Terasen Gas Inc.
2004 Resource Plan

Terasen Gas

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April 6, 2005

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Mr. R.J. Pellatt, Commission Secretary

Dear Sir:

Re: Terasen Gas Inc. ("Terasen Gas") – 2004 Resource Plan

Terasen Gas would like to submit the attached Terasen Gas Inc. 2004 Resource Plan in accordance with British Columbia Utilities Commission (the "Commission") Letter No. L-5-04, dated February 6, 2004, for the Commission's review. This filing follows an extension to the original submission date of November 30th, 2004 to the end of first quarter 2005, resulting from resource constraints as confirmed in Terasen Gas' letter of November 25th, 2004.

This Resource Plan, covering the Interior and Coastal service areas of Terasen Gas, was prepared in accordance with the Resource Planning Guidelines released by the Commission in December, 2003. If you have any questions regarding the Resource Plan's content, please contact James Wong at 604-592-7871.

Yours very truly,

TERASEN GAS INC.

Original signed

Scott A. Thomson

Attachments

TERASEN GAS INC.

2004 RESOURCE PLAN

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EXECUTIVE SUMMARY

Introduction

Terasen Gas Inc. ("Terasen Gas") provides natural gas transmission and distribution services to approximately 789,000 residential, commercial, industrial and transportation customers in more than 100 communities in British Columbia. For the purpose of this Resource Plan, Terasen Gas' gas delivery systems are delineated by operating pressure; Transmission systems operate under pressures in excess of 2,069 kilopascals ("kPa") and Distribution systems operate under pressures below 2,069 kPa. The Terasen Gas transmission pressure system is divided into three subsets; the Coastal Transmission system ("CTS"), the Interior Transmission system ("ITS") and Transmission Pressure laterals from the Duke Energy Gas Transmission and TransCanada Pipeline systems.

Natural gas for Terasen Gas' Coastal region customers is delivered from upstream sources on the Duke Energy pipeline system to the Huntingdon trading point near Abbotsford. The Terasen Gas 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 ranging in diameter from 6 inch to 42 inch operating at pressures up to 583 pounds per square inch gauge (psig). 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 Terasen Gas' Interior region customers is delivered from sources in British Columbia via the Duke Energy 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 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 TCPL system at Yahk. The Kingsvale and Yahk interconnects are capable of both receipt and delivery allowing bi-direction flow between these two points.

Resource Planning

The Resource Planning process evaluates demand and supply options over a long term 20 year planning horizon and considers their economic, environmental, and social characteristics. The British Columbia Utilities Commission ("BCUC") describes the planning process as:

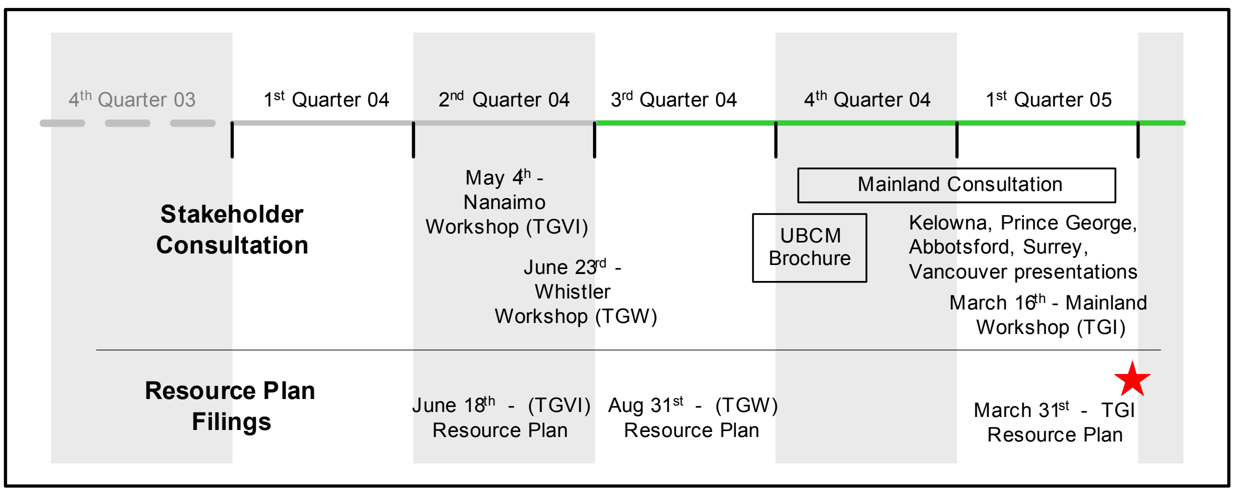
> *"Resource Planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run."*

Although Resource Planning at Terasen Gas is not new, the Province amended Section 45 of the *Utilities Commission Act*, which sets out the regulatory framework for Resource Planning, in 2003 to implement B.C.'s Energy Policy. The BCUC subsequently prepared revised Resource Planning Guidelines in December 2003, under which this Resource Plan has been prepared.

Resource Planning is part of an ongoing planning process at Terasen Gas which includes broader regional planning initiatives. Terasen Gas has recently completed a Regional Resource Planning study that assesses the natural gas 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 Terasen Gas 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.

Terasen Gas has maintained a consistent approach to Resource Planning with its sister companies, Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), which each submitted Resource Plans in mid to late 2004. Figure ES-1 shows the activity timeline for all three Resource Plans.

Figure ES-1 2004 Resource Planning Timeline – Terasen Group of Companies



UBCM = Union of British Columbia Municipalities

Resource Planning Objectives

Terasen Gas' Resource Planning objectives form the basis for evaluating potential resource options in the Resource Plan, including major infrastructure projects, gas supply alternatives, and demand side programs. These objectives are set out in Table ES-1.

Table ES-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 objectives reflect Terasen Gas' 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.

Gas Supply Overview

Terasen Gas, through its Midstream management group, is responsible for contracting of all Midstream resources needed to move gas from market / supply hubs to the distribution system and to provide balancing and peaking services for all customers. Midstream resources are those owned or leased by Terasen Gas that are used to store, transport and manage the gas purchased on behalf of Terasen Gas customers, before it reaches the Terasen Gas distribution system. Terasen Gas uses the pipeline, storage resources, peaking, LNG, hedging and sale activities to manage load variability and resultant cost variances.

Terasen Gas has two types of customers: distribution (bundled sales rate or "Core Market") and transportation customers. Core Market customers (primarily Residential, Commercial and Small Industrial customers) typically use a significant portion of their gas requirements for heating applications. Consequently, gas demand for the Core Market is weather sensitive. Due to the weather dependency, sufficient gas supplies and resources must be purchased to meet the requirements for the Core Market based on the design peak day of each year. Gas is primarily consumed during the winter; therefore gas purchasing throughout the year is shaped to meet these characteristics.

