increase in residential and power generation load of 2.4% and 5.9%, respectively.

The 2005 NWGA Outlook Study forecasts a potential peak-day capacity shortfall in the I-5 Corridor (includes Southwest BC, Western Washington, and Western Oregon) beginning as early as 2007/08. In British Columbia, BC Hydro's electricity demand growth is estimated at 25%-45% by 2025. In the absence of any new sources of electricity generation in the PNW, meeting this demand growth will pose a significant challenge. In the I-5 Corridor, a significant amount of gas-fired electric generation capacity is currently under-utilized. As in the rest of North America, the only short-term response to increases in electricity demand will have to be served through gas-fired sources which represent a significant wildcard in forecasting natural gas demand within the region. Terasen Gas estimates that the under-utilized gas-fired generation facilities could represent a potential peak day demand of up to 1 Bcf/d versus approximately 0.3 Bcf/d that is currently forecast in the NWGA study.

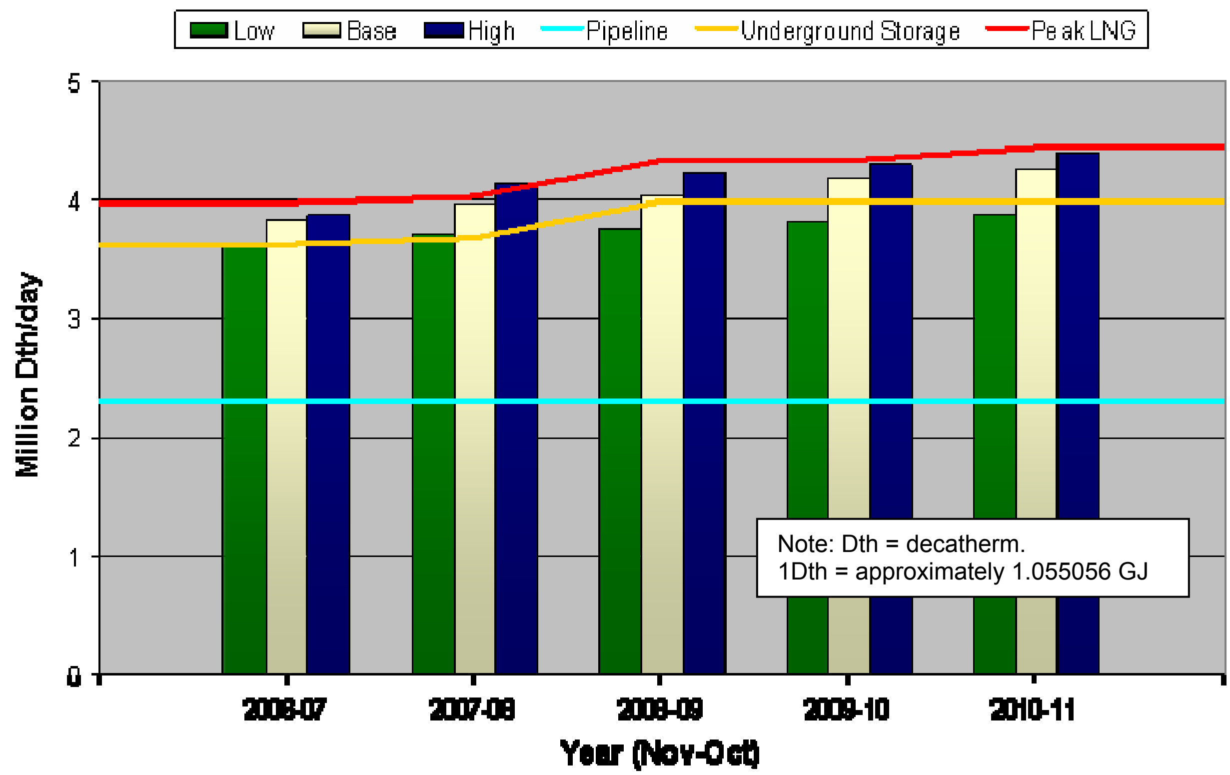
The NWGA, with input and updated information from member utilities including Terasen Gas, is currently working to update the Outlook Study for release in by the third quarter of 2006. Preliminary results reveal an overall reduction in annual demand in the I-5 Region compared to the 2005 forecast, with slightly higher demand in the residential and commercials sectors and lower demand in power generation and industrial sectors. This shift toward higher levels residential and commercial demand results in a rise in design day demand, since these customers have usage patterns that are more sensitive to cold weather. Design day demand for the region is marginally higher in 2006 than in 2005 due to the increase in residential and commercial demand. The study's preliminary results indicate that while both pipeline and storage capacity in the region is adequate at present, additional infrastructure such as storage will be required to meet the growth in design day in the near term. Further, as the natural gas infrastructure in the PNW runs efficiently, there is little redundancy built in to address potential

[47] Northwest Gas Outlook: Natural Gas Demand, Supply and Service Capacity in the Pacific Northwest, NWGA, June 2005 (www.nwga.org/pub_docs/2005_outlook.pdf)

supply shortfalls or infrastructure disruptions. In order to plan now for the demands of tomorrow, permitting and regulatory processes must be responsive enough to facilitate necessary projects that will ensure supply is available when needed.

Figure 5-2 below illustrates the design peak day load requirements and infrastructure availability in the I-5 over the next 5 years. Incremental infrastructure includes future planned and proposed Mist expansion forecasted in service for 2007, JPS storage expansion forecasted in service 2008 and the Mt Hayes Vancouver Island LNG storage forecasted in service in 2010. As the figure shows, without the additional capacity brought on by the expansions, the region would experience a very tight supply and demand balance under expected or base and high demand conditions.

Figure 5-2: Total Firm Day Supply/Demand Balance in the I-5 Corridor Area



Source: NWGA 2006 Northwest Gas Outlook Preliminary Findings

The NWGA 2005 Northwest Gas Outlook can be accessed from the NWGA website at www.nwga.org. In addition, Appendix F provides a summary of the preliminary findings of the updated NWGA 2006 Northwest Gas Outlook including further details on current gas storage and supply resources for the PNW Region.

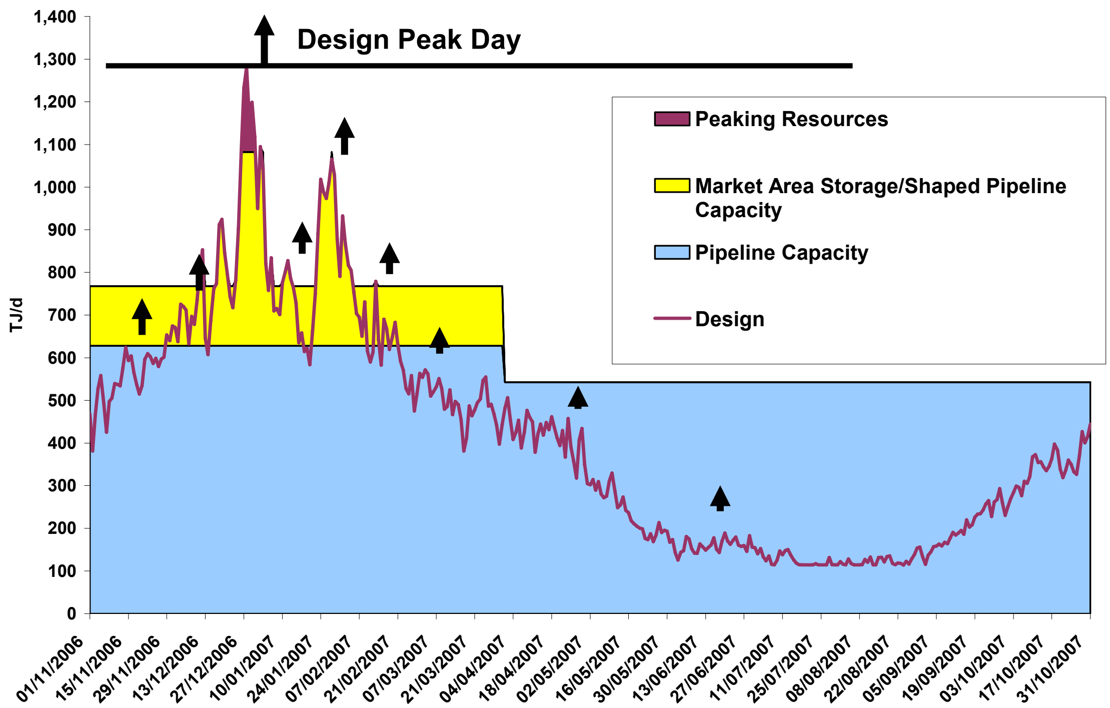
5.3.2 TGI Long Term Planning Objectives

TGI's longer-term contracting strategy continues to be driven by the same objectives as the short-term supply and price risk plans of ensuring safe, reliable and cost-effective natural gas deliveries while maintaining contracting flexibility. TGI maintains flexibility in its longer-term planning strategy, particularly in light of numerous internal and external initiatives which may alter the mix of resources in the portfolio. While TGI's longer-term strategy is developed around a number of key principles that are set out in the Annual Contracting Plan, in meeting future demand growth TGI recognizes the following as significant regional issues affecting its longer term contracting decisions:

- The region's peak load is growing more rapidly than its base load, forcing the industry to re-examine the use and adequacy of pipeline and storage capacity.
- All utilities in the PNW region face the need to add new resources to meet load growth.
- Large infrastructure projects require longer lead times.

TGI's gas supply portfolio must not only meet peak design day demand but also manage elevated loads over extended periods of colder weather, and mitigate any interruptions in delivery capacity related to both transportation and storage. The basic physical resources available to TGI include pipeline and gas storage contracts with the cost and characteristics of each resource typically determining where they best fit in the supply portfolio. Figure 5-3 below is an illustrative example of the resource mix for TGI. While pipeline is the most cost effective resource for base load supply (365 days of the year), shorter-term storage contracts (30 days duration) have typically been more cost effective to meet winter peak loads.

Figure 5-3: TGI Illustrative Resource Stack to Meet Design Peak Day



To satisfy peak day growth TGI will incorporate into its portfolio a mix of shorter duration resources and longer duration pipeline resources subject to market and renewal availability. Typically TGI would choose to increase cost effective shorter term duration resources such as market area storage (yellow area in figure above) to meet peaking and seasonal requirements however the availability of these types of resources is limited.

Table 5-1 below provides the mix of resources expected to be utilized during a peak day event that might occur over the 2006/07 contract year, the subsequent three years, and by 2014/15. A combination of pipeline and market area storage resources will be required to meet the future incremental resource requirements. Due to the changing economics of each supply option and uncertainties around future market developments, the resource portfolios outlined below represent only one static depiction of an unlimited number of variations which may unfold.

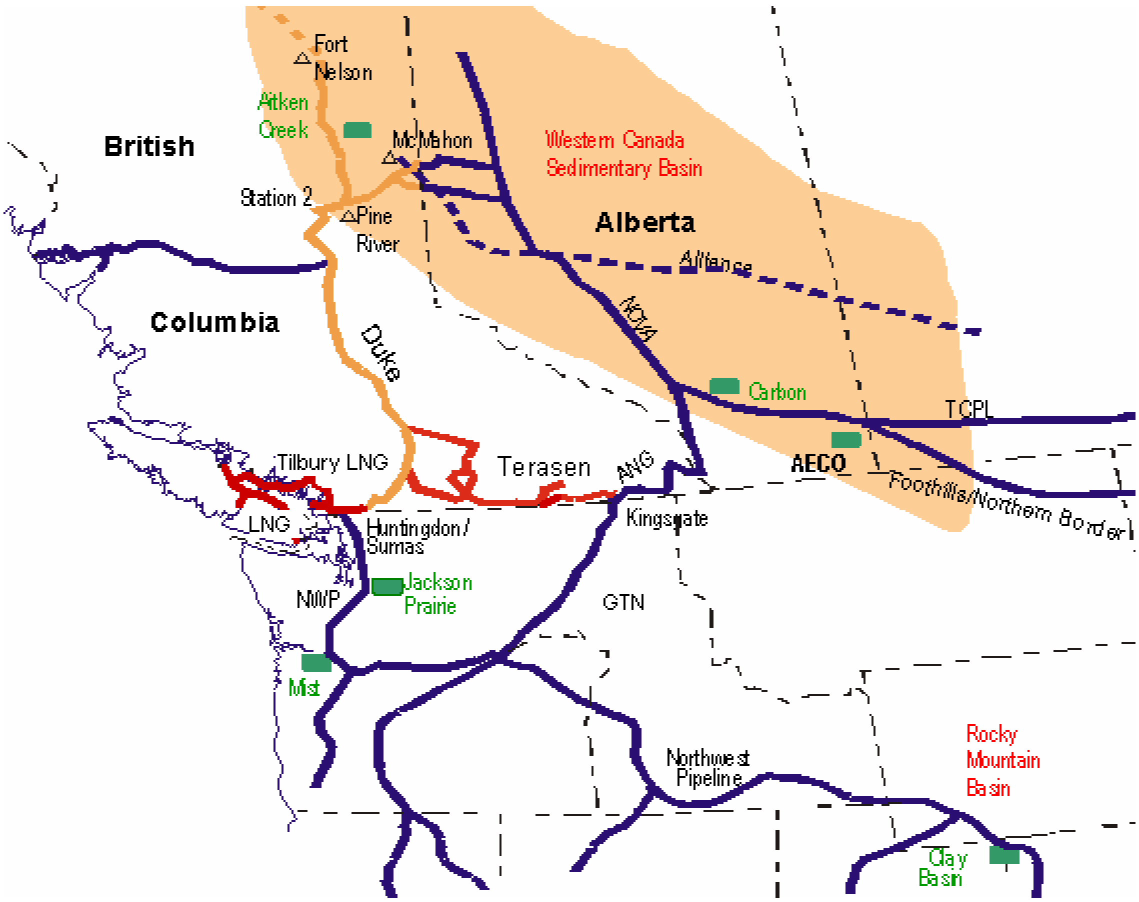
Table 5-1: TGI Peak Day Supply Portfolio 2006/07 to 2014/15

Available Resources (TJ/d)	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2014/15**
Pipeline	326	326	326	326	326	326
Seasonal Supply	366	366	366	366	366	366
Market Area Storage	253	253	253	253	253	253
Peaking Supply	338	338	338	338	338	338
Incremental Resources		19	39	61	84	140
Total Resources (TJ/d)	**1,283**	**1,302**	**1,322**	**1,344**	**1,367**	**1,423**
Peak Day Demand (TJ/d)	**1,282**	**1,302**	**1,322**	**1,344**	**1,367**	**1,423**

Virtually all pipeline capacity held by TGI includes evergreen rights that allow TGI the option to renew expired pipeline contracts. TGI's ability to renew its majority of Off System market area storage contracts is subject to market availability at the time of renewal. As illustrated in the regional map provided in Figure 5-4 below, JPS and Mist storage are the Off System market area storage options that require NWP transport contracts to redeliver supply to the Huntingdon/Sumas market area. TGI negotiates varying expiry dates for these storage contracts to reduce the risk of renegotiating all storage agreements during years of high prices. TGI must also mitigate this risk with the possibility that third parties will retain the expiring storage contracts to meet their own load requirements. The risk of utilities retaining expiring storage contracts is significant since 75% of TGI and TGVI's Off System market area storage contracts are subject to recall over the next 8 years. Just this past year, TGI received notice from Avista Corporation ("Avista Corp") to terminate an existing JPS storage agreement requiring TGI to review alternative resource options. In addition, a utility in the region, which has an agreement with Avista Corp similar to TGI's storage contract, received recall notice for all of its JPS storage capacity. TGI's reliance on third party storage owners represents a potential risk since the utility has no control over the availability of capacity and deliverability over the long-term. In its long term planning, TGI must take into account that all regional utilities face the same need to satisfy demand growth and will do so by either recalling expiring assigned assets or adding new resources.

To meet future peak day growth TGI's options include contracting additional baseload pipeline capacity such as on the Westcoast system, contracting Off System market area storage with associated NWP redelivery capacity north to the Huntingdon/Sumas market area, or developing on-system storage capacity such as the proposed Mt Hayes LNG Storage Facility on Vancouver Island.

Figure 5-4 TGI Resource Options



5.3.3 Pipeline and Storage Options

5.3.3.1 Westcoast T-South

Westcoast has experienced unprecedented levels of de-contracting in the past couple of years as a result of regional infrastructure additions, North American pricing dynamics, and changes in the traditional end-use markets. Significant changes in Westcoast's shipper profile, including the withdrawal of gas marketers, and a continuing reduction in the number of producers holding firm service as a result of excess transmission take-away capacity out of BC into Eastern markets are the primary forces behind the decline in the level of firm service contracts on T-North and T-South.

For November 1, 2005, 39% of Westcoast's T-South capacity from Station 2 to Huntingdon was de-contracted, with the level of turn-back capacity increasing to approximately 48% for November 1, 2006. Along the same lines, de-contracting of T-North capacity to Station 2 totalled 32% for November 1, 2005, and approximately 46% for the subsequent year.

Table 5-2 T-South Capacity Contracted for November 1, 2006

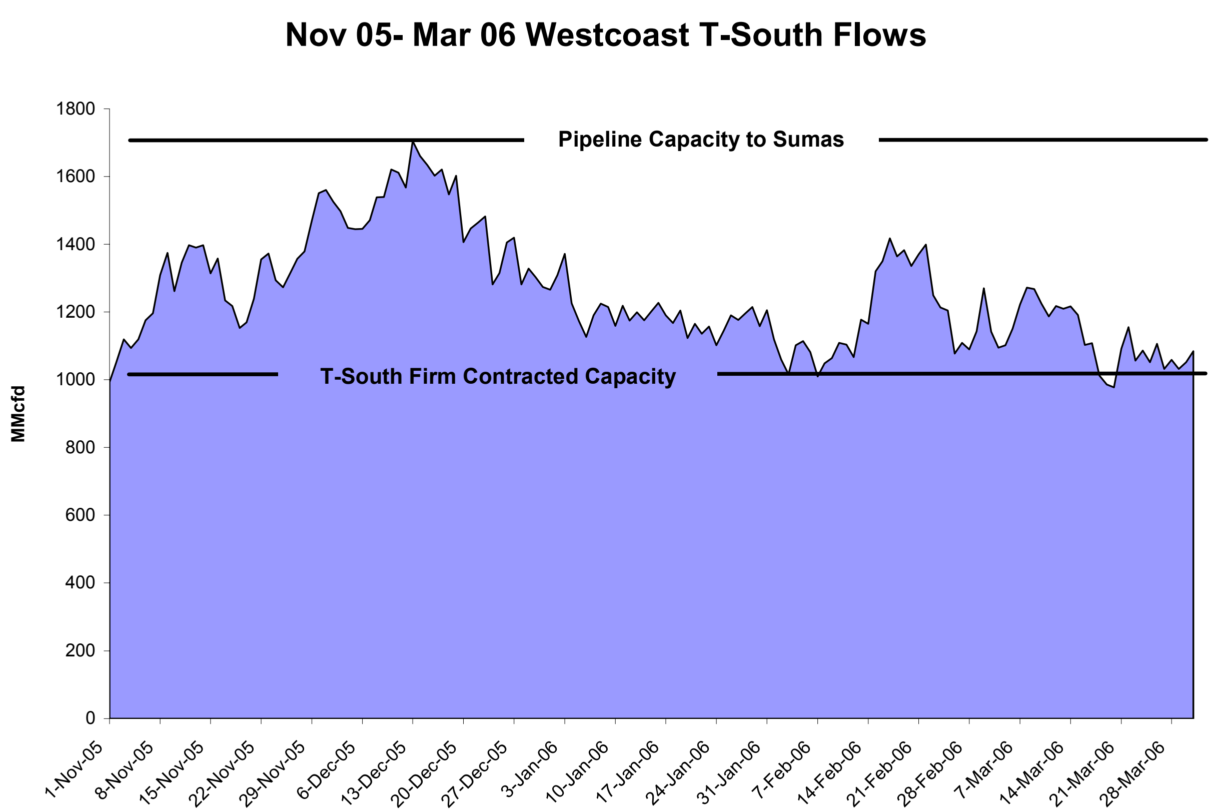
T-South Capacity Contracted for November 1, 2006
As at March 16, 2006

Segment	Design Capacity (MMcf/d)	Contracted Capacity for Nov 1, 2006 (MMcf/d)	Decontracted Capacity (MMcf/d)	% Decontracted
Station 2 ⟶ PNG	110	39	71	65%
Station 2 ⟶ Inland (Savona & Kingvale)	224	189	35	16%
Station 2 ⟶ Huntingdon	1,597	832	765	48%
Kingsvale ⟶ Huntingdon	105	105	0	0%
Total	**2,036**	**1,165**	**871**	**43%**

The erosion of firm contract levels raises the cost of both firm and interruptible service tolls. Based on Westcoast's average final tolls for 2006, firm rates for T-North long haul service have increased 23% and T-South to the Lower Mainland have increased 28% relative to 2005. T-South Long-Haul interruptible ("IT") tolls for 2006 have also increased considerably by approximately 30% relative to 2005.

Though producers have chosen to relinquish T-South capacity on Westcoast, the regional need for supply to the Huntingdon market above the currently contracted 1 Bcf level is still required during normal to cold winter days. This means that interruptible capacity must flow in order to satisfy regional demand. This is shown in Figure 5-6 below which illustrates the region required interruptible T-South capacity to flow virtually all of this past winter of 2005/06 in order to meet regional demand requirements. In fact, on December 13, 2005 the full 1.7 Bcf of T-South capacity flowed on a slightly colder than normal day this past winter. TGVI and TGI's combined demand on that day was approximately 655 TJ/d versus a design day forecast of 1366 TJ/d.

Figure 5-5: Nov 05 – Mar06 Westcoast T-South Flows



In its evaluation of capacity adequacies in the 2005 NWGA Outlook Study[48], the existing 1.7 Bcf of Westcoast capacity is already being accounted for to meet current forecasted regional design peak day requirements. In order to meet incremental regional peak day growth using Westcoast would require pipeline capacity expansion to Huntingdon. However, expansions on Westcoast are highly unlikely in the foreseeable future given the significant levels of de-contracted T-South capacity to the border. Though the existing Westcoast capacity will not satisfy incremental regional peak day growth, the uncontracted Westcoast capacity is still considered a resource option for TGI in meeting TGI's peak day growth. As such, TGI also considers T-South capacity in its long term evaluation of future resource additions.

5.3.3.2 Southern Crossing Pipeline

In 1999, BC Hydro entered into a Firm Transportation and Peaking Service Agreement on TGI's Southern Crossing Pipeline ("SCP") for 52.5 MMcf/d with a demand charge of $3.6 million per annum for a primary term of 10 years expiring on November 1, 2010. The SCP demand charges were paid by BC Hydro to TGI and allocated as revenue in the Delivery Margin

[48] Northwest Gas Outlook: Natural Gas Demand, Supply and Service Capacity in the Pacific Northwest, NWGA, June 2005 (www.nwga.org/pub_docs/2005_outlook.pdf)

requirement. The agreement included a Put Option with Terasen Inc. that allowed BC Hydro to assign the transportation service and peaking gas agreements to Terasen Inc. for the remaining period in the primary term upon 13.5 months notice.

On September 15, 2004, BC Hydro provided notice to Terasen Inc. to exercise its option to assign the SCP Transportation and Peaking Service Agreements to Terasen Inc. effective November 1, 2005. By exercising the Put Option, BC Hydro effectively transferred all obligations under the Agreements to Terasen Inc. with respect to the SCP demand charges and the peaking service option provided for TGI. Subsequently, TGI evaluated the benefit of utilizing the turn-back SCP capacity to replace the shortfall in peaking requirements effective November 1, 2005. The net benefit or savings to core customers of the combined transactions – the use of SCP capacity and de-contracting of T-South Long Haul transport – was estimated at approximately $2-3 million per annum, based on forecast Westcoast tolls at the time of the SCP/IPC submission on June 1, 2005. Since then due to changing market conditions, SCP transportation has become increasingly more valuable. The net benefit is now expected to be approximately $23 million for the period 2005 to 2010, an increase of $11 million from the estimates provided in the June 2005 filing.

The use of BC Hydro's SCP capacity as part of the Midstream resource portfolio allows TGI to optimize the associated Kingsvale to Huntingdon capacity on the Westcoast system which was reserved for BC Hydro's use in conjunction with the SCP transportation. Furthermore, the segmentation of T-South Long-Haul capacity enabled TGI to de-contract 54 TJ/d of relatively expensive T-South Long-Haul transportation while allowing the Utility, on normal days, to optimize the acquired SCP capacity by aligning stranded T-South Inland and Kingsvale South segments to effectively create Long-Haul transport. Currently TGI relies on SCP as a peaking resource however depending on market conditions TGI has the option to in the future to consider the SCP resource as seasonal or baseload resource.

5.3.3.3 Northwest Pipeline

Northwest Pipeline ("NWP") is a bi-directional pipeline that utilizes a combination of physical and displacement capacity to meet its firm contract commitments to contractually flow supply from supply basins, to/from market hubs and to/from storage facilities. TGI and TGVI rely primarily on NWP to deliver supply from downstream storage facilities to the Huntingdon/Sumas market area.

To receive supply from a downstream storage facility TGI and TGVI will pay a storage demand charge for the storage contract and a redelivery charge for the physical receipt of supply at the Huntingdon/Sumas market area. Supply from a downstream storage facility can be contractually delivered to the Huntingdon/Sumas market area by purchasing firm transportation on NWP and paying an annual demand charge referred to as the TF-1 rate or by negotiating contractual displacement arrangements with third party NWP shippers. Historically NWP has offered a TF-2 Rate that provided delivery from storage contracts and was priced at the TF-1 firm NWP rate but applied only on the number of days of withdrawal from storage. For example, TGI currently has a TF-2 contract that is based on 36 day withdrawal from storage priced at the firm TF-1 rate for 36 days or if spread over 365 days would result in a rate of 10% of the firm annual TF-1 rate. However, all TF-2 capacity is currently fully contracted and NWP has stated that no incremental TF-2 capacity will be made available.

Typically displacement contracts are offered by third party shippers that hold firm NWP transportation and firm downstream storage contracts. Currently a majority of TGI and TGVI's shorter term redelivery from downstream storage consists of third party redelivery agreements that rely on displacement whereby gas destined for markets south of Huntingdon/Sumas is diverted to TGVI and TGI and replaced further south by the gas from downstream storage facilities. This implies that on a peak day, there is actually less gas available to flow south to NWP because it is being diverted for TGI and TGVI. However, on design peak and cold days NWP requires a minimum flow south through Huntingdon/Sumas onto the NWP pipeline system to satisfy Seattle area load requirements. If this minimum is not reached then NWP will issue an Operational Flow Order ("OFO") requiring certain shippers to flow supply south through the Huntingdon/Sumas market centre. This condition will place the ability of third parties to offer displacement contracts at risk. Any demand growth on the Canadian side of the border near Huntingdon will further diminish flows to NWP and decrease the availability of displacement contracts. Similarly, demand growth between Sumas and Seattle increases the amount of gas that NWP requires to flow south of the border, thereby negatively impacting on TGI and TGVI's ability to contract for cost-effective displacement redelivery from downstream storage.[49] In recent discussions third party providers have indicated to TGI and TGVI a reluctance to transact long term displacement deals primarily due to the potential OFO issue on NWP. Therefore TGI and TGVI's reliance on displacement contracts creates not only a price risk for TGI and TGVI but a supply reliability risk given that TGI and TGVI may not be able to rely on the availability of displacement deals on a year to year basis. For longer term evaluation TGI and TGVI can not assume that displacement contracts are available at current prices and must assume the downstream storage will require firm NWP redelivery capacity.

In early spring 2006, NWP indicated in its Jackson Prairie Incremental Firm Storage Service Open Season Term Sheet[50] that 180,000 Mcf/d (187,000 Dth/d) of existing TF-1 transportation north of JPS was available. This capacity was existing northbound capacity released by NWP on a short term basis. It is TGI's understanding that since the JPS Open Season 100,000 – 130,000 Mcf/d of the northbound TF-1 transportation from JPS has been contracted and that there is approximately 50,000 – 80,000 Mcf/d of existing northbound TF-1 transportation from JPS currently available. During initial discussions NWP has indicated to TGI that the cost of the northbound transportation for storage delivery from JPS will be offered to the market through negotiations at a rate in the range of 30%-50% of the firm TF-1 rate for 365-day capacity.

On June 30, 2006 NWP filed its 2006 Rate Case to FERC.[51] The filing represents the first general rate increase that NPW has requested since its rate application Docket No. RP96-367 filing in 1995. The 1995 rate application contained a Settlement Agreement that set out conditions intended to avoided repeated rate increases and provide rate stability for customers. NWP submits in the 2006 Rate Case filing that developments since the 1995 filing require NWP

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[49] When an OFO is issued, shippers are required to actually flow the gas in the direction stipulated under their NWP transportation agreements, or face significant financial penalties equivalent to four times the absolute highest day price traded on the NWP system.

[50] Page 4 of NWP Jackson Prairie Incremental Firm Storage Service Open Season Term Sheet Attachment 4 included in Appendix G.

[51] The total FERC filing can be downloaded from the FERC Site at http://www.ferc.gov/industries/gas/gen-info/rate-filings.asp.

to request an increase to existing rates in order to allow NWP to recover its cost of service. As illustrated in the table below, NWP is proposing a 57% increase to the TF-1 (Large) rate from US$0.2776/Dth to US$0.43712/Dth with an anticipated effective date of January 2007. Preliminary analysis indicates that the cost of TGI and TGVI's existing NWP transportation contracts will increase by approximately $500K a year due to the proposed rate changes.

Table 5-3 Current and Proposed NWP Rates[52]

Current and Proposed Rates

	Current (Per Dth)	Proposed (Per Dth)
TF-1(Large)		
◆Reservation Rate	$0.27760	$0.43712
◆Commodity Rate	$0.03000	$0.00756
◆100% L.F. Rate	$0.30760	$0.44468
TF-1 (Small)		
◆50% L.F Volumetric Rate	$0.58521	$0.88180
Evergreen Expansion (15-yr levelized)		
◆Reservation Rate	$0.39547	$0.41621
◆Commodity Rate	$0.03000	$0.00369
◆100% L.F. Rate	$0.42547	$0.41990
Evergreen Expansion (25-yr levelized)		
◆Reservation Rate	$0.37893	$0.39748
◆Commodity Rate	$0.03000	$0.00369
◆100% L.F. Rate	$0.40893	$0.40117

Note: Traditional, non-levelized rates for the Evergreen Expansion 15 and 25-year contracts would be approximately $0.07 higher than the levelized rates.

The NWP Rate Case is not expected to conclude prior to 2007 however for the purposes of its longer term market area storage evaluation included in Appendix G, TGI has assumed a TF-1 rate of US$0.39/Dth. This TF-1 rate of US$0.39/Dth had been previously estimated based on expectations prior to NWP's rate filing however is lower than the TF-1 rate requested by NWP and therefore will produce a more conservative (lower) market area storage cost estimate.

A significant cause of the rate increase is NWP's capacity replacement project that was ordered by the US Office of Pipeline Safety ("OPS") in December 2003 and is scheduled to be completed by November 2006. Two pipeline failures in the fall of 2003 on Northwest Pipe 26" mainline required removal of large segments of the 26" line in the I-5 Corridor from service, thereby decreasing approximately 360 MMcf/d of capacity that was formerly available between Sumas and Portland. NWP received approval from FERC to remove from service and replace the 26" line with looping, compression and capacity turn-back to meet its firm contractual

[52] NWP Rate Case Summary June 2006: www.1line.williams.com/ Files/Northwest/NorthwestInfoPosting Frameset.html

obligations in November 2006. The cost of this capacity replacement project is approximately $300 million. The capacity replacement project will not provide incremental pipeline capacity it will only replace the capacity of the 26" line that was removed. In order to add incremental northbound pipeline capacity from JPS, NWP will be required to expand capacity north of JPS at a minimum cost to expansion shippers of the full NWP TF-1 firm toll. At this time there is no incremental expansion north of Jackson Prairie scheduled by NWP.

5.3.3.4 Market Area Storage

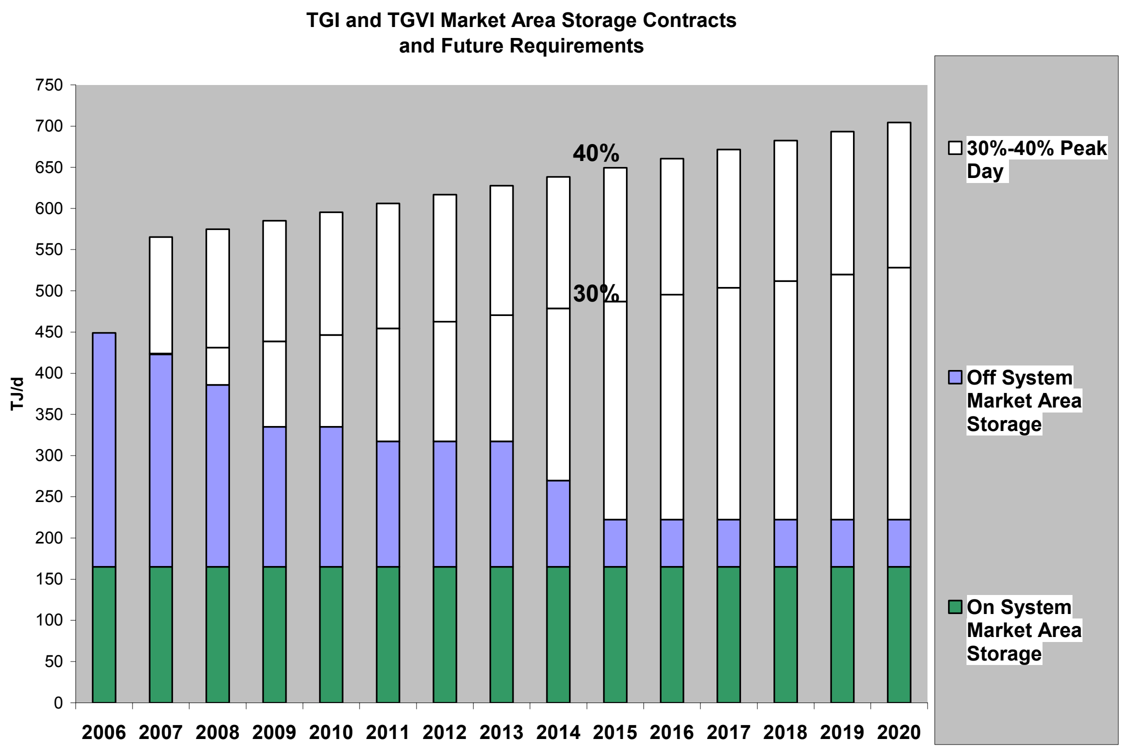
Storage has been an integral part of the TGI's portfolio since it provides supply diversification, increased security of supply, a natural price hedge, and operational flexibility to manage swings in demand and reduce imbalances with interconnecting pipelines such as Westcoast and NWP. Increasingly, regional gas utilities have opted for gas storage instead of pipeline capacity to meet weather-sensitive loads. Gas withdrawn from storage during high demand periods reduces the need for seasonal and peaking resources that, in the past, has been served by regional pipeline systems. As discussed in the 2005 NWGA Outlook study[53] the need for incremental shorter term duration resources is growing in the region as peak day growth is increasing at a faster rate than baseload growth forcing the industry to examine pipeline and storage capacity.

The market area storage resources, which represent shorter term duration resources, available to TGI include both On System and Off System market area storage. Tilbury LNG storage expansion located on TGI's Lower Mainland transmission system and a future Mt Hayes LNG storage facility located on TGVI's Vancouver Island transmission system represent On System market area storage options. JPS and Mist storage located downstream of the Huntingdon/Sumas market area are the Off System market area storage options that require NWP transport contracts to redeliver supply to the Huntingdon/Sumas market area.

Illustrated below (Figure 5-8) are TGI and TGVI's existing market area storage resources and the future range of market area storage contracting that will be required to manage TGI and TGVI load growth and replace expiring market area storage contracts. While TGI's current peak day portfolio consists of approximately 30% of market area storage (JPS/Mist/Tilbury), other utilities in the PNW (such as Puget Sound Energy and Northwest Natural Gas Company) utilize On System or nearby storage assets to serve approximately 50% to 60% of their peak day demand. TGI and TGVI have included an upper market area storage range that would be required to satisfy 40% of design peak day requirements. This 40% of design peak day requirement does not set the upper limit for TGI and TGVI's potential market area storage it simply provides an illustrative example of the amount of market area storage that TGI and TGVI could be required to contract over the next few years. In Figure 5-6 it is assumed that existing storage contracts with the option to renew continue to be held by TGI and TGVI for the period.

[53] Northwest Gas Outlook: Natural Gas Demand, Supply and Service Capacity in the Pacific Northwest, NWGA, June 2005 (www.nwga.org/pub_docs/2005_outlook.pdf)

Figure 5-6 TGI and TGVI Market Area Storage Contracts and Future Requirements



The chart concludes that due to incremental requirements driven by growth and expiring storage contracts, both market area storage and incremental cost effective market area storage will be required in the future. The possible market area storage options are discussed below.

Jackson Prairie Storage

JPS, located in Western Washington, is one of two underground storage facilities available to TGI. JPS is jointly owned by Puget, Avista Corp and NWP, with capacity expansions (not deliverability) over the years in response to growth in the seasonal gas requirements of its owners and the operational needs of NWP.

On February 1, 2006, NWP initiated an Open Season for incremental firm storage service based on expansions of JPS of approximately 300,000 Mcf/d (312,000 Dth/d) of additional deliverability, and the 6.3 Bcf of storage working gas capacity. As a one-third owner of the storage facility, NWP has rights to 33% of the proposed expansion service. NWP offered the market its one third of the total deliverability at a fixed Cost of Service rate for a minimum contract term of 20 years. The market responded by contracting for the full offered deliverability with terms that averaged 32 years. TGI and TGVI submitted a bid with varying term lengths and were subsequently awarded a total of 54,233 Dth/d of the deliverability. Subject to the necessary approvals, NWP anticipates that the working gas capacity component of its proposed service will be developed in monthly phases from early 2007 through late 2010, and the firm deliverability component will be available commencing November 2008.

Redelivery from JPS to the Huntingdon/Sumas market area which is required with the JPS facility was not part of the recent JPS Open Season. As discussed in Section 5.3.3.3, for longer term Off System storage evaluation, TGI must assume the Off System storage capacity will require firm NWP pipeline redelivery capacity. The indications are that there is approximately 50,000 – 80,000 Mcf/d of existing northbound TF-1 transportation from JPS currently available. During initial discussions with NWP, NWP indicated to TGI that the cost of the northbound transportation from JPS will be offered to the market through negotiations at a rate in the range of 30%-50% of the firm TF-1 rate for 365-day capacity.

Mist Storage Facility

The Mist is owned by Northwest Natural Gas ("NWN") and is located in northwest Oregon. Mist consists of a number of smaller depleted natural gas pools that have been expanded over time as NWN has responded to its core and third party storage holders by developing additional pools that have increased Mist's capacity and deliverability. Due to upward pressure on land, drilling, labour, and equipment and service costs across the entire exploration and production sector, as well as the high cost of natural gas that may be required as cushion gas, additional reservoir development at Mist will be a higher cost proposition than in the recent past.

Mist is currently fully contracted, however NWN is currently planning to expand Mist in 2007 provided there is sufficient market demand at the rate levels needed to justify such an expansion. Aside from the cost of incremental storage the major factor which would limit the amount of incremental Mist storage TGI can contract will be its ability to contract for incremental, cost effective and reliable redelivery service from Mist to the Huntingdon/SIPI area. This storage resource is located further south than JPS on the NWP system and therefore there is even less NWP capacity available to facilitate redelivery to Sumas.

Tilbury LNG Storage Expansion

TGI has the option to expand the capacity and/or the delivery capability of its existing LNG tank at Tilbury on TGI's Lower Mainland transmission system. Currently, the LNG tank holds approximately 600 MMcf/d of capacity with 150 MMcf/d of deliverability. An expansion at Tilbury could help meet TGI's need for increased deliverability and security of supply within the region. TGVI would also consider this as an option to meet incremental peak day growth. However while the Tilbury LNG expansion could likely provide similar gas supply benefits as the proposed LNG storage facility on Vancouver Island, the Vancouver Island location currently provides greater on system benefits to both TGI and TGVI by minimizing future transmission pipeline infrastructure additions, and should proceed prior to any expansion at Tilbury. As a result no detailed evaluation of a Tilbury expansion has been performed at this time.

Mt Hayes Island LNG Storage

In February 2005, TGVI received conditional approval from the BCUC to build a 1 Bcf LNG storage facility at Mt Hayes, near Ladysmith, on Vancouver Island for a target in-service date of November 2007. However, approval of the LNG Facility was conditional on the Duke Point power project proceeding which was subsequently terminated by BC Hydro in July 2005. TGVI is currently re-evaluating the feasibility of locating the peak shaving facility on Vancouver Island at Mt Hayes to provide storage services to both Vancouver Island and TGI's Lower Mainland natural gas customers. In order to realize economies of scale and offer additional firm service to TGI, TGVI is also evaluating expanding the facility to 1.5 Bcf.

As a gas supply option, locating the facility on Vancouver Island would provide both TGI and TGVI customers the ability to avoid the cost of downstream Off System market area storage and baseload/seasonal pipeline capacity. The LNG facility on Vancouver Island would also be an important new resource for TGVI and TGI providing enhanced flexibility and diversification to its longer-term peaking portfolio. It would also minimize the potential risk of third party market area storage holders retaining or recalling a significant portion of TGVI and TGI's existing market area storage contracts causing TGVI and TGI to seek out more costly resource alternatives.

The location of the Vancouver Island LNG storage facility upstream of NWP's north flow constraint at Chehalis will also provide incremental resources for the region and alleviate concerns of reduced south flow requirements to NWP on cold and design peak days increasing the likelihood that some portion of TGI and TGVI's existing redeliveries from JPS and Mist storage facilities will still be available in the future. While the LNG Storage facility will help to meet incremental requirements due to future peak day growth, TGVI and TGI will continue to require Off System market area storage resources.

To estimate the market value of LNG storage TGI evaluated the alternative Off System market area storage resources. TGI has evaluated a 15 day market area storage contract based on the most recent estimated cost of service of the JPS Open Season storage contract and redelivery transport costs to Huntingdon based on 30-50% of TF-1 rates derived from recent discussions with NWP.

The more recent estimate for a 15 day underground storage alternative including an estimated transportation redelivery charge equates to an annual cost of $107 to $140 for 1 GJ of deliverability to Huntingdon. Redelivery transport from the downstream storage facility to the Huntingdon market area represents over 50% of this cost. While short-duration resources such as downstream storage are preferable options over baseload assets such as year-round transportation capacity, the shorter duration resources such as market area storage must be cost effective. Given incremental Westcoast T-South capacity is a regional alternative to market area storage for TGI it will establish an estimated upper range that TGI will pay for market area storage. TGI's alternative resource will range from $107, representing the low end of market area storage, to $180, representing Westcoast T-South with no mitigation, for 1 GJ delivered to the Huntingdon/Sumas market area. The market Off System market evaluation is provided in detail in Appendix G.

Although the Mt Hayes project had been previously approved, before a new LNG storage proposal can proceed, TGVI will be required to make a new application to the Commission seeking approval for the project and a service agreement with TGI for LNG storage service. The project requires a minimum 3-year construction period once approvals are obtained. Consequently, the earliest in-service date for the Vancouver Island LNG facility will be 2010.

5.4 Gas Supply Planning Conclusions

To meet future peak day growth TGI will incorporate into its portfolio a mix of shorter and longer duration resources subject to market availability. While growth in peak day may be practically met with pipeline and seasonal storage a majority will be met through shorter term duration resources such as market area storage. As outlined in the 2005 NWGA Outlook Study the need for incremental shorter term duration resources is growing in the region as peak day growth is increasing at a faster rate than baseload growth forcing the industry to examine pipeline and storage capacity. For TGI, market area storage is a cost effective shorter term duration resource providing supply diversification, supply security, a natural price hedge, and operational flexibility to manage swings in demand and reduce imbalances with interconnecting pipelines such as Westcoast and NWP.

Approximately 75% of TGI and TGVI's Off System market area storage contracts provided by third party storage owners are subject to recall over the next 8 years. TGI's reliance on third party storage owners represents a potential risk since the utility has no control over the availability of capacity and deliverability over the long-term. In its long term planning, TGI must take into account that all regional utilities face the same need to satisfy demand growth and will do so by either recalling expiring assigned assets or adding new resources.

When evaluating future resource options TGI will evaluate cost effective On System market area storage resource options that will assist in mitigating the risk with the possibility that third parties will retain expiring storage contracts. The Mt Hayes LNG storage on Vancouver Island is a viable option for TGI to evaluate. The Vancouver Island location is an optimal location since the major regulatory siting requirements have been completed and there are additional on system benefits achieved by minimizing future transmission pipeline infrastructure additions.

TGI established the market value of LNG storage by evaluating the alternative Off System market area storage resources. TGI has evaluated a 15 day market area storage contract based on the most recent estimated cost of service of the JPS Open Season storage contract and updated redelivery transport costs to Huntingdon derived from recent discussions with NWP. The annual cost of a 15 day underground storage alternative including an estimated transportation redelivery charge equates to $107 to $140 for 1 GJ of deliverability to Huntingdon. Redelivery transport from the downstream storage facility to the Huntingdon market area represents over 50% of this cost. Given incremental Westcoast T-South capacity is a regional alternative to market area storage for TGI it will establish an estimated upper range that TGI will pay for market area storage. TGI's alternative resource will range from $107, representing the low end of market area storage, to $180, representing Westcoast T-South with no mitigation, for 1 GJ delivered to the Huntingdon/Sumas market area. Detailed analysis is provided in Appendix G. Before an LNG storage project can proceed, TGVI will be required to re-apply to the Commission for a new CPCN and TGI will be required to put in place a service agreement with TGVI for LNG storage service.

6 RESOURCE PORTFOLIO DEVELOPMENT AND EVALUATION

6.1 Introduction

One of the primary roles of Resource Planning is to assess capacity and resource alternatives over a range of expected demand scenarios to determine the preferred resources required to meet demand over the long term. Natural gas is moved from producer to end user through a pipeline system. The capacity of a pipeline system is determined by the diameter and length of the pipeline, and the supply and required delivery pressures, and the allowable maximum operating pressure ("MOP"). To overcome friction and allow gas to flow through the pipeline, a pressure differential between the supply and delivery points is required. Compressors are often used to increase the pressure differential and move large volumes of natural gas at high pressures through the transmission system to major delivery points. The end pressures, which vary with flow, are controlled by pressure regulating stations before the natural gas enters the distribution systems.

To determine whether its pipeline systems would meet demand growth, TGI assesses both supply side resources such as pipeline, compression, and on-system storage which would increase the physical capacity of a delivery system, or demand side resources such as energy efficiency programs or industrial curtailment which would reduce gas demand during peaking periods by changing customer usage patterns and limiting industrial consumption. A brief description of supply side and demand side resources available to TGI is provided below.

6.1.1 Supply Side Resources

<u>Pipeline</u>

To increase the effective cross-sectional area of a pipeline section to increase throughput capacity, an existing pipeline can be replaced by a larger diameter pipe, or a parallel pipeline (a loop) can be added to an existing one.

<u>Compression</u>

Compressors are added to increase capacity in two ways. The first is the addition of new units or replacement with larger units to increase the discharge pressure at an existing station. The second is to add new stations along the pipeline to maintain a higher average operating pressure.

<u>On-system Storage</u>

Storage facilities located within a service region are considered 'on-system' supply side resources. Natural gas is typically injected in the storage facility during low-demand periods and is withdrawn during high demand periods. During high demand periods, these storage facilities provide direct deliverability into the system to maintain pipeline operating pressure. This increases the system deliverability during periods of high demand without the need for additional throughput capacity from pipeline and compression facilities. In addition, the storage facilities provide additional supply sources to increase system security and reliability.

There are two general types of storage facilities: underground facilities use salt caverns or depleted gas wells to store large amounts of natural gas under pressure, and LNG facilities which cool natural gas into a liquid state and store it in insulated tanks.

6.1.2 Demand Side Resources

Industrial Curtailment

Industrial curtailment refers to the right to recall firm transportation service from industrial customers, under specified conditions, to meet Core market requirements. The ability of a transportation customer to offer curtailment is often related to its ability to curtail its production or fuel switch. This offers value to all customers by deferring the overall need to add supply side resources to meet firm demand requirements. TGI has limited industrial curtailment on the CTS and ITS where total industrial load represents less than 10% of total design day demand for each individual system.

Energy Efficiency Programs

Energy efficiency or demand side management programs are intended to modify or influence the way customers utilize energy services. It may include conservation measures and fuel substitution programs. These programs may offer value to all customers by reducing or deferring the need to add supply side resources to meet firm demand requirements.

6.2 Portfolio Development

A resource portfolio is a selection of resource components to meet the requirements of a particular demand forecast over the planning period. Supply side resource components are identified by system hydraulic analyses of the transmission systems. The major criteria considered in the development of each resource portfolio are as follows:

- Optimization of resource capacity addition(s) to meet demand requirements over a 20 year planning period, with sensitive analysis evaluation for a 15 year and 25 year planning periods

- Expected demand under design temperature conditions. The design temperature is based on an extreme value statistical analysis of historical temperature data to determine the coldest daily temperature based on a one in twenty year return period. The design temperatures are specific to different weather zones within TGI's service regions.

- In determining additional resource requirements, only core market and firm transportation demands are considered under design temperature conditions. Generally TGI does not plan capacity addition to meet interruptible demands.

- The CTS, which operates at a relative low operating pressure range and covers a relative small geographic area does not have sufficient linepack capability to absorb hourly demand fluctuations. Therefore, capacity requirements for the CTS are based on design hourly demand.

- In contrast, the ITS, which operates at a high operating pressure range up to 1,440 psig, covers a large geographic area and does have sufficient line capability to absorb hourly demand fluctuations. Capacity requirements for the ITS are therefore based on design daily demand.

- Large infrastructure projects typically require long lead times due to regulatory reviews, public consultation, conceptual design, detailed engineering, and construction schedules. This lead time are taken into account to determine the feasibility of a resource being available to meet a future capacity shortfall.

- Note that this Resource Plan focuses on the resource requirements for transmission systems only.

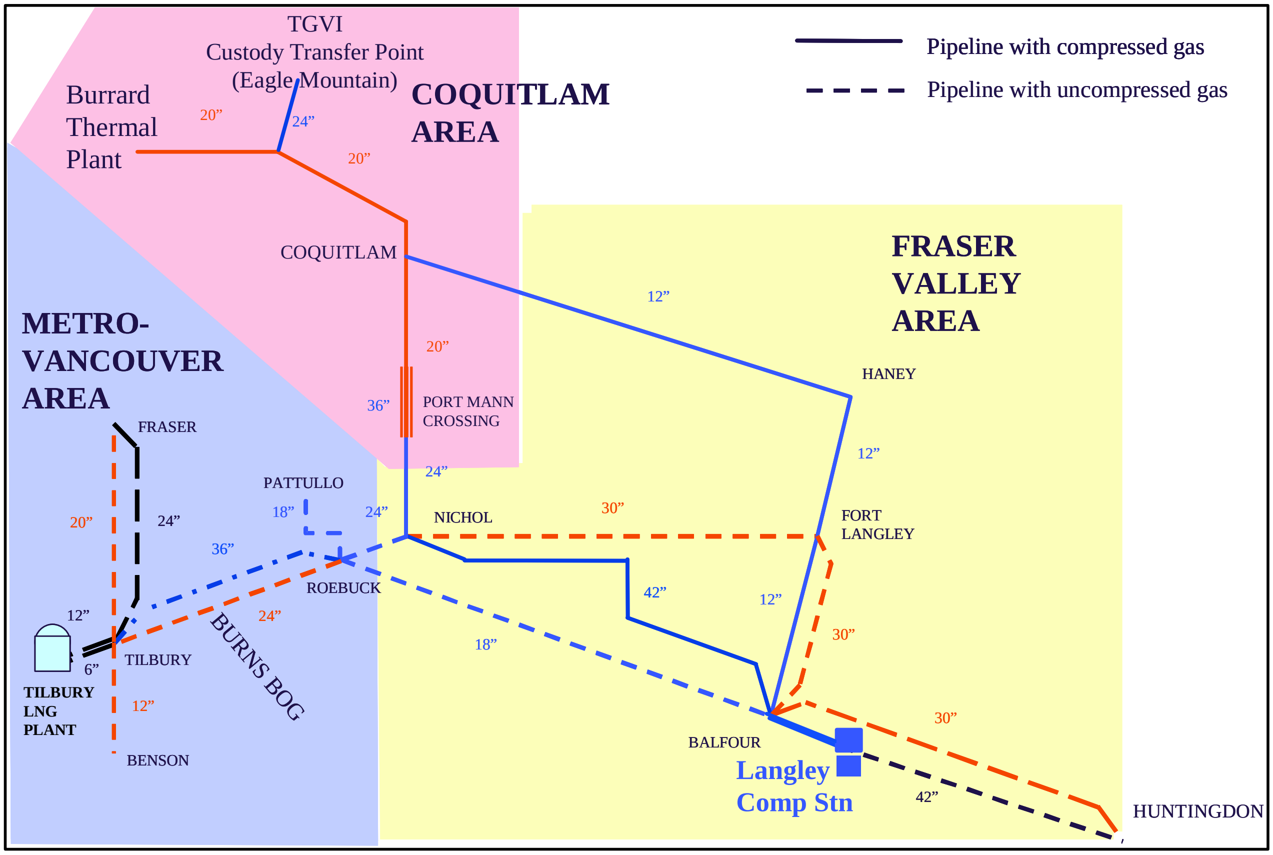
Figure 1-1 in Section 1 illustrates the pipeline systems for the Terasen Gas group of companies. In addition to serving communities and industrial users directly off the Westcoast pipeline in the north and central British Columbia and TransCanada pipeline in the south-eastern British Columbia, TGI operates and maintains two major transmission systems: the CTS serving the Lower Mainland, and the ITS serving the North Thompson, Okanagan and Kootenay regions. These two systems operate independent of each other hence are assessed separately for resource expansion requirements.

6.3 Coastal Transmission System

6.3.1 General Description

Figure 6-1 is a simplified schematic of the CTS. The system consists of 265 kilometres of transmission pipe ranging from NPS 6 to 42 operating at pressures up to a MOP of 583 psig. The Langley compressor station is used to maintain system pressure during high demand periods. The Tilbury LNG peak-shaving storage facility is used to meet gas supply requirement as well as increasing system deliverability to the CTS during high demand periods. The CTS serves as the backbone for distribution systems in the three general service areas within the Lower Mainland: Fraser Valley, Metro Vancouver, and Coquitlam.

Figure 6-1 CTS schematic



As illustrated in Figure 7-1, the majority of the CTS in the Fraser Valley and Metro Vancouver areas is already looped and consequently is expected to have sufficient capacity to meet long-term demand requirements. The Coquitlam area is primarily fed by a single pipeline from Nichol in Surrey. A secondary feed from a pipeline from Balfour in Langley supplies less than five percent of the required capacity to the Coquitlam area. Based on the current demand forecast, this single feed to the Coquitlam area would potentially require future resource expansion within the planning period. The remainder of this section is therefore is limited to a review of the demand and capacity requirements in the Coquitlam Area.

6.3.2 Core Demand And Transportation Requirements – Coquitlam Area

The single feed of the CTS serving the Core market in the Coquitlam area also serves, TGVI at Eagle Mountain and BC Hydro at Burrard Thermal. The demands from each and their impact on resource requirement are discussed in more details below.

Core Market in Coquitlam Area

The Core market in The Coquitlam area represents 15% of total Lower Mainland Core market demands. The Core market peak day growth for the Coquitlam area matches close with that for the Lower Mainland at 1-2% per year. The impact from the core market growth has minimal impact on the requirement for the CTS resource.

TGVI

TGVI serves its core markets on Sunshine Coast and Vancouver Island, as well as TGS and, in the near future, TGW service areas, and provides transportation service to ICP and the six mills represented by the Vancouver Island Gas Joint Venture (“VIGJV”). TGVI holds capacity across the CTS to serve its gas transport requirements from Huntingdon to the beginning of its transmission system at Eagle Mountain. As reviewed in TGVI's 2006 Resource Plan filed concurrently with this TGI Resource Plan, TGVI is currently examining resource options to meet growing core market demand on its transmission system and to manage the uncertainty regarding the long term requirements for its major transportation customers: namely, the six pulp and paper mills currently under the VIGJV agreement and BC Hydro for service to ICP. The existing VIGJV agreement expires at the end of 2012; however, it is anticipated that these customers will continue to have firm gas transportation requirements over the long term. BC Hydro's current service agreement for ICP expires at the end of 2007 and although it is expected BC Hydro will require ICP to continue to provide electrical generation capacity over the planning period, the nature of the transportation service (firm or interruptible) is less certain.

TGVI's 2006 Resource Plan identifies two resource portfolio options to meet demand requirements:

1. the LNG Storage Portfolio whereby the proposed Mt Hayes LNG storage facility proceeds
2. the Pipe and Compression Portfolio whereby additional compressor stations and/or pipeline looping projects are added along the TGVI system

In both options, TGVI would require incremental capacity on the CTS. However, TGVI's incremental transportation requirements on the CTS are lower for the LNG Storage portfolio as TGVI would use the on-Island peak-shaving facility to supplement the capacity of its transmission system.

In addition, TGI is evaluating a proposal to contract for storage capacity from the proposed Mt Hayes facility as part of TGI's gas supply portfolio. In this scenario, delivery of TGI's storage gas is effectively done through displacement thereby reducing the CTS delivery requirement to TGVI at Eagle Mountain. It is likely that TGI would be requiring the storage gas during peak periods; this could further reduce the CTS capacity requirements to serve TGVI.

Burrard Thermal

BC Hydro holds 275 TJ/d firm CTS transportation capacity under the Bypass Transportation Agreement (“BTA”) for the Burrard Thermal in Port Moody and also assigns 22 TJ/d of this capacity to TGVI to support firm transportation service to ICP on Vancouver Island. The

Langley compressor station was installed in 2000 to maintain adequate operating pressure of the two pipelines serving the Coquitlam area and to meet BC Hydro firm transportation requirements for the Burrard Thermal and ICP.

The BTA expires in 2030; however BC Hydro has the right to terminate the agreement as early as 2009. For resource planning of CTS capacity requirements, TGI assumes the transportation service requirements for Burrard Thermal based on information contained in BC Hydro's 2006 IEP[54]. In particular, TGI has assumed that three units at Burrard Thermal (Units 4-6) are relied on for electrical capacity between 2006 and 2008 and all six units are required between 2009 and 2013. This equates to a demand of 120 TJ/d for 2006-2008 and 231 TJ/d for 2009-2013.

As discussed in the 2006 IEP, BC Hydro is currently reviewing the future of Burrard Thermal beginning in 2014. It is TGI's understanding that 2014 is the earliest BC Hydro expects a major transmission reinforcement project to serve the lower mainland can be completed which would allow it to consider other resources to replace the Burrard Thermal capacity.

6.3.3 CTS Capacity Expansion Requirement

In the 2004 Resource Plan, TGI demonstrated that the expected demands on the CTS could result in an expansion requirement as early as 2009. However, at that time it was expected that TGVI's requirements to serve Vancouver Island would include long term firm service to BC Hydro for ICP and the proposed Duke Point Power generation facility. BC Hydro has since cancelled the Duke Point project and is examining the requirement to hold firm service for ICP. As a result, the requirement for CTS capacity expansion has been deferred.

To determine the earliest a capacity expansion could be required, TGI examined a scenario that considered the highest transportation requirement that could be reasonably expected over the planning period based on the following assumptions:

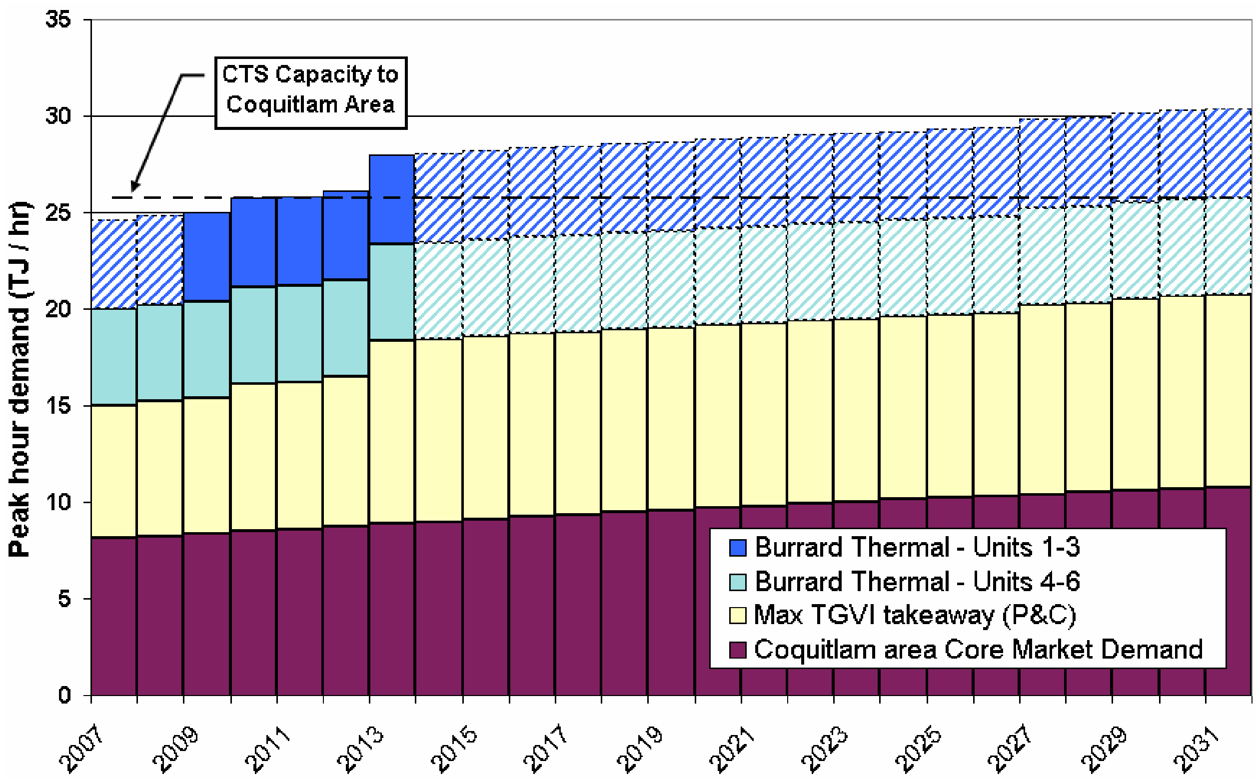
- TGVI's Mt Hayes LNG facility does not proceed, and TGVI pursues the Pipe and Compression resource portfolio while maximizing its takeaway capacity to provide firm service to the both Joint Venture member mills and ICP
- BC Hydro relies on firm transport capacity for all six units at Burrard Thermal
- CTS Core Market demand growth is consistent with TGI's High demand forecast

Figure 6-2 illustrates the CTS capacity to serve these loads based on these assumptions and demonstrates that the earliest a facility addition could reasonably be required is 2011. Since the Coquitlam core load impact is small, the capacity expansion requirement is unlikely to be deferred if lower core demand growth is realized. However, if TGVI does not expand its system to provide firm service to ICP, the take-away capacity at Eagle Mountain would be lower and would defer the need for CTS expansion beyond 2013.

[54] 2006 Integrated Electricity Plan. BC Hydro. p4-24. http://www.bchydro.com/info/epi/epi43498.html

In addition, if TGVI pursues the LNG Storage portfolio to serve its firm loads, including ICP, and builds the proposed Mt Hayes LNG storage facility, TGVI's take-away capacity at Eagle Mountain would be lower and would also defer the need for CTS expansion beyond 2013. Similarly, if TGI contracts with TGVI for storage service from Mt Hayes, TGI can use the LNG send-out to reduce physical deliveries to Eagle Mountain during peak periods and further defer the need for CTS capacity expansion.

Figure 6-2 CTS Facility Timing



6.3.4 CTS Resource Options

In TGI's 2004 Resource Plan, the following resource options were identified:

- Phased pipeline loop between Nichol and Noon's Creek. The system is currently served with a NPS 24 pipeline between Nichol and Port Mann, a NPS 36 pipeline crossing the Fraser River, and a NPS 20 pipeline between Cape Horn, Noon's Creek, and Burrard Thermal. Pipeline looping would consist of a NPS 30 pipeline parallel to the existing pipeline and within existing right-of-way. The pipeline looping would occur in three phases – Nichol to Port Mann (4.3 km), Cape Horn to Coquitlam (5.1 km), and Coquitlam to Noon's Creek (4.3 km).

- Additional compression at the Langley compressor station. Up to two compressor units can be added to the Langley compressor station within the existing site. This would assist in maintaining pipeline pressure along the Nichol – Noon's Creek – Burrard Thermal corridor.

- Compressor station near Nichol station. A compressor station near the Nichol would assist in maintaining pipeline pressure along the Nichol – Noon's Creek – Burrard Thermal corridor.

- Expansion of the Tilbury LNG facility. The Tilbury LNG facility holds 0.6 Bcf of storage and 150 mmscfd of deliverability. An additional storage and vapourization facilities can be added to the existing facility without site expansion.

- TGVI's Mt Hayes LNG Storage project on Vancouver Island. This storage project would reduce TGVI's capacity requirement across the CTS, and also TGI could contract for storage services to provide additional deliverability capacity on the CTS.

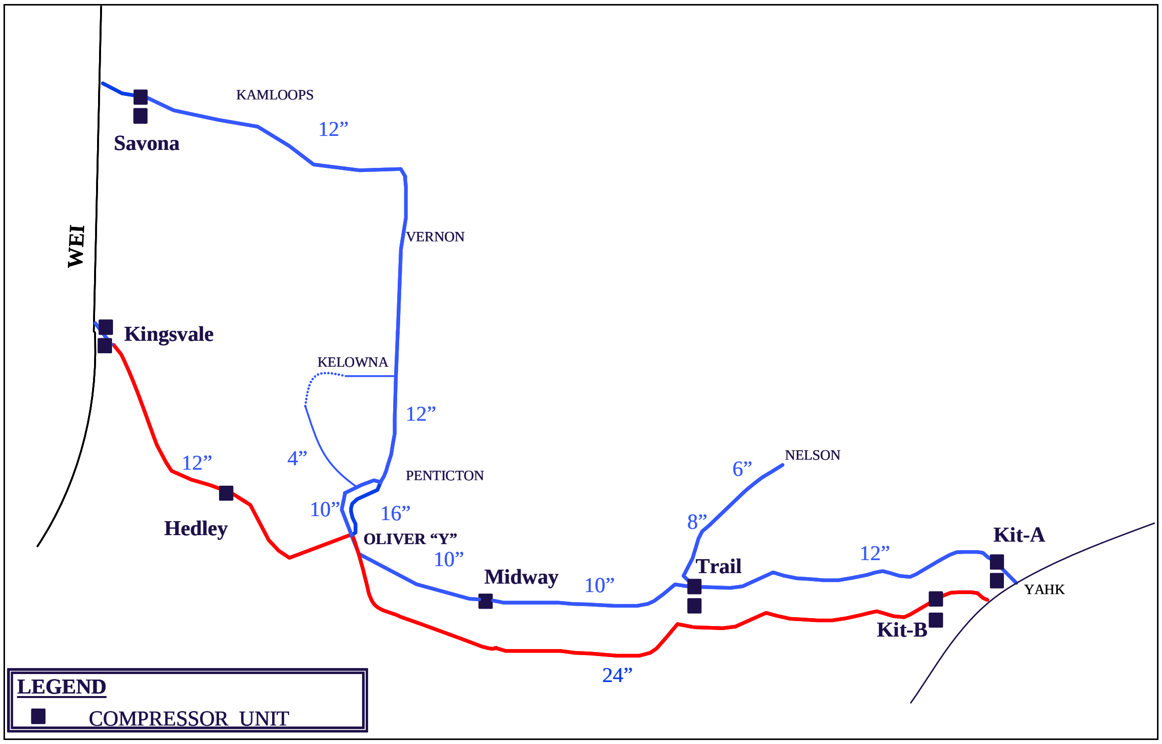
The uncertainty surrounding the future operation of Burrard Thermal makes the storage options more attractive than adding transmission capacity. As can be seen from figure 7-2, if Burrard Thermal is de-activated, the requirement for CTS expansion is beyond the planning period. As a result, if the CTS capacity was expanded through compression or looping to meet a 2011 requirement, and Burrard Thermal was subsequently terminated, there is a higher risk of stranded capacity. On-system storage options, on the other hand, also offer gas portfolio benefits and continue to be used and useful even if BC Hydro is to terminate the BTA.

6.4 Interior Transmission System

6.4.1 General Description

Figure 6-3 is a simplified schematic of the ITS. The system consists of 1,515 kilometres of transmission pipe ranging from NPS 4 to 24 and operating at MOPs between 700 and 1,440 psig. Gas received from Westcoast at Savona supplies the Core market and transport customers in the Thompson and North Okanagan regions via a NPS 12 pipeline. Gas received from TransCanada at Yahk supplies the Core market and transport customers in the West Kootenay region via a NPS 12 pipeline to Trail and a NPS 10 pipeline to Oliver-Y. The NPS 24 SCP transports gas from Yahk to Oliver-Y. From Oliver-Y, NPS 10 and 16 pipelines transport the gas from the SCP to serve the Core markets and transport customers in South and Central Okanagan regions. Also, from Oliver-Y, a NPS 12 pipeline transports gas from the SCP to Kingsvale for re-delivery to the CTS via Westcoast.

Figure 6-3 ITS Schematic



6.4.2 Core Demand and Transportation Requirements

Within the ITS, close to 60% of the core market demand is concentrated in the South, Central and North Okanogan regions. In addition, close to 80% of the core market growth is also within the same regions. Future incremental facility additions would be those required to transport gas to the same regions.

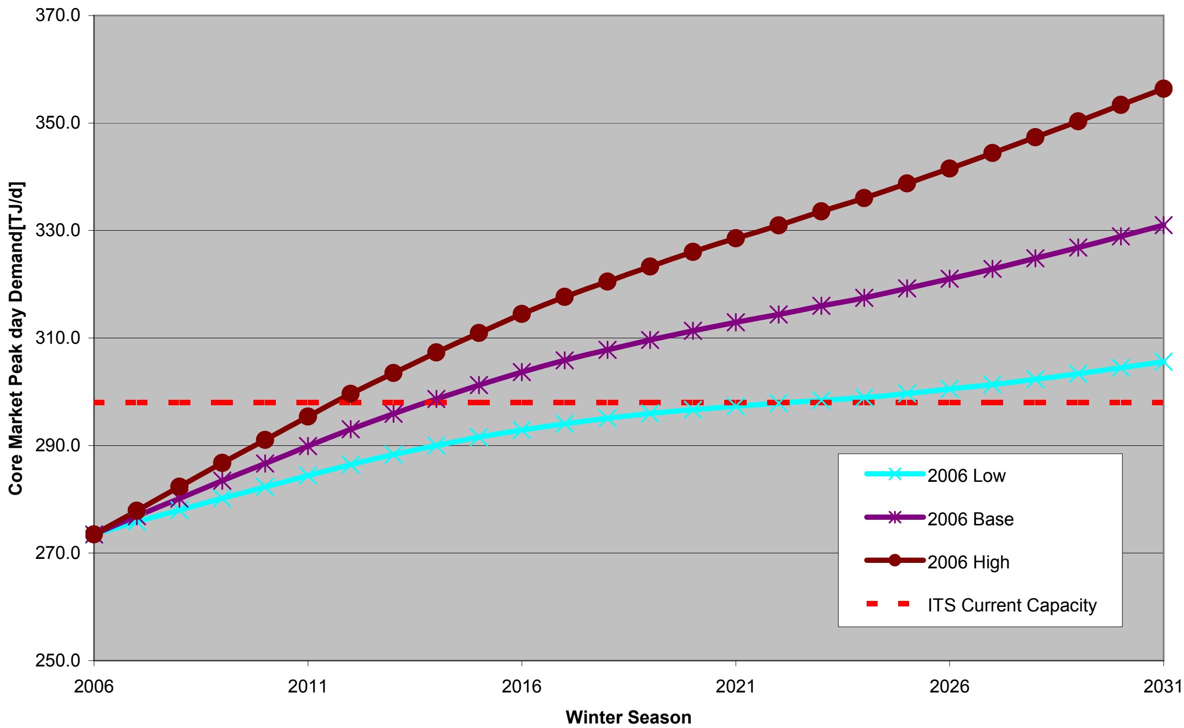
As industrial demand is expected to remain stable, differences in the timing for facility additions result entirely from the residential and commercial customer growth forecasts in the Okanagan regions.

6.4.3 Facility Requirements

Figure 6-4 shows the demand forecasts for the ITS including the timing for the first facility addition. In the Base case, a facility addition is required in 2015. For the Low and High cases, a facility addition is required in 2023 and 2013 respectively. In the 2004 Resource Plan, the first facility addition was identified to be required in 2015, 2014, and 2010 respectively for the low, base and high cases. The deferred facility addition schedule in the current Resource Plan reflects the observed reduced peak day use rates of the core market customers.

The ITS has several large industrial customers who have firm transportation agreements which offer TGI the right to recall the firm service for 5 days in a calendar year. For resource planning of the ITS, TGI has assigned the recallable demand to the design peak days to defer potential incremental facility additions.

Figure 6-4 ITS Facility Timing



On the ITS, three resource options have been identified:

- Phased pipeline looping between Penticton and Winfield, north of Kelowna. This pipeline looping would increase gas supply delivered from TransCanada at Yahk via the SCP. This high growth area between Penticton and Kelowna is currently served with a NPS 12 pipeline. The first two phases of the pipeline looping – Penticton to Naramata (23.7 km) and Naramata to Mission (15.0 km) – would follow the existing pipeline right-of-way. Due to population growth in Kelowna, the final phase would bypass Kelowna and terminate at Winfield. The entire pipeline loop would be NPS 20.

- Phased pipeline looping between Savona and Kamloops. This is an alternative to the pipeline looping between Penticton and Winfield. This pipeline looping would increase gas supply delivered via the Westcoast at Savona. This pipeline loop contemplates a two phase NPS 16 pipeline: 17.2 km from Savona to Valve SN-2, and 14.8 km from Valve SN-2 to Kamloops.

- LNG storage facility between Falkland and Vernon. A LNG storage facility allows natural gas to be stored in times of low demands when excess pipeline capacity is available, and provides on-system delivery to the Okanogan regions during high demand periods to augment the delivery capacity of the ITS.

6.5 Impact of Energy Efficiency Programs

As discussed in Section 4, a CPR was recently completed for TGI. Among other things, the report examines the potential for introducing energy efficiency or conservation programs to help manage customer demand. The CPR also examined the potential for demand growth due to fuel substitution programs which would support the selection of natural gas, where appropriate, over other energy alternatives, such as substituting gas in place of electricity for space heating. The CPR also identified hurdles to meeting the achievable potential of these programs including partnership funding and an appropriate regulatory framework.

The principle objective of these programs is to reduce the end user's energy costs by promoting conservation measures and choosing the right energy source for the right application. In addition, often one of the benefits of energy efficiency programs is to reduce or defer the need to expand the delivery capacity of the transmission system to meet expected load requirements.

On the CTS, the CPR indicates there is potential for a net reduction in gross design day demand of 26.7 TJ by 2010/11 growing to 61.9 TJ in 2015/16. This represents approximately 6% of the 2015/16 CTS gross design day demand. As discussed above, however, the Core demand in the Coquitlam area represents only 15 % of CTS demand, and therefore energy efficiency programs have limited potential for deferring transmission expansion requirements in the Lower Mainland. The timing of any expansion capacity requirement on CTS will depend primarily on the long term requirements of Burrard Thermal.

On the ITS, however, expansion requirements will be driven by Core market growth and therefore there is a greater opportunity for energy efficiency programs to impact the timing expansion facility additions. The CPR indicated that there is a potential net reduction in gross design day demand of 11.6 TJ in 2010/11 growing to 22.3 TJ in 2015/16, representing approximately 5% of the 2015/16 ITS gross design day demand. This has the potential to defer the need for ITS expansion requirement shown in Figure 7.4 above by 5-6 years.

6.6 Resource Portfolio Evaluation

As discussed in Section 7.3.3, the earliest a facility addition could be required on the CTS is 2011. This assumes the CTS Core market experiences growth consistent with the High demand forecast, TGVI's proposed Mt Hayes facility does not proceed and TGVI expands its transmission system to meet the requirements of the VIGJV mills and ICP over the long term, and BC Hydro continues to require capacity to serve 6 units at Burrard Thermal. If TGVI's proposed Mt Hayes LNG facility on Vancouver Island proceeds, the requirement for CTS upgrade can be deferred significantly.

On the ITS, the first facility addition is needed in 2015 in the Base demand scenario, although this requirement could be advanced to 2013 in the High core market growth demand scenario. Facility timing on the ITS is only affected by the difference in Core market growth and therefore may also benefit from the implementation of energy efficiency and/or demand side management programs.

As the need for a facility addition is not within the 4-year Resource Planning Action Plan window for both the CTS and ITS, identification and detailed financial evaluation of preferred resource options to meet growth have not been prepared as part of this Resource Plan. TGI will continue to monitor core demand growth on its system and developments surrounding the future operation of ICP and Burrard Thermal and its impact on the CTS. For the ITS, TGI will continue to monitor growth in the residential and commercial segments.

6.7 Relationship to 5-Year Capital Plan and Statement of Facilities Extensions

The Commission, in its Letter No. L-30-05, acknowledging receipt of TGI's 2004 Resource Plan, stated that TGI's 2006 Resource Plan Update should include a Statement of facilities extensions. In response to this recommendation, TGI is appending its 5-Year Regular Capital Plan and 5-Year Major Capital Plan (Appendix H) to its 2006 Resource Plan. In aggregate these two plans constitute the Company's 5-Year Capital Plans.

TGI has segmented its 5-Year Capital Plans as follows:

Regular Capital Plan
- Customer Driven Capital
- Non-Customer Driven Capital

Major Capital Plan
- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital includes forecast Capital Expenditures that are under $1 million. These expenditures have been categorized into either customer driven capital or non-customer driven capital. This category excludes Capitalized Overheads, Contributions in aid of Construction ("CIAC") and Allowance for funds used during construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGI in excess of $5 million have required a CPCN.

TGI's 5-Year Capital Plans for the period 2006 to 2010 are presented to provide additional background and context for the Resource Plan. TGI is of the view that these Capital Plans are not included for the purposes of approval by the BCUC as part of its review of the TGI Resource Plan. TGI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. TGI is of the view that its 2006 Annual Review Application included detailed capital expenditures that were reviewed and approved by Commission on December 9, 2005 by Order No. G-132-05. Consistent with past practice, TGI continues to believe that the appropriate forum for review of its Capital Expenditures is its Performance Based Regulation ("PBR") and Annual Review proceedings.

As TGI's 5-Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the *Utilities Commission Act*.

TGI has endeavoured to provide a comprehensive 5-Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company's Annual Review filing, which is anticipated in October, 2006.

7 STAKEHOLDER CONSULTATION

Stakeholder needs and concerns are critical to Resource Planning. More than simply facilitating open communication, effective stakeholder consultation provides the Company with insights that can impact the entire planning process, from trends that influence demand forecasting and DSM analysis through to the development of an action plan for implementing preferred planning solutions. Terasen Gas has a record of conducting effective stakeholder consultation programs and continues to do so in preparing this plan.

7.1 Stakeholder Consultation to Date

This Section provides an update on stakeholder consultation activities through 2005 and 2006, and also draws upon activities completed in late 2004 and early 2005 related to the previous TGI Resource Plan, which was submitted in April, 2005. For TGI, the Resource Planning issues affecting stakeholders have not changed significantly in the past year.

In its 2003 Resource Planning Guidelines, the BCUC encourages utilities to tailor their consultation efforts to areas of the planning process that will prove the most effective and to use methodologies that best fit their needs. In 2005 and again in 2006, TGI completed a review of the CTS and ITS transmission systems in the context of updated demand forecasts and identified no immediate impacts on local communities. Significant transmission facility expansions resulting from system constraints are not likely required until the year 2011 for the CTS and 2013 on the ITS, at the earliest. With no immediate system expansion that would impact communities, TGI has found that stakeholder interest remains mild to low. TGI therefore continues to follow a stakeholder consultation process through 2006 that targets high growth municipalities and the business community in discussing energy issues. Discussions continue to focus on:

- The role of natural gas in sustainable, community energy planning
- Efficient use of energy resources
- Regional gas supply and storage issues
- Provincial/regional growth and energy use trends
- Terasen Gas programs for efficient energy use, and
- Resource Planning at TGI to ensure natural gas service is provided safely, reliably and cost effectively over the long term.

TGI's Community Relations representatives have continued to nurture the relationships with municipalities that were established through the 2004-05 Resource Planning presentations and to develop new relationships with communities in discussing these energy issues. The Terasen Gas Utilities also conduct ongoing First Nations consultation in each of its subsidiary service regions, including TGI, pursuant to the company's statement of principles and commitment to respect the social, economic and cultural interests of First Nations.

7.1.1 General Stakeholder Workshops

TGI held workshops in both 2005 and 2006 to discuss resource planning issues with a broad range of interested stakeholders.

Table 7-1 Summary of General Stakeholder Workshops

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
Stakeholder workshop / presentation Lower Mainland **March 16, 2005**	- Background to Resource Planning - Future energy outlook for natural gas customers - Planning considerations (supply and demand side) - Supply needs and market characteristics - Potential new DSM initiatives - Resource portfolio considerations & preliminary evaluation - Planned CTS / ITS expansion required	Direct mail invitations were sent to stakeholders and stakeholder groups including: - customers & business - municipal & provincial government & BCUC - environmental and energy related non government organizations (NGO) - Interveners from the 2003 and 2004 revenue requirement application - BC Hydro	19 people attended including customer, government, BCUC, BC Hydro, NGO and Intervenor Representatives
Combined TGI & TGVI General Stakeholder Workshop on Resource Planning – Vancouver **June 20th, 2006**	- Regional supply and storage planning issues, - Terasen Gas demand forecasts, - Energy efficiency and fuel switching programming, - Resource options and evaluation and the status of the Mt Hayes LNG proposal. - A representative from the Northwest Gas Association presented details on regional (I-5 corridor) planning issues.	Over 600 stakeholders were invited to take part. Invited stakeholders included the Commission, Government ministries, interveners, First Nations, municipalities, interest groups and key customers	22 people attended including customer, government, BCUC, BC Hydro, NGO and Intervenor Representatives

Issues raised by stakeholders during the 2005 workshop generally followed the pattern of topics presented by Terasen Gas staff. These issues included:

- Risks to supply upstream of the Terasen Gas transportation and distribution systems;
- New infrastructure within the Regional Market (I-5 Corridor and Alberta – BC transportation pipelines) that could affect gas supply and pricing;
- Efficiency of natural gas equipment for new, incremental energy loads and the drivers and trends affecting consumer decisions;
- The component demand forecasts and considerations included within the Interior and Coastal region forecasts;

- The drivers of natural gas and electricity prices and customer addition forecasts;
- Costs included within the economic tests (RIM and TRC) for new and proposed DSM programs;
- The potential impact of DSM programs on demand and thus on the potential to offset capital costs;
- Significant discussion around how the various BC Hydro demand components are incorporated into the demand forecast; and
- The likelihood of Terasen Gas filing a CPCN application in the near future.

Most of the comments raised during the 2005 workshop were requests for clarification of technical details of the Resource Plan or discussion and assurances that Terasen Gas has carefully considered external factors influencing the demand forecast and project timing. As a result, Terasen Gas has endeavoured to clarify the analysis and presentation of data discussed at the workshop within this document.