Transportation customers are large commercial and industrial customers who manage their own gas supply requirements. These customers purchase their own gas in the wholesale market and provide it to Terasen Gas at the inter-connect of Duke's T-South pipeline and the Terasen Gas system near Huntingdon, B.C. or at the various interconnects between Duke or TransCanada's BC pipeline and Terasen Gas in the Inland delivery area. Terasen Gas then transports the gas from those interconnects to the customers' facilities.

Market considerations are a key component in long-term Resource Planning for meeting gas supply obligations. When Terasen Gas purchases gas to deliver to its distribution customers, it must consider not only the domestic market in British Columbia, but also the market in the U.S. Pacific Northwest and the continental market of North America. The continental gas supply perspective is important when evaluating the requirement for new facilities that are to be used over their lifetime of thirty or more years. Terasen Gas has reviewed the latest forecasts for gas reserves from a variety of sources and is satisfied that ample supply exists to serve Terasen Gas' customers over the planning period.

In planning for future gas supply for its service territory, it is also important for Terasen Gas to know what the competing demands are in other areas that could impact Terasen Gas' ability to secure future supply. The power generation sector has a significant role in the energy market due to its potential to exert a significant amount of demand. Power generation represents an increasing percentage of the Pacific Northwest region's overall demand.

A gas supply portfolio is the package of contracted supply resources to ensure a reliable supply of natural gas to its customers over the course of a year and long term. Generally, Terasen Gas' supply portfolio consists of a range of gas purchase contracts to meet forecasted design day demand. Terasen Gas uses third-party pipeline capacity to access contracted natural gas resources throughout the year, including peaking resources that allow the interruption of gas supply to specific customers during periods of high demand (known as curtailment). In planning the gas supply portfolio for Terasen Gas, a balanced combination of these resources must be in place to manage the varying demand for gas on an annual basis. In assembling a gas supply portfolio to meet demand, Terasen Gas balances the objective of least cost against objectives of reducing rate volatility and ensuring supply reliability and security.

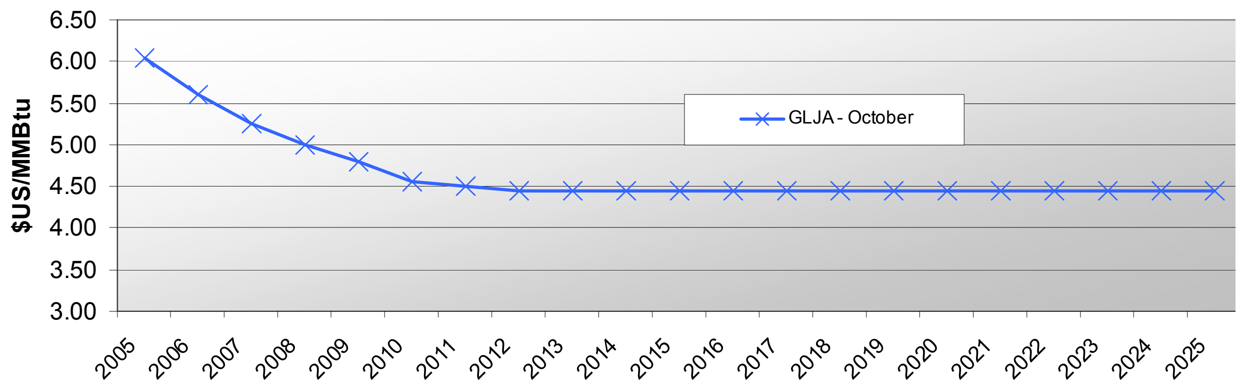
Given the age of the existing infrastructure in the Pacific Northwest and its availability, Terasen Gas is increasingly concerned about the potential impact of unplanned outages on the availability of supply. Terasen Gas' resource portfolio aims to lessen the impact of infrastructure disruption events that are likely to occur. Terasen Gas continues to evaluate scenarios that could lead to the disruption of gas supply, the potential impact of these events on its portfolio and the Utility's ability to mitigate the impact of these events within the existing portfolio.

Energy Outlook

In forecasting future demand for natural gas and planning for future infrastructure needs, Terasen Gas examines expected natural gas prices within the competitive energy market. The energy outlook section discusses independently prepared natural gas prices, expected pressures on electricity rates and a range of other trends arising in the energy industry.

Figure ES-2 provides the October, 2004 Natural Gas price forecast prepared by Gilbert, Laustsen, Jung and Associates (GLJA), a respected private petroleum industry consultancy that regularly prepares natural gas and oil price forecasts on a quarterly basis. GLJA expectations benefit from tracking recent trends in oil and gas supply, as well as other trends in the natural gas industry and the cost of competing fuels.

Figure ES-2 - GLJA October 2004 Natural Gas Price Forecast



Source: Gilbert Laustsen Jung Associates Ltd., October 2004
(2004 Real Constant Dollars)

GLJA forecasts that within the next 5 years, new sources of gas supply, such as imported LNG and possibly Arctic gas will have a moderating effect on near future gas prices, but that over the long term, gas prices will continue to maintain a relationship to the price of oil. The industry outlook on the price of oil, as evidenced by the futures market, is that oil prices will be flat to declining in real terms over the next 5 to 10 years since currently, the cost of new production is generally less than the current market price. The GLJA forecast shows a declining price in natural gas over the next 5 years, followed by a flattening of prices (in real, constant dollars) over the long term.

Two major electric utilities provide electrical service in British Columbia. FortisBC Inc. supplies electricity within south Central B.C., while BC Hydro serves the vast majority of the Province. In both service areas, B.C. enjoys some of the lowest electricity rates in Canada and North America, yet natural gas still enjoys a competitive advantage on an annual energy use basis within the Province. For BC Hydro, their low electricity rates have been held constant for the past ten years until a recent rate increase approval by the BCUC. There is a looming need for new sources of electric generation which is going to require new investments in electricity infrastructure. This will exert upward pressure on electricity prices over the long term. In summary, Terasen Gas expects natural gas prices to remain competitive with electricity into the future.

In addition to the competitiveness of gas and electricity prices, Terasen Gas has reviewed a number of other current energy and related technology trends that have the potential to impact the energy market place. These trends and technologies include hog fuel applications in industrial settings, distributed electrical generation, community energy planning and fleet vehicle solutions. In summary, natural gas is expected to remain a major component in both commercial and community energy applications for the foreseeable future.