The June 2006 workshop addressed both the TGI and TGVI Resource Plans and their interrelated nature. Issues raised by attendees during that workshop included:

- Raising the dollar threshold for requiring CPCNs to something more than $5 M in order to relieve some of the regulatory burden on the Utilities.
- What improvements have been made to our customer addition forecasting methodology?
- How can the impact of free-riders or incentives on the true benefit/cost analysis of DSM programs be assessed? To do so might require separating out actions that people would have taken even without the riders (for example: old equipment that is scheduled for replacement with or without incentives).
- What has been the success record in partnering with both BC Hydro and Fortis on the New Home Program?
- Terasen Gas was urged to look at the customer's bill, not just rates, when assessing value and impacts of DSM programs, particularly as it impacts low income customers.
- If partnerships for programs don't materialize, can/will Terasen Gas proceed anyway?
- Discussion and concern regarding regional gas supply and storage constraints and what is driving increase costs for these resources.

7.1.2 BC Hydro Consultation

TGI maintains open, consultative communications with BC Hydro. Most recently, discussions with BC Hydro have focused on understanding future plans and demand issues for Burrard Thermal and ICP, and reviewing the resource options now available to TGI. Further, BC Hydro and Terasen Gas worked together on the energy CPR studies completed for each company earlier this year and will continue to work together wherever practical energy efficiency and load switching programming.

7.1.3 Customer Advisory Consultation

Customers and stakeholders were invited to attend TGI's semi-annual Customer Advisory Council meeting held on April 26, 2006. The meetings are a requirement of the current Performance Based Rate agreement to ensure that information on company performance and planning information is shared with our customers. TGI took the opportunity to present information to assist customers with energy planning, highlight the design advantages of natural gas, promoted the importance of using the right fuel for the right place at the right time and provide a forum for feedback on issues impacting all the Terasen Gas Utilities, including TGI.

7.1.4 Business Community Consultation

Terasen Gas executives took advantage of two opportunities, in January and May, 2006, to address the business community at separate Vancouver Board of Trade luncheons. At these luncheons executives discussed the important role of natural gas in a healthy Provincial economy, the extensive natural gas reserves remaining, upcoming and proposed projects and other issues that affect TGI and the natural gas industry. Opportunities and avenues for feedback on these issues were provided.

7.2 Future Consultation Opportunities for Stakeholders

TGI will continue to share Resource Planning information and recommendations with stakeholders throughout the regions. Planning for continued consultation with targeted and interested municipalities through the remainder of 2006 is underway to continue discussions on resource planning and energy issues affecting communities. As the investigation of on system LNG storage on Vancouver Island proceeds toward a potential CPCN application by TGVI as discussed in Section 5, additional stakeholder consultation will be conducted in anticipation of filing timelines in the fall 2006. Further discussions with stakeholders will include the value of on system storage to TGI and potential participation in a service agreement with TGVI for Mt Hayes LNG storage capacity.

8 ACTION PLAN

The Action Plan describes the actions that Terasen Gas intends to pursue over the next four years based on the information and evaluation provided in this Resource Plan.

1. *Continue to monitor and evaluate customer demand by*:

   a. Monitoring Core customer demand including commercial and industrial transport service trends in both the Coastal and Interior service regions.

   b. Continuing to assess the impact of emerging energy trends and technologies on demand for natural gas.

   c. Continuing to monitor the load demand from natural gas use for vehicles which, due to regional air quality and global GHG concerns, has the potential to increase more quickly then has been seen in the recent past, and contribute to a higher demand forecast scenario.

   d. Continuing to assess Terasen Gas' success rate in penetrating the multi-family dwelling, residential customer sector and incorporating these changes into customer addition rates in the demand forecasts.

2. *Continue with existing and implement new Demand Side Management initiatives*.

TGI will evaluate the potential for an expanded DSM strategy based on the CPR results and will communicate results and recommendations during the fall of 2006 Where increased funding is required to support expanded DSM activities, TGI will submit a request to the Commission outlining the additional funding requirements and the scope of the DSM activities planned.

3. *Continue to pursue partnering opportunities regarding energy efficiency measures*.

TGI will continue to pursue partnering opportunities with NRCan, Industry and BC Hydro and support the Ministry of Energy and Mines and Petroleum Resources in their target to reduce the energy consumption in residential and commercial buildings.

4. *Examine funding opportunities for the preparation and implementation of marketing plans that will help Terasen Gas reach customer targets and build energy efficient gas load for both new and existing customers*.

Adding new customers and encouraging existing customers to make high efficiency gas appliance choices will be critical in maintaining competitive energy choices in the region. Marketing programs and materials will be essential for encouraging new customers to choose natural gas, increasing gas usage per account and reducing the individual's share of fixed costs. Each of these conditions will in turn help to maintain a competitive position for natural gas.

5. *Monitor customer growth on the CTS system and continue to investigate options to address future capacity shortfalls*.

The most significant factor driving potential expansion requirements will be BC Hydro's future operation of Burrard Thermal and to a smaller degree ICP. TGI will closely monitor developments on this front and bring forward recommendations in a timely fashion when it appears that action is required.

6. *Work with TGVI to examine the feasibility of the Mt Hayes LNG facility as an on-system storage resource for both utilities*.

TGI will work with TGVI to assess the value of storage services based on building a 1.5 BCF facility. Following additional stakeholder consultation, TGVI will then determine the timing and the appropriate course of action to advance the LNG project. Once approvals are obtained, the LNG Storage facility requires 36 months to complete and fill the tank. Therefore, the earliest the facility would be available is November 2010.

9 GLOSSARY

Annual demand – the cumulative daily demand for natural gas over an entire year.

Avoided cost – the incremental cost that a utility would incur to purchase gas supplies and capacity equivalent to that saved under a demand side management program. Components of avoided cost could include energy, capacity, storage, transmission and distribution.

BCUC (British Columbia Utilities Commission) – the BCUC is the provincial body regulating utilities in British Columbia.

BTA – Bypass Transportation Agreement whereby TGI transports natural gas from Huntingdon to Burrard Thermal across its Coastal Transmission System

CFT (Call for Tenders) – in this document, CFT refers to a specific Call for Tenders that BC Hydro has initiated as part of a review of electricity supply options for Vancouver Island.

Cogeneration – in this document, cogeneration refers to the generation of both electrical and thermal power simultaneously by utilizing the waste heat from a gas turbine to generate steam.

Commission – see BCUC.

Compression, compressor station – the application of increased pressure to a natural gas pipe system to create gas flow. Higher levels of compression can be applied to increase the carrying and storage capacity of the pipe. Increased pressure is applied through a compressor station constructed along the pipeline.

Core, core customers, core market – residential, commercial and small industrial customers that have gas delivered to their home or business (bundles sales). Terasen Gas purchases natural gas and delivers it to the customer in a bundled sales rate. Core Market customers typically use a significant portion of their gas requirements for heating applications, resulting in weather sensitive demand.

CPCN (Certificate of Public Convenience and Necessity) – is a certificate obtained from the British Columbia Utilities Commission under Section 45 of the *Utilities Commission Act* for the construction and/or operation of a public utility plant or system, or an extension of either, that is required, or will be required, for public convenience and necessity.

CPR (Conservation Potential Review) – a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency.

Curtailment – the planned interruption of gas supply to specific customers during periods of high demand for natural gas – usually during extreme cold weather events.

Daily demand – the amount of natural gas consumed by Terasen Gas' customers throughout each day of the year.

Demand forecast – a prediction of the demand for natural gas into the future for a given period and under a specified set of expected future conditions.

Demand side, Demand Side Management (DSM) – defined as "any utility activity that modifies or influences the way in which customers utilize energy services". From Terasen Gas' perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources.

Design-day, design-hour demand – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: peak day).

DHW – domestic hot water.

EIA – Section of the US Department of Energy (DOE) providing statistics, data, analysis on resources, supply, production, consumption for all energy sources.

EnerGuide – an energy rating program managed by the Office of Energy Efficiency at Natural Resources Canada, that uses interactive tools to help energy-wise consumers and industries make the right choice when purchasing "off the shelf" equipment such as motors, dry-type transformers, HVAC, lighting products, refrigeration products, boilers, compressors, and pumps.

EPA – Electricity Purchase Agreement.

ENERGY STAR – is an international symbol for energy efficiency and is administered and promoted in Canada by Natural Resources Canada ("NRCan").

Extreme Value Analysis – a statistical technique that models extreme events, such as very cold weather, to allow generalization about the likely recurrences of these events.

GHG – Greenhouse gas.

GJ - Gigajoule – a measure of energy of natural gas - one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC).

GLJ – GLJ Petroleum Consultants Ltd. is a private petroleum industry consultancy serving clients who require independent advice relating to the petroleum industry, including the preparation of natural gas and oil price forecasts on a quarterly basis.

GSHP – Ground source heat pumps are a form of geo-exchange system.

GWH – Giga-watt Hours.

Heating degree day – a measure of the coldness of the weather experienced. The number of heating degree days for a given day is calculated based on the extent to which the daily mean temperature falls below a reference temperature, 18 degrees Celsius.

Huntingdon/Sumas – gas flow regulating stations on either side of the British Columbia/US border through which much of the regional gas supply is traded.

I-5 Corridor – the natural gas regional market area served by infrastructure located along Interstate 5 in the north western US. The I-5 Corridor includes BC's Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

ICP (Island Cogeneration Plant) – A cogeneration plant located at Elk Falls, Campbell River supplying electricity and thermal energy on Vancouver Island.

IEP (Integrated Electricity Plan) – BC Hydro's 2006 Integrated Resource Plan.

Industrial curtailment – see curtailment.

Interruption – see curtailment.

IPP – Independent Power Producers.

IRP (Integrated Resource Plan) – see Section 1 for a detailed description of Resource Planning. An integrated resource plan is a document that details the resource planning process and outcomes that guide a utility in planning to serve its customers over the long term.

JV (Joint Venture) – see Vancouver Island Gas Joint Venture.

JV TSA – Vancouver Island Gas Joint Venture Transportation Service Agreement.

LNG (Liquefied natural gas), LNG storage – natural gas stored under high pressure turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed.

LNG Import Terminals – Terminals that receive liquefied natural gas that is shipped in large tankers from overseas. LNG Import terminals are considered supply resources not storage resources.

Load – the total amount of gas demanded by all customers at a given point in time.

Load duration, load duration curve – a graphical representation of the daily loads over a period of time, typically one year, sorted from highest load to lowest load.

Load shaping – demand side management strategies that affect the shape of the annual demand curve for a given year or years (see Section 4.0 for further details).

Looping – the twinning of sections of gas supply transportation pipe to improve storage and flow characteristics within the service area.

LTAP – BC Hydro's Long Term Acquisition Plan which identifies the preferred resources, both supply and demand, that the utility intends to acquire over the long-term to serve the growing demand for electricity in BC.

MEMPR – Ministry on Energy and Mines and Petroleum Resources.

MMCF – 1 million cubic feet.

MOP – maximum operating pressure.

NEB (National Energy Board) – an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. Visit www.neb-one.gc.ca.

NGV – Natural Gas Vehicles**.**

Normal demand (also called annual demand) – when considering historical normal demand, this is the actual demand experience that has been adjusted to account for weather that has been colder/warmer than normal. The expected demand during a year of normal weather conditions. When considering forecast normal demand, this is the expected demand under normal weather conditions. Normal weather conditions are based on a rolling 10 year average of heating degree days experienced during each of the 10 years.

NRCan – Natural Resources Canada is a Government of Canada department specializing in the sustainable development and use of natural resources - energy, minerals, metals and forests.

NWGA – Northwest Gas Association is a trade organization of the Pacific Northwest natural gas industry. Its members include six natural gas utilities, including Terasen Gas, serving communities in Idaho, Oregon, Washington and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region.

Peak day, peak demand, peak day demand – the maximum expected amount of gas in any one day or hour required by customers on the TGI system. Since Core customers' demand is primarily weather dependent, design-day or design-hour demand is forecasted based upon a statistical approach called Extreme Value Analysis, which provides an estimate of the coldest day weather event expected with a 1 in 20 year return period. For transportation customers, the design-day is equivalent to the firm contract demand. (See also: design-day.)

PJ - Petajoule – equal to 1000 Terajoules or 10^6 Gigajoules.

Portfolio, resource portfolio, supply portfolio – selected supply and/or demand resources that, when grouped together, can meet the future demand and supply needs of a service area.

psig – pounds per square inch gauge.

Ratepayer Impact Measure (RIM) Test – a measure of the distribution of equity impacts of DSM programs on non-participating rate-payers. From this perspective, a program is cost effective if it reduces a utility's rates. This can be expressed as a ratio or in dollars of net benefits.

Rate volatility – the amount to which natural gas rates fluctuate and the frequency of those fluctuations.

Resources – demand side and supply side means available to meet forecasted energy needs. Examples of supply side resources within the context of the Resource Planning process are Pipeline Looping, Compression and Storage. Examples of demand side resources are industrial customer curtailment and load management programs for residential and commercial customers.

RRA – Revenue Requirement Application.

Tcf – Trillion cubic feet.

TJ - Terajoule – equal to 1000 Gigajoules.

Total Resource Cost (TRC) Test – a test used to evaluate the economic benefits and costs of utility DSM program from the perspective of all utility customers. Test can be expressed as a ratio or dollars of net benefits.

Transportation customers – customers who purchase natural gas directly from producers or brokers and pay the utility a fee to deliver the gas to their facilities.

VIGJV (Vancouver Island Gas Joint Venture) – a joint venture of industrial customers (primarily large mills) on Vancouver Island who contract for transportation services as a single entity.

APPENDIX A

BC Utilities Commission Resource Planning Guidelines

BRITISH COLUMBIA UTILITIES COMMISSION

Resource Planning Guidelines

Issued: December 2003

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PURPOSE AND SCOPE OF THE RESOURCE PLANNING GUIDELINES

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist the development of such plans.

The Utilities Commission Act ("UCA") was amended in 2003 to provide the Commission with a mandate to implement the policy actions of the Provincial Government's November 2002 energy policy, "Energy For Our Future: A Plan For BC" ("Energy Plan"). Amendments to Section 45 of the UCA expand upon and clarify the planning requirements of utilities and the Commission's role to review filed plans to determine whether expenditures are in the public interest and whether associated rate changes are necessary and appropriate. The additions to Section 45 of the UCA are as follows:

> 45 (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission;
>
> (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
>
> (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;
>
> (c) a plan of how the public utility intends to reduce the demand for energy and the expenditures required for that purpose.
>
> (6.2) After receipt of a plan filed under subsection (6.1), the commission may:
>
> (a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in the plan;
>
> (a) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and
>
> (b) determine the manner in which expenditures referred to in the plan can be recovered in rates.

On the basis of subsection 6.1, the Commission will require that any resource plans filed under paragraph 6.1, (a), (b) and (c) be prepared in accordance with the Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources (including "BC Clean Electricity" as referred to in the Energy Plan), and those which focus on conservation of energy and Demand Side Management ("DSM").[1] Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and

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[1] *Demand Side Management* may be defined as a deliberate effort to decrease, shift or increase energy demand. Utilities develop DSM programs to encourage customers to enact DSM measures. Because of measurement difficulties and uncertainty about consumer behavior, DSM programs should be evaluated before and after implementation to determine their full impacts.

assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service.

In most circumstances, Certificates of Public Convenience and Necessity ("CPCN") applications should be supported by resource plans filed pursuant to Section 45 of the UCA. The Commission expects that resource plans will help facilitate the review of utility revenue requirements and rate applications.

The Guidelines do not alter the fundamental regulatory relationship between the utilities and the Commission. The Guidelines do not mandate a specific outcome to the planning process, nor do they mandate specific investment decisions. The Guidelines provide general guidance regarding Commission expectations of the process and methods for utilities to follow in developing plans that reflect their specific circumstances. More specific directions regarding resource plans will be provided to utilities on a utility to utility basis. Further directions may address issues regarding the elements of the resource plan or the underlying methodology. The Commission will review resource plans in the context of the unique circumstances of the utility in question. For this reason, the Guidelines do not distinguish between the circumstances of small and large utilities or between transmission and distribution utilities, nor do they prescribe specific planning horizons or approaches to resource acquisition. Although the Guidelines are not prescriptive in that sense, after review of a resource plan the Commission expects to be prescriptive on a utility by utility basis, as necessary, to facilitate cost-effective delivery of a reliable and secure supply that meets demand for a utility's service.

RESOURCE PLANNING GUIDELINES

1. Identification of the planning context and the objectives of a resource plan

Key underlying issues and assumptions that inform the planning context should be identified and discussed (e.g., reliability and security issues, risk factors, major uncertainties). Objectives include, but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; compliance with government regulations and stated policies; and consideration of social and environmental impacts.[2]

2. Development of a range of gross (pre-DSM) demand forecasts

In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions the utility can take to influence demand (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts.[3] More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others. The energy end-use categories[4] used to analyze DSM programs should be compatible with those used in demand forecasting, so that at any point a consistent distinction can be made between demand with and without DSM on an end-use category-specific basis. Thus, the gross demand forecast should be structured in such a way that the savings, load shifting or load building due to each DSM resource can be allocated to specific end-uses in the demand forecast.

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[2] Bonbright, Danielsen and Kamerschen, (Principles of Public Utility Rates, 1988, Ch.8, p.165) suggest that the rates set by utility commissions invariably involve some discretionary judgment about the extent to which broader social principles should influence ratemaking. Because of social and environmental impacts, the rates charged by utilities may be allowed to deviate from those that would result from a rate determination based exclusively on financial least cost. The objectives to be addressed may be identified by the utility, intervenors, or government. The BC Utilities Commission interprets its jurisdiction as extending only to consideration of environmental and social impacts that are likely to become financial costs in the foreseeable future.

[3] In other words, gross forecasts represent an attempt to simulate markets in which the utility did nothing to influence demand. Of course, this is not entirely possible. Utilities will continue to require rate increases and existing DSM programs will affect demand as will already ordered rate design changes. However, the assumptions made with respect to these factors in estimating future gross demand should be clearly specified so that the effects of these assumptions may be distinguished from the effects of future utility actions designed to influence demand.

[4] The term *End-use categories* is intended to mean energy consumption by categories of end-user, such as industrial, commercial, or residential. Guideline No. 2 does not prescribe *end-use forecasting* or *end-use modeling*, but rather requests that forecast outputs and DSM results be organized and checked according to end-use categories.

3. Identification of supply and demand resources

Feasible[5] individual supply and demand resources, both committed and potential, should be listed. Individual resources are defined as indivisible investments or actions by the utility to modify energy and/or capacity supply, or modify (decrease, shift, increase) energy and/or capacity demand.

4. Measurement of supply and demand resources

Each supply-side and demand-side resource must be measured against the objectives established under Guideline No. 1. This includes identifying utility and customer costs (life cycle costs, impact on rates, etc.), associated risks, and lost opportunities.[6] Characterizing the feasible supply and demand resources could also include reporting how these resources perform[7] relative to specific social and environmental objectives. This can facilitate a more comprehensive understanding of the tradeoffs between objectives as they may be associated with various supply and demand resources. Supply and demand resource cost estimates should represent the full costs of achieving a given magnitude of the resource. These cost estimates may be represented as supply curves; i.e. graphs showing the unit costs associated with different magnitudes of the resource.

5. Development of multiple resource portfolios

For each of the gross demand forecasts, several plausible resource portfolios should be developed, each consisting of a combination of supply and demand resources needed to meet the gross demand forecast. The gross demand forecasts and the resource portfolios should cover the same period, generally 15 to 20 years into the future.

6. Evaluation and selection of resource portfolios

For each of the gross demand forecasts, the set of alternative resource portfolios that match the forecast are assessed against the objectives. Analysis of the tradeoffs between portfolios and how they perform under uncertainty will facilitate determining which portfolio performs best relative to the stated objectives. This process will lead to the selection of a set of preferred resource portfolios, each portfolio matching one of the gross demand forecasts.[8]

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[5] Feasible resource options are defined as those options consistent with the objectives of the resource planning process, as established under Guideline No. 1. For example, government policy may rule out a particular technology or form of energy.

[6] *Lost opportunities* are opportunities that, if not exploited promptly, are lost irretrievably or rendered much more costly to achieve. Examples can include cogeneration opportunities that are available but not taken when renovating a pulp and paper mill, or additional insulation that is not installed in a new house.

[7] Performance measures may be quantitative or qualitative.

[8] Guidelines No. 4 through No. 6 may require an iterative process to account for any interdependencies.

7. Development of an action plan

The selection process in Guideline No. 6 provides the components for the action plan. The action plan consists of the detailed acquisition steps for those resources (from the selected resource portfolio) which need to be initiated over the next four years in order to meet the most likely gross demand forecast. The action plan should include a contingency plan that specifies how the utility would respond to changed circumstances, such as changes in loads, market conditions or technology and resource options. For resources with considerable uncertainty, the action plan should incorporate an experimental design and monitoring plan to allow for hindsight evaluation of associated market impacts and full resource costs.

8. Stakeholder input

Although utility management is responsible for its resource planning and resource selection process, utilities should normally solicit stakeholder input during the resource planning process. Methods could include stakeholder collaboratives, information meetings, workshops, and issue papers seeking stakeholder response. Utilities are encouraged to focus such efforts on areas of the planning process where it will prove most useful and to choose methods that best fit their needs.

9. Regulatory input

To streamline the regulatory process, utilities are encouraged to seek review and comment from Commission staff during the various phases of resource plan preparation.

10. Consideration of government policy

A resource plan filed in accordance with the UCA and these Guidelines should be consistent with government policy, as it is expressed in legislation (e.g. efficiency standards) or in specific policy statements and directives. Emerging policy issues, such as increased control of emissions, may be addressed as risk factors.

11. Regulatory review

Upon receipt of a resource plan filed pursuant to Section 45, paragraph 6.1, the Commission will establish a review process, as necessary, pursuant to Section 45, paragraph 6.2. A review may provide, as the Commission considers appropriate, opportunities for written and/or oral public comment.

APPENDIX B

Northwest Gas Association
Natural Gas Supply in the Pacific Northwest
Newsletter Update, Volume 1, Issue 2

VOLUME 1, ISSUE 2

NWGA
NORTHWEST GAS ASSOCIATION

NATURAL GAS SUPPLY IN THE PACIFIC NORTHWEST

IN THIS ISSUE:
- Status of the region's natural gas supply
- A closer look at liquefied natural gas (LNG)
- Balancing future natural gas supply and demand

Almost everyone feels the impact of higher energy prices. Growing worldwide demand for energy in all its forms - along with isolated supply disruptions - contribute to higher prices and higher monthly energy bills. We also feel the effect of higher energy prices when we buy groceries, gasoline and other goods.

Higher energy prices beg the questions: What is the status of energy sources used in the Pacific Northwest? What steps can we take now to help avoid future price and supply problems?

For Pacific Northwest natural gas consumers, the questions are timely. More than enough natural gas supplies exist to serve regional consumers now and in the future. Still, it is only prudent to plan for the long term particularly since the process of financing, public consultation, siting, permitting and building new natural gas supply or delivery facilities takes years.

The regional supply outlook is good because the Pacific Northwest is located adjacent to two prolific supply regions. However, the region's supply and delivery network is not isolated from the rest of North America. Rather, it is linked to and influenced by the greater continental market. Therefore, a look at the bigger picture is in order.

Public and private energy experts agree that plenty of natural gas exists across the continent, and that the North American appetite for it is growing more quickly than our ability to produce it. Demand for natural gas is expected to grow by some 30 percent across the continent in the next two decades, requiring additional supply domestically and from abroad.

One point is clear: there is no single solution to serving growing demand. Meeting future demand will not be achieved solely by expanding production in traditional supply areas or offshore, or solely by building an Alaskan natural gas pipeline, or solely by importing more natural gas from around the globe. It will require implementing all of these tactics, along with energy conservation and efficiency.

Meeting future demand will require expanding & diversifying our natural gas supply.

This White Paper explores the region's current natural gas supply, the integration of the larger continental market and how it influences the region, and actions required to achieve a balanced energy future.

NATURAL GAS SUPPLY IN THE PACIFIC NORTHWEST

NATURAL GAS SUPPLY

The Pacific Northwest is located between two prolific natural gas production areas: the Western Canada Sedimentary Basin (WCSB) and the U.S. Intermountain West (mostly in Colorado, Utah and Wyoming). Government and private sector estimates place remaining proven reserves in these two areas at about 85 trillion cubic feet (Tcf), with an ultimate resource potential of more than 500 Tcf of natural gas.

Proven reserves are those known to exist with a high degree of probability and able to be economically developed in today's business climate. **Ultimate resource potential** describes the best current estimate of all resources that exist in a particular region, regardless of current economic feasibility.

Total annual production in these basins is expected to grow approximately 11 percent by the end of this decade – from 24.3 Bcf/d in 2004 to nearly 27 Bcf/d in 2010 - with 75 percent of the incremental supply coming from U.S. production and the remainder from Canadian production.[1] Consequently, there is sufficient supply capability from traditional sources to serve the Pacific Northwest market's growth projections for the duration of the decade and beyond.

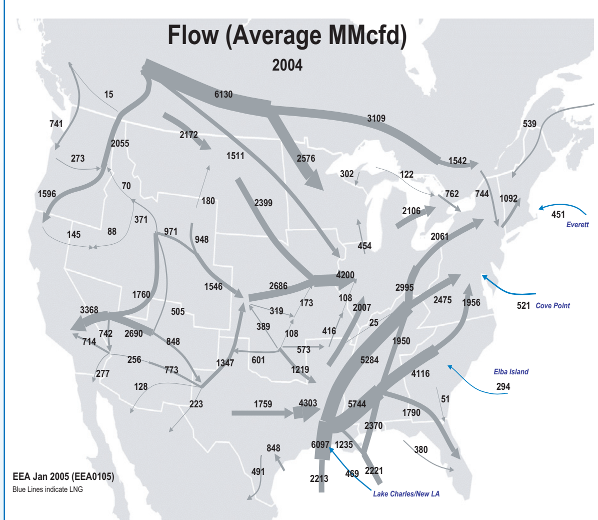
Map of Natural Gas Supply Basins Serving the Northwest
The majority of natural gas consumed in our region comes from the Western Canada Sedimentary Basin, which exports about 60 percent of its total production to the U.S. The rest of our supply comes from the Rockies region. In the next five years, production will grow in both areas, with about one quarter of the incremental growth coming from the WCSB and the rest from the Rockies.

However, new infrastructure has been built in recent years to link these prolific production areas to consuming markets in the Midwest and Northeast in competition with the Pacific Northwest market. The trend will continue as large and growing markets seek access to additional supplies. For instance, the Rockies Express proposed by Kinder Morgan and Sempra, and the Continental Connector proposed by El Paso are both contemplated to move natural gas produced in the Rockies to eastern markets. Consequently, the Pacific Northwest must compete for its natural gas supplies in this increasingly integrated continental market.

Growth in natural gas production in North America hasn't kept pace with demand.

In a nutshell, the issue is this: New production capability across North America is struggling to keep pace with growing continental demand. As existing North American resources mature and produce less gas, efforts to cultivate new non-conventional sources have encountered hurdles and time delays. And as North America looks within and increasingly beyond its borders for additional supply, support from local communities for new energy facilities such as LNG import terminals to accept vital imports is critical.

So, how will growing demand be met if North American gas production remains nearly flat, and efforts to line up new domestic and worldwide resources are restricted?



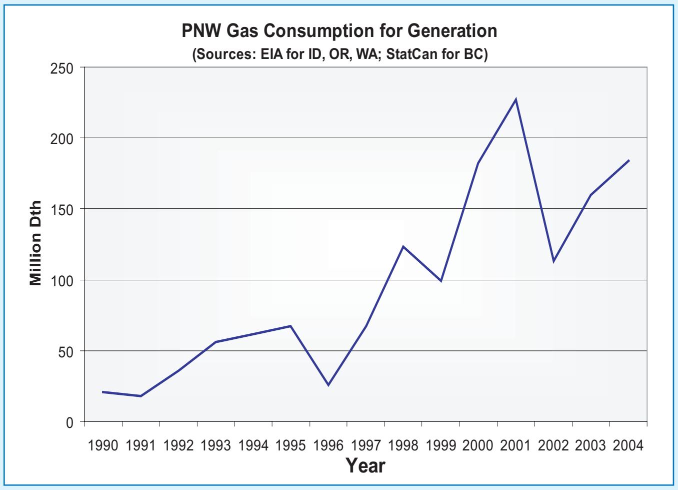
Recently enhanced connections between production areas in Canada and the U.S. Rockies to population centers in the U.S. Midwest and Northeast have consumed the gas supply bubble once enjoyed by Northwest consumers.

1. Source: Wood Mackenzie, *Long-term Market View* May, 2005.

NATURAL GAS SUPPLY IN THE PACIFIC NORTHWEST

GROWING DEMAND FOR NATURAL GAS IN THE PACIFIC NORTHWEST

According to the Northwest Gas Outlook published by the Northwest Gas Association (NWGA), the number of residential and commercial natural gas customers in the Pacific Northwest grew by nearly 12 percent between 1999 and 2004. This growth occurred despite a regional economic downturn and steep energy price increases in western North America during 2000-01.

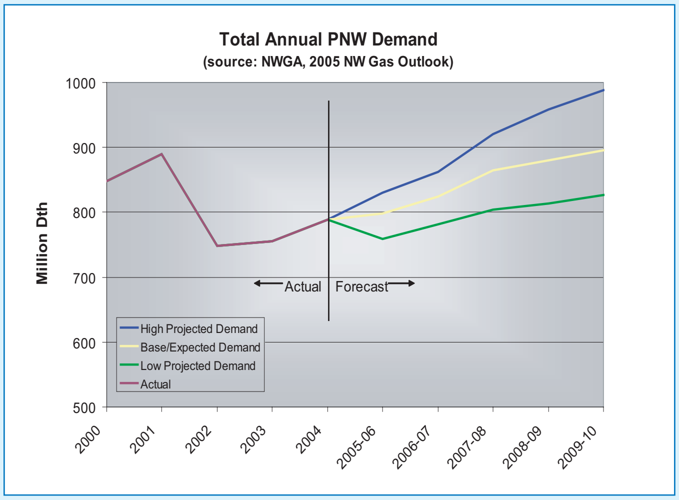


A clean and domestically (North American) produced energy source, natural gas has lower environmental hurdles than coal and nuclear energy and fewer economic and technological challenges than many renewable energy sources. As a result, consumers continue to choose natural gas for everything from home heating to industrial processes, including electric generation.

Regional growth in demand for electricity requires ongoing investments in new generation resources. Renewable resources like bio-mass and wind are promising but have scale and system integration issues. Therefore, - and because natural gas is cleaner than many other fuels - large additions in new electric supply are likely to come from gas-fired plants.

Energy conservation spurred by the higher energy prices of recent years will brake demand. In fact, on a per customer basis, natural gas demand has dropped. But economic growth in the region is likely to outpace energy conservation.

By 2010, according to the Northwest Gas Outlook, natural gas demand in the Pacific Northwest is expected to increase across all market sectors by an average of 2.5 percent per year, with much of this growth coming from the electric generation sector.



Given the increasingly integrated nature of North American gas markets, a broader longer-term perspective on North American supply and demand is warranted. Demand is expected to grow in the U.S. and Canada by almost 30 percent by 2025. U.S. demand for natural gas will increase from 22.3 Tcf[2] in 2004 to a projected 30.7 Tcf,[3] while Canadian demand will grow from 2.8 Tcf in 2003 to an estimated 4.2 Tcf[4] in 2025. In both countries, electrical generation contributes significantly to projected natural gas growth, although industrial use is the largest demand driver in Canada.

This sizable increase in continental demand will create strong competition for those natural gas supplies upon which the region depends…and provides ample incentive to participate in efforts to expand continental supply.

FOCAL POINT - A Closer Look at LNG

Imported natural gas supplies must serve a growing role in the continental and regional energy picture. The U.S. Energy Information Administration (EIA) projects LNG imports must increase from under 1 Tcf in 2004 to more than 6 Tcf by 2025 – a six-fold increase – to meet projected continental demand. That would be enough to serve upwards of 20 percent of U.S. natural gas consumption.

Recent technological improvements and streamlined production have made the cost of LNG imports more competitive, spurring interest in expanding or building new LNG import terminals throughout North America. In the U.S. alone, four existing terminals are being expanded, the first new terminal in 20 years began service in March 2005, and more than 40 new terminals have been proposed to regulators, including four in Oregon and two in British Columbia.

[2] U.S. Energy Information Administration (EIA), *Annual U.S. Natural Gas Consumption by End Use*, June, 2005
[3] EIA, *Annual Energy Outlook 2005*, February, 2005, Table A13.
[4] National Energy Board of Canada (NEB)

NATURAL GAS SUPPLY IN THE PACIFIC NORTHWEST

Still, LNG importation faces a host of hurdles, including:

Shipping. LNG has been shipped across the globe for more than 40 years without any significant accidents or safety issues. The robust worldwide trade of LNG that occurs daily demonstrates that LNG can be handled safely and securely. Nevertheless, safety concerns often top the list of objections when an LNG import terminal is proposed. Knowing the facts can help allay those fears:

LNG SAFETY

LNG has been delivered across the oceans for about 40 years without major accidents or safety problems. In that time, more than 40,000 LNG cargo deliveries were made over 60 million miles. Working closely with regulators, LNG suppliers, shippers and import terminal operators constantly update the engineering and design of tankers and storage facilities, as well as already-stringent security measures. Many contract with international experts to test their safety and security procedures and training. Today, more than 150 LNG ocean tankers safely transport more than 110 million metric tons of LNG annually to more than 40 ports around the world, including such major urban ports as Boston and Tokyo.

✷ **LNG is not stored under pressure and cannot explode.** The U.S. Federal Energy Regulatory Commission website notes, "LNG is not explosive. When LNG is heated and becomes a gas, the gas is not explosive if it is unconfined. Natural gas is only flammable within a narrow concentration range in the air (5% - 15%). Less air does not contain enough oxygen to sustain a flame, while more air dilutes the gas too much for it to ignite."

✷ **LNG terminal operators must coordinate with security and law enforcement agencies to create security plans, which are then subject to regulatory approval.** Foreign ports where tankers are loaded must have their own security plans, and tankers themselves are double hulled and outfitted with alarms and fire protection equipment.

✷ **LNG facilities in the U.S. and Canada must conform to strict building codes and standards.** LNG facilities are designed to contain 100% of the LNG in the unlikely event of a leak. They are also designed to withstand earthquakes and other natural disasters. According to the U.S. Energy Information Administration (EIA), "All LNG facilities are designed to prevent fires and contain the LNG in the event of a spill. In the United States, these facilities must conform to standards set by [a number of federal agencies], the National Fire Protection Association, State utility commissions, port authorities, and other local agencies."

Financing. The average LNG import facility requires an investment of hundreds of millions of dollars. And that is just the tail end of the larger investment required to establish new flows of LNG across the globe. A large majority of the overall costs are incurred building the liquefaction plants in existing production areas and the ships to transport the LNG to markets. Therefore, economies of scale become important, making larger facilities more economic than smaller ones. As the size and costs of a project increase, so does its financial risk.

Location. The requisite size of these facilities has important implications with regard to where they are located. In addition to being able to accommodate large tanker ships, an LNG import facility must be located in areas that directly serve a large market area (*e.g.,* Southern California, the Northeast) or have access to infrastructure that links to large market areas (*e.g.,* Pacific Northwest to California, Gulf Coast to the Midwest and the Northeast). In addition, expansions of associated infrastructure (*e.g.,* pipelines) are often necessary, adding cost and regulatory complexity to a project.

Permitting process. Navigating through the regulatory approval process is difficult. In the U.S., several layers of regulatory oversight are required by the National Energy Policy Act (NEPA). At a minimum, the application process involves several federal, state and local agencies, and the public. Each agency may specify its own requirements and have its own timelines.

Regardless of where it is located, LNG will play an important role in diversifying and expanding regional and continental natural gas supplies. By itself, additional supplies of LNG will not lower the price of natural gas. Rather, the price of LNG is likely to be determined by the price of domestically produced natural gas. In addition, North America must be prepared to offer prices for LNG that are competitive with other major market areas that utilize LNG including Japan, Korea, Europe and the large emerging markets in China and India. Nevertheless LNG remains a vital component of a comprehensive, market-based energy policy that also encourages the development of domestic natural gas resources.

Source: Center for Liquefied Natural Gas, www.lngfacts.com

BALANCING FUTURE SUPPLY AND DEMAND

No matter what the commodity, when supplies fail to keep pace with growing demand the inevitable result is higher and more volatile prices. The steady climb in wholesale natural gas prices in recent years provides ample evidence of this economic principle.

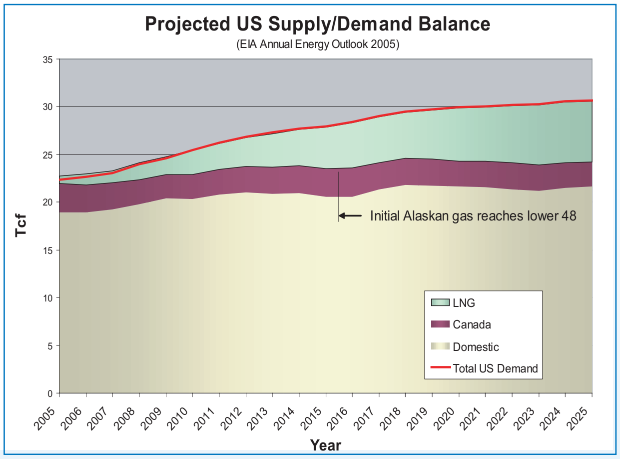
Further evidence can be found in recent experience: When they blew through the Gulf of Mexico, Hurricanes Katrina and Rita took out almost 20 percent of North American natural gas production. The market was not able to replace that lost supply from other sources such as increased production in other regions and increased LNG imports. Consequently, the wholesale price of natural gas spiked.

Supply restrictions, coupled with declining traditional production, means we must cultivate new natural gas resources.

There are two solutions to high energy prices: reducing demand and/or expanding supply. Higher prices provide strong incentives for both courses of action.

Higher prices provide consumers with more incentive to conserve. Demand reductions can range from temporary conservation (turning down the thermostat) to permanent cutbacks like weatherization and appliance upgrades, to large scale industrial closures (in response to higher energy costs).

Enhancing supply is a trickier proposition. While current and forecast pricing provides strong incentives for suppliers to bring on more production, other factors have influenced the flow of new supply. Some large North American gas fields are in decline, and access to the continent's most promising potential resources remains restricted (*e.g.,* offshore exploration and access to U.S. non-park public lands).

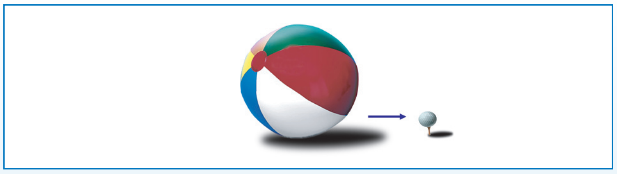


LNG (green area) will play a vital role serving U.S. demand over the next decades as overall U.S. and Canadian supplies grow only slightly or hold steady. Alaskan gas will provide a much needed domestic supply boost after 2016.

Restrictions on new supply sources coupled with declining conventional production, means new natural gas resources **must** be cultivated to serve the continent and the region. Future new resources will come from the North American frontier and across the globe, and will include both conventional and non-conventional sources:

- **Frontier Gas Supplies** in the Mackenzie River Delta (Canada) and the Alaska North Slope have enough proven natural gas reserves to satisfy U.S. natural gas demand for more than a decade.[5] Alaskan gas, projected to come online around 2016, will be the single largest potential source of relief for North American gas consumers.
- **Offshore resources**. An estimated 120 Tcf of offshore natural gas resources are currently off limits to development – 80 Tcf off U.S. shores[6] and 40 Tcf off the Canadian west coast. Both nations are reviewing their drilling moratoria and considering limited development, but none is expected before 2010.
- **Coalbed methane (CBM) reserves**. Extracted from coal seams, CBM is already being produced in significant quantities in the U.S. According to the EIA, in 2001 it accounted for about 7 percent of U.S. annual natural gas production and its potential has barely been tapped; the U.S. Rockies alone contain estimated CBM reserves of 596 Tcf. In Canada, where CBM reserves are estimated at 500 Tcf[7], drilling activity is increasing rapidly.

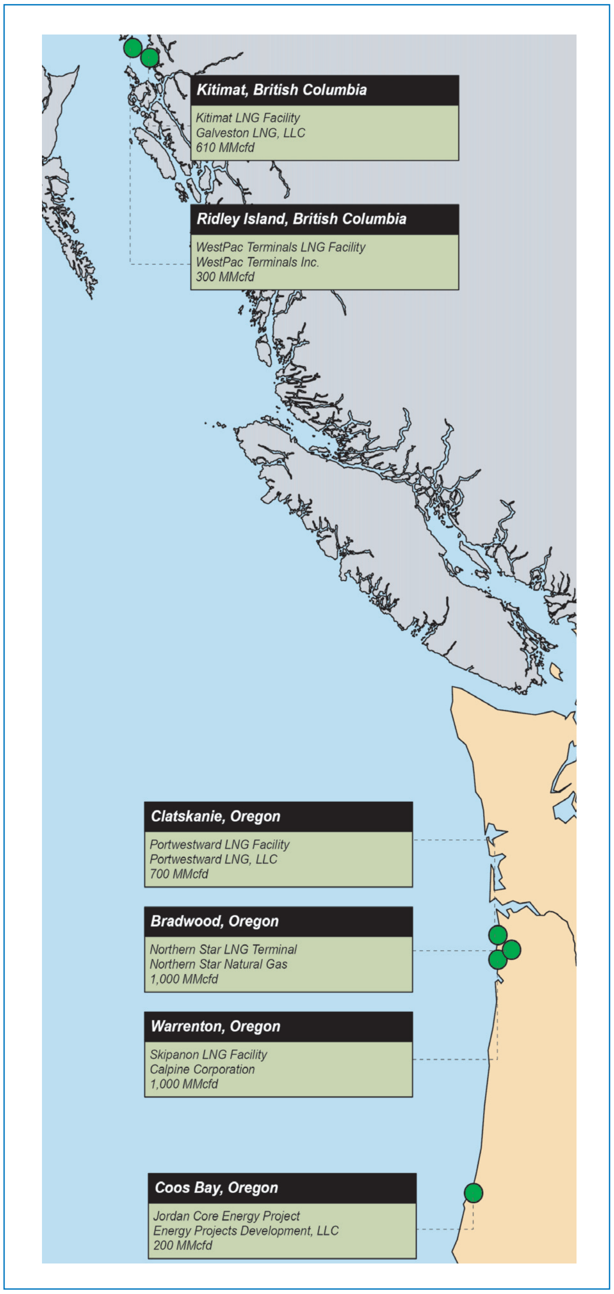
  In addition to CBM, other unconventional natural gas resources are increasingly accessible (*e.g.,* shale and tight gas). Recovery of these resources will be assisted by the development and application of new discovery, drilling and extraction technologies.
- **Liquefied natural gas (LNG) Imports**. LNG is currently exported by 12 countries, including Indonesia, Trinidad and Tobago, Qatar, Algeria, Nigeria, and Australia, with a combined annual export capacity of nearly 7 Tcf. Supply from these countries is expected to increase by 30 percent to more than 9 Tcf by 2007, with an additional 3 Tcf in exports expected from new producing countries.[8]



Liquefied natural gas is gas made liquid by cooling to -260° F. LNG occupies less than 1/600 of the volume of vapor and weighs less than half as much as water, making long distance shipping economically feasible.

[5] American Gas Association, *Meeting Consumer Demand for Natural Gas*, February, 2003.
[6] National Petroleum Council, *Balancing Natural Gas Policy*, September 2003.
[7] Alberta Geological Survey, *Introduction to Coalbed Methane Exploration Areas in Alberta*, October, 2003.
[8] EIA, "*The Global Liquefied Natural Gas Markets: Status and Outlook,*" 2004.

Proposed LNG Import Terminals, Pacific Northwest*



California Energy Commission, May 2005

NEXT STEPS

Ensuring that the Pacific Northwest is served with an adequate, reliable and economic mix of natural gas supplies is vital for the region to grow and flourish. As continental supply expansions are pursued by the industry, the region must fully support those efforts. Securing supplies into the region will help mitigate future risk (and higher costs) for the near and longer term. It is also essential that regulatory processes are aligned with system planning efforts and nimble enough to accommodate changing market dynamics.

Some governmental jurisdictions are taking action to open up previously restricted areas for development. The recently enacted U.S. Energy Policy Act of 2005 encourages increased natural gas production in the U.S. and an earlier Congressional action will help expedite construction of the Alaska Gas Pipeline. Jurisdictions in Canada have taken similar steps, implementing incentives to encourage exploration and development of new natural gas resources.

To balance our energy future, more such proactive policies are needed. To access global LNG supplies and to ensure that other required energy facilities are in place, coordination must be encouraged among local, state and federal agencies to streamline the siting/permitting process for these facilities and establish regulatory certainty. The U.S. National Commission on Energy Policy has already recognized this, stating in a recent report "...it is essential to reduce the barriers that now hamper the siting of new, needed energy infrastructure…"[9] The Commission advocates establishing "clear and accessible agency rules, timelines and siting criteria" to simplify and expedite development.

"…it is essential to reduce the barriers that now hamper the siting of new, needed energy infrastructure…"

Northwest consumers need to build on this momentum to ensure that fresh supplies of natural gas are brought to market from untapped continental, offshore and global sources – and to educate themselves so they can make informed decisions about building necessary new energy infrastructure.

9. National Commission on Energy Policy, "*Ending the Energy Stalemate*," December 2004.

This White Paper was published by the Northwest Gas Association (NWGA) to provide the public, policy makers, opinion leaders and the media with accurate and timely information about the dynamics of natural gas supply and demand in the Pacific Northwest and supply actions needed to meet future demand. NWGA members include six natural gas utilities serving communities in Oregon, Washington, Idaho and British Columbia, and three interstate pipelines that move natural gas from supply basins into and through the region. NWGA members deliver or distribute all of the natural gas consumed in the Pacific Northwest. For more information contact us or visit our Web site.

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APPENDIX C

Terasen Gas Presentation to the Vancouver Board of Trade

Choice & Consequences: A View to B.C.'s Energy Future

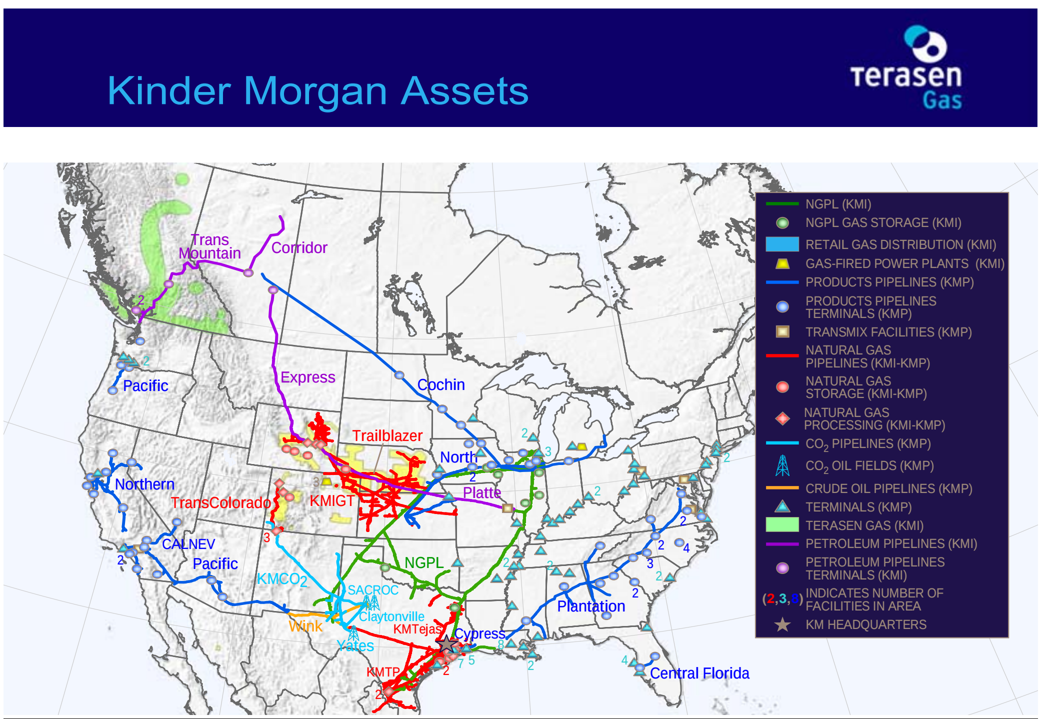
Randy Jespersen's speaking remarks to the Vancouver Board of Trade
May 9, 2006

Thank you Ross (Tokmakian) for your kind words of introduction. The luncheon sponsorship by Telus and Accenture Business Services for Utilities is greatly appreciated. I'm most interested to learn how you folks smoked this one past Darren and Bill. I hope not to disappoint.

And good afternoon ladies and gentlemen.

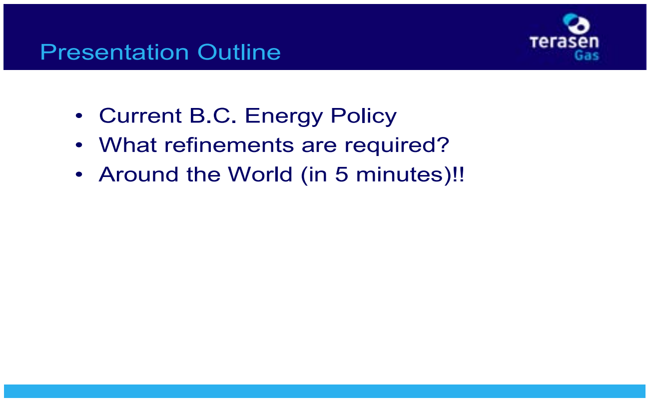
I'm grateful to have this opportunity to be here today and talk to you about energy with a view to B.C.'s energy future.

But, first a bit of refresher on Terasen Gas. We serve almost 900K or approximately 95% of BC's gas consumers. We have approximately $3B in rate base, invest more than $100M annually and employ approximately 1200 people, all here in B.C.

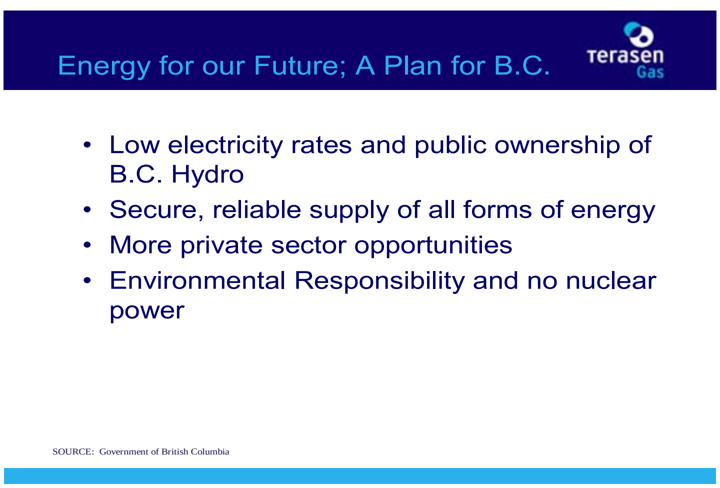


We have always been an investor-owned utility and were acquired last year by Kinder Morgan Inc. of Houston. As evidenced by the map, Kinder Morgan is a substantial player in oil, petroleum products, natural gas and carbon dioxide pipelining; liquids and dry bulk terminalling and now gas distribution businesses with an enterprise value approaching $35B USF.

Between Terasen Gas and KMCI, we transport approximately 60% of the energy consumed by British Columbians.



My remarks today will reference the current B.C. Energy Policy, speak to refinements worthy of consideration in its forthcoming update, and time permitting, will quickly address natural gas supply demand and pricing fundamentals as deduced by Cambridge Energy Associates, a leading energy consultancy.



Four years ago, the provincial government released its first energy plan: The plan, Energy for our Future, A Plan for B.C., was based around four cornerstones:

- Low electricity rates and public ownership of B.C. Hydro
- Secure, reliable supply of all forms of energy

- More private sector opportunities
- Environmental responsibility and no nuclear power

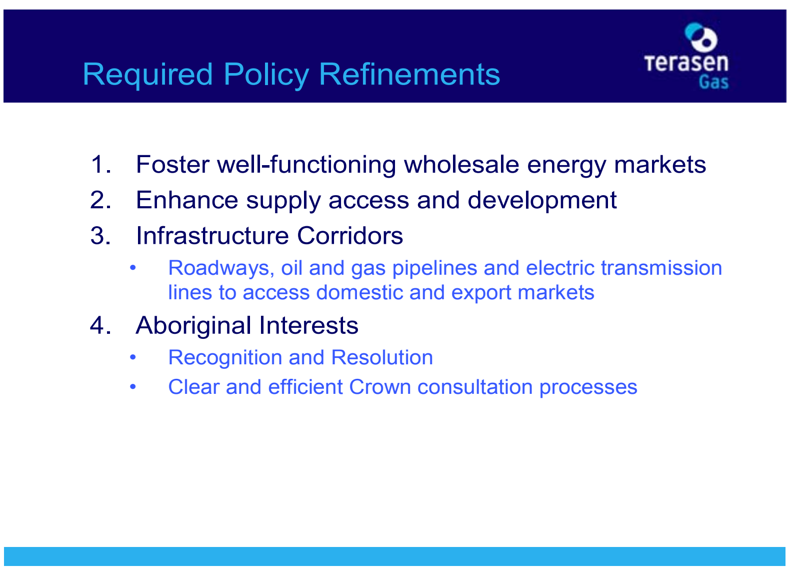
With respect to consumers, the vast majority of that plan focused on electricity with little mention of other forms of energy. Oil and natural gas were highlighted mainly in terms of exploration and working towards developing the province's potential offshore resources.

But by and large, the provincial energy plan used the words "energy" and "electricity" interchangeably.

Many of the goals laid out in the plan, such as increased electric supply and private sector involvement are still that – goals yet to be achieved.

The plan also called for small volume customers to have more choice in selecting the supplier and pricing of their natural gas. I'm pleased to say we're well on the way to making that happen.

The provincial government is currently updating the energy plan. It has before it a golden opportunity to lay out policy that will encourage investment and provide the energy sector with the necessary tools to meet BC's growing demand in a reliable and secure manner and ensure we continue using our energy resources wisely.



Today, I want to share our view of the province's energy needs beyond electricity and the objectives that need to be laid out in the 2006 energy plan, a plan that will reflect the challenges and opportunities within the energy sector.

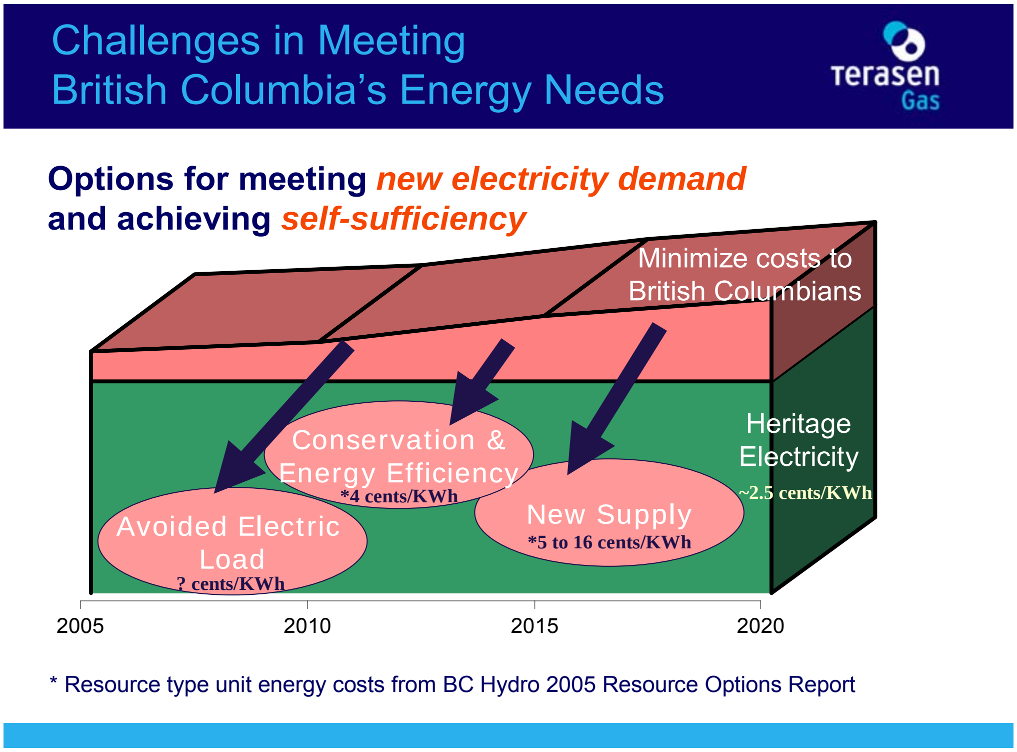
1. Well-Functioning Wholesale Energy Markets are the best means to ensure a fair and reasonable equilibration of supply demand and price. To ensure this, policy makers should set to establish:
   - That there be adequate delivery capacity for supply to access alternative markets and demand to access alternative supplies under all reasonable conditions
   - The permitting of fuel substitution
   - That there is adequate clarity of price signals to evoke market response
   - Efficient outcomes based regulatory models

   With this framework, impacts of supply, demand and price variations would be balanced across broad geographies and energy forms. For British Columbians, we would have solid comfort that we would never be price disadvantaged to others but rather advantaged. Firstly as consumers given our close proximity to supply and secondly, from living in a Province which is rich in energy resources which generate substantial royalties, $2.2B forecast for '06, to fund health, education, infrastructure and other societal priorities. Additive to this are the economic stimulus from investment for resource and industrial development.

2. Enhanced Supply Access and Development includes competitive royalty structures and an efficient regulatory environment for balanced development of roads, gathering systems, plant and port expansions as well land access including coal bed methane and offshore development. Our government gets this and needs to be encouraged to do more.

3. Infrastructure Corridors need to be established that ease the anguish and pave the way for highways, oil and gas pipelines and electric transmissions lines to serve both domestic and export markets. We need to end the balkanization of how we approach these matters today and not let our own lack of foresight and cooperation give over the agenda to special interest groups.

4. Much needs to be done in recognizing the importance of resolving longstanding aboriginal land claims and a more clear and efficient Crown Consultation Process. Again, I applaud the Premier and his team's direction here and encourage the Federal government to do the same.



Before moving to the next goal let me first spend a few minutes on B.C. Hydro.

BC currently enjoys essentially the lowest electrical rates in all of North America. Much of this has to do with our heritage electrical generating system – most of which was built in the 1950's and 1960's. That capital investment was made long ago and we continue to reap the benefits today.

Public policy in BC calls for low cost based electricity rates in contrast to market based rates for other energy forms. While the benefits are clear, the negatives are less evident but never-the-less real. Little has been done to encourage investment in new generating capacity or transmission infrastructure. B.C. homes and businesses rank amongst the worst with respect to being efficient electricity consumers. Single family homes today use 6% more electricity than they did 10 years ago.

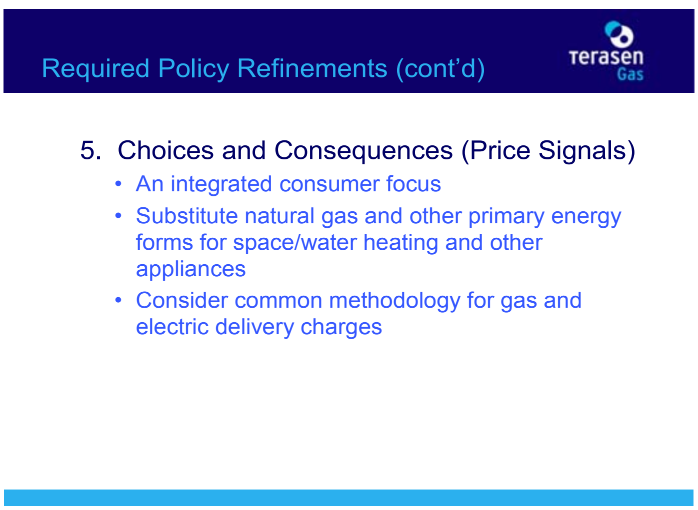
Today, BC is no longer self-sufficient when it comes to electricity.

Today BC Hydro is forced to import 13 per cent of the total amount of electrical power used in BC. And the majority of that power is generated in Alberta or the U.S. by burning natural gas or coal.

That's a fact lost on many British Columbians. Many people still believe the myth that BC has a surplus of electricity. We don't and we agree that BC should not only be self sufficient but an exporter of electricity.

The slide shows the growing deficit BC Hydro faces over time along with three strategies to address it. BC Hydro's 2005 report referenced New Supply costs ranging from 5 - 16¢/Kwh, conservation and energy efficiency costs of approximately 4¢/Kwh compared to the heritage electricity costs of 2.5¢/Kwh which are collected in rates. That's right, new supply costs more than it is sold for and is not sustainable.

We believe that greater reliance and focus needs to be made on preserving heritage electric capacity for uses where it makes the most sense; things like computers, lighting, televisions, etc. while avoiding and shedding existing demand which can be better served with other energy forms.



Resource planning for B.C. must be conducted on an integrated level with all energy utilities working cooperatively together to find solutions for meeting the demands of B.C. energy consumers. The integrated approach needs to include a diverse mix of energy options. We can no longer afford to evaluate energy projects purely from a lowest-cost perspective from an individual utility energy form perspective.

We need to encourage better choices in terms of how we use energy. Simply put, we need to use the right fuel in the right place at the right time.

We live in a free-market economy. Business owners and B.C. consumers make decisions based on how costs impact their bottom line or their discretionary income. The price signals they receive help shape their behavior.

In the case of electricity, pricing signals are harder for the consumer to read because the consumer is generally not paying the true costs of connecting to the electric system or the costs of generating and moving electricity from source to the end user. When rates are set too low, people pay no heed to conservation and they use electricity in place of other, more appropriate energy sources for various applications.

The provincial government acknowledged this problem in its 2002 Energy Plan which says: "Low electricity rates, however, provide a poor price signal for consumers to conserve and invest in energy efficiency."

I am not advocating that electricity must or should move to market based rates. What I am advocating is that mechanisms be put in place which ensure that price signals are not so masked as to result in the squandering of our heritage electric assets, deterring efficient investment or impairing existing investment; all of which yield higher than necessary societal cost.

To encourage use of the right fuel in the right place, utility connection policies need to be more reflective of the true costs of serving the customer and not be based on the depreciated costs of heritage assets. Surcharges could be used to discourage inefficient uses of electricity or alternatively incentives, akin to the Power Smart model, could be used by BC Hydro to shed or avoid inefficient demand. Step rates and or time of use rates are other considerations.

Clearly, if we want to be successful in promoting sustainable use of all our resources for years to come, pricing signals have to be right. The government needs to enact policy to address this critical issue.

Another anomaly which adds further confusion to price signals is how gas and electricity delivery charges are levied. Electricity utilizes a "one size fits all" postage stamp methodology whereby electricity delivery charges are the same whether you are in Prince George, Kitimat or Victoria. Natural gas rates on the other hand grow with distance as you flow south on Duke's transmission system and then across Pacific Northern Gas' system to Kitimat or across our coastal transmission system and more again across the transmission system we acquired from Westcoast to get to Victoria.

Are the different methodologies an accident of circumstance or good policy? We believe that either BC Hydro rates should reflect distance related costs or that natural gas delivery companies should be encouraged and incented to adopt a postage stamp model.

Challenges in Meeting
British Columbia's Energy Needs

Terasen Gas

Right Fuel, Right Use, Right Time

Driver of Change
• growing trend towards Multi-Family Housing

Electric baseboard systems
• low potential to convert to future technologies
• increase demand for new electrical supply

Natural gas, geothermal, other hydronic systems
• limit future dependence on electrical supply
• easily convertible to future technologies
• may have higher capital cost but overall lifecycle cost advantage

The majority of BC's housing starts are multi-family with a concentration of high rises in the larger metropolitain areas. Many of these are utilizing base board heating which puts additional stress on the environment and ultimately, will result in increased prices for electricity.

When you consider that much of the incremental additional electricity BC Hydro needs to import is created by burning natural gas or coal, the disconnect between reality and the choices we make is even more pronounced.
Does it make sense to heat our homes using electricity that was generated outside BC by burning natural gas at 60 per cent efficiency? Isn't it more reasonable to heat our homes directly using modern, natural gas heating appliances that are 90 per cent efficient or more?

Nearly 80 per cent of residential energy use is related to space or water heating. Moving this load to natural gas will help curb the demand for electricity while not impacting the operating costs or the cost of natural gas to BC consumers.

I quote from the Progress Board's report on energy which recommends that: "Natural gas companies and the provincial government should communicate that advantages of natural gas in displacing other fossil fuels and in being more energy efficient than electricity for many uses."

We are working with Fortis and BC Hydro along with Natural Resources Canada and the provincial Ministry of Energy and Mines to provide incentives to builders, developers and homeowners to encourage the use of natural gas for space and water heating rather than electricity.

Geo-exchange and hydronic systems are other good options to consider. We are working with the Resort Municipality of Whistler on a geo-exchange system for the Athlete's Village and we are proposing Vancouver consider a hydronic system using a natural gas boiler design that can accommodate waste sewer heat or other technologies in the future for the East False Creek development.

Impact of Electric Baseboard Heating in Multi-Family Suites

Terasen Gas

Space heating

~162 GWh per year

by 2010

annual kWh savings of 2.8 million compact fluorescent light bulbs

29 Mega Watt Electricity Generation Plant

The space heating requirements for the 60,000 multi-family dwelling housing starts forecast by CMHC between now and 2010 translates to approximately 162 Gwh/year of electricity load for heating.

For comparative purposes, BC Hydro would have to provide 2.8 million compact fluorescent light bulbs, (and, as Mark Jaccard has noted previously, people would actually have to install them and not put them on a shelf) in order to achieve electricity energy efficiency gains to serve this load.

Alternatively, they would have to purchase the output equivalent to a 29 mega watt generating plant or sign up approximately five new run of the river projects.

In Portland, Calgary or Toronto, this heating load would be efficiently and economically served by natural gas. For a high-rise in Vancouver, the probability is slim given electric prices and connection fee practices. The quantum increases substantially when one considers load shedding opportunities available to BC Hydro as consumers make decisions on replacing hot water tanks, dryers, stores, etc.

Required Policy Refinements (cont'd)

Terasen Gas

6. Public ownership should not be a barrier to private sector investments
7. Public Transportation

My last two points on Policy are quite simple and for the brevity of time, I won't dwell on them too long.

Public Ownership should not be a barrier to private sector investments and this goes hand in hand with the current policy goal calling for more private sector opportunities. Policy makers should study carefully and implement appropriate change in order to achieve their goal.

If provincial or municipally owned entities wish to partake in business arenas which can readily be served by private enterprise, they should be governed by the same rules and regulations. Examples include comparability of deemed equity thickness for purposes of determining rates. Seabreeze was rather vocal on this issue recently when they came to understand that their project could not compete against the 100% taxpayer debt funded project that BCTC is moving forward with.

Taxpayer dollars are hard-earned and scarce and are better used for schools, hospitals and roadways and other public programs rather than for ventures where there are efficient alternatives.

Cleaner Public Transportation

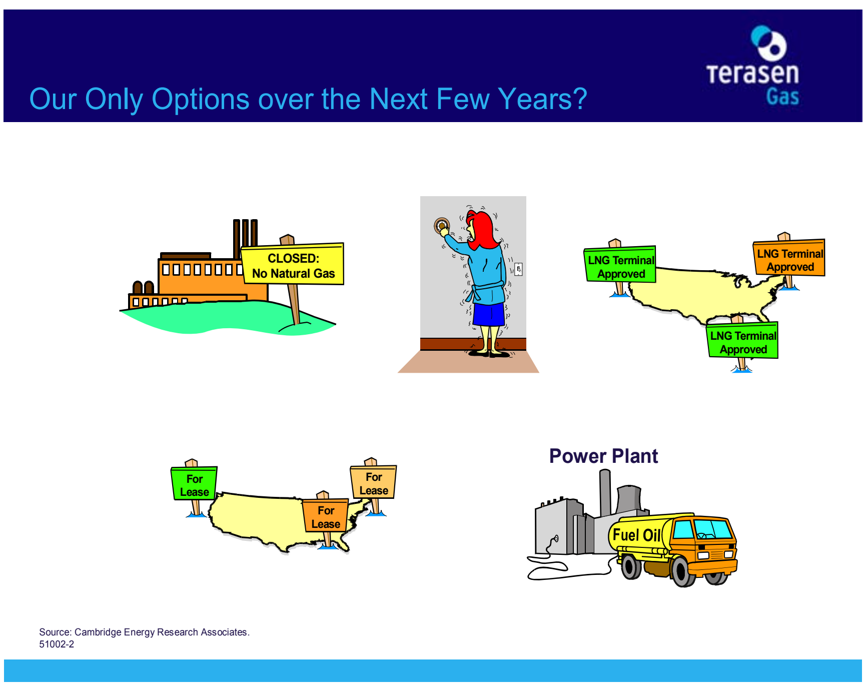
The 2002 Energy Policy did not deal with energy use for transportation, a sector which accounts for 38 per cent of BC's energy use and is the largest single contributor to air quality degradation in the lower mainland.

We agree with the BC Progress Board that now is an ideal time to create a policy encouraging the use of alternative fuels, particularly for public transportation and municipal fleets.

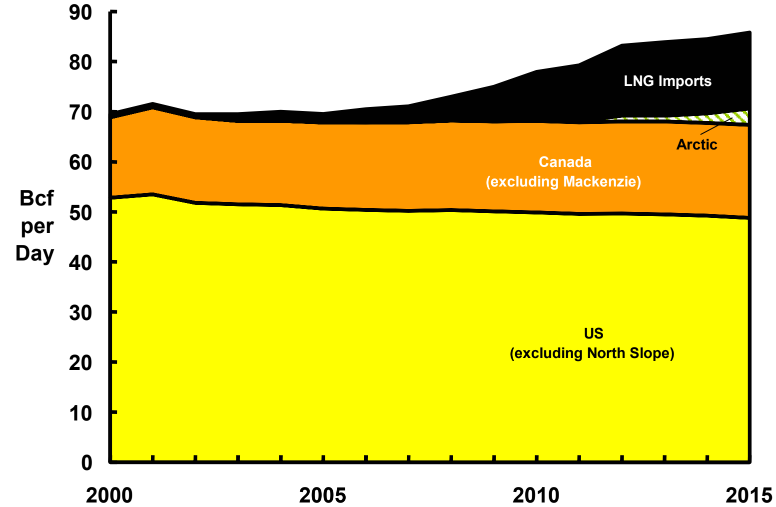
Public transportation and fleet vehicles powered by clean energy sources with lower emissions such as compressed natural gas, hybrids and perhaps some day hydrogen, offer attractive alternatives to traditional petroleum powered transportation.

We are currently working with the Resort Municipality of Whistler to create an integrated energy system for the community and help it obtain its sustainability goals. Part of that system involves converting its municipal fleet of buses and garbage trucks to clean, burning natural gas from diesel, a move we estimate will improve air quality and result in a six to 25 per cent reduction in greenhouse gas emissions.

Government support for alternative powered public transportation will not only allow BC to maintain its regional and provincial competitiveness through enhanced air quality and technical competence but it will move us further along the path of developing sustainable energy options.

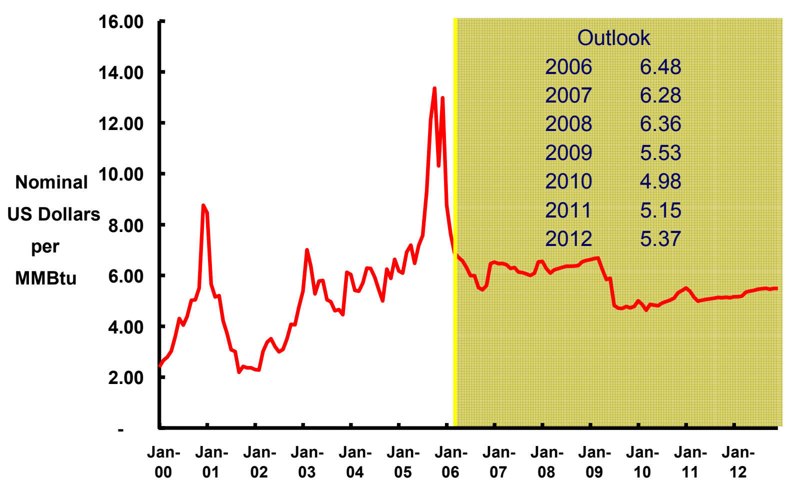


A Growing Role for New Supplies: LNG Imports to Meet Growing Demand

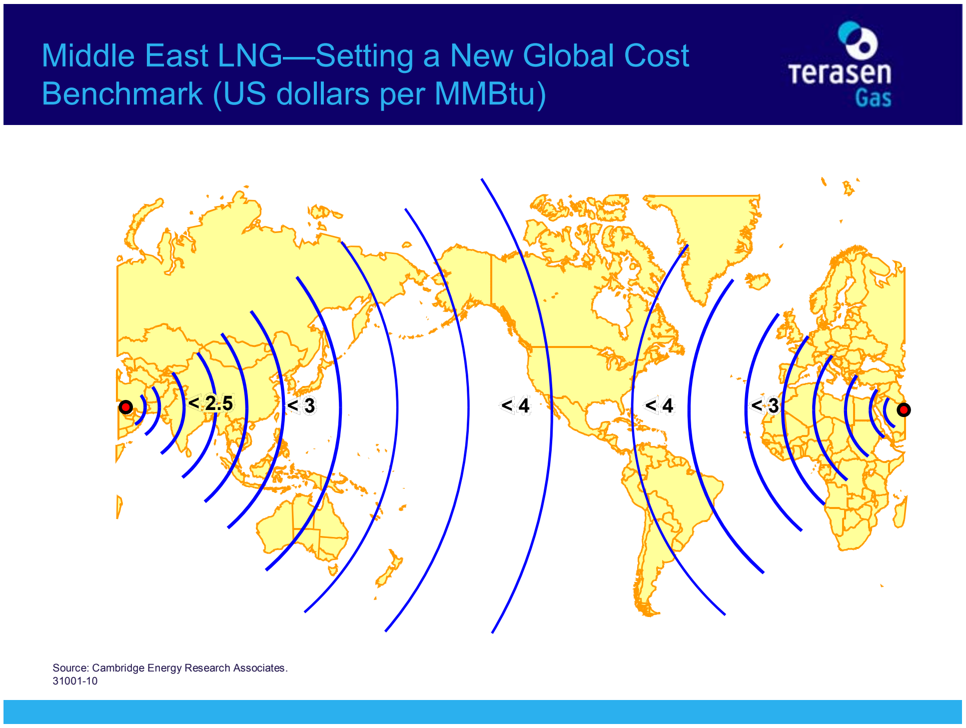


Source: Cambridge Energy Research Associates.
Updated February 2006.
Note: LNG imports include those into the US, Canada, Baja California, and the Bahamas.

CERA Long-term Outlook, April 2006
(Henry Hub Spot Price, nominal dollars)



Source: Cambridge Energy Research Associates.



I know that I have given you a lot to think about in a short period & apologize if I've confused you in places. I'd be glad to take questions at the close or please don't be shy to give me a call at some later date.

You've been a great audience & I thank you for an opportunity to share our views here today.

Enjoy the rest of your day.

APPENDIX D

Terasen Gas
2006 Energy Forum Overview

2006 BC Energy Forum

Sustainable Development and Energy Choice

January 24/25, 2006

Introduction

Overview and Purpose

Terasen Gas led and coordinated the 2006 BC Energy Forum on sustainability which provided an opportunity to bring diverse energy experts and multiple stakeholders together. Along with our co-sponsors (BC Ministry of Energy, Mines and Petroleum Resources, BC Hydro Power Smart, Natural Resources Canada and BOMA British Columbia), speakers from across Canada, California and the United Kingdom were brought together for the two day event to exchange information and views, share ideas and challenge assumptions and plan energy choices for sustainable future.

Sustainability is of considerable interest to stakeholders today, as we search for solutions to maximize the value of B.C.'s energy resources and support sustainable development. Through an integrated approach to energy choice and planning, we will be able to achieve economic, social and environmental goals.

- Economic – highest and best use; value add
- Social – supporting communities; preserve benefit of heritage electric assets
- Environment – clean air, water and energy

The two day forum provided an excellent venue for diverse stakeholders to move towards a common understanding of what sustainability means and to develop an understanding of the essential components of a sustainable development framework that harmonizes stakeholders' interests concerning energy choice.

Organizing Committee Members and their Organizations

Terasen Gas and BC Hydro were the primary organizers of the Sustainability Forum. Representatives from the respective organizations involved in planning and organizing the forum included:

- BC Hydro
  - Derek Henriques, Manager, Quality Assurance & Evaluation
  - Karen Leach, Special Assignment Sustainability

- Terasen Gas
  - James Wong, Manager, Market Planning and Development
  - David Bodnar, Director of Community, Aboriginal and Government Relations
  - Joan Hess, Manager, Corporate and Marketing Communications
  - Bev Macham, Confidential Assistant

In addition, Jocelyn Fraser from Communicate Public Affairs was contracted to facilitate the organization of the forum.

Sponsoring Organizations

In addition to Terasen Gas and BC Hydro, other sponsoring organizations included:

- Natural Resources Canada (NRCAN)
- Ministry of Energy, Mines and Petroleum Resources (MEMPR)
- Building Owners and Managers Association of British Columbia (BOMA)

Targeted Audience

The primary goal was to invite a broad cross-section of stakeholders involved in energy planning to exchange information and views, share ideas, challenge assumptions and plan energy choices for a sustainable future. Invited guests and participants to the Energy Forum included representatives from federal, provincial and municipal governments; industry associations, non-government organizations, environmental groups, energy utilities, builders / developers and architects and energy users.

In total, approximately 200 people participated in the two day event.

Forum Agenda

2006 BC ENERGY FORUM

SUSTAINABLE DEVELOPMENT & ENERGY CHOICE: VISION FOR 2020

PROGRAM

Master of Ceremonies:
Mike Cleland, President of the Canadian Gas Association

Presented by:

Terasen Gas

BC hydro POWER SMART

British Columbia Ministry of Energy, Mines and Petroleum Resources

Natural Resources Canada / Ressources naturelles Canada

BOMA British Columbia

Morris J. Wosk Centre for Dialogue • Vancouver, British Columbia • January 24/25 2006

JANUARY 24 - DAY 1: Setting the Stage

7:30 - 8:00 a.m. Forum Registration and Continental Breakfast

8:00 - 8:05 a.m. Introduction to Forum and Presidents of Canadian Electricity Association and the Canadian Gas Association
Jan Marston, Vice President Gas Supply and Transmission, Terasen Gas Inc. will welcome guests and discuss the importance of this forum for the future of energy planning.

8:05 - 8:30 a.m. The Views of the Canadian Electricity Association and the Canadian Gas Association on Sustainability
Mike Cleland, President of the Canadian Gas Association and *Hans Konow, President of the Canadian Electricity Association* will provide their organizations' and industries' perspective on sustainability and energy planning and choice.

8:30 - 9:15 a.m. Sustainable Fossil Fuels: The Unusual Suspect in the Quest for Clean and Enduring Energy
Mark Jaccard, Professor, School of Resource and Environmental Management, Simon Fraser University, where he directs the Energy and Materials Research Group. More and more people believe we must quickly wean ourselves from fossil fuels – oil, natural gas and coal – to save the planet from wars, environmental catastrophe and economic collapse. According to Professor Jaccard, this view is misguided. Our vast fossil fuel resources will be the cheapest source of clean energy for the next century and perhaps longer. By buying time for increasing energy efficiency, developing renewable energy technologies and making nuclear power more attractive, fossil fuels will play a key role in our quest for a sustainable energy system.

9:15 - 10:30 a.m. Governments and their Views and Policies on Sustainability
Margaret McCuaig Johnston, Assistant Deputy Minister of Natural Resources Canada, Peter Ostergaard, Assistant Deputy Minister, Electricity and Alternative Energy, Ministry of Energy, Mines and Petroleum Resources and *Tom Osdoba, Manager of Sustainability, City of Vancouver* will speak to their positions and policies on sustainability and energy choice, what they want to achieve and their long-term strategies to fostering energy choice and sustainable development including specific actions such as partnerships with industries and providing funding.

Moderator
Doug Little, Vice President Customer and Strategy Development, BC Transmission Corporation

10:30 - 10:50 a.m. Coffee Break

10:50 - 12:00 p.m. Energy Efficiency and Conservation – An Integral Part of Sustainability
Louis Marmen, Director at Natural Resources Canada, Steve Hobson, Acting Manager of BC Hydro Power Smart, and *Douglas Stout, Vice President of Marketing and Business Development, Terasen Gas.* Energy efficiency and conservation are two of our greatest allies today in keeping energy costs affordable and ensuring high customer satisfaction levels. Representatives from the Federal and Provincial governments, BC Hydro and Terasen Gas will talk about their perspectives, why energy efficiency is an integral part of sustainability, the organizations' current policies, strategies and efforts on energy efficiency, what is working and what barriers exist.

Moderator
Andrew Pape-Salmon, Manager, Energy Efficiency and Community Energy Solutions, Ministry of Energy, Mines and Petroleum Resources, Government of British Columbia

12:00 - 1:00 p.m. Lunch and Sponsors' Exhibits

1:00 - 1:30 p.m. Lunch Speaker Address – A Regulator's View on Sustainability and Resource Planning
Robert Hobbs, Chairman of the BCUC will share his views on the regulator's role in fostering sustainable development in the energy sector. The BCUC has a role in ensuring the energy sectors it regulates select and present cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers and communities over the long run.

1:30 - 2:15 p.m. High Efficiency Applications in Today's Energy World
John Cockburn, Senior Chief, Standards and Labelling, Housing and Equipment Division, Natural Resources Canada and Roy Hughes, Energy Management Engineer, BC Hydro will speak on examples of high efficiency commercialized equipment used today, including efficient uses of electricity for solid state lighting.

2:15 - 3:00 p.m. The Transportation Challenge
Rob Safrata, President of Novex Couriers and *Mitchell Pratt, Vice President of Public Policy and Business Development, Clean Energy (California).* Transportation is among the top contributors to air quality degradation and climate change. More hybrid, alternative fuel and smart cars are being seen than ever before. The speakers will share their companies' experiences and challenges in encouraging the use of environmentally friendly vehicles such as gasoline/electric hybrids and natural gas powered vehicles.

3:00 - 3:20 p.m. Coffee Break

3:20 - 3:50 p.m. B.C. as a Leader in Sustainable Environmental Management
Hon. Barry Penner, Minister of Environment

3:50 - 5:05 p.m. Growing the Sustainable Energy Sector in B.C. – An Update on the Alternative Energy and Power Technology Task Force for Emerging End-Use Technologies.
An update on the work of the Alternative Energy and Power Technology Task Force, co-chaired by Mossadiq Umedaly, Chair of Xantrex Technology Inc., and the Honourable Barry Penner, Minister of Environment,

and presented by Mr. Umedaly. This will be followed by end-use technology companies discussing their successes, benefits and roles in a sustainable energy future, impacts of their technology on existing energy systems and barriers that exist to commercialization.

Nazir Mulji, Vice President Business Development, Xantrex Technology Inc.
Brad Forth, President and CEO, Power Measurement Inc.
Art Aylesworth, CEO, Carmanah Technologies Corporation
David Demers, CEO, Westport Innovations Inc.

Moderator
Mossadiq Umedaly, Chair of Xantrex Technology Inc.

5:05 - 5:15 p.m. Wrap-up of day 1
Mike Cleland, President of the Canadian Gas Association

All participants are invited to a reception to be held from 5:15 – 7:00 p.m. hosted by

eaga canada

JANUARY 25 - DAY 2: Working Towards a Sustainable Development Framework

7:30 - 8:00 a.m. Sign-in and Continental Breakfast

8:00 - 8:30 a.m. Energy Choice and Planning in B.C.
Hon. Richard Neufeld, Minister of Energy, Mines and Petroleum Resources will outline the Ministry's vision of a future state of energy choice and planning in British Columbia, the issues, actions and possible solutions that can help bridge the gaps for British Columbia including the importance of energy efficient buildings.