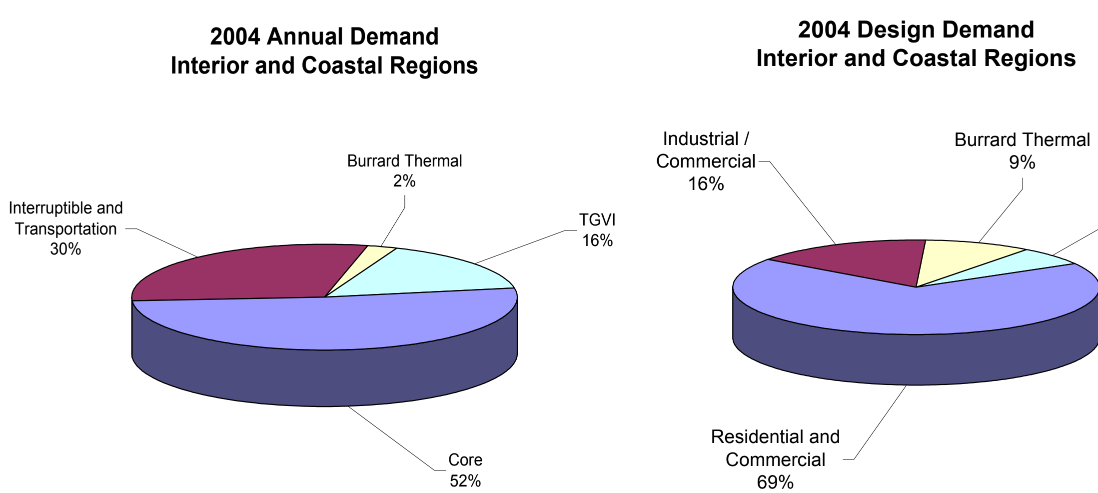
While natural gas still holds a dominate share of the energy market for the single family residential market sector, electric baseboard heaters are being installed in far more new apartment and condominium developments in B.C. than is natural gas, most likely due to the lower initial capital cost and ease of installation of this technology. A review of the efficiencies of using natural gas to generate marginal increases in electrical supply versus using natural gas directly in the home suggests that the latter is a far more efficient use of natural gas energy. Continuing to install electric baseboard heaters under these conditions has significant conservation, air quality and cost implications for our energy future in B.C.

Used in efficient ways, 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. High efficiency condensing technology, individual metering capabilities for multi-unit developments, highly efficient distributed energy systems and natural gas fleet vehicle solutions are all existing technologies that can bring significant energy efficiencies and emissions reductions to the end user. Natural gas' role in hydrogen fuel technology and other energy solutions of tomorrow appears promising.

Demand Forecast

Using a planning horizon of 20 years, Terasen Gas has prepared a range of forecasted gross demand scenarios to account for uncertainties and to facilitate a comprehensive understanding of the potential resource portfolios that it might employ to balance supply and demand. Included in these scenarios are the forecasted demand from Terasen Gas' transportation only customers, of which BC Hydro's Burrard Thermal Generating Station has a significant impact on expected demand. The Burrard Station has a potential demand of approximately 230 TJ/day in the running of up to six generating units. There are a number of potential variations in timing and options for BC Hydro operating the generating units at Burrard Station that Terasen Gas has reflected in its forecast demand scenarios for the Coastal Region. BC Hydro also requires natural gas to run the proposed Duke Point Power plant ("DPP") and the existing Island Cogeneration Plant ("ICP"). This gas must be transported across the CTS to the TGVI system, which starts at Eagle Mountain in Coquitlam. Figure ES-3 provides the 2004 profiles of the Annual Demand and Design Day Demand for customers of Terasen Gas.

Figure ES-3 Customer Profiles – 2004 Annual Demand and Design Day Demand



The Transmission systems are designed to be able to supply all of Terasen Gas' firm (non-interruptible) customers demand under design demand conditions. Terasen Gas uses a statistical approach called Extreme Value Analysis to determine its design demand – a 1 in 20 year return period for the coldest day weather event occurring. As indicated in Figure ES-3, Core Market customers have the greatest impact on design period demand. Factors affecting the Core Market customers' forecasted demand for gas are growth in the number of customers, usage patterns of the customers impacted by technology and economic factors, and weather.

Since the Interior and Coastal regions of Terasen Gas' service areas are separate systems with weather and different construction, operating and supply point characteristics, demand forecasts for each region are developed separately. The CTS forecast scenarios are summarized as:

- High – Includes high Core Market customer growth as well as the following BC Hydro demand; the 275 TJ/d requirement of the BC Hydro Bypass Transportation Agreement (BTA) is maintained despite BC Hydro's expectation that only 3 units may be required at Burrard until 2009. An increase in contract demand in 2009 from 275 TJ/d to 321 TJ/d for the remainder of the planning period is assumed for dependable service to ICP, DPP, and Burrard Thermal.
- Base – Includes the base scenario level of Core Market demand as well as the following BC Hydro demand; the requirements based on the stated operating context for Burrard that only 3 units generating units will be required at Burrard until 2009 and 45 TJ/d are required to operate each of ICP and DPP from 2007 onward. An increase in total demand in 2009 to 321 TJ/d is also assumed but only until 2014, after which only 90 TJ/d is included for ICP and DPP.
- Low – Includes low Core Market demand (10% below Base case growth levels) as well as the following BC Hydro demand; Burrard continues to operate with only three units on standby until 2014 and only service to ICP is required thereafter.

The transportation demand from TGVI is based on requirements outlined in the TGVI LNG Certificate of Public Convenience and Necessity application decision dated February 15th, 2005. In the high and low scenarios where both ICP and DPP are expected on Vancouver Island, the requirement for transport across the CTS assumes that an LNG facility is added to the TGVI system at Mt. Hayes. In the low scenario, where ICP but not DPP demand is assumed on Vancouver Island, the requirement for transport across CTS assumes TGVI system expansion with compression, pipeline looping and continued reliance on curtailment. Demand from the ICP remains the same at 45 TJ/day in each of the scenarios. Figure ES-4 below provides a matrix showing the components and timing of incremental transportation demand in the demand forecast scenarios that have been developed for the CTS.