8:30 -10:00 a.m. Energy Choice – Costs and Consequences – An Executive Panel Discussion – Right Product, Right Place, Right Time
A panel of four executives representing leading energy corporations and associations in BC *(BC Hydro – Mary Hemmingsen, Acting Senior Vice President Distribution; Terasen Gas – Randy Jespersen, President; Fortis BC – John Walker, President and CEO; Canadian Clean Power Coalition – Robert Bell, Vice President, Marketing, Luscar Ltd.)* each presenting a summary of their organization's view/ positions on energy choice and efficiency. After that, there will be a discussion and debate of the issues regarding the right energy choice within a sustainable development framework. The issues include views on what is the appropriate energy choice within a sustainable development framework and what each organization should be doing to contribute to overall long term sustainable vision for our communities.

Moderator
Dan Kirschner, Executive Director, Northwest Gas Association

10:00 -10:20 a.m. Coffee Break

10:20 - 12:15 p.m. Showcase Sustainable Projects - Communities Leading the Way
Hear about projects and listen to communities explain and showcase their vision of sustainable development and energy choice and what they have done to lead the way.

Sustainability in the Whistler Community
Brian Barnett, General Manager of Engineering & Public Works

A Neighbourhood Energy Utility in the False Creek Precinct of the City of Vancouver
Innes Hood, Senior Advisor, The Sheltair Group and Rob Bennett, Project Manager, Sustainability Office, City of Vancouver

GeoExchange in Transition
Lyn Ross, Chair, GeoExchange BC

BOMA Go Green Program
Paul LaBranche, Executive VP, BOMA BC

Moderator
Freda Pagani, Director, Sustainability at UBC

12:15 - 1:30 p.m. Lunch

Lessons and Experiences from Other Jurisdictions

1:30 - 2:00 p.m.
Helping Low Income Households to Keep Warm – The English Experience
Pam Wynne, Head of Fuel Poverty Team, Department for Environment Food and Rural Affairs. The Fuel Poverty Strategy published in 2001 set out the challenge of fuel poverty and how it would be tackled. Fuel poverty is caused by a number of factors – the energy efficiency of a property, the price of fuel and income levels. So tackling fuel poverty needs a mixed approach. Hear about the work undertaken and lessons learned towards achievement of fuel poverty targets and how that has helped to encourage low income households to improve the energy efficiency of their properties in a sustainable way.

2:00 - 2:30 p.m. Sustainability – Lessons and Experiences from California. What the future holds.
Michael Peevey, President of the California Public Utilities Commission will share experiences and lessons learned from California.

2:30 - 2:45 p.m. Closing remarks and Forum wrap-up
Mike Cleland, President of the Canadian Gas Association

2006 BC Energy Forum Budget

In total, the two day event cost $53,000 net of registration fees received. Approximately $45,000 was spent on venue arrangements and meals with the remaining expenditures on supporting materials and print.

Executive Summary of Participant Feedback Survey - 2006 BC Energy Forum

The 2006 BC Energy Forum, which took place on January 24 – 25, 2006, was well attended by approximately 200 delegates (including 36 speakers). An online survey was sent to each attendee asking them to share their thoughts on the forum they attended (37 responded). Below are the results of the survey.

Question 1 - Overall impression of forum – **19 per cent** felt the forum was "extremely valuable," **70 per cent** rated it as "very valuable" and "valuable" while 11 per cent rated it as "somewhat valuable."

Question 2 - Good use of time – **92 per cent** felt the forum was a good use of their time, with 11 per cent rating it "extremely useful," 35 per cent rating it "very useful" and 46 per cent rating it as "useful."

Question 3 - Participants were asked to rate each presentation using a scale of 1 to 4 (with 1 meaning the 'most useful' to 4 meaning 'not useful'). Participants could also choose 'no opinion.'

On Day 1, January 24:

1. **The Views of the Canadian Electricity Association and the Canadian Gas Association on Sustainability,** presented by *Mike Cleland, President of the Canadian Gas Association* and *Hans Konow, President of the Canadian Electricity Association.*

   Respondents rated this presentation as:
   Most useful - **0 per cent**
   Useful - **51 per cent**
   Somewhat useful - **35 per cent**

2. **Sustainable Fossil Fuels: The Unusual Suspect in the Quest for Clean and Enduring Energy,** presented by *Mark Jaccard, Professor, School of Resource and Environmental Management, Simon Fraser University.*

   Respondents rated this presentation as:
   Most useful - **38 per cent**
   Useful - **32 per cent**

3. **Governments and their Views and Policies on Sustainability**, presented by: *Margaret McCuaig Johnston, Assistant Deputy Minister of Natural Resources Canada, Peter Ostergaard, Assistant Deputy Minister, Electricity and Alternative Energy, Ministry of Energy, Mines and Petroleum Resources* and *Tom Osdoba, Manager of Sustainability, City of Vancouver.*

   Respondents rated this presentation as:
   Most useful – **24 per cent**
   Useful - **49 per cent**

4. **Energy Efficiency and Conservation — An Integral Part of Sustainability**, presented by: *Louis Marmen, Director at Natural Resources Canada, Steve Hobson, Acting Manager of BC Hydro Power Smart,* and *Douglas Stout, Vice President of Marketing and Business Development, Terasen Gas.*

   Respondents rated this presentation as:
   Most useful – **11 per cent**
   Useful - **57 per cent**

5. **A Regulator's View on Sustainability and Resource Planning**, presented by: *Robert Hobbs, Chairman of the BCUC*

   Respondents rated this presentation as:
   Most useful – **14 per cent**
   Useful - 50 per cent

6. **High Efficiency Applications in Today's Energy World**, presented by: *John Cockburn, Senior Chief, Standards and Labeling, Housing and Equipment Division, Natural Resources Canada and Roy Hughes, Energy Management Engineer, BC Hydro*

   Respondents rated this presentation as:
   Most useful – **8 per cent**
   Useful – 38 per cent

7. **The Transportation Challenge**, presented by: *Rob Safrata, President of Novex Couriers* and *Mitchell Pratt, Vice President of Public Policy and Business Development, Clean Energy (California).*

   Respondents rated this presentation as:
   Most useful – **19 per cent**
   Useful – 35 per cent

8. **B.C. as a Leader in Sustainable Environmental Management**, presented by: *Hon. Barry Penner, Minister of Environment*

   Respondents rated this presentation as:
   Most useful – **22 per cent**
   Useful – 41 per cent

9. **Growing the Sustainable Energy Sector in B.C. — An Update on the Alternative Energy and Power Technology Task Force for Emerging End-Use Technologies** presented by: *Nazir Mulji, Vice President Business Development, Xantrex, Technology Inc., Brad Forth, President and CEO, Power Measurement Inc., Art Aylesworth, CEO, Carmanah Technologies Corporation, David Demers, CEO, Westport Innovations Inc.*

   Respondents rated this presentation as:
   Most useful – **22 per cent**
   Useful – **39 per cent**

Question 4 - Participants were asked to rate each presentation using a scale of 1 to 4 (with 1 meaning the 'most useful' to 4 meaning 'not useful'). Participants could also choose 'no opinion.'

On Day 2, January 25:

1. **Energy Choice and Planning in B.C.,** presented by: *Hon. Richard Neufeld, Minister of Energy, Mines and Petroleum Resources*

   Respondents rated this presentation as:
   Most useful – **22 per cent**
   Useful – **44 per cent**

2. **Energy Choice - Costs and Consequences: An Executive Panel Discussion - Right Product, Right Place, Right Time**. A panel of four executives representing leading energy corporations and associations in BC *(BC Hydro – Mary Hemmingsen, Acting Senior Vice President Distribution; Terasen Gas – Randy Jespersen, President; Fortis BC – John Walker, President and CEO; Canadian Clean Power Coalition – Robert Bell, Vice President, Marketing, Luscar Ltd.)*

   Respondents rated this presentation as:
   Most useful – **33 per cent**
   Useful – **42 per cent**

3. **Showcase Sustainable Projects – Communities Leading the Way,** including presentations by: *Brian Barnett, General Manager of Engineering & Public Works for* Sustainability in the Whistler Community; *Innes Hood, Senior Advisor, The Sheltair Group and Rob Bennett, Project Manager, Sustainability Office, City of Vancouver for* A Neighbourhood Energy Utility in the False Creek, Precinct of the City of Vancouver; *Lyn Ross, Chair, GeoExchange BC for* GeoExchange in Transition; *Paul LaBranche, Executive VP, BOMA BC for* BOMA Go Green Program; Moderator *Freda Pagani, Director, Sustainability at UBC*

   Respondents rated this presentation as:
   Most useful – **47 per cent**
   Useful – **28 per cent**

4. **Helping Low Income Households to Keep Warm - The English Experience**, presented by: *Pam Wynne, Head of Fuel Poverty Team, Department for Environment Food and Rural Affairs.*

   Respondents rated this presentation as:
   Most useful – **22 per cent**
   Useful – **17per cent**

5. **Sustainability - Lessons and Experiences from California. What the future holds**. Presented by: *Michael Peevey, President of the California Public Utilities Commission.*

   Respondents rated this presentation as:
   Most useful – **25 per cent**
   Useful – **25per cent**

Question 5 – Future forum topics – 14 participants suggested future topics including:

- Transportation/energy-related topics
- More real life examples of energy conservation/initiatives/alternatives
- Economic incentives – how and when to use them best
- Local government and community energy planning initiatives
- NGO/energy-related issues

Question 6 – Forum format and timing – 62 per cent found the forum to be the "right amount of time" while 38 per cent felt there was "not enough time." Of the 38 per cent who felt there was not enough time, 77 per cent specifically noted there was not enough time for discussion and Q&As – although Day 2 time for questions improved over Day 1.

Question 7 – Forum location – 97 per cent of respondents felt the Wosk Centre was a "good" location, while only three per cent said it "needed improvement." Of the comments provided, 77 per cent responded favourably, "fantastic location," "the Wosk Centre is an excellent venue for such a forum."

Question 8 – Comfort of forum facilities – 92 per cent of respondents felt the comfort was "good," five per cent felt it was "adequate."

Question 9 – Forum meals and refreshments – 81 per cent of respondents felt the meals and refreshments were "good" including "lunch was excellent / very good." 17 per cent felt they were "adequate" and gave suggestions such as "coffee was weak" and "provide more than just coffee at breaks."

Question 10 – Provide additional comments about the forum. Ten participants provided comments, the majority of which were positive such as:

> "Do it again. This was a fantastic event!"
>
> "Great job. The delegates, speakers and topics were relevant and diverse."
>
> "Very good forum, best one I've been to in a long time. I would encourage Terasen Gas or other major energy related companies to hold similar forums each year – informative, enlightening and encouraging.

APPENDIX E

TGI Annual and Design Day Demand Forecast
Base Demand Scenario

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Coastal Region

Year-Ending Accounts by Rate Class

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	511,165	519,470	528,435	538,137	548,255	558,438	568,732	579,217	589,468
Rate 2	51,414	51,720	51,980	52,243	52,515	52,786	53,055	53,327	53,589
Rate 3	3,802	3,824	3,844	3,863	3,883	3,903	3,923	3,943	3,963
Rate 4	0	0	0	0	0	0	0	0	0
Rate 5	350	350	350	350	350	350	350	350	350
Rate 6	34	34	34	34	34	34	34	34	34
Total Coastal Region - Core	566,765	575,398	584,643	594,627	605,037	615,511	626,094	636,871	647,404
Transportation and IT Customers									
Rate 7	2	2	2	2	2	2	2	2	2
Rate 22	28	28	28	28	28	28	28	28	28
Rate 23	981	985	990	994	999	1,004	1,009	1,014	1,019
Rate 25	461	461	461	461	461	461	461	461	461
Rate 27	88	88	88	88	88	88	88	88	88
Total Coastal Region - Transportiation and IT	1,560	1,564	1,569	1,573	1,578	1,583	1,588	1,593	1,598
Total Coastal Region	**568,325**	**576,962**	**586,212**	**596,200**	**606,615**	**617,094**	**627,682**	**638,464**	**649,002**

Percent Change in Year-end Accounts by Rate Class

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	1.7	1.6	1.7	1.8	1.9	1.9	1.8	1.8	1.8
Rate 2	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Rate 3	-3.2	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT									
Rate 7	-33.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	1.2	0.4	0.5	0.4	0.5	0.5	0.5	0.5	0.5
Rate 25	-5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Coastal Region	**1.6**	**1.5**	**1.6**	**1.7**	**1.7**	**1.7**	**1.7**	**1.7**	**1.7**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	107.6	106.3	106.4	106.8	106.7	106.7	106.7	106.7	106.7
Rate 2	315.9	312.2	312.4	313.6	313.5	313.5	313.5	313.5	313.5
Rate 3	3,366.4	3,305.4	3,328.2	3,376.9	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5
Rate 4	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0
Rate 5	10,113.5	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8
Rate 6	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5
Transportation and IT									
Rate 7	21,093.6	21,093.6	21,096.3	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6
Rate 22	520,083.9	523,596.9	527,456.6	530,868.9	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5
Rate 23	4,865.0	4,787.0	4,811.0	4,866.3	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7
Rate 25	19,206.9	19,244.5	19,324.7	19,389.8	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4
Rate 27	59,311.1	60,703.3	61,575.8	61,810.0	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6

Annual Demand by Rate Class (TJ)

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	55,072	55,291	56,298	57,547	58,574	59,662	60,762	61,882	62,977
Rate 2	16,149	16,055	16,146	16,290	16,370	16,455	16,539	16,625	16,707
Rate 3	13,213	13,050	13,206	13,467	13,609	13,680	13,751	13,822	13,894
Rate 4	78	78	78	78	78	78	78	78	78
Rate 5	3,540	3,539	3,539	3,539	3,539	3,539	3,539	3,539	3,539
Rate 6	198	198	198	198	198	198	198	198	198
Total Coastal Region - Core	88,250	88,211	89,466	91,120	92,368	93,612	94,867	96,144	97,393
Transportation and IT									
Rate 7	42	42	42	42	42	42	42	42	42
Rate 22	14,562	14,661	14,769	14,864	14,960	14,960	14,960	14,960	14,960
Rate 23	4,155	4,110	4,150	4,217	4,252	4,273	4,273	4,273	4,273
Rate 25	8,854	8,872	8,909	8,939	8,978	8,978	8,978	8,978	8,978
Rate 27	5,231	5,342	5,419	5,439	5,433	5,433	5,433	5,433	5,433
Total Coastal Region - Transportation and IT	32,845	33,027	33,288	33,502	33,665	33,686	33,686	33,686	33,686
Total Coastal Region (Core, Transportation and IT)	**121,095**	**121,238**	**122,754**	**124,621**	**126,032**	**127,297**	**128,553**	**129,830**	**131,079**

Coastal Region Design Day Demand (TJ/day):

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-2	2012-13	2013-14	2014-15
Coastal Region - Core (Aggregate)	938.6	952.9	968.2	984.8	997.0	1007.1	1022.9	1034.4	1045.1

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Coastal Region

Year-Ending Accounts
by Rate Class

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	599,832	609,814	619,190	628,027	636,646	644,952	653,106	661,043	669,029
Rate 2	53,851	54,102	54,336	54,553	54,764	54,963	55,157	55,347	55,534
Rate 3	3,983	4,002	4,021	4,036	4,051	4,066	4,081	4,095	4,109
Rate 4	0	0	0	0	0	0	0	0	0
Rate 5	350	350	350	350	350	350	350	350	350
Rate 6	34	34	34	34	34	34	34	34	34
Total Coastal Region - Core	658,050	668,302	677,931	687,000	695,845	704,365	712,728	720,869	729,056
Transportation and IT Customers									
Rate 7	2	2	2	2	2	2	2	2	2
Rate 22	28	28	28	28	28	28	28	28	28
Rate 23	1,025	1,031	1,036	1,039	1,042	1,045	1,048	1,051	1,055
Rate 25	461	461	461	461	461	461	461	461	461
Rate 27	88	88	88	88	88	88	88	88	88
Total Coastal Region - Transportiation and IT	1,604	1,610	1,615	1,618	1,621	1,624	1,627	1,630	1,634
Total Coastal Region	**659,654**	**669,912**	**679,546**	**688,618**	**697,466**	**705,989**	**714,355**	**722,499**	**730,690**

Percent Change in Year-end Accounts by Rate Class

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	1.8	1.7	1.5	1.4	1.4	1.3	1.3	1.2	1.2
Rate 2	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3
Rate 3	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT									
Rate 7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	0.6	0.6	0.5	0.3	0.3	0.3	0.3	0.3	0.4
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Coastal Region	**1.6**	**1.6**	**1.4**	**1.3**	**1.3**	**1.2**	**1.2**	**1.1**	**1.1**

Annual Use Rate per Customer
by Rate Class (GJ)

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	106.7	106.7	106.7	106.7	106.7	106.7	106.7	106.7	106.7
Rate 2	313.5	313.5	313.5	313.5	313.5	313.5	313.5	313.5	313.5
Rate 3	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5
Rate 4	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0
Rate 5	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8
Rate 6	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5
Transportation and IT									
Rate 7	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6
Rate 22	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5
Rate 23	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7
Rate 25	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4
Rate 27	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6

Annual Demand
by Rate Class (TJ)

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	64,084	65,151	66,153	67,097	68,017	68,905	69,776	70,623	71,477
Rate 2	16,789	16,868	16,941	17,009	17,075	17,137	17,198	17,258	17,316
Rate 3	13,965	14,033	14,097	14,158	14,213	14,267	14,318	14,366	14,413
Rate 4	78	78	78	78	78	78	78	78	78
Rate 5	3,539	3,539	3,539	3,539	3,539	3,539	3,539	3,539	3,539
Rate 6	198	198	198	198	198	198	198	198	198
Total Coastal Region - Core	98,654	99,867	101,006	102,080	103,121	104,125	105,107	106,062	107,022
Transportation and IT									
Rate 7	42	42	42	42	42	42	42	42	42
Rate 22	14,960	14,960	14,960	14,960	14,960	14,960	14,960	14,960	14,960
Rate 23	4,273	4,273	4,273	4,273	4,273	4,273	4,273	4,273	4,273
Rate 25	8,978	8,978	8,978	8,978	8,978	8,978	8,978	8,978	8,978
Rate 27	5,433	5,433	5,433	5,433	5,433	5,433	5,433	5,433	5,433
Total Coastal Region - Transportation and IT	33,686	33,686	33,686	33,686	33,686	33,686	33,686	33,686	33,686
Total Coastal Region (Core, Transportation and IT)	**132,340**	**133,552**	**134,692**	**135,765**	**136,807**	**137,810**	**138,793**	**139,748**	**140,707**

Coastal Region Design Day Demand (TJ/day):

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Coastal Region - Core (Aggregate)	1054.0	1069.9	1080.8	1091.2	1096.1	1108.2	1117.4	1127.1	1132.6

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Coastal Region

Year-Ending Accounts by Rate Class

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	676,778	684,107	691,321	698,422	705,540	712,632	719,790	726,915
Rate 2	55,713	55,884	56,049	56,208	56,367	56,522	56,678	56,832
Rate 3	4,123	4,136	4,149	4,161	4,173	4,185	4,196	4,207
Rate 4	0	0	0	0	0	0	0	0
Rate 5	350	350	350	350	350	350	350	350
Rate 6	34	34	34	34	34	34	34	34
Total Coastal Region - Core	736,998	744,511	751,903	759,175	766,464	773,723	781,048	788,338
Transportation and IT Customers								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	28	28	28	28	28	28	28	28
Rate 23	1,058	1,061	1,064	1,067	1,070	1,073	1,076	1,079
Rate 25	461	461	461	461	461	461	461	461
Rate 27	88	88	88	88	88	88	88	88
Total Coastal Region - Transportiation and IT	1,637	1,640	1,643	1,646	1,649	1,652	1,655	1,658
Total Coastal Region	**738,635**	**746,151**	**753,546**	**760,821**	**768,113**	**775,375**	**782,703**	**789,996**

Percent Change in Year-end Accounts by Rate Class

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	1.2	1.1	1.1	1.0	1.0	1.0	1.0	1.0
Rate 2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Rate 3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT								
Rate 7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Coastal Region	**1.1**	**1.0**	**1.0**	**1.0**	**1.0**	**0.9**	**0.9**	**0.9**

Annual Use Rate per Customer by Rate Class (GJ)

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	106.7	106.7	106.7	106.7	106.7	106.7	106.7	106.7
Rate 2	313.5	313.5	313.5	313.5	313.5	313.5	313.5	313.5
Rate 3	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5	3,394.5
Rate 4	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0
Rate 5	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8	10,112.8
Rate 6	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5	5,823.5
Transportation and IT								
Rate 7	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6	21,093.6
Rate 22	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5	534,276.5
Rate 23	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7	4,883.7
Rate 25	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4	19,474.4
Rate 27	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6	61,740.6

Annual Demand by Rate Class (TJ)

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	72,304	73,087	73,857	74,616	75,376	76,134	76,899	77,660
Rate 2	17,373	17,426	17,478	17,528	17,578	17,626	17,675	17,723
Rate 3	14,461	14,505	14,549	14,590	14,630	14,671	14,712	14,749
Rate 4	78	78	78	78	78	78	78	78
Rate 5	3,539	3,539	3,539	3,539	3,539	3,539	3,539	3,539
Rate 6	198	198	198	198	198	198	198	198
Total Coastal Region - Core	107,953	108,833	109,700	110,549	111,400	112,247	113,101	113,948
Transportation and IT								
Rate 7	42	42	42	42	42	42	42	42
Rate 22	14,960	14,960	14,960	14,960	14,960	14,960	14,960	14,960
Rate 23	4,273	4,273	4,273	4,273	4,273	4,273	4,273	4,273
Rate 25	8,978	8,978	8,978	8,978	8,978	8,978	8,978	8,978
Rate 27	5,433	5,433	5,433	5,433	5,433	5,433	5,433	5,433
Total Coastal Region - Transportation and IT	33,686	33,686	33,686	33,686	33,686	33,686	33,686	33,686
Total Coastal Region (Core, Transportation and IT)	**141,639**	**142,519**	**143,385**	**144,235**	**145,086**	**145,932**	**146,787**	**147,633**

Coastal Region Design Day Demand (TJ/day):

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Coastal Region - Core (Aggregate)	1144.1	1151.0	1159.2	1163.7	1176.4	1184.6	1191.5	1193.8

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Interior Regions

Year-Ending Accounts by Rate Class

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	222,166	225,462	228,826	232,119	235,441	238,661	241,706	244,560	247,251
Rate 2	22,482	22,784	23,040	23,299	23,568	23,829	24,067	24,290	24,501
Rate 3	815	834	851	867	884	900	914	927	940
Rate 4	0	0	0	0	0	0	0	0	0
Rate 5	48	48	48	48	48	48	48	48	48
Rate 6	6	6	6	6	6	6	6	6	6
Total for Interior Regions - Core	245,517	249,134	252,771	256,339	259,947	263,444	266,741	269,831	272,746
Transportation and IT									
Rate 7	2	2	2	2	2	2	2	2	2
Rate 22	27	27	27	27	27	27	27	27	27
Rate 23	188	192	195	198	201	204	206	208	210
Rate 25	115	115	115	115	115	115	115	115	115
Rate 27	10	10	10	10	10	10	10	10	10
Total for Interior Regions - Transportation and IT	342	346	349	352	355	358	360	362	364
Total for Interior Regions	**245,859**	**249,480**	**253,120**	**256,691**	**260,302**	**263,802**	**267,101**	**270,193**	**273,110**

Percent Change in Year-end Accounts by Rate Class

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	1.6	1.5	1.5	1.4	1.4	1.4	1.3	1.2	1.1
Rate 2	1.2	1.3	1.1	1.1	1.2	1.1	1.0	0.9	0.9
Rate 3	-0.7	2.3	2.0	1.9	2.0	1.8	1.6	1.4	1.4
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT									
Rate 7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	-3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	2.7	2.1	1.6	1.5	1.5	1.5	1.0	1.0	1.0
Rate 25	-1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total for Interior Regions	**1.5**	**1.5**	**1.5**	**1.4**	**1.4**	**1.3**	**1.3**	**1.2**	**1.1**

Annual Use Rate per Customer by Rate Class - Interior

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	84.8	83.6	83.8	84.4	84.5	84.5	84.5	84.5	84.5
Rate 2	290.4	286.9	287.3	288.7	288.7	288.7	288.7	288.7	288.7
Rate 3	3,513.1	3,469.6	3,474.5	3,495.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2
Rate 4	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0
Rate 5	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9
Rate 6	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0
Transportation and IT									
Rate 7	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2
Rate 22	785,359.2	785,248.8	780,529.9	779,603.7	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9
Rate 23	5,496.2	5,420.3	5,440.8	5,491.1	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8
Rate 25	61,494.1	62,316.0	62,483.7	62,590.6	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2
Rate 27	87,161.0	87,619.2	87,717.4	87,815.7	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9

Annual Demand by Rate Class (TJ):

Core	2006	2007	2008	2009	2010	2011	2012	2013	2014
Rate 1	18,765	18,770	19,095	19,508	19,810	20,079	20,335	20,574	20,800
Rate 2	6,442	6,450	6,529	6,635	6,713	6,789	6,857	6,921	6,982
Rate 3	2,895	2,936	3,008	3,094	3,167	3,233	3,291	3,353	3,415
Rate 4	43	43	43	43	43	42.6	42.6	42.6	42.6
Rate 5	667	667	667	667	667	667	667	667	667
Rate 6	20	20	20	20	20	20	20	20	20
Total for Interior Regions - Core	28,832	28,886	29,361	29,968	30,420	30,831	31,212	31,578	31,927
Transportation and IT									
Rate 7	12	12	12	12	12	12	12	12	12
Rate 22	21,205	21,202	21,074	21,049	21,029	21,029	21,029	21,029	21,029
Rate 23	1,031	1,038	1,062	1,088	1,108	1,124	1,136	1,147	1,158
Rate 25	7,072	7,166	7,186	7,198	7,209	7,209	7,209	7,209	7,209
Rate 27	872	876	877	878	879	879	879	879	879
Total for Interior Regions - Transportation and IT	30,191	30,294	30,211	30,225	30,236	30,253	30,265	30,276	30,287
Total for Interior Regions	**59,023**	**59,181**	**59,572**	**60,193**	**60,656**	**61,084**	**61,477**	**61,854**	**62,214**

Interior Regions Design Day Demand (TJ/day):

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-2	2012-13	2013-14	2014-15
Core (Aggregate)	339.4	344.4	349.5	354.5	358.4	360.4	365.8	369.1	372.2

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Interior Regions

Year-Ending Accounts
by Rate Class

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	249,827	252,193	254,368	256,213	257,967	259,502	260,846	262,125	263,414
Rate 2	24,704	24,892	25,061	25,206	25,343	25,461	25,569	25,665	25,764
Rate 3	952	963	972	981	989	996	1,003	1,009	1,016
Rate 4	0	0	0	0	0	0	0	0	0
Rate 5	48	48	48	48	48	48	48	48	48
Rate 6	6	6	6	6	6	6	6	6	6
Total for Interior Regions - Core	275,537	278,102	280,455	282,454	284,353	286,013	287,472	288,853	290,248
Transportation and IT									
Rate 7	2	2	2	2	2	2	2	2	2
Rate 22	27	27	27	27	27	27	27	27	27
Rate 23	212	214	216	218	220	222	224	226	228
Rate 25	115	115	115	115	115	115	115	115	115
Rate 27	10	10	10	10	10	10	10	10	10
Total for Interior Regions - Transportation and IT	366	368	370	372	374	376	378	380	382
Total for Interior Regions	**275,903**	**278,470**	**280,825**	**282,826**	**284,727**	**286,389**	**287,850**	**289,233**	**290,630**

Percent Change in Year-end Accounts by Rate Class

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	1.0	0.9	0.9	0.7	0.7	0.6	0.5	0.5	0.5
Rate 2	0.8	0.8	0.7	0.6	0.5	0.5	0.4	0.4	0.4
Rate 3	1.3	1.2	0.9	0.9	0.8	0.7	0.7	0.6	0.7
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT									
Rate 7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total for Interior Regions	**1.0**	**0.9**	**0.8**	**0.7**	**0.7**	**0.6**	**0.5**	**0.5**	**0.5**

Annual Use Rate per Customer
by Rate Class - Interior

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5
Rate 2	288.7	288.7	288.7	288.7	288.7	288.7	288.7	288.7	288.7
Rate 3	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2
Rate 4	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0
Rate 5	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9
Rate 6	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0
Transportation and IT									
Rate 7	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2
Rate 22	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9
Rate 23	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8
Rate 25	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2
Rate 27	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9

Annual Demand
by Rate Class (TJ):

Core	2015	2016	2017	2018	2019	2020	2021	2022	2023
Rate 1	21,016	21,215	21,398	21,553	21,700	21,829	21,942	22,050	22,158
Rate 2	7,041	7,096	7,144	7,187	7,226	7,260	7,291	7,319	7,348
Rate 3	3,473	3,532	3,583	3,625	3,666	3,700	3,731	3,762	3,793
Rate 4	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6
Rate 5	667	667	667	667	667	667	667	667	667
Rate 6	20	20	20	20	20	20	20	20	20
Total for Interior Regions - Core	32,260	32,573	32,856	33,094	33,322	33,519	33,694	33,860	34,028
Transportation and IT									
Rate 7	12	12	12	12	12	12	12	12	12
Rate 22	21,029	21,029	21,029	21,029	21,029	21,029	21,029	21,029	21,029
Rate 23	1,170	1,181	1,192	1,203	1,215	1,226	1,237	1,249	1,260
Rate 25	7,209	7,209	7,209	7,209	7,209	7,209	7,209	7,209	7,209
Rate 27	879	879	879	879	879	879	879	879	879
Total for Interior Regions - Transportation and IT	30,298	30,310	30,321	30,332	30,344	30,355	30,366	30,377	30,389
Total for Interior Regions	**62,559**	**62,882**	**63,177**	**63,426**	**63,665**	**63,874**	**64,060**	**64,238**	**64,417**

Interior Regions Design Day Demand (TJ/day):

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Core (Aggregate)	374.1	377.8	380.4	383.3	384.1	387.6	389.2	390.2	390.2

Appendix E:
TGI Demand Forecast Details
Base Demand Scenario

Interior Regions

Year-Ending Accounts by Rate Class

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	264,674	266,076	267,580	269,126	270,741	272,412	274,152	275,918
Rate 2	25,860	25,968	26,086	26,205	26,331	26,460	26,596	26,731
Rate 3	1,022	1,029	1,036	1,043	1,051	1,059	1,067	1,075
Rate 4	0	0	0	0	0	0	0	0
Rate 5	48	48	48	48	48	48	48	48
Rate 6	6	6	6	6	6	6	6	6
Total for Interior Regions - Core	291,610	293,127	294,756	296,428	298,177	299,985	301,869	303,778
Transportation and IT								
Rate 7	2	2	2	2	2	2	2	2
Rate 22	27	27	27	27	27	27	27	27
Rate 23	229	230	232	234	236	238	240	242
Rate 25	115	115	115	115	115	115	115	115
Rate 27	10	10	10	10	10	10	10	10
Total for Interior Regions - Transportation and IT	383	384	386	388	390	392	394	396
Total for Interior Regions	**291,993**	**293,511**	**295,142**	**296,816**	**298,567**	**300,377**	**302,263**	**304,174**

Percent Change in Year-end Accounts by Rate Class

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6
Rate 2	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
Rate 3	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.7
Rate 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation and IT								
Rate 7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 23	0.4	0.4	0.9	0.9	0.9	0.8	0.8	0.8
Rate 25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate 27	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total for Interior Regions	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**

Annual Use Rate per Customer by Rate Class - Interior

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	84.5	84.5	84.5	84.5	84.5	84.5	84.5	84.5
Rate 2	288.7	288.7	288.7	288.7	288.7	288.7	288.7	288.7
Rate 3	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2	3,497.2
Rate 4	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0	3,967.0
Rate 5	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9	13,903.9
Rate 6	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0	3,300.0
Transportation and IT								
Rate 7	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2	5,837.2
Rate 22	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9	778,867.9
Rate 23	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8	5,504.8
Rate 25	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2	62,684.2
Rate 27	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9	87,913.9

Annual Demand by Rate Class (TJ):

Core	2024	2025	2026	2027	2028	2029	2030	2031
Rate 1	22,264	22,382	22,508	22,638	22,774	22,914	23,060	23,208
Rate 2	7,376	7,408	7,442	7,476	7,512	7,550	7,588	7,626
Rate 3	3,820	3,851	3,886	3,923	3,958	3,999	4,040	4,082
Rate 4	42.6	42.6	42.6	42.6	42.6	42.6	42.6	42.6
Rate 5	667	667	667	667	667	667	667	667
Rate 6	20	20	20	20	20	20	20	20
Total for Interior Regions - Core	34,191	34,371	34,566	34,768	34,974	35,192	35,418	35,645
Transportation and IT								
Rate 7	12	12	12	12	12	12	12	12
Rate 22	21,029	21,029	21,029	21,029	21,029	21,029	21,029	21,029
Rate 23	1,265	1,271	1,282	1,294	1,305	1,316	1,328	1,339
Rate 25	7,209	7,209	7,209	7,209	7,209	7,209	7,209	7,209
Rate 27	879	879	879	879	879	879	879	879
Total for Interior Regions - Transportation and IT	30,394	30,400	30,411	30,423	30,434	30,445	30,456	30,468
Total for Interior Regions	**64,585**	**64,771**	**64,977**	**65,190**	**65,408**	**65,637**	**65,874**	**66,113**

Interior Regions Design Day Demand (TJ/day):

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32
Core (Aggregate)	394.2	395.9	398.1	398.6	401.2	403.9	406.0	406.5

APPENDIX F

Northwest Gas Association
Regional Gas Supply and Storage Presentation

NW Natural Gas Market Outlook

Dan Kirschner, Executive Director
Northwest Gas Association

TGI Resource Plan – Stakeholder Workshop
June 20, 2006

NWGA
NORTHWEST GAS ASSOCIATION

NWGA
NORTHWEST GAS ASSOCIATION

5335 SW Meadows Rd., #220
Lake Oswego, OR 97035
(503) 624-2160
www.nwga.org

NWGA Members:

Avista Corporation

Cascade Natural Gas Co.

Intermountain Gas Co.

NW Natural

Puget Sound Energy

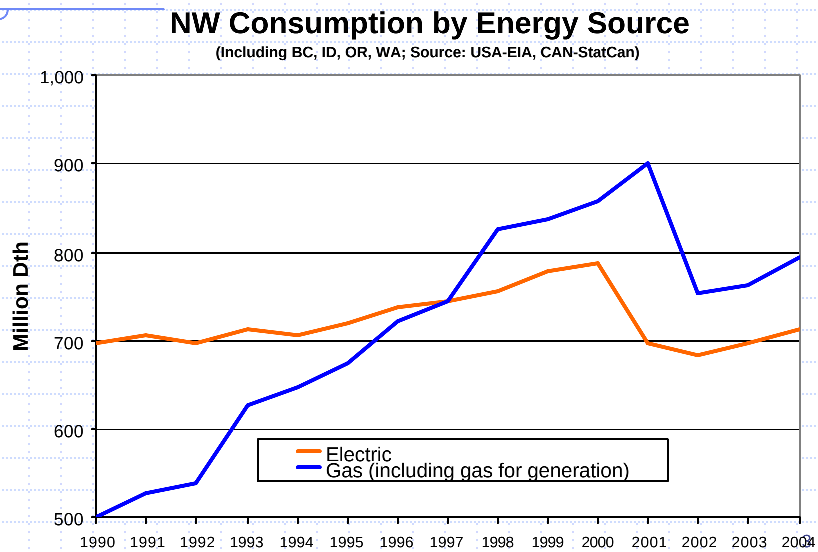
Duke Energy Gas Transmission

Terasen Gas

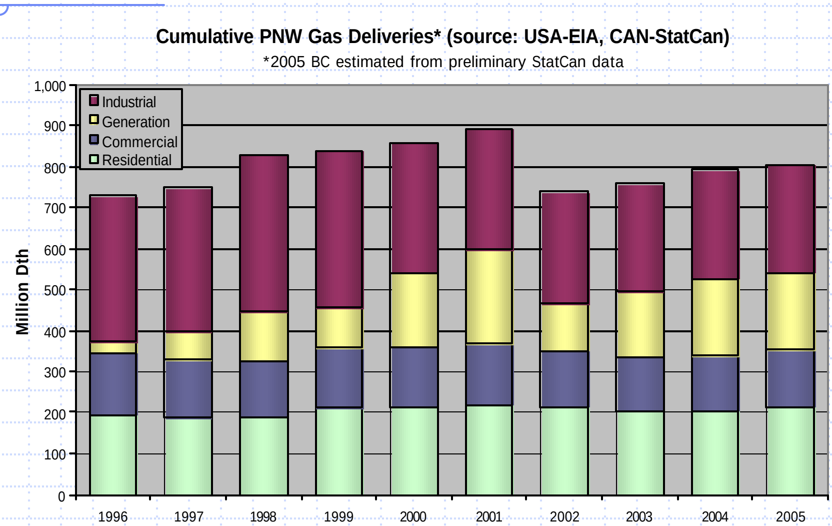
TransCanada's GTN System

Williams NW Pipeline

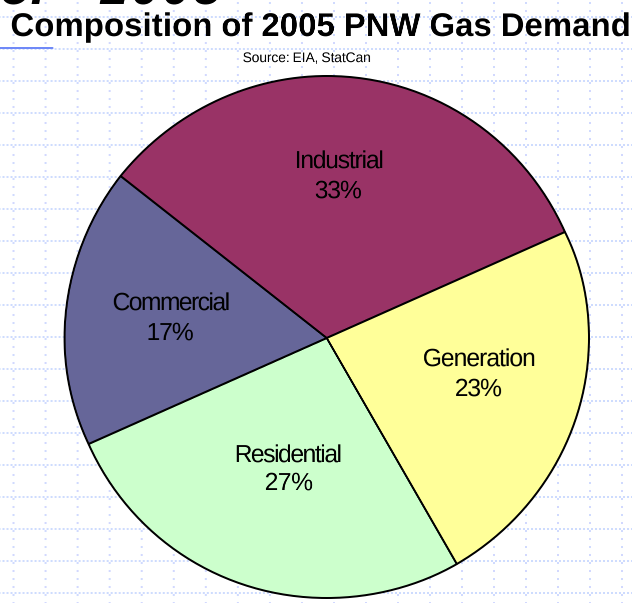
Gas a Vital Part of NW Energy Scene



Recent Gas Demand



Proportion of Gas Demand by Sector - 2005



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Gas Demand Forecast

(2006-07 through 2010-11)

	Low Growth Case		Base (expected) Case		High Growth Case	
	Average Annual	**Cumulative**	**Average Annual**	**Cumulative**	**Average Annual**	**Cumulative**
Total	**1.0%**	**4.1%**	**2.1%**	**8.1%**	**2.7%**	**10.2%**
Residential	1.9%	7.3%	3.2%	11.9%	4.2%	15.2%
Commercial	1.3%	4.9%	2.5%	9.3%	3.1%	11.5%
Industrial	0.0%	0.1%	0.5%	2.0%	0.6%	2.4%
Generation	1.1%	4.1%	2.6%	9.7%	3.2%	11.9%

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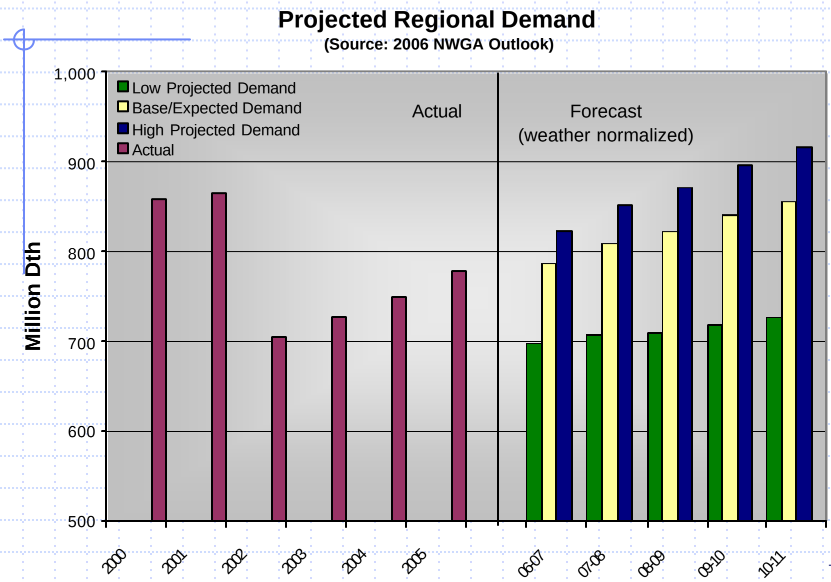
Demand Forecast



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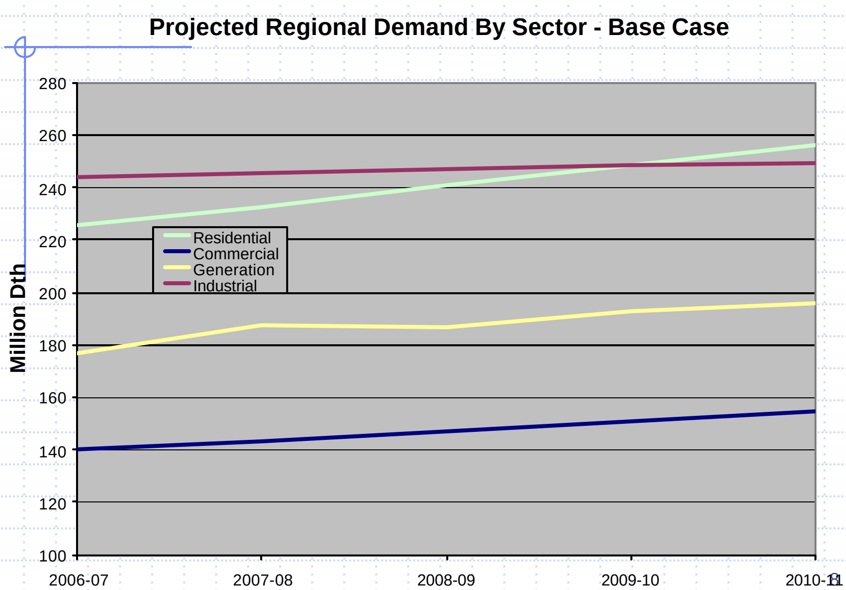
Demand Forecast by Sector