Figure ES-4 Matrix of Gross Demand Forecast Scenarios for the Coastal Transmission System

Terasen Gas Inc. Gross Demand Forecast Scenarios for the Coastal Transmission System	Demand Forecast Components (TJ/day)																							
					BC Hydro Transportation Forecast Components and Potential Timing for Changes in Demand																			
					2005 Component Demand					2007 Component Demand					2009 Component Demand					2015 Component Demand				
	TGI Core	+	TGVI Transportation	+	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal
TGI High Forecast	High		Base		45		0		230	45		45		185	45		45		231	45		45		231
TGI Base Forecast	Base		Base		45		0		120	45		45		120	45		45		231	45		45		0
TGI Low Forecast	Low		Base		45		0		120	45		0		120	45		0		120	45		0		0

TGI = Terasen Gas Inc.
TGVI = Terasen Gas Vancouver Island Inc.
ICP = Island Cogeneration Plant
DPP = Duke Point Power plant

For the Interior Transmission System, the gross demand forecast scenarios have been limited to three; High, Base and Low reflecting different scenarios for customer additions only over the planning horizon.

For the Core Market component of demand on both the CTS and ITS, the conditions assumed for customer additions and demand growth in the base, high and low demand forecast scenarios are described below.

Base Forecast

For the Base forecast scenario, the price of natural gas commodity remains relatively competitive to its primary alternative fuel, electricity, over the forecast horizon. Price volatility for natural gas will continue and be similar to that experienced in recent years. The housing type mix, single family dwelling ("SFD") versus multi family dwelling ("MFD"), is not expected to change materially over the forecast period from the recent average of 45% SFD and 55% MFD.

New gas accounts due to conversions from alternate fuels are assumed to be negligible as conversion activity during the last couple years has averaged only approximately 300 per year. Annual growth rates for the planning period 2004 – 2026 average 2% per year.

High Forecast

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. The competitiveness of natural gas remains relatively competitive to its primary alternative fuel, electricity, over the forecast horizon. In addition, Terasen Gas is able to capture a significantly higher proportion of new housing starts compared to recent experience, particularly in the MFD market segment. Annual growth rates for the planning period 2004 – 2026 average approximately 3% per year.

The High forecast scenario supports Terasen Gas' objective of achieving one million customers for its gas utility entities by 2010, primarily through residential customer additions. This growth is expected to be achieved primarily through new construction attachments and increased penetration of the multi-family dwelling sector. Marketing efforts will focus on capturing as much new construction starts as possible to see that they are piped for natural gas heating and appliances. Managing relationships with builders, developers and communities will be important.

Low Forecast

For planning purposes, the Low forecast reflects a reduction of 10% of the annual customer additions 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 MFD, a market segment in which Terasen Gas is unable to increase its capture rate. Annual growth rates for the planning period 2004 – 2026 are expected to average approximately less than 2% per year.

The results of adding demand from all demand components in each of the High, Base and Low design demand forecasts in both the CTS and ITS are provided in Figures ES-5 and ES-6 respectively.

Figure ES-5. CTS Gross Design Hour Demand Forecasts

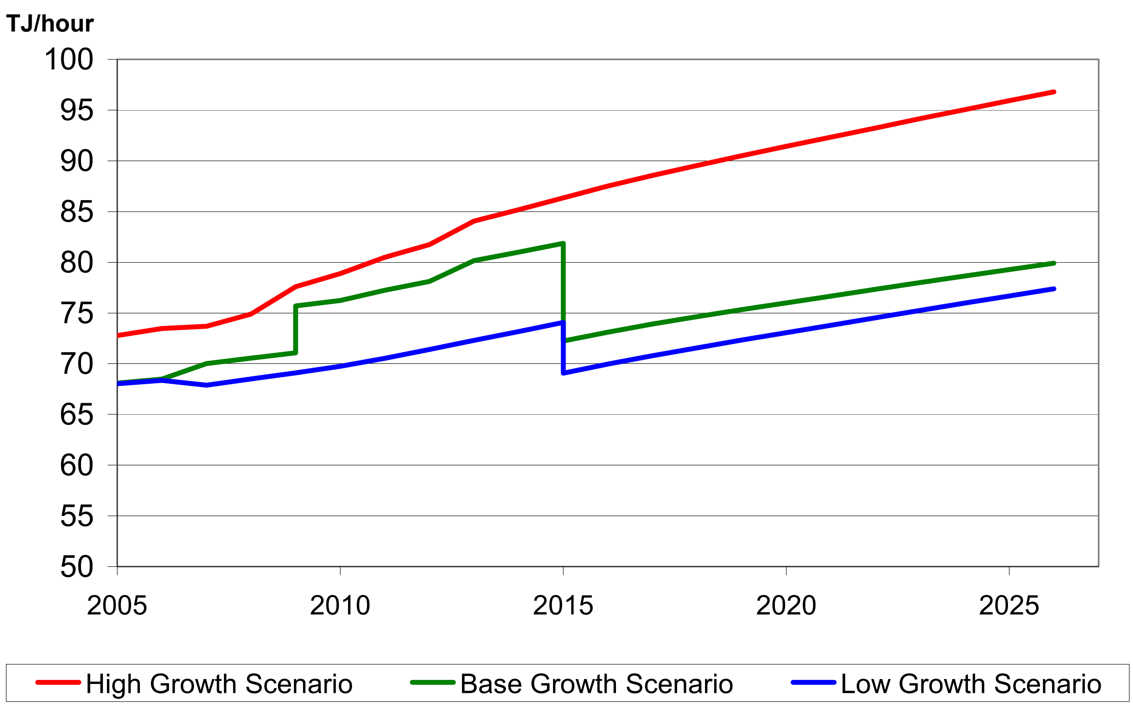
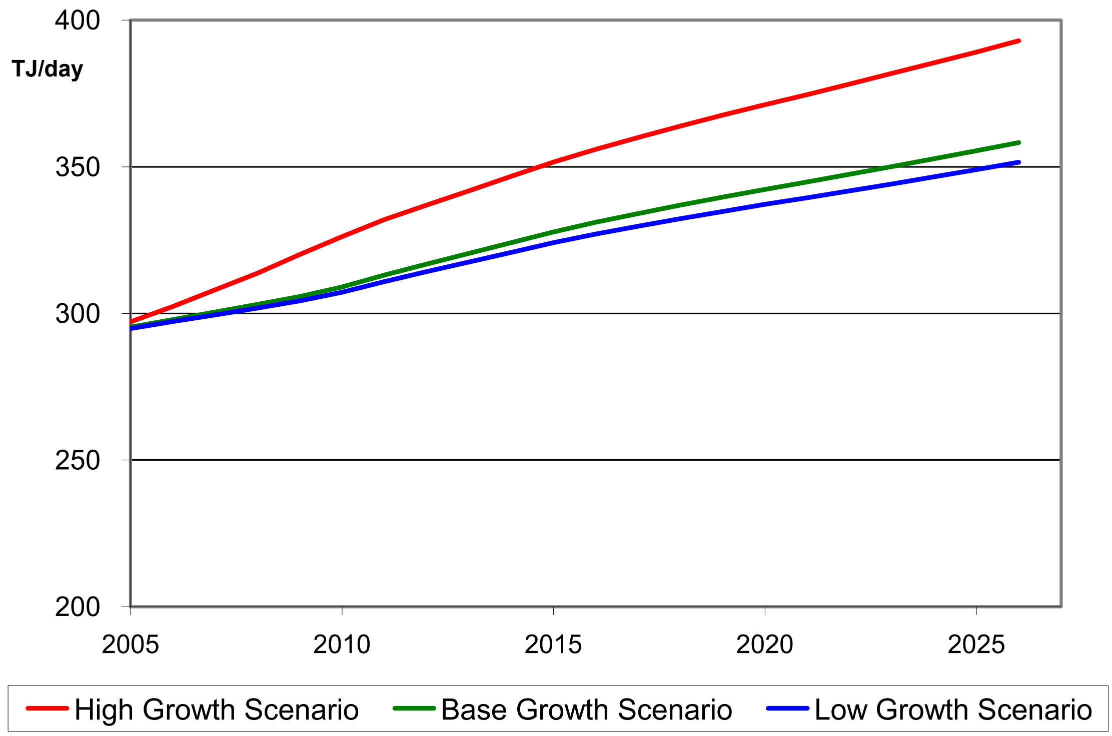


Figure ES-6. ITS Gross Design Day Demand Forecasts



Demand Side Management ("DSM") Resources

Demand Side Management refers to "utility activity that modifies or influences the way in which customers utilize energy services." Terasen Gas offers demand side management programs for the Core Market that are targeted to improving the energy efficiency of the residential and commercial customer.

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.

There has also been a growing interest by governments to reduce the 30 billion tonnes of world-wide annual greenhouse gas ("GHG") emissions. Terasen Gas has attempted, whenever feasible, to partner with other organizations to leverage Utility DSM funds; Natural Resources Canada, BC Hydro, FortisBC, and appliance manufacturers have all participated in Terasen Gas programs providing benefits to customers and the environment. Looking ahead, the Alternative Energy Policy Branch of the Ministry of Energy and Mines ("MEM") has received approval for its application to the federal "Opportunities Envelope" for $11 million over a two year period for energy efficiency measures of which $3 million is earmarked to support Terasen

Gas' DSM programs. They will become the primary partner for a number of the Terasen Gas' DSM initiatives proposed for 2005 through 2007.

The approach of the MEM proposal was to leverage existing programs and delivery channels to support a Province wide market transformation strategy. Table ES-2 shows a summary of the MEM's funding proposal – $118 million available through all sources to support energy efficiency programs and training in B.C.

Table ES-2 MEM Funding Sources for Market Transformation Strategy

Incentives recorded in MEM application (Fiscal year ends March 31)	Funding Source (Thousand $)				
	BC Gov't	Utilities	Industry Sources	Opportunities Envelope	Total
2004-05 Programs	$2,477	$26,264	$1,360	$1,640	$31,741
2005-06 Programs	$8,246	$27,302	$1,448	$5,022	$42,019
2006-07 Programs	$11,365	$27,727	$1,287	$4,338	$44,717
Total Joint Programs	$22,089	$81,294	$4,094	$11,000	$118,476

For the TGI specific programs proposed for 2005, the anticipated Total Resource Cost net benefit is almost $7 million from seven different DSM partnering opportunities covering both residential and commercial programs. Terasen Gas also anticipates participation from over 6,000 customers, savings of 4.6 million GJs of energy over the measure life and GHG reductions of over 235,000 tonnes of CO_2e.

In some cases, DSM programs can also play a role in deferring system improvements by reducing design day system demand. However, the current portfolio represents only approximately 0.1% of design demand and would be even smaller if evaluated in terms of impact on a specific community's distribution system.

In October 2004, Terasen Gas initiated a Conservation Potential Review ("CPR"). A CPR examines available technologies and determines their "conservation potential" over the study period through economic screening. The CPR compares the economic and achievable potential of viable measures to a base case scenario. The CPR has three key objectives:

(a) Characterization of available natural gas technologies inclusive of energy efficiency and fuel substitution.

(b) Identification of the size of the potential opportunities over a set study period.

(c) Economic modelling of DSM programs, fuel substitution and energy efficiency measures.

The CPR results will form the basis for future program development within a comprehensive DSM portfolio. It is anticipated that the CPR will be completed by mid 2005.

Resource Portfolio Development and Evaluation

The capacity of a pipeline system is limited by the pipeline size, design pressure, and the length of the pipeline. To overcome friction and allow gas to flow through the pipeline, a pressure differential between the inlet and the downstream delivery points is required. Compressors are used to create the pressure differential and move large volumes of natural gas at high transmission pressures to major delivery points. The end pressures, which vary with flow, are controlled by pressure regulating stations before the natural gas enters the pipeline distribution system. Generally, there are four types of resources that can be used to increase the physical capacity of a pipeline system – pipeline looping, compression, storage and industrial curtailment.