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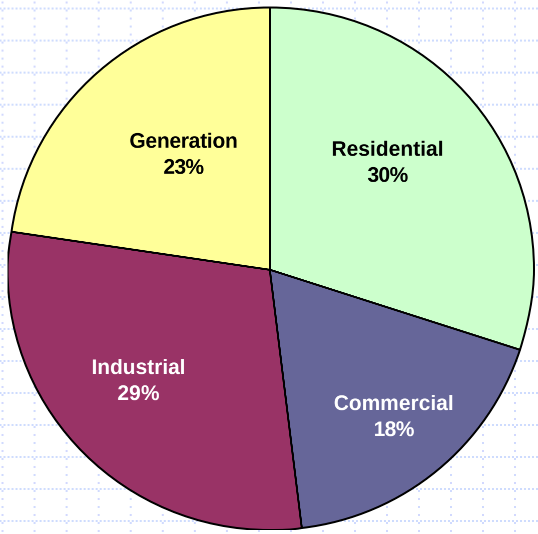
Proportion of Projected Gas Demand by Sector: 2010-2011

Composition of PNW Demand - Base Case



Change from <u>2005</u>:

Residential

↑ 3%

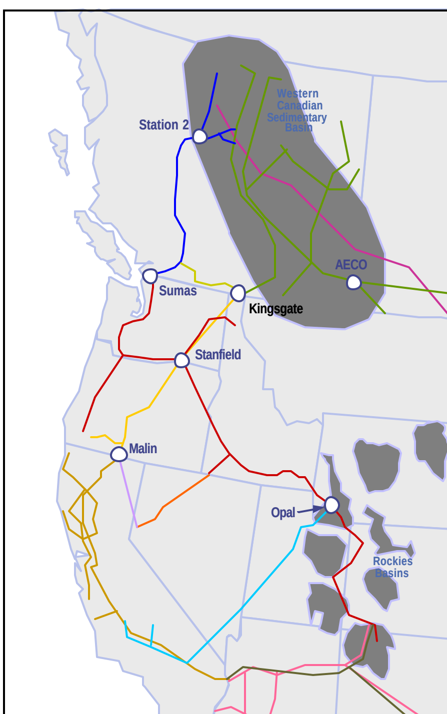
Commercial

↑ 1%

Industrial

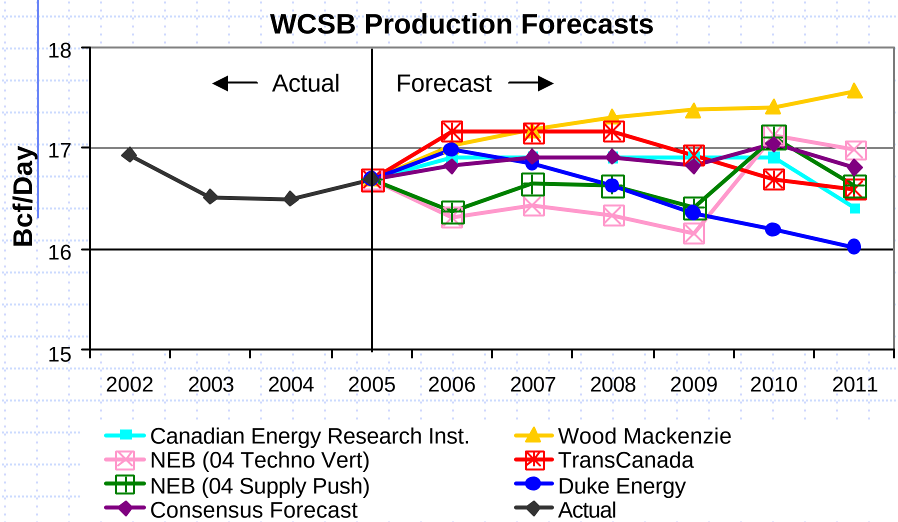
↓ 4%

Generation ↔

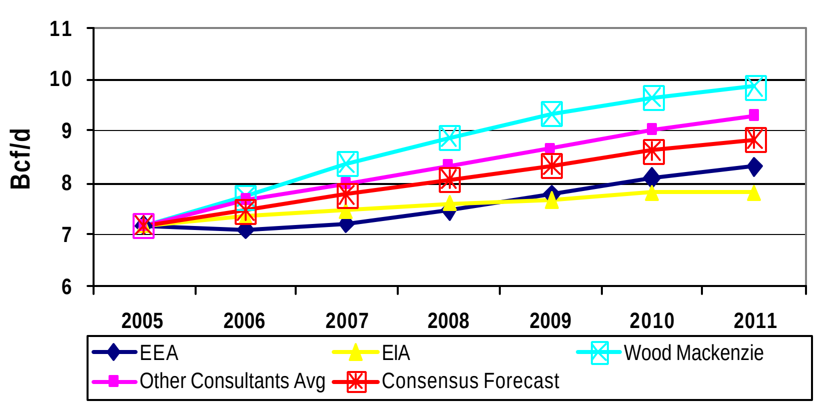


Northwest Gas Supply

WCSB Production



Rockies Production



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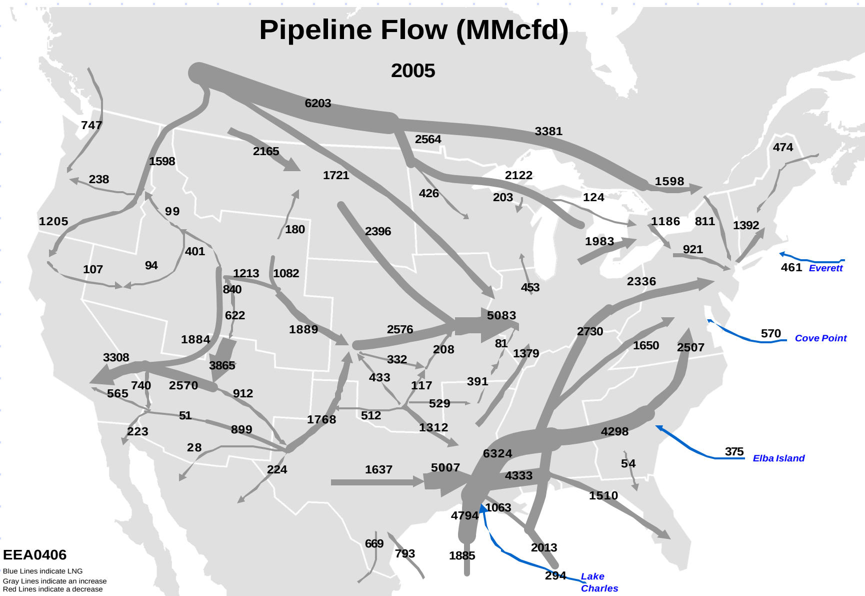
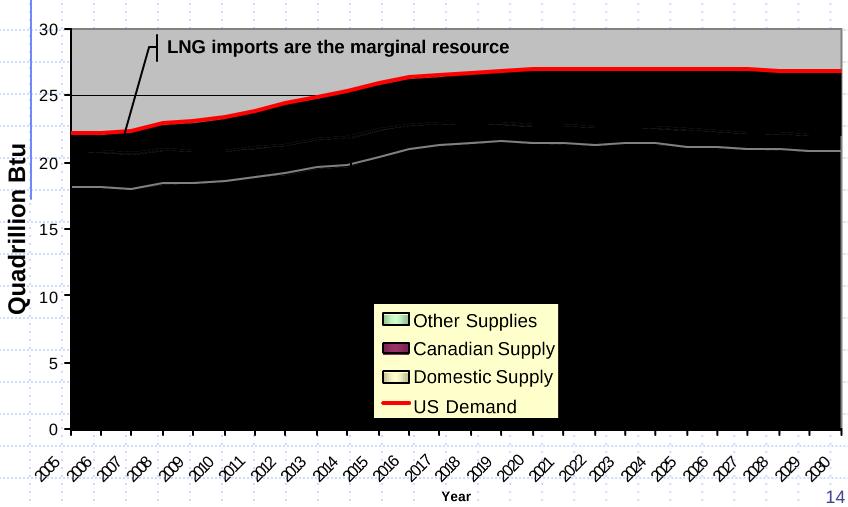
Supplies Flow to Demand



Growing Demand, Slowing Supply

Projected US Supply/Demand Balance

(EIA Annual Energy Outlook 2006)



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Northwest LNG Proposals

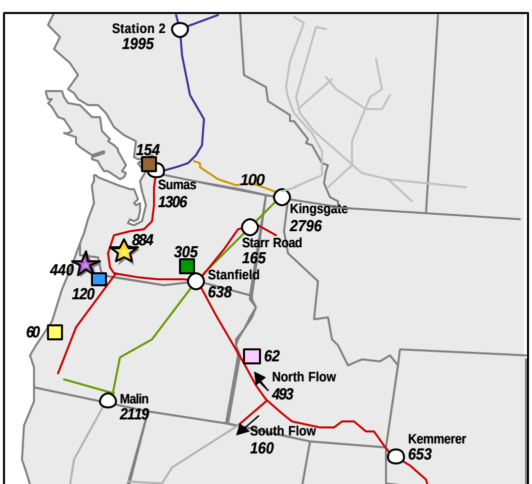
① PortWestward LNG
② Skipanon LNG
③ Jordan Cove LNG
④ Northern Star LNG
⑤ Tansy Point
⑥ Kitimat LNG
⑦ WestPac Terminal

Why LNG?
- Vast reserves
  - no local market
  - pipelines not viable
- decreasing costs

Challenges include:
- Local acceptance
- Regulatory/Permitting
- Commercial considerations:
  - economics/financing
  - takeaway infrastructure
  - worldwide competition
  - supplier commitment

Northwest Gas Infrastructure

Capacity at Major Interconnects & Storage Facilities (MDth/day)

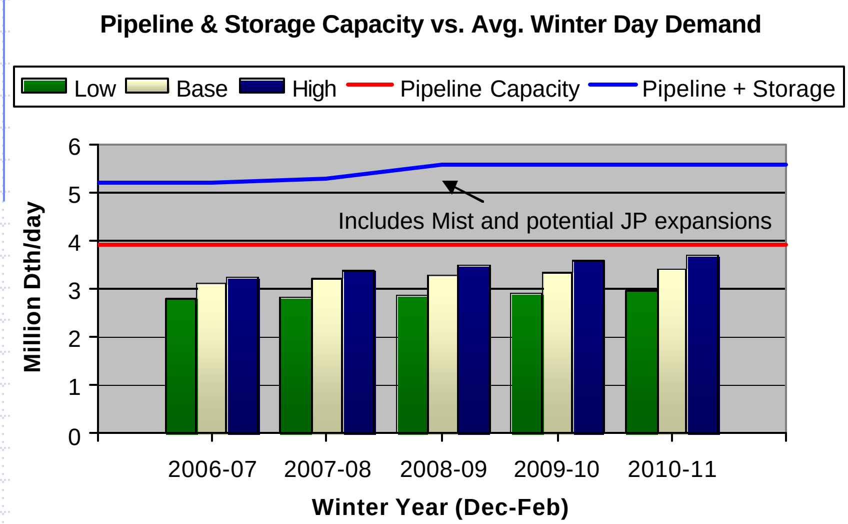


Pipelines
- DEGT BC Pipeline
- Williams NWP
- TransCanada - GTN
- Terasen S. Crossing

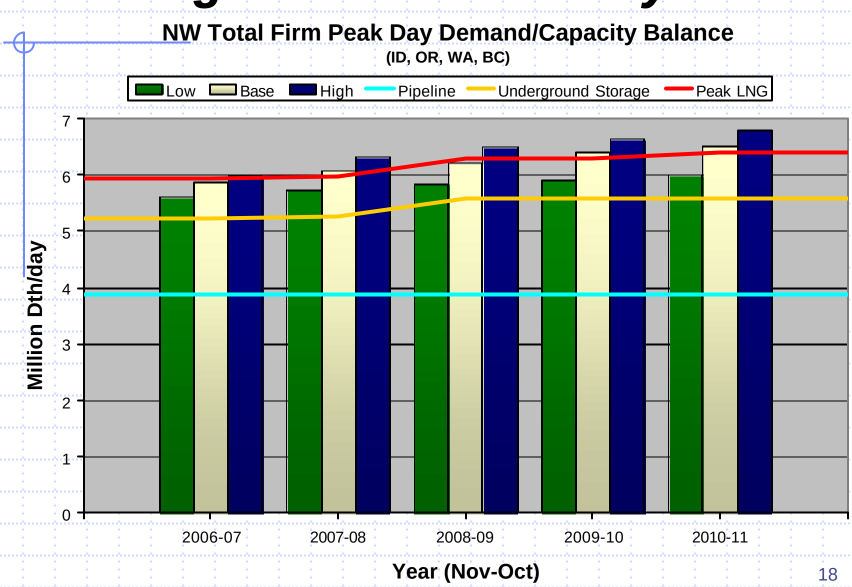
Storage Facilities
- Jackson Prairie
- Mist

LNG Facilities
- Plymouth
- Newport
- Portland
- Tilbury
- Nampa

Capacity to Serve NW Demand: Average Winter Day



Capacity to Serve Demand: Region-wide Peak Day



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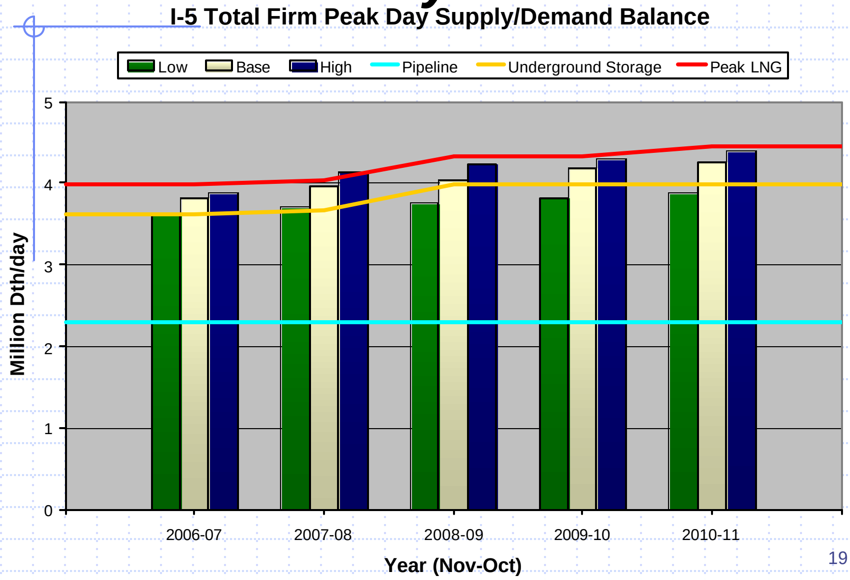
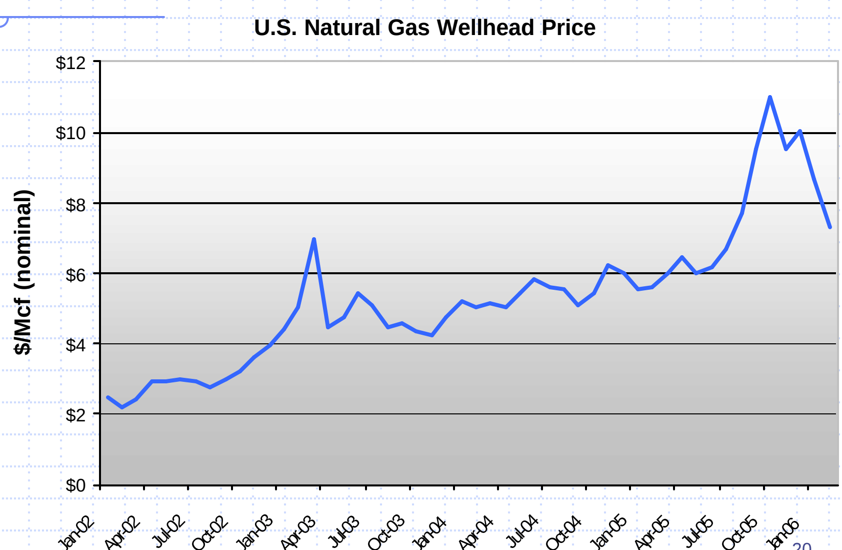
Capacity to Serve Demand: I-5 Peak Day



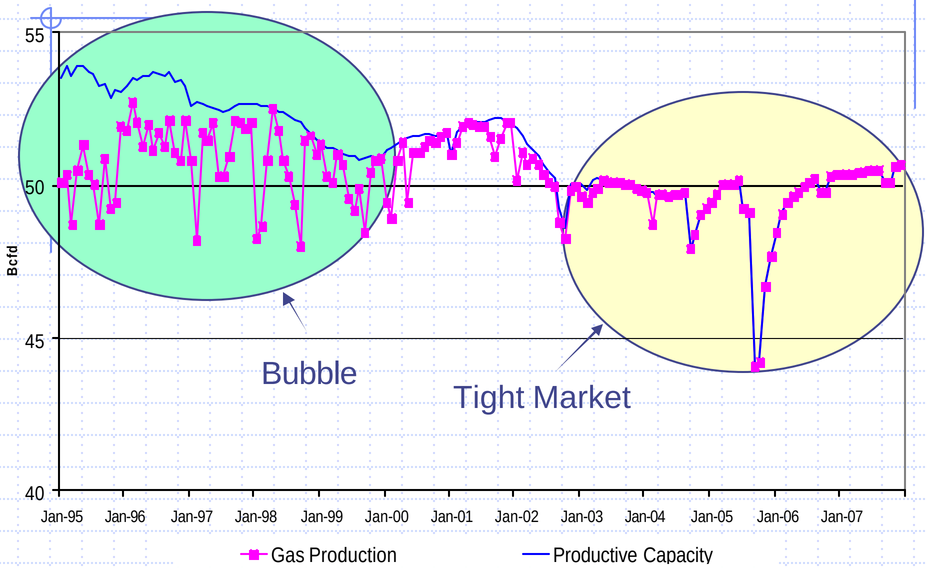
Recent Gas Prices



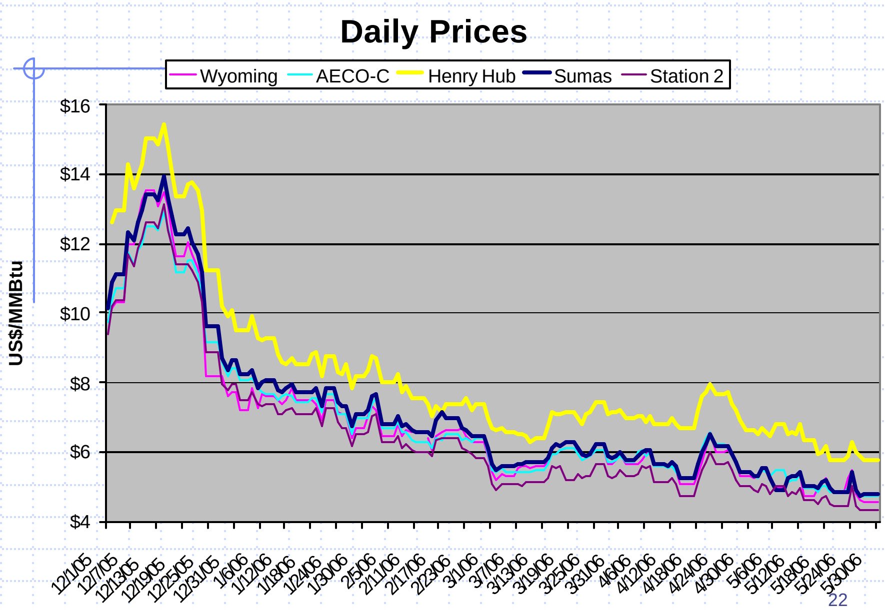
Source: EIA

Productive Capacity

Source: Energy and Environmental Analysis, Inc.



The Good News (but for how long?)



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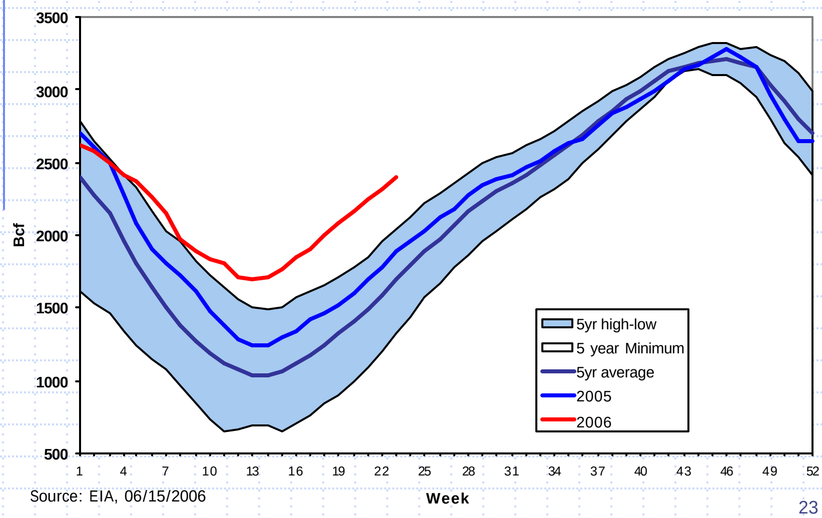
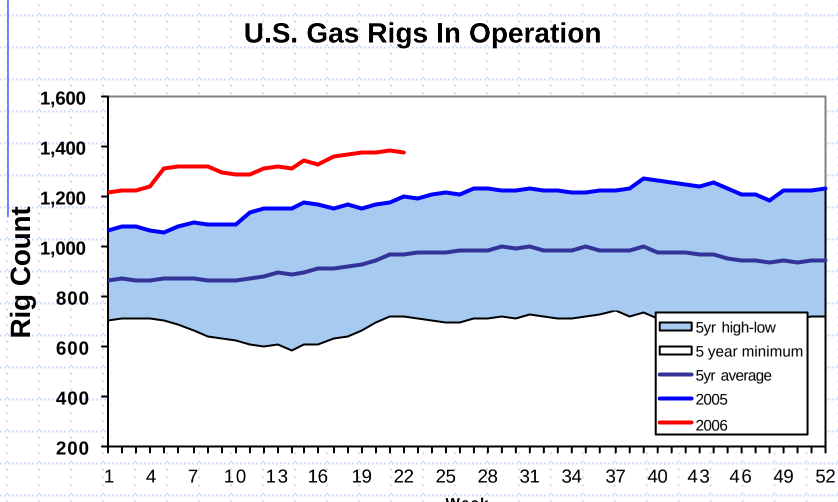
Source: Platts Gas Daily and EIA Natural Gas Weekly Update

Price Drivers: Storage (Supply)



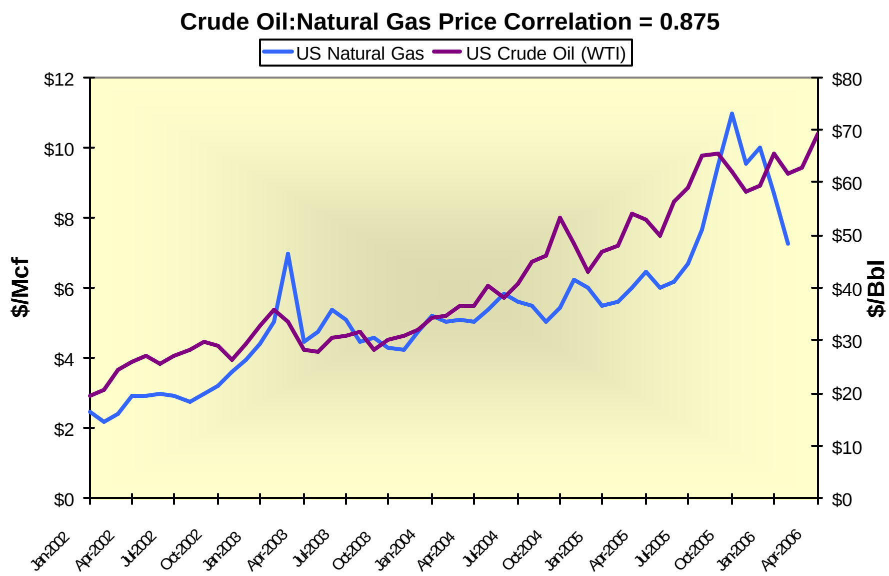
Source: EIA, 06/15/2006

Price Drivers: Production



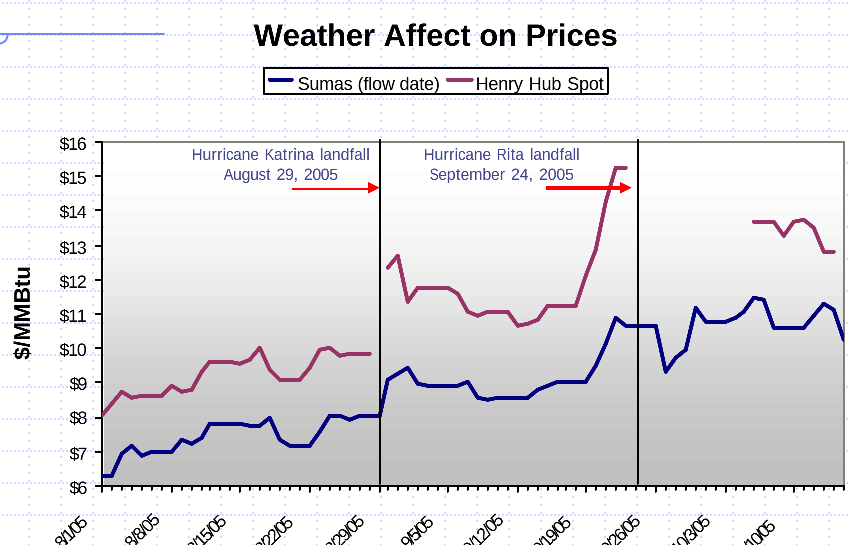
Source: Baker Hughes, 06/09/2006

The Price of Oil Has an Impact…



Source: EIA

As Does the Weather



Source: Energy Information Administration

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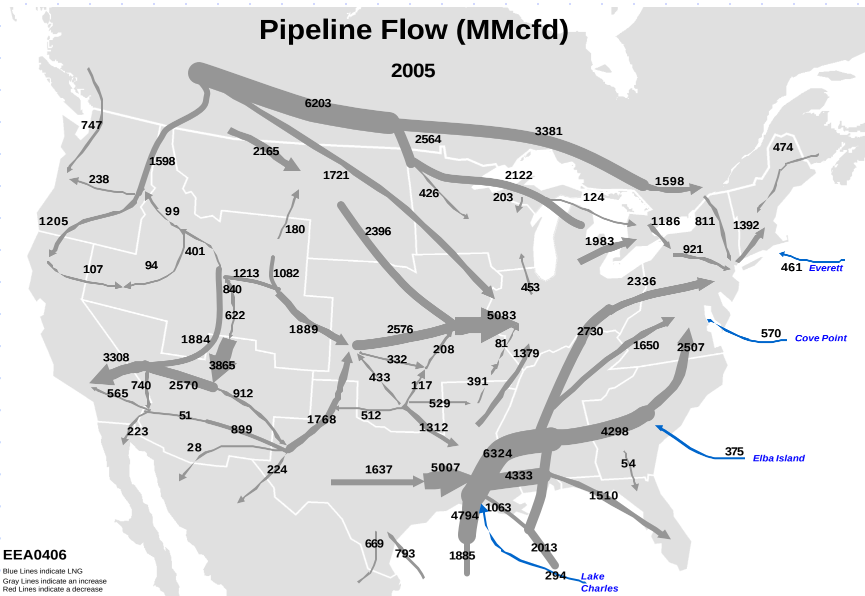
Markets Are Connected



Natural Gas Demand

- Natural gas demand in PNW will grow moderately over next five years.
  - normal weather, economic conditions
- Load shape changing: peak loads growing faster than base.

28

Natural Gas Supply

- There is plenty of gas, but...
  - N. American production struggling to keep up with growing demand.
- N. America increasingly integrated
- PNW consumers will benefit from incremental supplies.

29

Natural Gas Prices

- Natural gas prices have moderated;
- Prices remain volatile: tight supply/demand balance
  - weather, production, etc.

30

Natural Gas Infrastructure

- Transmission/storage capacity adequate to serve region at present.
- Very efficient system; little redundancy; how to serve changing load shape.
- Permitting/regulatory processes must be nimble; facilitate necessary projects when required.
- Infrastructure takes time. Information sharing helps ensure supply is available when needed.

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Duke Energy Gas Transmission
Terasen Gas
TransCanada's GTN System
Williams NW Pipeline

APPENDIX G

Market Area Storage Analysis

Appendix G – Market Area Storage Analysis

A. Overview

As discussed in Section 5 of the 2006 Resource Plan, the Pacific Northwest region is experiencing faster peak day growth than annual demand which in turn puts increasing pressure on resources that are available to meet forecasted peak day demand. TGI and TGVI are experiencing similar growth patterns and have a growing need for incremental resources to meet future peak day demand.

TGVI is proposing to construct an LNG peak shaving facility at Mt Hayes on Vancouver Island. The facility would serve to meet TGVI's system capacity requirements, and would also provide TGVI gas supply benefits by allowing it to avoid the contracting of other storage or pipeline resources to meet peaking gas supply requirements on its system. The location of the LNG Storage facility on Vancouver Island also allows TGVI to offer storage services to TGI to serve the Lower Mainland. As all gas transported to the TGVI system is first transported across the TGI Coastal Transmission System, the Mt Hayes LNG facility is effectively an "On-System" resource for TGI as well as TGVI. TGVI is considering a 0.5 to 1.5 BCF facility with the equivalent of 10 days of send-out capacity or deliverability. The target in-service date is 2010.

This Appendix will provide an assessment of the alternate long term resources available to TGI and TGVI to meet future peak day growth in order to determine the market value of storage services that can be provided by the Mt Hayes LNG facility. As the market value of off-system resources is similar for both utilities, for the purposes of this assessment, TGVI and TGI are jointly referred to as Terasen Gas. The following alternatives are considered:

- Off-System market area storage based on Jackson Prairie Storage ("JPS") and/or Mist storage capacity plus NWP transportation capacity to redelivery gas from these underground storage facilities to the Huntingdon market area

- Westcoast ("WEI") T-South Capacity from Station 2 to Huntingdon/Sumas

In general, Terasen Gas views market area storage as the preferred resource to meet shorter duration load requirements as it is typically more cost effective than baseload pipeline capacity. Currently Terasen Gas holds market area storage contracts with JPS and Mist, both underground facilities located in the I-5 corridor downstream of Huntingdon/Sumas. Alternatively, Terasen Gas could hold baseload WEI T-South pipeline capacity to meet its peak day requirement, and mitigate the cost of holding the capacity by offering it to the market when it is not required.

The following sections provide a detailed assessment of the market valuation of Off-System market area storage and WEI T-South baseload capacity in meeting Terasen Gas's shorter duration requirements based on the most current information available to Terasen Gas. The results indicate that the value of the Mt Hayes Storage service based on an equivalent Off System market area storage alternative, including the estimated NWP transportation redelivery charge, equates to an annual cost of $107 to $140 for 1 GJ of deliverability to the Huntingdon/Sumas market area. Alternatively, the value based on baseload WEI T-South resource used to satisfy shorter term duration requirements for 1 GJ delivered to Huntingdon will cost on an annual basis between $132 including forecasted T-South demand charge recovery to $180 excluding T-South demand charge recovery. TGI's alternative resource to satisfy shorter term duration requirements will range from $107, representing the low end of market area storage, to $180, representing Westcoast T-South with no mitigation, for 1 GJ delivered to the Huntingdon/Sumas market area.

B. Description of Off System Resources

(i) Off-System Market Area Storage

In the analysis, it is assumed that Terasen Gas will require a resource to satisfy short-term peaking requirements of 5 to 10 days. To satisfy the 5 to 10 day requirement, a 15 day Off System market area storage contract was evaluated. As illustrated in Attachment 6, an equivalent Off System market area storage contract requires 15 days because the withdrawal capability declines as gas is withdrawn from storage and total gas storage inventories levels decline.

The market area storage valuation is based on the estimated cost of service storage contract associated with the current JPS expansion project and redelivery transport cost estimates to Huntingdon derived from recent discussions with NWP. As discussed in Section 5 of TGI's Resource Plan, Terasen Gas must assume that for longer term evaluation, JPS or Mist Storage contracts will require firm NWP redelivery capacity to Huntingdon during the winter months. NWP has indicated that there is some northbound firm TF-1 capacity available for storage re-delivery in the I-5 corridor however a very limited amount of this capacity is available to deliver northward from the Mist storage facility. As a result, redelivery from the Mist facility will be more constrained than JPS, which will make it more difficult for NWN to offer competitive pricing for incremental storage services to serve the Huntingdon/Sumas market. Since the JPS expansion project pricing provides the most recent long term transacted pricing that is also transparent, Terasen Gas has assumed the JPS expansion project cost of service rates represents the best available information in its evaluation of long term incremental market area storage costs.

Jackson Prairie Storage

On February 1, 2006, NWP initiated an Open Season for 100,000 Mcf/d (104,000 Dth/d) of incremental firm storage service based on NWP's one third ownership of the planned JPS expansion of approximately 300,000 Mcf/d (312,000 Dth/d) of additional deliverability, and 6.3 Bcf of storage working gas capacity. The fixed cost of service rate for the JPS contract estimated by NWP in the JPS Open Season included a capacity charge of US$0.00462/MMbtu/day and deliverability charge of US$0.05392/MMbtu/day. This translates into US$3.00/MMbtu for a 15 day market area storage contract.[1] For this evaluation, it is assumed that JPS Open Season pricing provides the most current estimate of incremental Off System market area storage costs over the planning period.

1 The US$3.00/mmbtu for 15 day JPS storage is derived by the following calculation [$0.00462 * capacity*365 days + $0.05392* deliverability*365 days]/ capacity. This is included in Attachment 4.

Redelivery from JPS to the Huntingdon/Sumas market area, which is required with downstream storage, was not offered as part of the NWP's JPS Open Season. However in the Open Season Term Sheet, NWP indicated that only 9,000 Dth/d of northbound TF-1 capacity may be available from Mist storage at Deer Island, while up to 187,000 Dth/d could be available from JPS.[2] Since that time it is Terasen Gas's understanding that up to 120,000 of this capacity has been contracted. In recent discussions NWP has indicated that that firm redelivery from JPS to the Huntingdon/Sumas market area will be based on negotiated rates and are expected to be priced at 30%-50% of the TF-1 rate for firm transportation capacity. As discussed in the Section 5.3 of the 2006 Resource Plan, for the purposes of the evaluation TGI and TGVI has assumed a TF-1 Rate of US$0.39/MMbtu/d which is lower than the TF-1 rate requested by NWP in its 2006 Rate Case Filing. The annual cost of delivering 1 GJ of a 15 day JPS storage contract to Huntingdon is estimated to cost $107 to $140 on a levelised basis.

Mist Storage

The Mist storage field is located in Northwest Natural's ("NWN") service territory and prior to the 2000 was used exclusively to meet NWN's market requirements. In 2000, NWN expanded the facility to allow interstate services, which in turn is regulated by FERC. At that time, FERC established a cost of service rate or "Recourse Rate" which sets the tariff rate of Mist storage rate based on the rolled-in cost of service of the entire facility. The incremental cost associated with the new facilities that were put in service to allow NWN to provide interstate services was lower than the cost of the underlying facilities which still provides NWN the flexibility to offer market based rates that were lower than the Recourse Rate. Though NWN has offered storage services at negotiated rates based on market value the "Recourse Rate" sets the cap that NWN can charge.

In the TGVI and TGI 2004 Resource Plans, the valuation of on-system storage service provided by the proposed Mt Hayes LNG Storage facility was based Mist storage service. Mist was the only facility at the time where capacity for new storage contract holders was being added and both TGVI and TGI had recently completed contracts with terms of 5 to 10 years with NWN. The price of Mist storage used in the TGVI's 2004 Resource Plan analysis was based on a negotiated market rate that included re-delivery to Huntingdon/Sumas and was assumed to remain constant over time. The negotiated market rate for a 15 day underground market area storage alternative including an estimated transportation redelivery charge equated to an annual cost of $82 for 1 GJ of deliverability to Huntingdon.

In the TGVI 2004 Resource Plan, in order to assess upper limit of potential Mist Storage costs the FERC regulated Recourse Rate was also evaluated. In this case the estimate of re-delivery costs from Mist to Huntingdon was based on re-delivery contracts that Terasen Gas had in place at the time associated with other third party storage arrangements. These redelivery contracts were priced at approximately 10% of the then current firm NWP TF-1 rate of US$0.27 per MMbtu/d and when combined with the

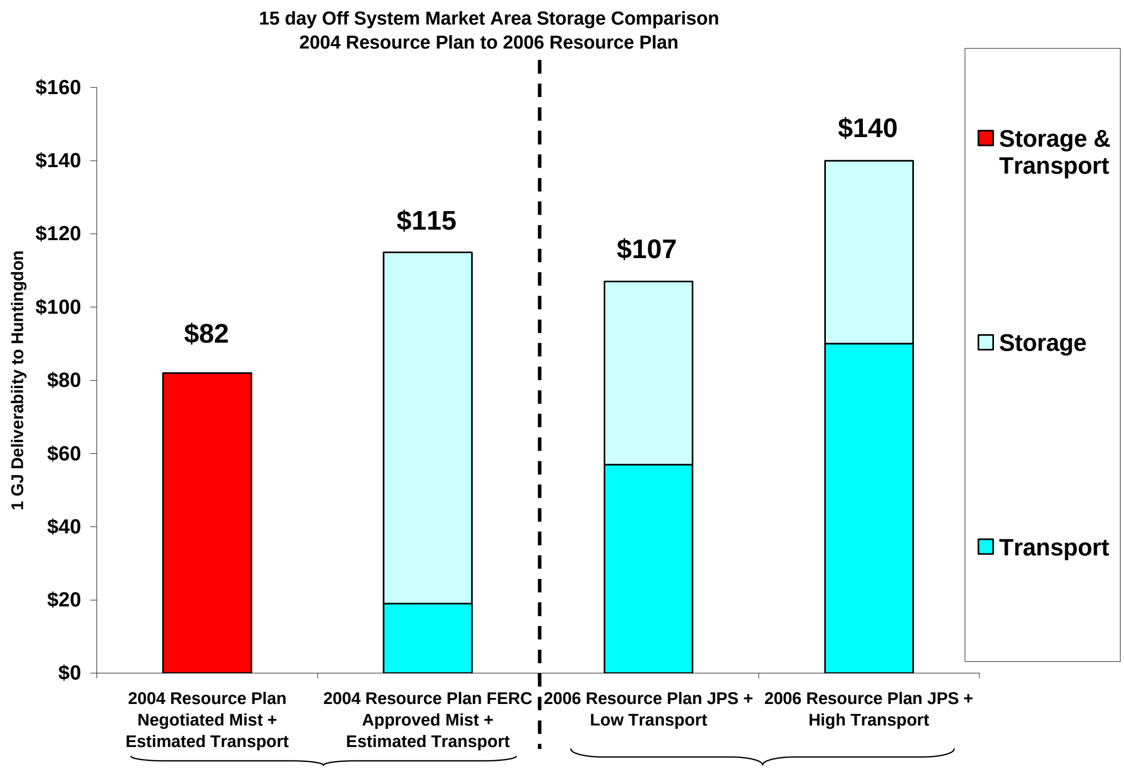
2 JPS Incremental Firm Storage service Open Season Term Sheet included in Attachment 4.

Recourse Rate for Mist storage capacity for a 15 day storage alternative equated to an annual cost of $115 for 1 GJ of deliverability to Huntingdon.[3]

This evaluation of the Mist market area storage alternative provided conservative results as it ignored the limitations on the level of NWP displacement pipeline capacity that may be available in the long term to Terasen Gas to Huntingdon as discussed in Section 5 of TGI's 2006 Resource Plan. If displacement capacity is not available, the next option is to contract for firm NWP pipeline capacity for redelivery from Mist Storage. As discussed previously, since both Mist storage and JPS will likely be priced competitively it is assumed that the Mist storage cost would fall somewhere between the JPS plus Redelivery estimate of $107 to $140 per GJ of deliverability to Huntingdon.

Figure 1 provides a comparison storage valuation provided in the 2004 Resource Plans to the current estimates JPS plus Redelivery. The more recent forecasted annual costs are higher than the estimated costs in the previous Resource Plan primarily due to increasing cost of NWP redelivery from JPS/Mist storage to the Huntingdon/Sumas market area. A detailed breakdown of the Off System market area storage assumptions is included in Section C of this appendix.