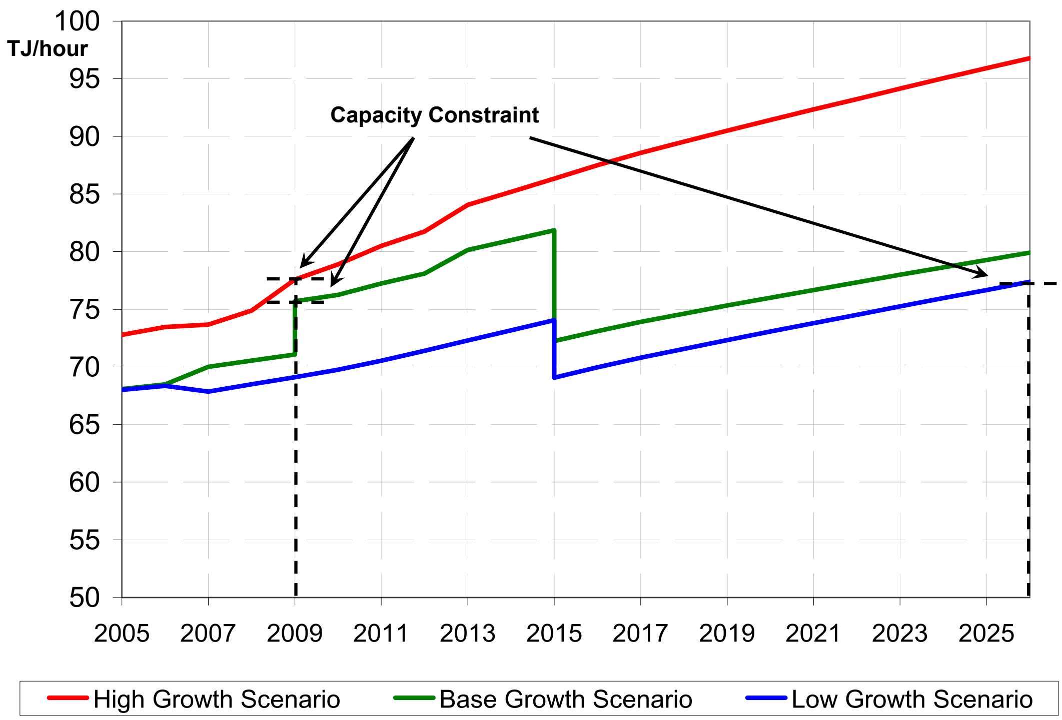
One of the primary roles of Resource Planning is to assess expansion alternatives over a range of expected demand scenarios to determine the preferred resources required to meet demand over the long term. The first step is to determine when demand growth will trigger the next capacity expansion on the existing pipeline system. Once this is established, multiple long-term system plans are assembled to address the requirements of each gross demand forecasts discussed above. Each plan identifies a portfolio of investments in capacity resources over the planning period differentiated by the type and timing of resources used.

CTS Resource Portfolios

Common to all CTS forecasts is the initial requirement to increase capacity on the northern leg of the system serving Coquitlam, Eagle Mountain, and Burrard Thermal. The results of hydraulic modelling conducted to date suggest that the preferred technical solution to this constraint will be a program of 30" looping from Nichol to Noons Creek. Once looping downstream of Nichol Station is completed, additional compression becomes a viable alternative to meet additional growth.

The loop would be constructed in three phases; Nichol to Port Mann (4.3 km), Cape Horn to Coquitlam (5.1 km), and Coquitlam to Noons Creek (4.3 km). Timing will ultimately depend on the rate of Terasen Gas Core Market customer growth realized, resolution of the requirements for on-Island generation and subsequent expansion of TGVI expansion requirements, and the timing and extent to which additional Burrard units are recalled into service. Figure ES-7 shows the expected timing of the initial constraint under each of the CTS demand forecasts.

Figure ES-7 CTS Capacity Constraints Reflected on the Demand Forecast Summary



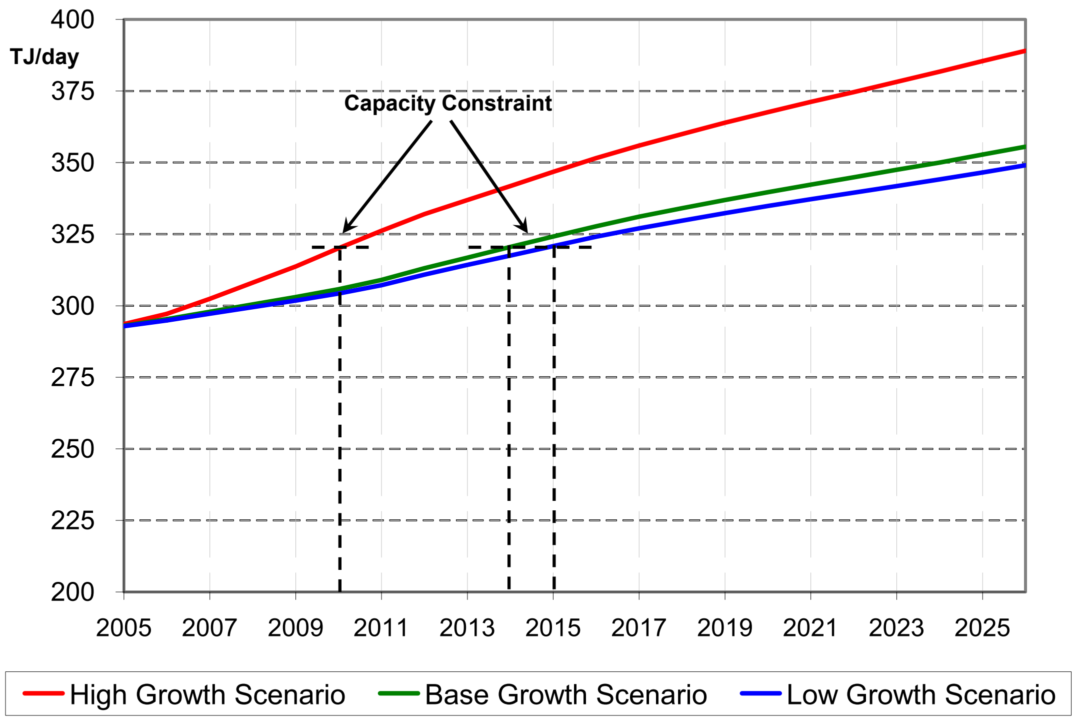
In anticipation of the 2009 requirement, Terasen Gas will continue to assess alternatives to defer the pipeline loop. These include contract demand reductions as well as alternatives based on additional on-system storage. Beginning in 2008, Terasen Gas expects to contract for storage services from TGVI based on available capacity from the Mt. Hayes facility. There may be opportunity to use this service or an expansion of the existing Tilbury facility to defer the upgrade. Given BC Hydro's expectation that full Burrard capacity will only be required for 6 years, a storage based expansion may be more cost effective than the pipeline loop. Unlike pipeline looping which only provides capacity, on-system storage provides both capacity as well as benefits in terms of avoided gas supply costs and reduced stranded asset risk.

ITS Resource Portfolios

On the ITS, the first constraint is expected to result from Core Market demand growth in the Thompson Okanagan region. Figure ES-8 shows the onset of the initial constraint under the High, Base, and Low forecasts scenarios.

The results of hydraulic modelling conducted to date have identified two alternatives to resolve the forecast capacity constraint; a phased program of 20" 1,035 psig looping between Penticton and Winfield, or the addition of a LNG storage facility near the existing pipeline between Falkland and Vernon. Figure ES-8 shows the expected timing of the initial constraint under each of the ITS demand forecasts.