Figure 1: Annual Cost of 1 GJ Market Area Storage Deliverability to Huntingdon, Cdn$

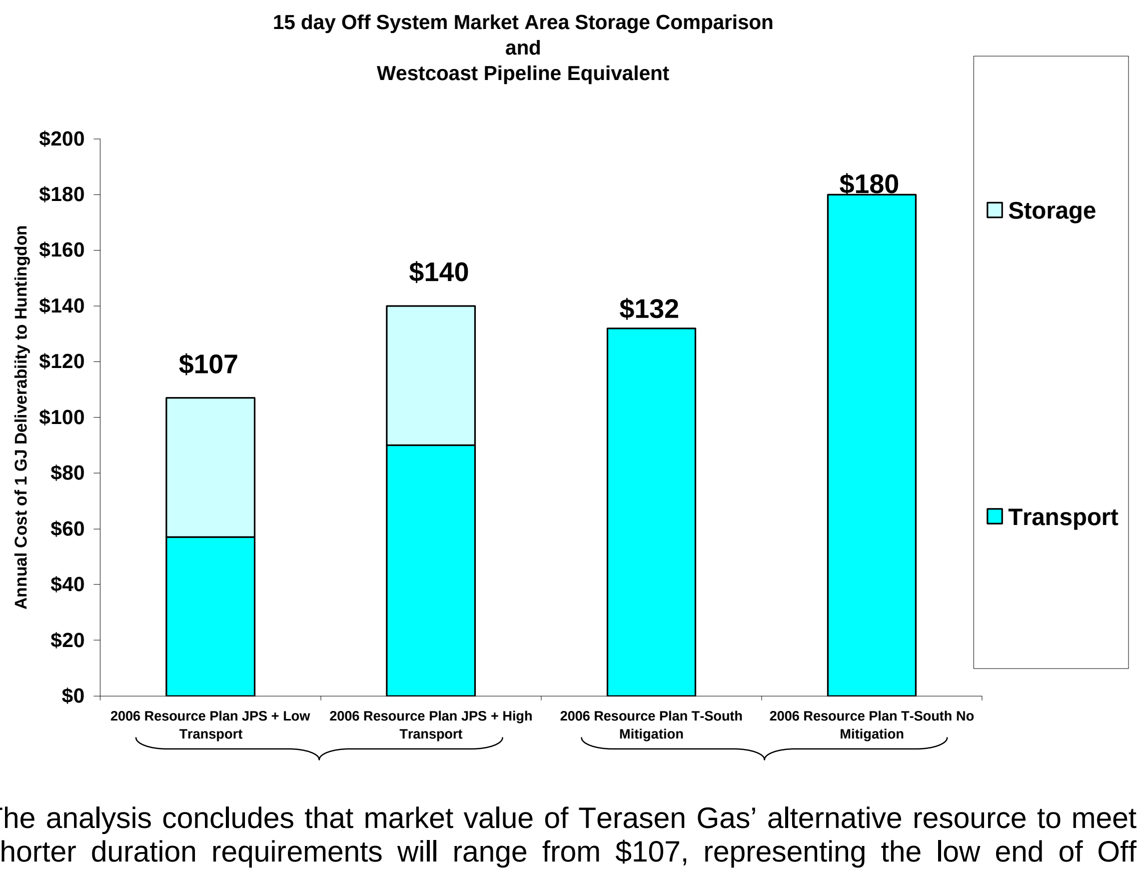


3 The FERC approved derivation of the $115 was included in the 2004 Resource Plan and LNG CPCN Exhibit B-3 BCUC IR #1 18.4. Due to confidentiality the derivation of the negotiated rate was not included.

(ii) Westcoast T-South Capacity

While short-duration resources such as market area storage are typically preferable options over baseload assets such as year-round transportation capacity, incremental available pipeline capacity would be considered if pipeline capacity was cost effective. Given incremental WEI T-South capacity is a regional alternative to market area storage for Terasen Gas it will also be evaluated as a resource to meet the shorter duration requirements. The table below illustrates the comparison of Off System market area storage to an alternative baseload WEI T-South resource used to satisfy shorter term duration requirements. The low cost of $132 per GJ of deliverability assumes that Terasen Gas is able to recovery WEI demand charges during the winter months when does not require the capacity to satisfy Core demand. The higher cost of $180 assumes that no mitigation revenue to offset annual demand charges is realized. A detailed discussion and breakdown of the T-South assumptions is included Section C of this appendix.

Figure 2: Annual Cost of 1 GJ Market Area Storage Deliverability to Huntingdon, Cdn$



The analysis concludes that market value of Terasen Gas' alternative resource to meet shorter duration requirements will range from $107, representing the low end of Off System market area storage, to $180, representing WEI T-South with no T-South demand charge recovery, for 1 GJ delivered to the Huntingdon/Sumas market area.

C. Assessment of Quantitative Benefits

The key drivers of the cost of Off System market area storage are the expected cost of the storage itself and the expected cost of redelivery of the gas back to the Huntingdon/Sumas market area. Underground storage costs include:

- storage facility demand charges,
- firm NWP transportation demand charges,
- fuel for storage injection, and
- fuel on NWP transportation required to move supply to/from Huntingdon/Sumas market area and the storage facility.

Since Sumas supply is injected into storage during the summer months, the Sumas summer price is used to derive the fuel cost component for storage injection and for transportation on NWP.

The key drivers of the cost of WEI T-South baseload capacity as an option to meet shorter duration requirements are

- the 365 day T-South demand charges,
- resell recovery of T-South demand charges for the November to February winter period minus the Core requirements in an average year and,
- the commodity differential between the daily winter Station 2 supply and summer Sumas supply in storage used to meet winter Core demand requirements. The commodity differential impact for gas consumed by the Core is included in the T-South baseload capacity scenario in order to compare results to the Off System market area storage scenarios.

This section provides a breakdown of the cost components used in evaluating Off System Market area storage and WEI T-South baseload capacity to meet shorter duration requirements. Detailed schedules supporting the evaluation are provided as Attachments 1, 2 and 3. The Off System storage market valuation in the TGVI 2004 Resource Plan is included as a reference.

(i) Off-System Market Area Storage

JPS Storage Assumptions:

- Minimum demand charge based on NWP JPS Open Season[4] cost of service rates consisting of a capacity charge of US$0.00462/MMbtu/day and deliverability charge of US$0.05392/MMbtu/day. (*Line 15 in Attachment 1)*
- No escalation in storage demand charges.
- Injection fuel of 0.58% of the Sumas Summer Price. (*Line 31 in Attachment 1)*.

Mist Storage Assumptions (based on FERC Recourse Rate):

- Storage Reservation Charge US$4.9361/Dth per month.
- Storage Capacity Charge US$0.0722/Dth per month.
- No escalation in storage demand charges.
- Injection fuel of 2.0% of the Sumas Summer Price.

NWP Transportation Assumptions:

- 30% -50 % of NWP TF-1 Rate for 365 days*. Line 44-45 Attachment 1.*

4 Capacity and Deliverability charges Included in Attachment 4.

- TF-1 rate assumed to be US$0.39/Dth. *Line 36-37 in Attachment 1.*
- No escalation in the TF-1 Rate.
- Pipeline Fuel of 1.92% of the Sumas Summer Price each way. *Line 21-22 Attachment 1.*
- No pipeline commodity charge.

Commodity Supply Assumptions:

- Summer Sumas Price based on GLJA April 2006 quarterly forecast. GLJA AECO forecasts prices based on calendar years from which the Sumas summer price is derived (Lines 2-8 of Attachment 1)
- Based on the assessment of the forward curve provided in Attachment 5, the summer price is forecast to be 94% and winter is 108% of the storage year price.

The annual cost of delivering 1 GJ of a 15 day JPS storage contract to Huntingdon is estimated to cost $107 to $140 on a levelised basis based on a discount rate of approximately 6.2%. The table below provides a breakdown of the annual cost derivation of 1 GJ of a 15 day JPS contract delivered to Huntingdon based on the 30% of TF-1 Rate scenario. Attachment 1 provides a further detailed breakdown of each cost component.

Figure 3: Cost Breakdown of JPS Storage Cost plus Transport Redelivery

<u>Example 2 - 15 Day Service</u>		
Service (days)	**15**	
Storage Service	$45.00	**Line Item 16 Attachment 1**
Transportation to TGVI system		
NWP Demand Charges 30% TF-1 Rate	$42.71	**Line Item 46 Attachment 1**
1.92% pipeline fuel X Commodity X (injection & withdrawal)	$2.39	**Line Item 26 Attachment 1**
0.58% storage fuel X Commodity	$0.54	**Line Item 32 Attachment 1**
Total Transportation Service	$45.64	
Total $ US Annual Cost for 1 Mmbtu of deliverability to Huntingdon	**$91**	
Total $ Cdn Annual Cost for 1 GJ of deliverability to Huntingdon	**$107**	

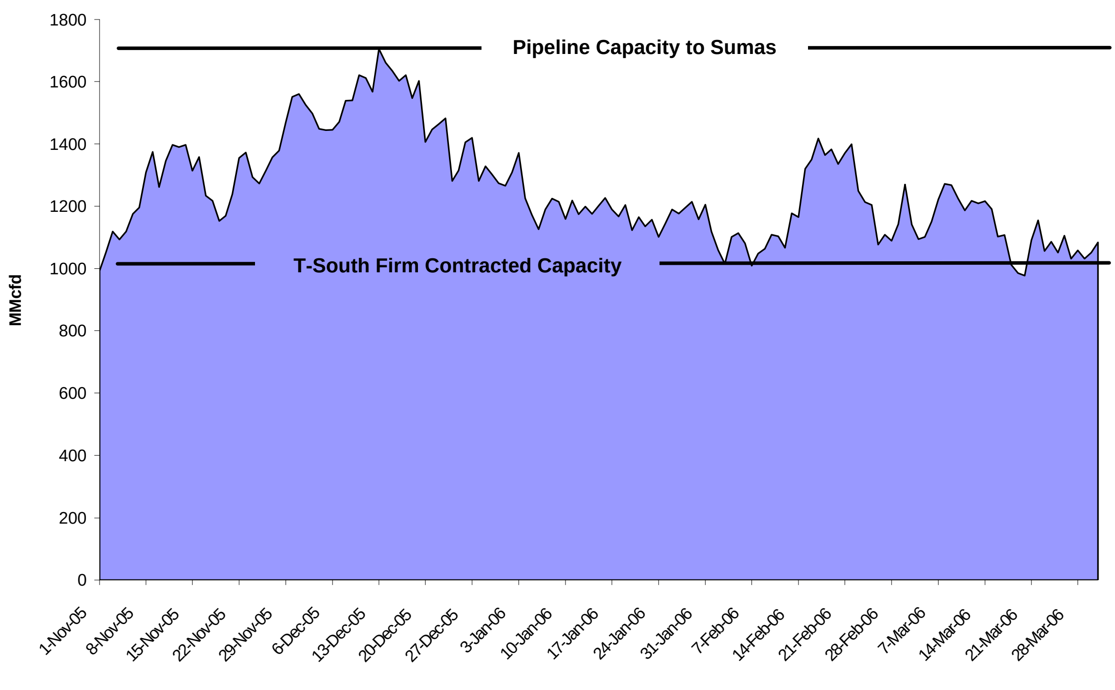
(ii) Westcoast T-South Capacity

An evaluation of contracting firm WEI T-South capacity as an alternative to off-system or on-system market area storage was performed to provide an upper limit to the value of storage resources beginning in 2010 when the Mt Hayes LNG Facility is proposed to be in-service. The evaluation includes an assessment of future WEI T-South demand charges and the mitigation value potential associated with recovered T-South demand charges from the T-South capacity that is held for 365 days but only required by Core customers for 5-10 days. Since Terasen Gas already holds T-South in its existing gas supply portfolios, the impact the re-contracting of incremental T-South capacity will have on their existing gas supply portfolios was also assessed.

There are currently significant levels of uncontracted capacity on WEI T-South. For the purposes of this evaluation it is assumed that by 2010, WEI T-South capacity will be 80% contracted and demand charge tolls will drop to a forecasted demand charge of $0.39/Mcf toll from 2006 levels of $0.42/Mcf. The 80% contracted scenario equates to 1200 MMcfd of firm contracted WEI capacity which matches the current average T-South flow during the winter months as illustrated in the graph below. If there is no capacity available at that time, and Westcoast expands to meet the incremental requirements, the overall tolls are expected to increase due to the incremental cost of the new facilites, however this eventuality has not been assessed.

The WEI T-South pipeline is a seasonal pipeline and based on 80% contracted level of T-South pipeline capacity, there is potential WEI shippers will be able to recover a portion of demand charges during peak winter months of November through to February. The amount of mitigation, however, will be dependent on the level of demand and the pricing dynamics at Station 2. The amount of T-South recovery of demand charges typically decreases as T-South pipeline capacity is re-contracted. The re-contracting of capacity typically reduces the overall differential between the Sumas price and Station 2 price since high levels of firm contracting encourages higher flows on T-South as WEI shippers are willing to flow supply to Huntingdon/Sumas market area as long as variable fuel charges are recovered. Since Terasen Gas purchase a majority of their gas supply at Station 2, the overall cost of the Terasen Gas' gas supply portfolios will increase. For this analysis it is assumed that the re-contracting benefit to Terasen Gas generated from the reduced tolls will be offset by the higher Station 2 prices increasing the cost of Terasen Gas' gas supply contracts.

Figure 4: Nov 05 – Mar 06 Westcoast T-South Flows



The T-South Schedule that illustrates the detailed year to year cost is included in Attachment 2 and 3. Attachment 2 assumes a portion of T-South recovery of WEI demand charges while Attachment 3 excludes T-South recovery of WEI demand charges. The year to year costs are based on the following assumptions:

T-South Transportation Assumptions:

- At 2010/11 The WEI toll Demand Charges will be Cdn$0.39/Mcf based on 80% re-contracted. *Line 12-13 in Attachment 2 and 3.*
- WEI toll Demand Charges escalate by 1.62% per year after 2010/11. This is based assessing WEI Cost of Service excluding deferral accounts and variable costs from 2005 to 2007. *Line 13 in Attachment 2 and 3.*
- 3% T-South pipeline fuel for winter months. *Line 17 in Attachment 2 and 3.*
- Full T-South demand charge recovery during the November - February months when not required by the Core market. *Line 22 in Attachment 2.*

Commodity Assumptions:

- The Westcoast scenario includes the impact of purchasing winter Station 2 daily supply versus the Sumas summer supply injected into storage to meet Core requirements. For the base case scenario the Core requires on average 750 MMcf of total supply.
- Daily Station 2 winter price is derived by taking 1.5 times the Station 2 Winter Price based on forecasted price volatility at Station 2 and is consistent with recent studies. *Line 15 in Attachment 2 and 3.*

The T-South annual cost of 1 GJ delivered to Huntingdon ranges from $132 including assuming T-South demand charge recovery during winter months to $180 excluding T-South demand charge recovery mitigation. The amount of mitigation will vary from year to year depending on market conditions therefore Terasen Gas believes that these figures represents the potential range of T-South annual costs in any one year while on average over the planning period would be closer to the middle or higher end of this range.

D. Summary

Terasen Gas has assessed the market value for the long term off system storage or pipeline resources available to meet future peaking load requirements as a proxy for determining the value of the storage benefits that can be provided by the proposed Mt Hayes LNG Storage facility.

The assessment demonstrates that current forecast of an Off System market area storage resource, including the NWP transportation redelivery charges, equates to an annual cost of $107 to $140 for 1 GJ of deliverability to the Huntingdon/Sumas market area. An alternative baseload WEI T-South resource used to satisfy shorter term duration requirements will incur an annual cost of 1 GJ delivered to Huntingdon between $132 assuming full recovery of T-South demand charges when the capacity is not required by the Terasen Gas to $180 excluding T-South demand charge recovery. While the T-South evaluation provides an upper range of the market cost, to determine the market value of the Mt Hayes Storage facility Terasen Gas has focused on the market valuation of Off System market Storage.

Appendix G - Attachment 1

Summary of Off System Market Area Storage Payments (2010 onwards)

Line Item																											
1	***From GLJA one year create summer/winter pricing (use forward curve relationship)....94% summer and 108% winter (forward market over forward 3 years)***												2% excalation as per GLJA														
2	***GLJA April 2006***																										
3	Sumas Winter Price US$/Mmbtu derived from AECO					$7.23	$6.95	$7.10	$7.24	$7.40	$7.59	$7.73	$7.89	$8.04	$8.20	$8.37	$8.53	$8.70	$8.88	$9.05	$9.23	$9.41	$9.60	$9.79	$9.99	$10.19	$10.39
4	Sumas Summer Price US$/Mmbtu derived from AECO					$6.01	$5.76	$5.89	$6.01	$6.14	$6.30	$6.42	$6.55	$6.68	$6.81	$6.95	$7.09	$7.23	$7.37	$7.52	$7.67	$7.83	$7.98	$8.14	$8.30	$8.47	$8.64
5	Storage Deliverability MMcfd					150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000	150,000
6	Storage Deliverability converted to GJs 1.07588 conversion					161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382	161,382
7	Storage Capacity GJ's based on 15 days Deliverability					2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730	2,420,730
8	NWP TF-1 Rate US$/Mmbtu					$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39	$0.39
9	**Storage Year**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**
10																											
11	**Storage Demand Charges**																										
12	NWP 15 day US$/Mmbtu	$0.00	$0.00	$0.00	$0.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
13	NWP 15 day US$/Mmbtu	$0	$0	$0	$0	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262	$7,262
14	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$45**																					
15																											
16	**Injection/Withdrawal Transportation Fuel**																										
17	Fuel %	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%	1.92%
18	Commodity	Commodity charge on NWP may be eliminated under new NWP Rate Case																									
19	Injection US				$0	$279	$268	$274	$279	$285	$293	$298	$304	$310	$317	$323	$329	$336	$343	$350	$357	$364	$371	$378	$386	$394	$402
20	Withdrawal US$	$0	$0	$0	$0	$93	$89	$91	$93	$95	$98	$99	$101	$103	$106	$108	$110	$112	$114	$117	$119	$121	$124	$126	$129	$131	$134
21																											
22	Assumptions																										
23	750,000 MMcfd usage any given year																										
24	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$2.39**																					
25																											
26																											
27	**Injection Storage Fuel**																										
28	Injection Fuel %	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
29	Injection fuel US$	$0	$0	$0	$0	$84	$81	$83	$84	$86	$88	$90	$92	$94	$96	$98	$100	$102	$104	$106	$108	$110	$112	$114	$117	$119	$121
30	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$0.54**																					
31																											
32																											
33	**Fixed NWP Transportation**																										
34	NWP-TF1 30% 15 day US$/Mmbtu/per # of day	$0.00	$0.00	$0.00	$0.00	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85	$2.85
35	NWP-TF1 50% 15 day US$/Mmbtu/per # of day	$0.00	$0.00	$0.00	$0.00	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75	$4.75
36																											
37	Assumptions																										
38	1. 30% TF-1 Rate 15 day = 0.39/Mmbtu * 30% * 365 days /15																										
39	2. 50% TF-1 Rate 15 day = 0.39/Mmbtu * 50% * 365 days /15																										
40																											
41																											
42	NWP-TF1 30% US$	$0	$0	$0	$0	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892	$6,892
43	NWP-TF1 50% US$	$0	$0	$0	$0	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486	$11,486
44	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon - 30% TF-1**					**$42.71**																					
45	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon - 50% TF-1**					**$71.17**																					
46																											
47																											
48	**Total Storage Demand and Transportation**																										
49	NWP TF-1 30% US$ Thousands	$0	$0	$0	$0	$14,611	$14,592	$14,601	$14,611	$14,621	$14,633	$14,642	$14,652	$14,662	$14,672	$14,682	$14,693	$14,704	$14,715	$14,726	$14,737	$14,749	$14,761	$14,773	$14,785	$14,798	$14,811
50	NWP TF-1 50% US$ Thousands	$0	$0	$0	$0	$19,205	$19,187	$19,196	$19,205	$19,215	$19,227	$19,237	$19,246	$19,256	$19,266	$19,277	$19,287	$19,298	$19,309	$19,320	$19,332	$19,343	$19,355	$19,367	$19,380	$19,392	$19,405
51																											
52	**Converted to Cdn$**																										
53																			**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**
54	Cdn$ Exchange Rate (GLJA)	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
55	**NWP 15 day with 30% TF-1 Cdn$ Thousands**	$0	$0	$0	$0	$17,189	$17,167	$17,178	$17,189	$17,201	$17,215	$17,226	$17,237	$17,249	$17,261	$17,273	$17,286	$17,298	$17,311	$17,324	$17,338	$17,352	$17,366	$17,380	$17,394	$17,409	$17,424
56	**NWP 15 day with 50% TF-1 Cdn$ Thousands**	$0	$0	$0	$0	$22,594	$22,573	$22,584	$22,594	$22,606	$22,620	$22,631	$22,643	$22,654	$22,666	$22,679	$22,691	$22,704	$22,717	$22,730	$22,743	$22,757	$22,771	$22,785	$22,800	$22,815	$22,830
57																											
58	**Storage Year**	**April 2006**																									
59	**Convert to Calendar year**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
60	**Cdn$ Millions**																										
61	**NWP TF-1 30%**					**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**	**$17**
62	**12 Year NPV @ 6.2% Cdn$Millions**					**$143**																					
63	**22 Year NPV @ 6.2% Cdn$Thousands**					**$205**																					
64	**12 year levelized @6.2% Cdn$Thousands**					**$17**																					
65	**22 year levelized @6.2% Cdn$Thousands**					**$17**																					
66	**12 year - Annual Cost Cdn$ for 1 GJ Delivered to Huntingdon**					**$107**																					
67	**22 year - Annual Cost Cdn$ for 1 GJ Delivered to Huntingdon**					**$107**																					
68																											
69	**NWP TF-1 50%**					**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**	**$23**
70	**12 Year NPV @ 6.2% Cdn$Thousands**					**$188**																					
71	**22 Year NPV @ 6.2% Cdn$Thousands**					**$269**																					
72	**12 year levelized @6.2% Cdn$Thousands**					**$23**																					
73	**22 year levelized @6.2% Cdn$Thousands**					**$23**																					
74	**12 year - Annual Cost Cdn$ for 1 GJ Delivered to Huntingdon**					**$140**																					
75	**22 year - Annual Cost Cdn$ for 1 GJ Delivered to Huntingdon**					**$140**																					

Appendix G - Attachment 2

Summary of T-South With Mitigation Payments (2010 onwards)

Line Item	*From GLJA one year create summer/winter pricing (use forward curve relationship)....94% summer and 108% winter (forward market over forward 3 years)*												2% excalation as per GLJA			
1	***April 2006 GLJA***															
2	GLJA AECO One Year Cdn$/GJ					$7.06	$6.63	$6.78	$6.92	$7.06	$7.25	$7.39	$7.54	$7.69	$7.85	$8.00
3	GLJA AECO Storage Year Cdn$/GJ					$6.95	$6.67	$6.81	$6.95	$7.11	$7.29	$7.43	$7.58	$7.73	$7.88	$8.04
4	Station 2 Storage Year Cdn$/GJ					$6.95	$6.67	$6.81	$6.95	$7.11	$7.29	$7.43	$7.58	$7.73	$7.88	$8.04
5	Station 2 Winter Price Cdn$/GJ 108% Storage Year					$7.51	$7.20	$7.36	$7.51	$7.68	$7.87	$8.02	$8.18	$8.35	$8.52	$8.69
6	Station 2 Summer Price Cdn$/GJ 94% Storage Year					$6.54	$6.27	$6.40	$6.54	$6.68	$6.85	$6.98	$7.12	$7.27	$7.41	$7.56
7	Sumas Winter Price US$/Mmbtu					$7.23	$6.95	$7.10	$7.24	$7.40	$7.59	$7.73	$7.89	$8.04	$8.20	$8.37
8	Sumas Summer Price US$/Mmbtu					$6.01	$5.76	$5.89	$6.01	$6.14	$6.30	$6.42	$6.55	$6.68	$6.81	$6.95
9	Exchange Rate					$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
10																
11	**Storage Contract Year**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
12	T-South Demand Charges Cdn$/Mcf					$0.39										
13	T-South Demand Charges Calendar Year Cdn$/GJ					$0.36	$0.37	$0.37	$0.38	$0.39	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43
14	T-South Demand Charges converted to Storage Year					$0.36	$0.37	$0.38	$0.38	$0.39	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43
15	Station 2 Winter Price					$7.51	$7.20	$7.36	$7.51	$7.68	$7.87	$8.02	$8.18	$8.35	$8.52	$8.69
16	Stn2 daily price 1.5 times winter					$11.27	$10.81	$11.04	$11.27	$11.52	$11.80	$12.04	$12.28	$12.52	$12.77	$13.03
17	Sumas Summer/Stn2 Winter daily Differential					$4.57	$4.38	$4.47	$4.57	$4.67	$4.78	$4.88	$4.98	$5.07	$5.18	$5.28
18	Stn2 Daily Winter T-South Fuel 3.3%					$0.37	$0.36	$0.36	$0.37	$0.38	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43
19																
20																
21	Fixed based on 150 mmcfd					$21,439	$21,786	$22,139	$22,498	$22,862	$23,233	$23,609	$23,992	$24,380	$24,775	$25,177
22	Variable based on 750 mmcf					$3,984	$3,821	$3,903	$3,984	$4,072	$4,174	$4,256	$4,342	$4,428	$4,517	$4,607
23	Mitigation					-$6,755	-$6,864	-$6,975	-$7,088	-$7,203	-$7,320	-$7,438	-$7,559	-$7,681	-$7,806	-$7,932
24	Total					$18,668	$18,743	$19,067	$19,394	$19,731	$20,087	$20,427	$20,774	$21,127	$21,486	$21,851
25	**Storage Contract Year**	**Apr 2006**														
26	**Convert to Calendar year**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
27																
28	Total					**$19**	**$19**	**$19**	**$19**	**$20**	**$20**	**$21**	**$21**	**$21**	**$22**	**$22**
29	**Discount**					**6.200%**										
30	**12 year PV Cdn$Millions**					**$167**										
31	**22 year PV Cdn$Millions**					**$252**										
32	**12 year levelized Cdn$Millions**					**$20**										
33	**22 year levelized Cdn$Millions**					**$21**										
34	**12 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$125**										
35	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$132**										

Line Item												
1	***April 2006 GLJA***											
2	GLJA AECO One Year Cdn$/GJ	$8.16	$8.33	$8.49	$8.66	$8.84	$9.01	$9.19	$9.38	$9.56	$9.75	$9.95
3	GLJA AECO Storage Year Cdn$/GJ	$8.20	$8.37	$8.53	$8.71	$8.88	$9.06	$9.24	$9.42	$9.61	$9.80	$10.00
4	Station 2 Storage Year Cdn$/GJ	$8.20	$8.37	$8.53	$8.71	$8.88	$9.06	$9.24	$9.42	$9.61	$9.80	$10.00
5	Station 2 Winter Price Cdn$/GJ 108% Storage Year	$8.86	$9.04	$9.22	$9.40	$9.59	$9.78	$9.98	$10.18	$10.38	$10.59	$10.80
6	Station 2 Summer Price Cdn$/GJ 94% Storage Year	$7.71	$7.87	$8.02	$8.18	$8.35	$8.51	$8.68	$8.86	$9.03	$9.22	$9.40
7	Sumas Winter Price US$/Mmbtu	$8.53	$8.70	$8.88	$9.05	$9.23	$9.41	$9.60	$9.79	$9.99	$10.19	$10.39
8	Sumas Summer Price US$/Mmbtu	$7.09	$7.23	$7.37	$7.52	$7.67	$7.83	$7.98	$8.14	$8.30	$8.47	$8.64
9	Exchange Rate	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
10												
11	**Storage Contract Year**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**
12	T-South Demand Charges Cdn$/Mcf											
13	T-South Demand Charges Calendar Year Cdn$/GJ	$0.43	$0.44	$0.45	$0.45	$0.46	$0.47	$0.48	$0.48	$0.49	$0.50	$0.51
14	T-South Demand Charges converted to Storage Year	$0.43	$0.44	$0.45	$0.46	$0.46	$0.47	$0.48	$0.49	$0.49	$0.50	$0.51
15	Station 2 Winter Price	$8.86	$9.04	$9.22	$9.40	$9.59	$9.78	$9.98	$10.18	$10.38	$10.59	$10.80
16	Stn2 daily price 1.5 times winter	$13.29	$13.56	$13.83	$14.10	$14.38	$14.67	$14.97	$15.27	$15.57	$15.88	$16.20
17	Sumas Summer/Stn2 Winter daily Differential	$5.39	$5.49	$5.60	$5.72	$5.83	$5.95	$6.06	$6.19	$6.31	$6.44	$6.56
18	Stn2 Daily Winter T-South Fuel 3.3%	$0.44	$0.45	$0.46	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53
19												
20												
21	Fixed based on 150 mmcfd	$25,584	$25,999	$26,420	$26,848	$27,283	$27,725	$28,174	$28,631	$29,094	$29,564	$30,037
22	Variable based on 750 mmcf	$4,699	$4,793	$4,889	$4,987	$5,087	$5,189	$5,292	$5,398	$5,506	$5,616	$5,729
23	Mitigation	-$8,061	-$8,191	-$8,324	-$8,459	-$8,596	-$8,735	-$8,877	-$9,021	-$9,167	-$9,315	-$9,464
24	Total	$22,223	$22,601	$22,985	$23,376	$23,774	$24,178	$24,590	$25,008	$25,434	$25,866	$26,302
25	**Storage Contract Year**											
26	**Convert to Calendar year**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
27												
28	Total	**$22**	**$23**	**$23**	**$23**	**$24**	**$24**	**$25**	**$25**	**$26**	**$26**	**$23**

Appendix G - Attachment 3

Summary of T-South Without Mitigation Payments (2010 onwards)

Line Item	*From GLJA one year create summer/winter pricing (use forward curve relationship)….94% summer and 108% winter (forward market over forward 3 years)*										2% excalation as per GLJA																
1	*April 2006 GLJA*																										
2	AECO One Year Cdn$/GJ					$7.06	$6.63	$6.78	$6.92	$7.06	$7.25	$7.39	$7.54	$7.69	$7.85	$8.00	$8.16	$8.33	$8.49	$8.66	$8.84	$9.01	$9.19	$9.38	$9.56	$9.75	$9.95
3	AECO Storage Year Cdn$/GJ					$6.95	$6.67	$6.81	$6.95	$7.11	$7.29	$7.43	$7.58	$7.73	$7.88	$8.04	$8.20	$8.37	$8.53	$8.71	$8.88	$9.06	$9.24	$9.42	$9.61	$9.80	$10.00
4	Station 2 Storage Year Cdn$/GJ					$6.95	$6.67	$6.81	$6.95	$7.11	$7.29	$7.43	$7.58	$7.73	$7.88	$8.04	$8.20	$8.37	$8.53	$8.71	$8.88	$9.06	$9.24	$9.42	$9.61	$9.80	$10.00
5	Station 2 Winter Price Cdn$/GJ 108% Storage Year					$7.51	$7.20	$7.36	$7.51	$7.68	$7.87	$8.02	$8.18	$8.35	$8.52	$8.69	$8.86	$9.04	$9.22	$9.40	$9.59	$9.78	$9.98	$10.18	$10.38	$10.59	$10.80
6	Station 2 Summer Price Cdn$/GJ 94% Storage Year					$6.54	$6.27	$6.40	$6.54	$6.68	$6.85	$6.98	$7.12	$7.27	$7.41	$7.56	$7.71	$7.87	$8.02	$8.18	$8.35	$8.51	$8.68	$8.86	$9.03	$9.22	$9.40
7	Sumas Winter Price US$/Mmbtu					$7.23	$6.95	$7.10	$7.24	$7.40	$7.59	$7.73	$7.89	$8.04	$8.20	$8.37	$8.53	$8.70	$8.88	$9.05	$9.23	$9.41	$9.60	$9.79	$9.99	$10.19	$10.39
8	Sumas Summer Price US$/Mmbtu					$6.01	$5.76	$5.89	$6.01	$6.14	$6.30	$6.42	$6.55	$6.68	$6.81	$6.95	$7.09	$7.23	$7.37	$7.52	$7.67	$7.83	$7.98	$8.14	$8.30	$8.47	$8.64
9	Exchange Rate					$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85	$0.85
10																											
11	**Storage Contract Year**	**2006-07**	**2007-08**	**2008-09**	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**2024-25**	**2025-26**	**2026-27**	**2027-28**	**2028-29**	**2029-30**	**2030-31**	**2031-32**
12	T-South Demand Charges Cdn$/Mcf					$0.39																					
13	T-South Demand Charges Calendar Year Cdn$/GJ					$0.36	$0.37	$0.37	$0.38	$0.39	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43	$0.43	$0.44	$0.45	$0.45	$0.46	$0.47	$0.48	$0.48	$0.49	$0.50	$0.51
14	T-South Demand Charges converted to Storage Year					$0.36	$0.37	$0.38	$0.38	$0.39	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43	$0.43	$0.44	$0.45	$0.46	$0.46	$0.47	$0.48	$0.49	$0.49	$0.50	$0.51
15	Station 2 Winter Price					$7.51	$7.20	$7.36	$7.51	$7.68	$7.87	$8.02	$8.18	$8.35	$8.52	$8.69	$8.86	$9.04	$9.22	$9.40	$9.59	$9.78	$9.98	$10.18	$10.38	$10.59	$10.80
16	Stn2 daily price 1.5 times winter					$11.27	$10.81	$11.04	$11.27	$11.52	$11.80	$12.04	$12.28	$12.52	$12.77	$13.03	$13.29	$13.56	$13.83	$14.10	$14.38	$14.67	$14.97	$15.27	$15.57	$15.88	$16.20
17	Sumas Summer/Stn2 Winter daily Differential					$4.57	$4.38	$4.47	$4.57	$4.67	$4.78	$4.88	$4.98	$5.07	$5.18	$5.28	$5.39	$5.49	$5.60	$5.72	$5.83	$5.95	$6.06	$6.19	$6.31	$6.44	$6.56
18	Stn2 Daily Winter T-South Fuel 3.3%					$0.37	$0.36	$0.36	$0.37	$0.38	$0.39	$0.40	$0.41	$0.41	$0.42	$0.43	$0.44	$0.45	$0.46	$0.47	$0.47	$0.48	$0.49	$0.50	$0.51	$0.52	$0.53
19																											
20																											
21	Fixed based on 150 mmcfd					$21,439	$21,786	$22,139	$22,498	$22,862	$23,233	$23,609	$23,992	$24,380	$24,775	$25,177	$25,584	$25,999	$26,420	$26,848	$27,283	$27,725	$28,174	$28,631	$29,094	$29,564	$30,037
22	Variable based on 750 mmcf					$3,984	$3,821	$3,903	$3,984	$4,072	$4,174	$4,256	$4,342	$4,428	$4,517	$4,607	$4,699	$4,793	$4,889	$4,987	$5,087	$5,189	$5,292	$5,398	$5,506	$5,616	$5,729
23	Mitigation																										
24	Total					$25,423	$25,608	$26,042	$26,482	$26,935	$27,407	$27,866	$28,333	$28,809	$29,292	$29,784	$30,284	$30,792	$31,309	$31,835	$32,370	$32,914	$33,466	$34,029	$34,600	$35,180	$35,766
25	**Storage Contract Year**	**Apr 2006**																									
26	**Convert to Calendar year**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
27																											
28	**Total**					**$25**	**$26**	**$26**	**$27**	**$27**	**$28**	**$28**	**$28**	**$29**	**$29**	**$30**	**$30**	**$31**	**$31**	**$32**	**$33**	**$33**	**$34**	**$34**	**$35**	**$35**	**$30**
29	**Discount**					**6.200%**																					
30	**12 year PV Cdn$Millions**					**$228**																					
31	**22 year PV Cdn$Millions**					**$343**																					
32	**12 year levelized Cdn$Millions**					**$27**																					
33	**22 year levelized Cdn$Millions**					**$29**																					
34	**12 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$170**																					
35	**22 year - Cdn$ for 1 GJ Delivered to Huntingdon**					**$180**																					

NORTHWEST PIPELINE CORPORATION
JACKSON PRAIRIE INCREMENTAL FIRM STORAGE SERVICE
OPEN SEASON TERM SHEET

Background:

Northwest Pipeline Corporation ("Northwest") by means of this Open Season Term Sheet is soliciting binding precedent agreements for incremental firm storage service based on the expansion of the Jackson Prairie Storage Project ("Jackson Prairie"). As a one-third owner of Jackson Prairie, Northwest has rights to one-third of: (i) the 300,000 Mcf/d of expansion withdrawal capacity that currently is anticipated to be implemented at Jackson Prairie in November 2008 ("Deliverability Expansion"), and (ii) the expansion storage working gas capacity of up to 6.3 Bcf that Jackson Prairie began developing on a phased basis in 2002 ("Capacity Expansion"). Based on current development rates, the Capacity Expansion is assumed to be completed by late 2010. Northwest plans to use the first approximately 0.93 Bcf of its 2.1 Bcf share of the Capacity Expansion for system balancing, and currently expects that such amount will be developed by about year-end 2006.

Offered Service:

Subject to receipt and acceptance of all necessary FERC approvals, Northwest proposes to provide a phased, incremental firm storage service as a new option under Rate Schedule SGS-2F. For such incremental service at Jackson Prairie, Northwest is offering its 100,000 Mcf/d (104,000 Dth/d) share of the planned Deliverability Expansion ("Deliverability") and the last approximately 1.17 Bcf (1.2 TBtu) of its share of the on-going phased Capacity Expansion ("Capacity").

The Deliverability component of this incremental service will be available the later of November 1, 2008 or completion of Jackson Prairie's planned Deliverability Expansion. After completion of the portion of the Capacity Expansion targeted for Northwest's system balancing, but no earlier than February 1, 2007, the Capacity will be allocated monthly to participating expansion customers (pro rata based on Deliverability contract demands) as the Capacity is developed.

Northwest currently assumes that the Capacity will be developed at a rate of approximately 20,000 Dth/month from early 2007 through mid 2008, and at a rate of approximately 30,000 Dth/month thereafter. The following table illustrates estimated year-end cumulative Capacity levels and Deliverability.

Year	Capacity (Dth)	Deliverability (Dth/d)
2007	240,000	0
2008	540,000	104,000
2009	900,000	104,000
2010	1,200,000	104,000

The firm Deliverability rights will decline according to the formula in Section 9.2 of Rate Schedule SGS-2F that applies to existing firm storage service. Prior to availability of the firm Deliverability, Northwest proposes that participating expansion shippers would be able to utilize best-efforts withdrawal rights under Rate Schedule SGS-2F in conjunction with their Capacity rights.

Estimated Incremental Rates:

The maximum incremental reservation rates approved by the FERC for the offered expansion service will apply to the phased incremental storage service rights acquired by a participating expansion shipper. Northwest has derived illustrative phased incremental rates based upon recent forecasts of future gas prices for the cushion gas required for the phased Capacity and preliminary cost estimates for the new facilities necessary to implement the Deliverability. The following table summarizes the illustrative daily rates that would apply for each year during the Capacity development, and thereafter.

Year	Capacity Rate (per Dth of Capacity)	Deliverability Rate (per Dth of demand)
2007	$0.00272	n/a
2008	$0.00256	n/a (until Deliverability available)
2009	$0.00231	$0.08420
2010	$0.00214	$0.08420
2011	$0.00462	$0.05392

The illustrative rates that would apply after completion of the Capacity Expansion reflect incremental cost recovery equally split between the Deliverability contract demand and the Capacity demand consistent with traditional FERC storage rate design methodology. In its FERC application, Northwest will propose phased rates based upon updated cost estimates, consistent with the phased Capacity development, for the offered incremental storage service.

In addition, Northwest proposes to establish a best-efforts withdrawal rate for the participating customers that is equivalent to the Rate Schedule SGS-2F demand charge for non-incremental service (currently, $0.01689 per Dth), which will apply to all incremental storage volumes withdrawn during the period between commencement of the phased Capacity availability and the in-service date of the Deliverability Expansion.

Further, Northwest proposes that the incremental storage service will be subject to the same fuel use reimbursement factor as the existing SGS-2F service, which currently is 0.16% of storage injections.

Contract Term:

Bids must be for a primary service term commencing with the first availability of the phased Capacity for this service (projected to be about February 1, 2007) and extending through at least October 31, 2028 (approximately twenty years from the in-service date of the Deliverability Expansion).

Awarding Capacity:

If the total requests for the Deliverability exceed 104,000 Dth/d, the Deliverability and associated rights will be awarded to the shippers offering the longest contract terms. In case of a tie, such capacity rights will be allocated pro rata to the tied shippers based on requested Deliverability contract demands. Based upon the awarded Deliverability contract demands, monthly pro rata allocations of the Capacity will be made to the incremental shippers as such Capacity is developed.

For example, a Shipper awarded 52,000 Dth/d of Deliverability contract demand also will ultimately be awarded a total of approximately 0.6 TBtu of the phased Capacity, with such Capacity being developed and allocated in monthly increments until completion of the Capacity Expansion.

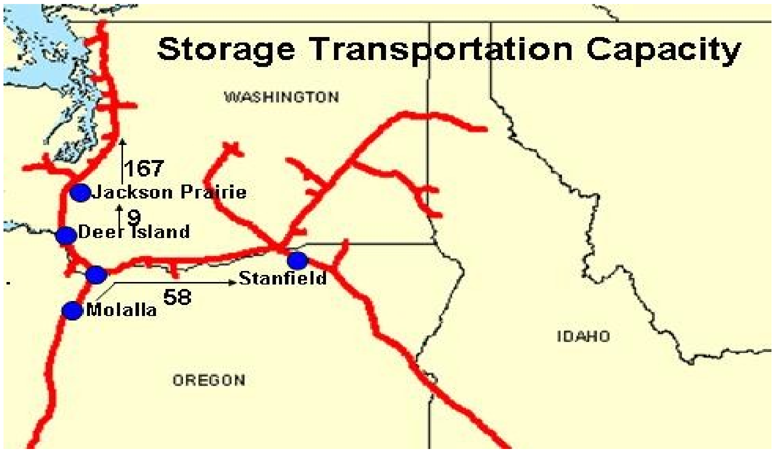
Open Season:

Shippers having an interest in obtaining a share of the offered incremental firm storage service must satisfy Northwest's creditworthiness requirements and complete, sign, and return the attached binding Precedent Agreement form via mail or facsimile no later than 5:00 p.m. MCT on Tuesday, February 28, 2006, to Mike Rasmuson or Jeff Leishman at:

Williams Northwest Pipeline Corporation
Marketing Services
295 Chipeta Way
Salt Lake City, Utah 84108
Fax: (801) 584-6950

Transportation Capacity:

As shown on its "Available Capacity" postings, Northwest currently is marketing Rate Schedule TF-1 transportation capacity that could be used in conjunction with storage at Jackson Prairie or Northwest Natural Gas Company's Mist storage. The following map illustrates the storage related transportation paths that will be available after completion of the Capacity Replacement Project in Docket No. CP05-32 (anticipated to be about November 1, 2006).



For new northbound TF-1 transportation from storage, Northwest could provide a total of approximately 178,000 Dth/d (9,000 from Deer Island plus 169,000 from Jackson Prairie), or a total of approximately 187,000 Dth/d from Jackson Prairie only. For eastbound transportation through the Columbia Gorge from Mist storage (Molalla receipt point), Northwest could provide approximately 58,000 Dth/d, with some relatively minor capital expenditures.

Parties interested in negotiating long-term transportation arrangements to match up with storage capacity or that have questions regarding the Storage Open Season should contact Mike Rasmuson at (801) 584-7278 or Jeff Leishman at (801) 584-6682.

APPENDIX G - ATTACHMENT 5

Forward Prices on Apr.6/2006

(Indications only)

	Spot	6-month	1-Year	2-Year	3-Year	4-Year
Ex. Rate	1.1530	1.1469	1.1418	1.1331	1.1259	1.1170

	Nymex $US/MMBtu settles	Aeco basis $US/MMBtu	Aeco Fixed $US/MMBtu	Sumas basis $US/MMBtu	Sumas Fixed $US/MMBtu	St2-Aeco bas $Cdn/GJ	St2-Aeco ba $US/MMBtu	St2 Fixed $US/MMBtu	St#2 basis $US/MMBtu	St2 Fixed $Cdn/GJ	Aeco Fixed $Cdn/GJ	Sumas Fixed $Cdn/GJ	Nymex $Cdn/GJ	Exchange Rate
May-06	$ 6.972	$ (1.180)	$ 5.79	$ (1.250)	$ 5.72	$ (0.370)	$ (0.34)	$ 5.45	$ (1.52)	$ 5.96	$ 6.33	$ 6.25	$ 7.62	1.1530
Jun-06	$ 7.177	$ (1.330)	$ 5.85	$ (1.380)	$ 5.80	$ (0.370)	$ (0.34)	$ 5.51	$ (1.67)	$ 6.02	$ 6.39	$ 6.34	$ 7.84	1.1530
Jul-06	$ 7.387	$ (1.375)	$ 6.01	$ (1.460)	$ 5.93	$ (0.370)	$ (0.34)	$ 5.67	$ (1.72)	$ 6.20	$ 6.57	$ 6.48	$ 8.07	1.1530
Aug-06	$ 7.562	$ (1.375)	$ 6.19	$ (1.400)	$ 6.16	$ (0.370)	$ (0.34)	$ 5.85	$ (1.72)	$ 6.39	$ 6.76	$ 6.73	$ 8.26	1.1530
Sep-06	$ 7.709	$ (1.450)	$ 6.26	$ (1.430)	$ 6.28	$ (0.370)	$ (0.34)	$ 5.92	$ (1.79)	$ 6.43	$ 6.80	$ 6.83	$ 8.38	1.1469
Oct-06	$ 7.904	$ (1.480)	$ 6.42	$ (1.370)	$ 6.53	$ (0.370)	$ (0.34)	$ 6.08	$ (1.82)	$ 6.61	$ 6.98	$ 7.10	$ 8.59	1.1469
Nov-06	$ 9.069	$ (1.700)	$ 7.37	$ (1.290)	$ 7.78	$ (0.220)	$ (0.20)	$ 7.17	$ (1.90)	$ 7.79	$ 8.01	$ 8.46	$ 9.86	1.1469
Dec-06	$ 10.129	$ (1.700)	$ 8.43	$ (1.290)	$ 8.84	$ (0.220)	$ (0.20)	$ 8.23	$ (1.90)	$ 8.94	$ 9.16	$ 9.61	$ 11.01	1.1469
Jan-07	$ 10.889	$ (1.700)	$ 9.19	$ (1.290)	$ 9.60	$ (0.220)	$ (0.20)	$ 8.99	$ (1.90)	$ 9.77	$ 9.99	$ 10.43	$ 11.84	1.1469
Feb-07	$ 10.889	$ (1.700)	$ 9.19	$ (1.290)	$ 9.60	$ (0.220)	$ (0.20)	$ 8.99	$ (1.90)	$ 9.77	$ 9.99	$ 10.43	$ 11.84	1.1469
Mar-07	$ 10.719	$ (1.700)	$ 9.02	$ (1.290)	$ 9.43	$ (0.220)	$ (0.20)	$ 8.82	$ (1.90)	$ 9.54	$ 9.76	$ 10.20	$ 11.60	1.1418
Apr-07	$ 9.064	$ (1.240)	$ 7.82	$ (1.240)	$ 7.82	$ (0.280)	$ (0.26)	$ 7.57	$ (1.50)	$ 8.19	$ 8.47	$ 8.47	$ 9.81	1.1418
May-07	$ 8.884	$ (1.240)	$ 7.64	$ (1.240)	$ 7.64	$ (0.280)	$ (0.26)	$ 7.39	$ (1.50)	$ 7.99	$ 8.27	$ 8.27	$ 9.61	1.1418
Jun-07	$ 8.939	$ (1.240)	$ 7.70	$ (1.240)	$ 7.70	$ (0.280)	$ (0.26)	$ 7.44	$ (1.50)	$ 8.05	$ 8.33	$ 8.33	$ 9.67	1.1418
Jul-07	$ 9.004	$ (1.240)	$ 7.76	$ (1.240)	$ 7.76	$ (0.280)	$ (0.26)	$ 7.51	$ (1.50)	$ 8.12	$ 8.40	$ 8.40	$ 9.74	1.1418
Aug-07	$ 9.054	$ (1.240)	$ 7.81	$ (1.240)	$ 7.81	$ (0.280)	$ (0.26)	$ 7.56	$ (1.50)	$ 8.18	$ 8.46	$ 8.46	$ 9.80	1.1418
Sep-07	$ 9.079	$ (1.240)	$ 7.84	$ (1.240)	$ 7.84	$ (0.280)	$ (0.26)	$ 7.58	$ (1.50)	$ 8.20	$ 8.48	$ 8.48	$ 9.83	1.1418
Oct-07	$ 9.154	$ (1.240)	$ 7.91	$ (1.240)	$ 7.91	$ (0.280)	$ (0.26)	$ 7.66	$ (1.50)	$ 8.28	$ 8.56	$ 8.56	$ 9.91	1.1418
Nov-07	$ 9.759	$ (1.510)	$ 8.25	$ (1.150)	$ 8.61	$ (0.230)	$ (0.21)	$ 8.04	$ (1.72)	$ 8.70	$ 8.93	$ 9.32	$ 10.56	1.1418
Dec-07	$ 10.334	$ (1.510)	$ 8.82	$ (1.150)	$ 9.18	$ (0.230)	$ (0.21)	$ 8.61	$ (1.72)	$ 9.32	$ 9.55	$ 9.94	$ 11.18	1.1418
Jan-08	$ 10.754	$ (1.510)	$ 9.24	$ (1.150)	$ 9.60	$ (0.230)	$ (0.21)	$ 9.03	$ (1.72)	$ 9.77	$ 10.00	$ 10.39	$ 11.64	1.1418
Feb-08	$ 10.749	$ (1.510)	$ 9.24	$ (1.150)	$ 9.60	$ (0.230)	$ (0.21)	$ 9.02	$ (1.72)	$ 9.69	$ 9.92	$ 10.31	$ 11.54	1.1331
Mar-08	$ 10.514	$ (1.510)	$ 9.00	$ (1.150)	$ 9.36	$ (0.230)	$ (0.21)	$ 8.79	$ (1.72)	$ 9.44	$ 9.67	$ 10.06	$ 11.29	1.1331
Apr-08	$ 8.479	$ (0.980)	$ 7.50	$ (0.940)	$ 7.54	$ (0.280)	$ (0.26)	$ 7.24	$ (1.24)	$ 7.77	$ 8.05	$ 8.10	$ 9.11	1.1331
May-08	$ 8.284	$ (0.980)	$ 7.30	$ (0.940)	$ 7.34	$ (0.280)	$ (0.26)	$ 7.04	$ (1.24)	$ 7.56	$ 7.84	$ 7.89	$ 8.90	1.1331
Jun-08	$ 8.344	$ (0.980)	$ 7.36	$ (0.940)	$ 7.40	$ (0.280)	$ (0.26)	$ 7.10	$ (1.24)	$ 7.63	$ 7.91	$ 7.95	$ 8.96	1.1331
Jul-08	$ 8.394	$ (0.980)	$ 7.41	$ (0.940)	$ 7.45	$ (0.280)	$ (0.26)	$ 7.15	$ (1.24)	$ 7.68	$ 7.96	$ 8.01	$ 9.01	1.1331
Aug-08	$ 8.439	$ (0.980)	$ 7.46	$ (0.940)	$ 7.50	$ (0.280)	$ (0.26)	$ 7.20	$ (1.24)	$ 7.73	$ 8.01	$ 8.05	$ 9.06	1.1331
Sep-08	$ 8.469	$ (0.980)	$ 7.49	$ (0.940)	$ 7.53	$ (0.280)	$ (0.26)	$ 7.23	$ (1.24)	$ 7.76	$ 8.04	$ 8.09	$ 9.10	1.1331
Oct-08	$ 8.534	$ (0.980)	$ 7.55	$ (0.940)	$ 7.59	$ (0.280)	$ (0.26)	$ 7.29	$ (1.24)	$ 7.83	$ 8.11	$ 8.16	$ 9.17	1.1331
Nov-08	$ 9.109	$ (1.160)	$ 7.95	$ (0.790)	$ 8.32	$ (0.230)	$ (0.21)	$ 7.73	$ (1.37)	$ 8.31	$ 8.54	$ 8.93	$ 9.78	1.1331
Dec-08	$ 9.654	$ (1.160)	$ 8.49	$ (0.790)	$ 8.86	$ (0.230)	$ (0.22)	$ 8.28	$ (1.38)	$ 8.89	$ 9.12	$ 9.52	$ 10.37	1.1331
Jan-09	$ 10.074	$ (1.160)	$ 8.91	$ (0.790)	$ 9.28	$ (0.230)	$ (0.22)	$ 8.70	$ (1.38)	$ 9.34	$ 9.57	$ 9.97	$ 10.82	1.1331
Feb-09	$ 10.049	$ (1.160)	$ 8.89	$ (0.790)	$ 9.26	$ (0.230)	$ (0.22)	$ 8.67	$ (1.38)	$ 9.26	$ 9.49	$ 9.88	$ 10.72	1.1259
Mar-09	$ 9.809	$ (1.160)	$ 8.65	$ (0.790)	$ 9.02	$ (0.230)	$ (0.22)	$ 8.43	$ (1.38)	$ 9.00	$ 9.23	$ 9.62	$ 10.47	1.1259
Apr-09	$ 7.754	$ (0.710)	$ 7.04	$ (0.680)	$ 7.07	$ (0.280)	$ (0.26)	$ 6.78	$ (0.97)	$ 7.24	$ 7.52	$ 7.55	$ 8.27	1.1259
May-09	$ 7.559	$ (0.710)	$ 6.85	$ (0.680)	$ 6.88	$ (0.280)	$ (0.26)	$ 6.59	$ (0.97)	$ 7.03	$ 7.31	$ 7.34	$ 8.07	1.1259
Jun-09	$ 7.616	$ (0.710)	$ 6.91	$ (0.680)	$ 6.94	$ (0.280)	$ (0.26)	$ 6.64	$ (0.97)	$ 7.09	$ 7.37	$ 7.40	$ 8.13	1.1259
Jul-09	$ 7.676	$ (0.710)	$ 6.97	$ (0.680)	$ 7.00	$ (0.280)	$ (0.26)	$ 6.70	$ (0.97)	$ 7.15	$ 7.43	$ 7.47	$ 8.19	1.1259
Aug-09	$ 7.736	$ (0.710)	$ 7.03	$ (0.680)	$ 7.06	$ (0.280)	$ (0.26)	$ 6.76	$ (0.97)	$ 7.22	$ 7.50	$ 7.53	$ 8.26	1.1259
Sep-09	$ 7.766	$ (0.710)	$ 7.06	$ (0.680)	$ 7.09	$ (0.280)	$ (0.26)	$ 6.79	$ (0.97)	$ 7.25	$ 7.53	$ 7.56	$ 8.29	1.1259
Oct-09	$ 7.834	$ (0.710)	$ 7.12	$ (0.680)	$ 7.15	$ (0.280)	$ (0.26)	$ 6.86	$ (0.97)	$ 7.32	$ 7.60	$ 7.63	$ 8.36	1.1259
Nov-09	$ 8.414	$ (0.945)	$ 7.47	$ (0.595)	$ 7.82	$ (0.230)	$ (0.22)	$ 7.25	$ (1.16)	$ 7.74	$ 7.97	$ 8.34	$ 8.98	1.1259
Dec-09	$ 8.974	$ (0.945)	$ 8.03	$ (0.595)	$ 8.38	$ (0.230)	$ (0.22)	$ 7.81	$ (1.16)	$ 8.34	$ 8.57	$ 8.94	$ 9.58	1.1259
Jan-10	$ 9.414	$ (0.945)	$ 8.47	$ (0.595)	$ 8.82	$ (0.230)	$ (0.22)	$ 8.25	$ (1.16)	$ 8.81	$ 9.04	$ 9.41	$ 10.05	1.1259
Feb-10	$ 9.404	$ (0.945)	$ 8.46	$ (0.595)	$ 8.81	$ (0.230)	$ (0.22)	$ 8.24	$ (1.16)	$ 8.73	$ 8.96	$ 9.33	$ 9.96	1.1170
Mar-10	$ 9.174	$ (0.945)	$ 8.23	$ (0.595)	$ 8.58	$ (0.230)	$ (0.22)	$ 8.01	$ (1.16)	$ 8.48	$ 8.71	$ 9.08	$ 9.71	1.1170
Apr-10	$ 7.154	$ (0.615)	$ 6.54	$ (0.565)	$ 6.59	$ (0.280)	$ (0.26)	$ 6.27	$ (0.88)	$ 6.64	$ 6.92	$ 6.98	$ 7.57	1.1170
May-10	$ 6.959	$ (0.615)	$ 6.34	$ (0.565)	$ 6.39	$ (0.280)	$ (0.26)	$ 6.08	$ (0.88)	$ 6.44	$ 6.72	$ 6.77	$ 7.37	1.1170
Jun-10	$ 7.019	$ (0.615)	$ 6.40	$ (0.565)	$ 6.45	$ (0.280)	$ (0.26)	$ 6.14	$ (0.88)	$ 6.50	$ 6.78	$ 6.83	$ 7.43	1.1170
Jul-10	$ 7.079	$ (0.615)	$ 6.46	$ (0.565)	$ 6.51	$ (0.280)	$ (0.26)	$ 6.20	$ (0.88)	$ 6.56	$ 6.84	$ 6.90	$ 7.49	1.1170
Aug-10	$ 7.137	$ (0.615)	$ 6.52	$ (0.565)	$ 6.57	$ (0.280)	$ (0.26)	$ 6.26	$ (0.88)	$ 6.62	$ 6.90	$ 6.96	$ 7.56	1.1170
Sep-10	$ 7.152	$ (0.615)	$ 6.54	$ (0.565)	$ 6.59	$ (0.280)	$ (0.26)	$ 6.27	$ (0.88)	$ 6.64	$ 6.92	$ 6.97	$ 7.57	1.1170
Oct-10	$ 7.224	$ (0.615)	$ 6.61	$ (0.565)	$ 6.66	$ (0.280)	$ (0.26)	$ 6.34	$ (0.88)	$ 6.72	$ 7.00	$ 7.05	$ 7.65	1.1170

(prices do not include physical premiums and are indications only)

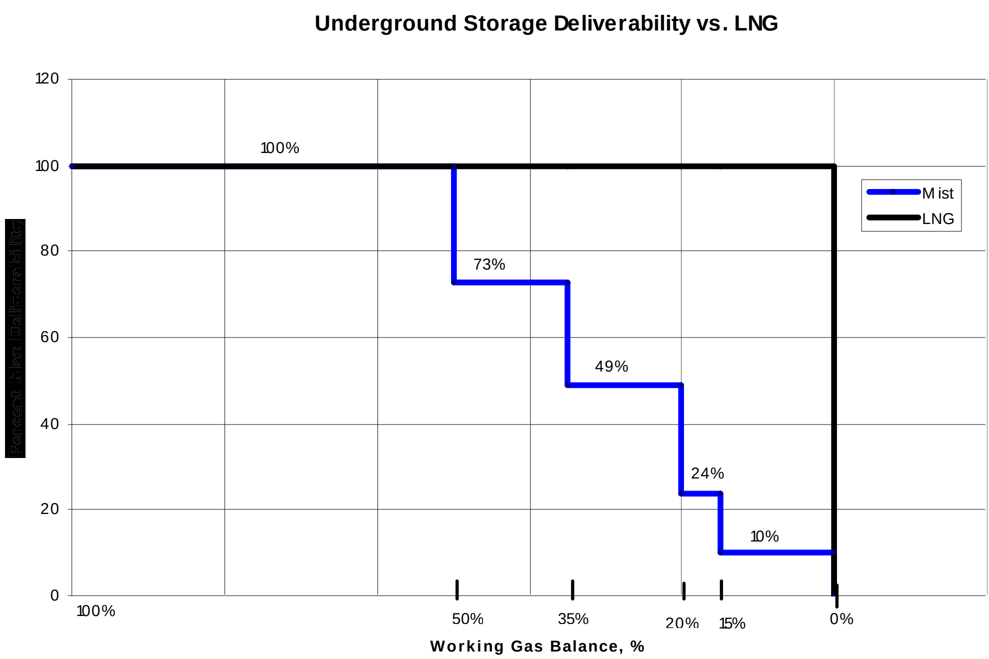
Strips	Nymex $US/MMBtu	Aeco $US/MMBtu	Sumas $US/MMBtu	St#2 $US/MMBtu	St#2 $Cdn/GJ	Aeco $Cdn/GJ	Sumas $Cdn/GJ	Nymex $Cdn/GJ
May06-Oct06	$ 7.45	$ 6.09	$ 6.07	$ 5.75	$ 6.27	$ 6.64	$ 6.62	$ 8.13
Nov06-Mar07	$ 10.34	$ 8.64	$ 9.05	$ 8.44	$ 9.16	$ 9.38	$ 9.83	$ 11.23
Apr07-Oct07	$ 9.03	$ 7.79	$ 7.79	$ 7.53	$ 8.15	$ 8.43	$ 8.43	$ 9.77
Nov07-Mar08	$ 10.42	$ 8.91	$ 9.27	$ 8.70	$ 9.38	$ 9.61	$ 10.00	$ 11.24
Apr08-Oct08	$ 8.42	$ 7.44	$ 7.48	$ 7.18	$ 7.71	$ 7.99	$ 8.03	$ 9.04
Nov08-Mar09	$ 9.74	$ 8.58	$ 8.95	$ 8.36	$ 8.96	$ 9.19	$ 9.59	$ 10.43
Apr09-Oct09	$ 7.71	$ 7.00	$ 7.03	$ 6.73	$ 7.19	$ 7.47	$ 7.50	$ 8.22
Nov09-Mar10	$ 9.08	$ 8.13	$ 8.48	$ 7.91	$ 8.42	$ 8.65	$ 9.02	$ 9.65
Apr10-Oct10	$ 7.10	$ 6.49	$ 6.54	$ 6.22	$ 6.59	$ 6.87	$ 6.92	$ 7.52

		Summer	Winter
Apr07-Mar 08	$ 8.92	94%	108%
Apr08-Mar 09	$ 8.49	94%	108%
Apr09-Mar 10	$ 7.96	94%	109%

Appendix G - ATTACHMENT 6

A. Decline Rates

Underground storage requires that the gas be injected or withdrawn from the storage reservoir. Because this involves pressurization of the reservoir, the ability to withdraw gas is tied to the volume of gas in the reservoir and as the volume of gas declines, pressure and deliverability generally decline as well. In order to account for the decline rates of underground storage deliverability, a slightly longer duration of underground storage capacity would be required to get a service similar to an alternative resource such as pipeline capacity or LNG storage that has constant deliverability rates. With underground storage, because of the decline in withdrawal capability as the reservoir is used, a larger capacity is required to maintain required deliverability. The following graph illustrates the difference between an alternative resource that has no decline and a typical underground storage facility for deliverability assuming maximum deliverability requirements for consecutives days.



The differences outlined above mean that differences in deliverability must be accounted for in comparing the value to the services. Hence, to satisfy the 6 to 10 day requirement TGI and TGVI would evaluate a 15 day Off System market area storage.

APPENDIX H

5-Year Capital Plan and Statement of Facilities Extensions

APPENDIX H

5 YEAR CAPITAL PLAN AND STATEMENT OF FACILITIES EXTENSIONS

1.1 Preamble

The Commission, in its Letter No. L-30-05, acknowledged receipt of TGI's 2004 Resource Plan. In its letter, it stated that TGI's 2006 Resource Plan Update should include a Statement of facilities extensions. In response to this recommendation, TGI is appending its 5 Year Regular Capital Plan and 5 Year Major Capital Plan to its 2006 Resource Plan. In aggregate these two plans constitute the Company's 5 Year Capital Plans.

TGI has segmented its 5 Year Capital Plans as follows:

Regular Capital Plan

- Customer Driven Capital
- Non-Customer Driven Capital

Major Capital Plan

- Capital Projects that do not require a CPCN
- Capital Projects that require a CPCN

Regular Capital includes forecast Capital Expenditures that are under $1 million. These expenditures have been categorized into either customer driven capital or non-customer driven capital. This category excludes Capitalized Overheads, Contributions in aid of Construction ("CIAC") and Allowance for funds used during construction ("AFUDC").

Major Capital projects are defined as those discrete projects that are in excess of $1 million (excluding AFUDC). These forecast expenditures have been categorized into projects which do not require a CPCN and those which do require a CPCN to proceed. Typically, major capital projects for TGI in excess of $5 million have required a CPCN.

TGI's 5 Year Capital Plans for the period 2006 to 2010 are presented to provide additional background and context for the Resource Plan. TGI is of the view that these Capital Plans are not included for the purposes of approval by the BCUC as part of its review of the TGI Resource Plan. TGI believes that the regulatory review process for Resource Plans is not the appropriate forum for review of its Capital Plans. TGI is of the view that its 2006 Annual Review Application included detailed capital expenditures that were reviewed and approved by Commission on December 9, 2005 by Order No. G-132-05. Consistent with past practice, TGI continues to believe that the appropriate forum for review of its Capital Expenditures is its Performance Based Regulation ("PBR") and Annual Review proceedings.

As TGI's 5 Year Regular Capital Plan and Major Capital Plans include all planned capital expenditures, TGI believes that this information satisfies the requirements of the statement of facilities extensions as set out in Section 45(6) of the *Utilities Commission Act*.

TGI has endeavoured to provide a comprehensive 5 Year Capital Plan as part of its submission. However, the projects and figures contained herein are subject to change and may be revised to reflect additional information as part of the Company's Annual Review filing, which is anticipated in October, 2006.

1.2 5 Year Regular Capital Plan

The following table identifies the cost projections for regular capital expenditure in 2006-2010. For the purposes of the 5 Year Capital Forecast, Regular Capital includes the following types of capital expenditures:

Capital Additions "Customer Driven" Capital

- Mains
- Services
- Meters for New Customer Additions

Other Regular Capital

- Meter Replacements
- Transmission Plant
- Distribution Plant
- IT Capital
- Non-IT Capital

Table 1 identifies the cost projections for regular capital expenditure in 2006-2010.

Table 1 - Forecast of Regular Capital Expenditures (2006 – 2010)

	2006 YEF	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast
Customer Driven Capital					
Mains	6,806	6,693	7,249	7,854	8,368
Services	13,925	13,692	14,830	16,068	17,120
Meters (Customer Additions)	4,027	3,886	4,209	4,560	4,859
	24,757	**24,271**	**26,288**	**28,482**	**30,347**
Other Regular Capital					
Meters - Replacement	12,098	12,327	19,064	19,976	20,933
Transmission Plant	6,363	5,932	5,145	4,841	5,063
Distribution Plant	16,921	8,999	9,449	7,793	7,949
IT	10,500	13,500	11,400	11,700	11,900
Non - IT	11,692	11,946	12,222	12,466	12,716
	45,475	**40,377**	**38,216**	**36,800**	**37,627**
Total Regular Capital	**70,233**	**64,647**	**64,504**	**65,282**	**67,974**

Note: All estimates exclude AFUDC

TGI is aware that the totals provided herein for 2006 and 2007 are different than those presented during the 2005 Annual Review proceeding. For the benefit of readers, below is a brief explanation of the primary driver(s) of the variance for each type of capital expenditure.

Customer Additions Capital forecast expenditures have been revised to reflect changes in the historical unit costs and revisions to the year end customer additions forecast.

For Systems Integrity and Reliability Capital, IT Projects and Non-IT Projects, TGI are not forecasting a significant change from the capital plan submitted in the TGI 2005 Annual Review.

Over the next three months, TGI will be revising its 5 Year Capital Forecast in advance of the TGI 2006 Annual Review submission. This exercise is consistent with its internal planning cycle and is anticipated to result in further refinements to the 5 Year Capital Plan.

2. 5 Year Major Capital Plan

2.1 Major Capital Projects that do not require a CPCN

Table 2 identifies the cost projections for major capital projects not subject to CPCN applications for the period 2006-2010.

Table 2 – Forecast of Major Capital Projects not requiring a CPCN (2006 – 2010)

	2006 YEF	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast
Transmission Plant					
Prince George #2 Lateral Replacement	625	1,075	-	-	-
LNG Coldbox Upgrade	100	750	2,250	-	-
Golden Ears Bridge Project (Transmission Portion	-	600	700	-	-
Distribution Plant					
Clearbrook, Riverside Road, Abbotsford	-		1,192	-	-
72nd St to 36th Avenue, Delta	10	1,790	-	-	-
Goudy Road and 36th Avenue, Delta	10	1,201	-	-	-
34B Avenue to 57th Street, Delta	-	-	1,038	-	-
Secondary Containment	2,484	-	-	-	-
Golden Ears Bridge Project (Distribution Portion)	-	300	300	-	-
IT					
Order Fulfillment Enhancements	1,010	-	-	-	-
Mobile UP Replacement	1,863	-	-	-	-
AM/FM GIS for Transmission	547	-	-	-	-
Desktop & Laptop Refresh	1,070	-	-	-	1,767
Café (Customer Attraction Front End)	360				
SAP Core Application Upgrade	-	2,040	-	-	-
IT Infrastucture Network Evergreening	-	1,183	-	-	-
SCADA System Upgrade	-	1,561	-	-	-
Non - IT					
No Major Projects Identified	-	-	-	-	
	8,079	**10,500**	**5,480**	**-**	**1,767**

2.1.1 Transmission Plant - Prince George #2 Lateral Replacement

Construction on this project is planned to commence in 2006 and be completed in 2007. It consists of replacing a 4.0 km section of the existing 168.3 mm O.D. pipeline with 219.1 mm O.D. pipeline to support firm load growth and address operating concerns such as shallow pipe, proximity to road ditches and lack of a dedicated right of way. The estimated cost of this project is $1.7 million (excluding AFUDC) and is expected to be in service in 2007. A discussion of this project can be found in Section B-1, Page 5 of the TGI 2005 Annual Review Application.

2.1.2 Transmission Plant - LNG Coldbox Upgrade

The LNG Coldbox is part of the plant component at TGI's Tilbury LNG Facility. The LNG Coldbox is the plant component that reduces gas temperature to -260 F, thereby converting natural gas into LNG. The existing plant was built in 1970-1971.

The LNG Coldbox consists of a number of very complex shell and tube, spiral-wound heat exchanges. A number of the tubes in one heat exchanger failed in early 2005. Repairs were successful but very challenging. A materials engineering investigation was completed as to cause and likelihood of additional failures in future. This report stated that further tube failures will occur.

As a non-operational Coldbox will result in TGI not being able to produce LNG, TGI is currently planning to spend approximately $3.1 Million (excluding AFUDC) for replacement of this plant. Preliminary work is expected to commence in 2006 and be completed by 2008.

2.1.3 Transmission and Distribution Plant - Golden Ears Bridge Project

TransLink, the Greater Vancouver Transportation Authority, is developing a new six-lane bridge across the Fraser River in the 200th Street corridor to improve the movement of people and goods in the Greater Vancouver region and is being designed to link communities on the south side of the Fraser River (Langley and Surrey) with the north-side communities of Maple Ridge and Pitt Meadows. Construction of the Golden Ears Bridge commenced on June 27th, 2006 and the bridge is expected to open to traffic in mid 2009.

TransLink and TGI have been involved in ongoing discussions regarding this project and as a result TGI has conducted conceptual and preliminary investigations into system modification which will be required as a result of this project. Based upon this information, TGI currently projects that total system modifications will cost in the region of $1.9 Million (excluding AFUDC). Of particular significance are two replacements of the 323 mm Livingston – Coquitlam transmission pressure pipeline, costing approximately $1.3 million (excluding AFUDC), due to encroachment of the bridge works near the pipeline in areas of soft soils. The other alterations to the gas system are routine relocations of distribution pressure mains and services. As this system modification is being driven by TransLink, TGI will attempt to minimize the total costs to be incurred by the Company by charging back TransLink a portion of the total overall costs. At this time, TGI has insufficient information to forecast the total amount it expects to recover from TransLink.

2.1.4 Distribution Plant – Clearbrook, Riverside Road, Abbotsford

This project consists of a 1.6 km loop of NPS 12 (323mm O.D.) pipeline operating at 275 psig (1,900 kPa). The estimated cost of this project is $ 1.19 million (excluding AFUDC). This project is currently planned to be constructed and in service in 2008. A discussion of this project can be found in Section B-1, Page 5 of the TGI 2005 Annual Review Application.

2.1.5 Distribution Plant - 72nd Street to 36th Avenue, Delta

This project is currently planned to be constructed in 2007. It consists of a 2.6 km loop of 323mm O.D (NPS 12) pipeline operating at 1,200 kPa (175 psig). The estimated cost of this project is $1.8 million (excluding AFUDC) and is expected to be in service in 2007. A discussion of this project can be found in Section B-1, Page 5 of the TGI 2005 Annual Review Application.

This system improvement is required to accommodate interruptible gas demand to greenhouses in the Delta area. With current high commodity costs, it is unclear whether this load will materialize. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load. With this loop installed greenhouses would not need to be curtailed until colder ambient temperatures are reached.

2.1.6 Distribution Plant - Goudy Road and 36th Avenue, Delta

This project is currently planned to be constructed in 2007. It consists of a 1.75 km loop of of 323mm O.D (NPS 12) pipeline operating at 1,200 kPa (175 psig). The estimated cost of this project is $1.21 million (excluding AFUDC) and is expected to be in service in 2007.

This system improvement is required to increase capacity to offset aggressive long term interruptible load growth projections that have been provided by the greenhouses in the Delta area, which are now questionable with the recent run-up in commodity costs. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load. A discussion of this project can be found in Section B-1, Page 6 of the TGI 2005 Annual Review Application.

2.1.7 Distribution Plant - 34B Avenue to 57th Street, Delta

This project is currently planned to be constructed in 2008. It consists of a 1.5 km loop of 323mm O.D (NPS 12) pipeline operating at 1,200 kPa (175 psig). The estimated cost of this project is $1.04 million (excluding AFUDC) and is expected to be in service in 2008.

This system improvement is required to increase capacity to offset aggressive long term interruptible load growth projections that have been provided by the greenhouses in the Delta area, which are now questionable with the recent run-up in commodity costs. This system improvement will only be installed if the affected greenhouses convert some, or all, of their interruptible load to firm load. A discussion of this project can be found in Section B-1, Page 6 of the TGI 2005 Annual Review Application.

2.1.8 Distribution Plant - Secondary Containment

To comply with Provincial and Federal legislation all storage containers that hold a volume greater than 250 litres of flammable or combustible liquid require secondary containment facilities.

In 2002 Terasen Gas embarked on a five year program to construct secondary containment facilities. The total estimated cost of this project is approximately $9.2 million (excluding AFUDC) and is expected to be complete in 2006. The remaining expenditure is forecasted at: $2.5 million in 2006 (excluding AFUDC). A discussion of this project can be found in Section B-1, Page 7 of the TGI 2005 Annual Review Application.

2.1.9 IT Capital – Order Fulfillment Upgrades

The Order Fulfillment business process is modeled within SAP. In 2006 it is planned to provide upgraded functionality to bridge process gaps and to streamline the receipt and processing of customer generated orders. The estimated cost of this project is $1.01 million (excluding AFUDC) and it is expected to be complete by the end of 2006. A discussion of this project can be found in Section B-1, Page 13 of the TGI 2005 Annual Review Application.

2.1.10 IT Capital - MobileUP Replacement

The MobileUP application is currently used for the Mobile Data Dispatch of customer service activities and the transfer of customer meter and billing information to the Energy Customer Information System. In 2006 it is planned to replace this application with SAP Mobile Asset Management, together with the Click scheduling engine. This conversion will align customer service activities with construction activities that have recently been transitioned to the SAP and Click platforms. The estimated cost of this project is $1.83 million (excluding AFUDC) and it is anticipated to be complete in 2006. A discussion of this project can be found in Section B-1, Page 14 of the TGI 2005 Annual Review Application.

2.1.11 IT Capital AM/FM GIS for Transmission

Automated Mapping/Facilities Management (“AM/FM”) for Transmission is an integrated Geographical Information System (“GIS”) and facilities management solution for the basic Transmission records and business processes. It will support business processes for: Pipeline Operations; Right of Way Property Management; Transmission Planning and Transmission Support. The proposed solution would extend the existing as-built paper and computer-assisted drafting (“CAD”) based record system with the enhanced features of an Automated Mapping system. The current estimated cost of this project is $1.72 million (excluding AFUDC) and it is anticipated to be complete in 2006.

2.1.12 IT Capital – Desktop and Laptop Refresh

This is an annual project to replace desktop and laptop computers. The number of units replaced on an annual basis varies depending of how long the computers have been in service. The estimated cost of units to be refreshed in 2006 is $1.07 million (excluding AFUDC) and the project is expected to be complete by the end of 2006.

The next projected year that the number of desktop and laptop units required to be replaced exceeds $1.0 million is in 2010. The current forecast expenditure for 2010 is $1.8 million (excluding AFUDC). A discussion of this project can be found in Section B-1, Page 14 of the TGI 2005 Annual Review Application.

2.1.13 IT Capital – Customer Attraction Front End (“Café”)

Café supports a number of key business units and processes in meeting customer growth targets. The technology functionality includes lead capture and tracking, distribution of marketing content and improved construction order processing for all companies. In 2006, this application was rolled out to the appropriate business units. Total costs attributable to the project are in process of being finalized and TGI anticipate total project costs to be approximately 1.5 Million (excluding AFUDC).

2.1.14 IT Capital – SAP Core Application Upgrade

SAP is the enterprise application that supports business processes for: Operate and Maintain; Order Fulfillment; Meter Management and Supply Chain. It also supports other back-office functions such as: Payroll; Finance and Performance Reporting. Vendor support of the current version of the SAP application (R3 v4.6C) expires in Q4 2006. An upgrade to the next supported version is therefore required to be in service in 2007. The total estimated cost of this project is $2.04 million (excluding AFUDC). This project is expected to be completed in 2007. A discussion of this project can be found in Section B-1, Page 14 of the TGI 2005 Annual Review Application.

2.1.15 IT Capital – IT Infrastructure Network Evergreening

This is an annual project to replace enterprise LAN switches, hubs and firewalls. The number of units replaced on an annual basis varies depending of how long the hardware has been in service. The estimated cost of units to be refreshed in 2007 is $1.18 million (excluding AFUDC) and the project is expected to be complete by the end of 2007. A discussion of this project can be found in Section B-1, Page 15 of the TGI 2005 Annual Review Application.

2.1.16 IT Capital - SCADA System Upgrade

The SCADA system operates controls and monitors Terasen Gas' transmission and compression facilities in British Columbia. Vendor support of the current version (6.0) of the SCADA application is expected to expire at the end of 2008. An upgrade to the next supported version is therefore required to be in service in 2008. The total estimated cost of this project is $1.56 million (excluding AFUDC). Implementation is expected to begin in 2007 and will be in service in 2008. A discussion of this project can be found in Section B-1, Page 15 of the TGI 2005 Annual Review Application.

2.2 Major Capital Projects that require a CPCN

Table 3 identifies the cost projections for major capital projects subject to CPCN applications for 2006-2010.

Table 3 Forecast of Major Capital Projects subject to CPCN Applications (2006 – 2010)

	2006 YEF	2007 Forecast	2008 Forecast	2009 Forecast	2010 Forecast
CPCN Applications & Deferral Accounts					
Mission IP System Upgrade	3,134	5,160	76	-	-
Vancouver LP Replacement	5,674	8,706	8,723		
Residential Unbundling	4,289	8,175	-	-	-
Gateway Project	187	11,900	9,300		
	13,283	**33,941**	**18,099**	**-**	**-**

2.2.1 Mission Intermediate Pressure ("IP") System Upgrade

It has been determined that portions of the existing pipeline adjacent to the Mission Highway Bridge as well as the Mission Regulator Station are at risk due to ground movement from seismic induced soil liquefaction and slippage associated with a seismic event of less than 1:100.

TGI believes that potential consequences of a relatively minor seismic event could result in a pipeline rupture and loss of gas service for approximately 10,000 TGI customers. Such an event would also trigger an extensive requirement for resources, both human and material, to undertake repairs. Terasen Gas is of the view that this situation poses increased safety risks to customers, employees, its contractors, and the general public.

On June 20, 2006, TGI applied for approval of a CPCN to complete a Seismic Upgrade of the Mission IP System. In order to address these seismic concerns, TGI is seeking approval of the following:

- Replacement of approximately 2 km of existing 168 mm (NPS 6) and 219 mm (NPS 8) OD IP pipeline, a portion, 219 mm (NPS 8), being on the Mission Highway Bridge, with approximately 2 km of 323 mm (NPS 12) OD IP pipeline installed across the Fraser River using Horizontal Directionally Drilled (“HDD”) technology;
- Iinstallation of approximately 1000 metres of 219 mm (NPS 8) polyethylene distribution pressure main; and
- Removal of the Mission Regulator Station.

In its application, TGI proposes to commence work in mid July, 2006 with project completion on approximately November 1, 2007. TGI currently estimates $8.37 Million (excluding AFUDC and Retirement Costs).

2.2.2 Low Pressure System – Vancouver Low Pressure (“LP”) System Replacement

Approximately 95km of LP mains are still in service in densely populated and established areas of Vancouver. The LP system serves approximately 7,500 customers including: commercial establishments; residences; schools and hospitals. It is planned to replace the steel/iron LP system with a polyethylene system, operating at Distribution Pressure of 420 kPa (60 psig), over a 3 year period commencing in 2006 with an expected completion in 2008.

In May 2006, TGI submitted a CPCN Application to complete this work. In its application, TGI projected that it would cost approximately $23.1 million (excluding AFUDC) to complete the 3 year replacement program. This CPCN application was approved by Commission on June 26, 2006 as per Order No. C-2-06.

2.2.3 Residential Unbundling

Since the release of the BC Energy Policy in 2002, Policy Action #19 stating that "Natural gas marketers will be allowed to sell directly to small volume customers", TGI has been facilitating providing commodity choice for small volume customers. The Commercial Commodity Unbundling program was launched in November 2004 with Residential Commodity Unbundling tentatively targeted to start in 2007.

With direction from the Commission, TGI completed a detailed design review and cost estimate using external consultants as part of its Pre-Scoping and Scoping Phases for Residential Unbundling between July 2005 and March 2006. To complete this work, the Commission approved $1.4 million in funding in 2005 to be recorded in a deferral account. On April, 2006, TGI submitted an application to enhance its business processes and systems as required to support the provision of commodity choice to residential customers in the TGI service area. In its application it specifically requested the following:

- Implement Commodity Unbundling for all residential customers in its service territory, excluding Fort Nelson and Revelstoke, effective November 1, 2007.
- Capital Expenditures of $11.1 million (in addition to those approved for the pre-scoping and scoping phases to implement the Residential Unbundling program.

At present, the Commission and Interveners are reviewing this CPCN application and a decision is expected by late summer 2006.

2.2.4 Gateway Program

The Gateway Program was established by the Province of British Columbia in response to the impact of growing regional congestion, and to improve the movement of people, goods and transit throughout Greater Vancouver. The Gateway Program includes three components:

- Port Mann /Highway 1 Project – This proposal includes twinning the Port Mann Bridge, upgrading interchanges and improving access and safety on Highway 1 from Vancouver to Langley.

- The South Fraser Perimeter Road Project is a proposed new four-lane, 80 km/h route along the south side of the Fraser River extending from Deltaport Way in southwest Delta to the Golden Ears Bridge connector road in Surrey/Langley.
- The North Fraser Perimeter Road Project is a proposed set of improvements on existing roads to provide an efficient, continuous route from New Westminster to Maple Ridge.

The Gateway Program is being managed by the Ministry of Transportation (“MoT”). The MoT and TGI have been involved in ongoing discussions regarding this project and as a result TGI has conducted conceptual and preliminary investigations into system modification which will be required as a result of this project. Based upon this preliminary information, TGI currently projects that total system modifications will cost in the region of $21.4 Million. TGI will attempt to minimize the costs to be incurred by the Company through negotiations with the MoT. Generally due to permit conditions, TGI incurs the costs of alteration of its existing facilities located in land already under MoT jurisdiction. When TGI must alter facilities outside of lands under the jurisdiction of the MoT, it is often able to have the MoT assume responsibility for some or all of the costs. At this time, TGI are not in a position to fully validate nor quantify the extent to which the MoT will assume costs attributable to this project.

TGI facilities are impacted by all three components of the Gateway Program; however the most significant impact is caused by the construction of the South Fraser Perimeter Road Project through the municipality of Delta. The modifications to TGI’s systems will include:

- Relocation of the Benson Regulator Station and the associated inlet and outlet pipelines as a result of the construction of a major highway interchange in an area of soft soil. Preliminary cost estimates are forecast to be approximately $6.1 Million.

- Relocation of transmission lines at 76th Street, Alexander Rd, and Nordel Way due to nearby highway encroachment and construction in areas of soft soils. Preliminary cost estimates are forecast to be approximately $11.4 million.

TGI are not in a position to file a CPCN for this project at this time. TGI anticipates filing a CPCN in late 2006 or early 2007.