Figure ES-8 ITS Capacity Constraint Reflected on the Demand Forecast Summary



The looping program provides benefits in addition to resolving the capacity shortfall, which would also be considered when establishing the timing of the expansion requirement:

- Increased capacity to access the AECO market for Alberta gas supply. This would result in greater supply diversity and may possibly lower gas supply costs depending on differential from Station 2 based supply.
- Resolution of pressure restrictions due to development adjacent to the original pipeline (class location changes). These pressure restrictions reduce capacity available to serve the region. Increased development activity could advance the need for expansion.

Likewise, the LNG alternative provides additional benefits which would also be considered when establishing the timing of the expansion requirement:

- Additional on-system storage increases supply diversity for Terasen Gas and allows the cost of incremental third party storage to be avoided.
- Unlike the pipeline looping alternative, available capacity has market value. Terasen Gas could use the facility to provide storage services to others, generating mitigating revenue to offset cost and lower stranded asset risk.

Since the ITS requirements fall outside the development schedule and action plan window, final analysis of these resource options has not yet been completed. Terasen Gas will continue to monitor demand growth in the region and development activity along the ITS.

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.

A preliminary review of the CTS and ITS transmission systems showed no immediate impacts on local communities, with significant system expansion not likely required until the year 2009. Therefore, stakeholder interest in Resource Planning was anticipated to be mild to low. Terasen Gas instead tailored a stakeholder consultation process that targeted high growth municipalities, stakeholders whose needs for energy planning would be the greatest. Meetings were held in Kelowna, Prince George, Vancouver, Surrey and Abbotsford and focused on engaging municipal representatives in discussing the Role of Natural Gas in Community Energy Planning and communicating to them the Resource Planning process Terasen Gas employs to ensure natural gas service is provided safely, reliably and cost effectively over the long term.

As expected, interest in specific Resource Planning technical issues was low, yet municipal staff were very interested in discussing energy issues which will directly impact their communities going forward. These issues are complementary to the Resource Planning process as they provide valuable insights into customer growth expectations and demand forecasts. The results of these sessions also suggest that, now more than ever, Terasen Gas should continue to engage key influencers within the urban development environment on issues that will help ensure the wisest and best use of natural gas.

Additionally, a separate workshop was conducted in the first quarter of 2005 for those energy industry stakeholders and interveners who would likely be interested in reviewing the details of the Resource Planning process and Terasen Gas' findings. Most of the comments raised during 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.

A subsequent meeting with BC Hydro was also held in the first quarter of 2005 where Terasen Gas' Resource Plan details to date were discussed. Among other things, BC Hydro staff clarified their current position regarding the future operations and demand needs expected at Burrard Thermal. The information has accordingly been incorporated into this Resource 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. *Continue to monitor customer demand by:*

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

   b. Working with BC Hydro to understand their demand for natural gas at the Burrard Thermal generating station.

   c. Assessing the impact of distributed generation projects and other emerging energy trends and technologies on demand for natural gas.

   d. Validating 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.

   e. Assessing 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 to investigate the options available to Terasen Gas to address the future capacity shortfall in the CTS north of Nichol Station as set out in Section 6.3.1.*

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

   Review of weather sensitivity and physical interruptions from pipeline outages suggests a need for additional capacity resources to meet peak day regional demand in the incidence of a moderately cold or low hydro year.

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

5. *Report back on the outcomes and recommendations of the Conservation Potential Review.*

   The Conservation Potential Review (to be completed by mid-2005) results will form the basis for future program development within a comprehensive DSM portfolio.

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.*

   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 very competitive position for natural gas.

1 INTRODUCTION AND BACKGROUND

1.1 Introduction to Terasen Gas Inc.

Terasen Gas Inc. ("Terasen Gas") provides natural gas transmission and distribution services to approximately 789,000 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).

Terasen Gas Inc. was formed in 1988 when the Provincial government privatized the natural gas division of BC Hydro and sold it to Inland Natural Gas Company Ltd., the gas distributor then operating in the interior of the Province. Terasen Gas employs approximately 1,200 employees with the main operations center located in Surrey, B.C.

Terasen Gas, formerly British Columbia Gas ("BC Gas"), is a wholly owned subsidiary of Terasen Inc., a private, shareholder-owned company whose shares trade on the Toronto Stock Exchange under the symbol TER. Terasen Inc. also owns and operates the following British Columbia based gas utilities:

- Terasen Gas (Whistler) Inc. ("TGW"), formerly Centra Gas Whistler Inc.,
- Terasen Gas (Squamish) Inc., formerly Squamish Gas, and;
- Terasen Gas (Vancouver Island) Inc. ("TGVI"), formerly Centra Gas British Columbia, which serves the Vancouver Island and the Sunshine Coast.

In total, the Terasen Gas group of companies (including Vancouver Island, Sunshine Coast, Whistler, Squamish, Lower Mainland, Interior) is the largest natural gas distribution Utility in the Pacific Northwest, serving more than 862,000 customers in British Columbia. Terasen Gas employs 1,400 people spread over more than 125 communities and operates more than 43,000 km of natural gas transmission and distribution pipelines. Terasen's utility operations, including Terasen Gas, are regulated by the British Columbia Utilities Commission[1] ("BCUC").

1.2 Terasen Gas Inc.'s Transmission System

For the purpose of this Resource Plan, Terasen Gas' gas delivery systems are delineated by operating pressure; Transmission systems operate under pressures in excess of 2,069 kilopascals ("kPa") and Distribution systems operate under pressures below 2,069 kPa. The Terasen Gas transmission pressure system is divided into three subsets; the Coastal Transmission system ("CTS"), the Interior Transmission system ("ITS") and the Transmission

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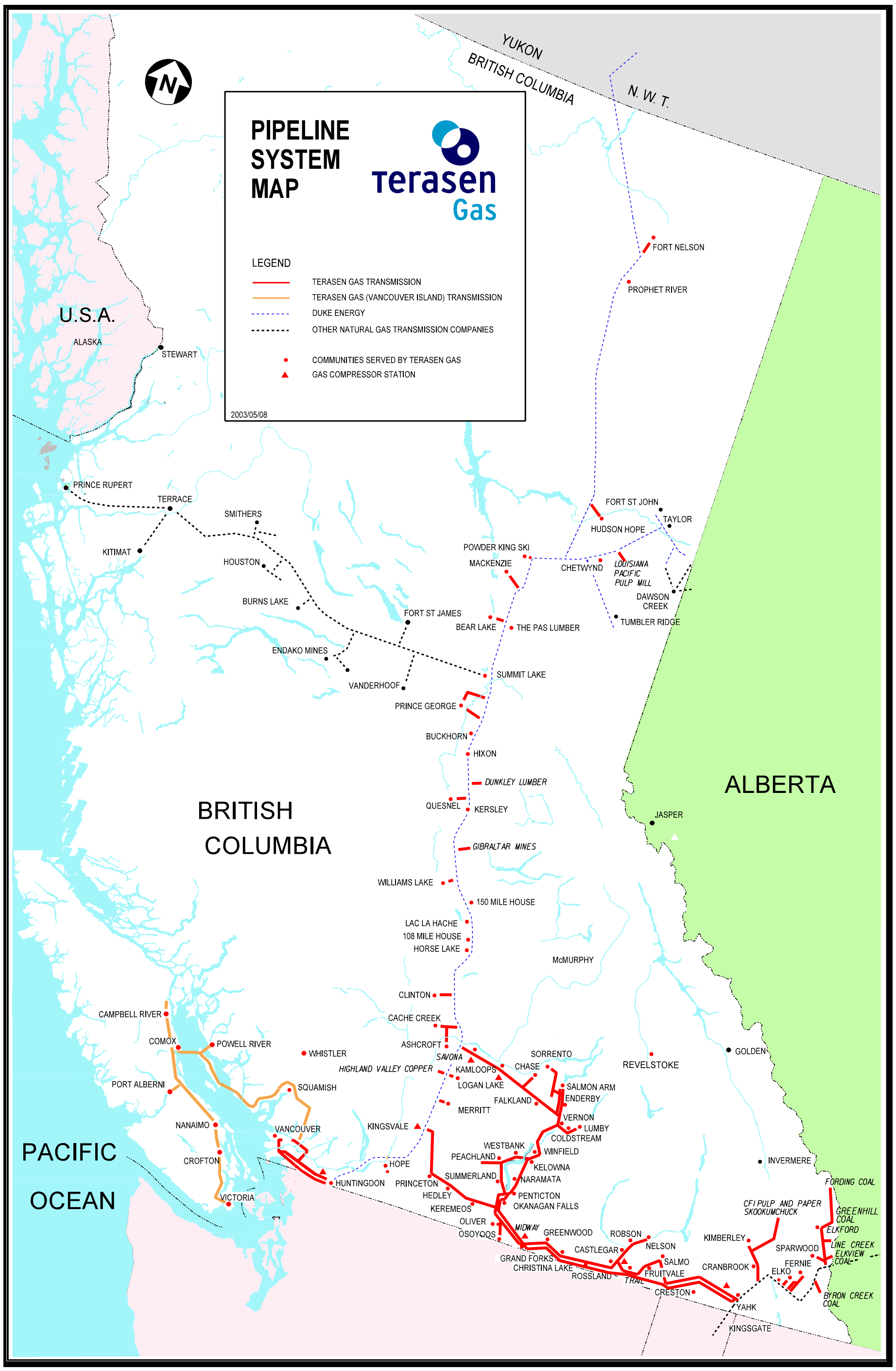
1 See Terasen Gas Inc April 2004 Rate Reference Guide for more detail information regarding Rate Schedules for customers.

Pressure laterals from the Duke Energy Gas Transmission and TransCanada Pipeline systems. Figure 1.1 is a Pipeline System Map of the Province of B.C. containing Terasen Gas' transmission pipelines.

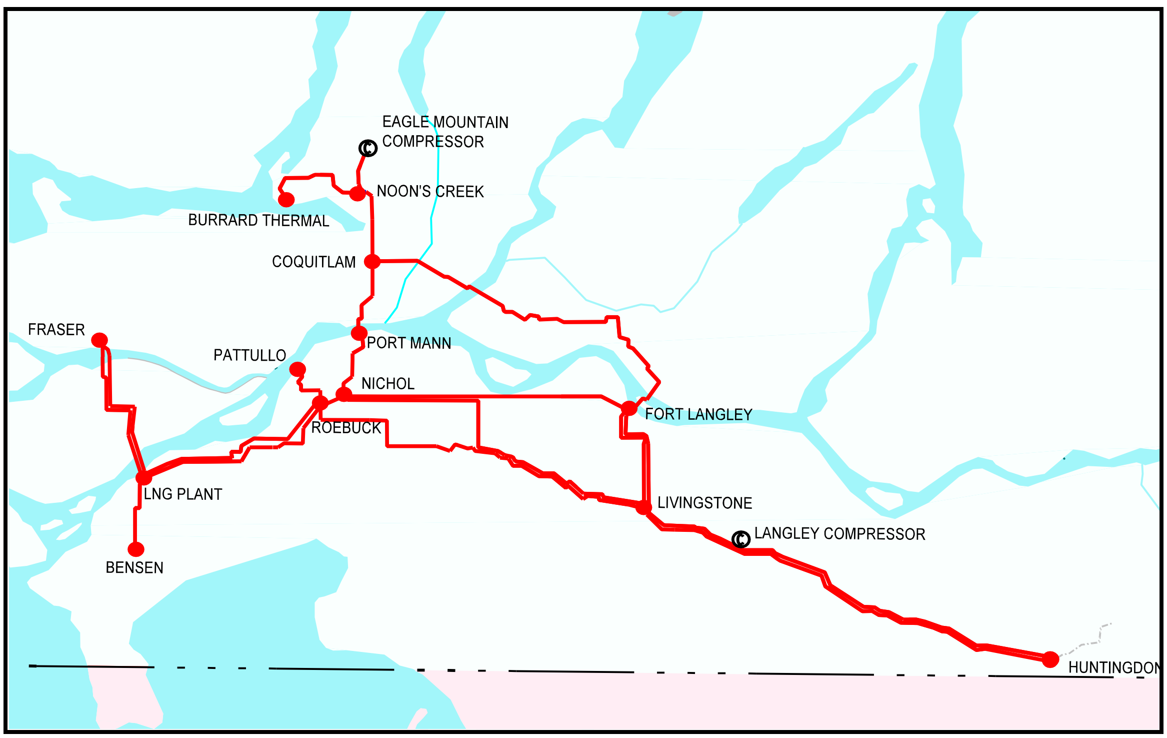
Figure 1.1 Terasen Gas Inc Transmission System



1.2.1 Coastal Transmission System

Natural gas for Terasen Gas' Coastal region customers is delivered from upstream sources on the Duke Energy pipeline system to the Huntingdon trading point near Abbotsford. The Terasen Gas 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 ranging in diameter from 6 inch to 42 inch operating at pressures up to 583 pounds per square inch gauge (psig). 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. Figure 1.2 illustrates the Terasen Gas CTS.

Figure 1.2 Coastal Transmission System

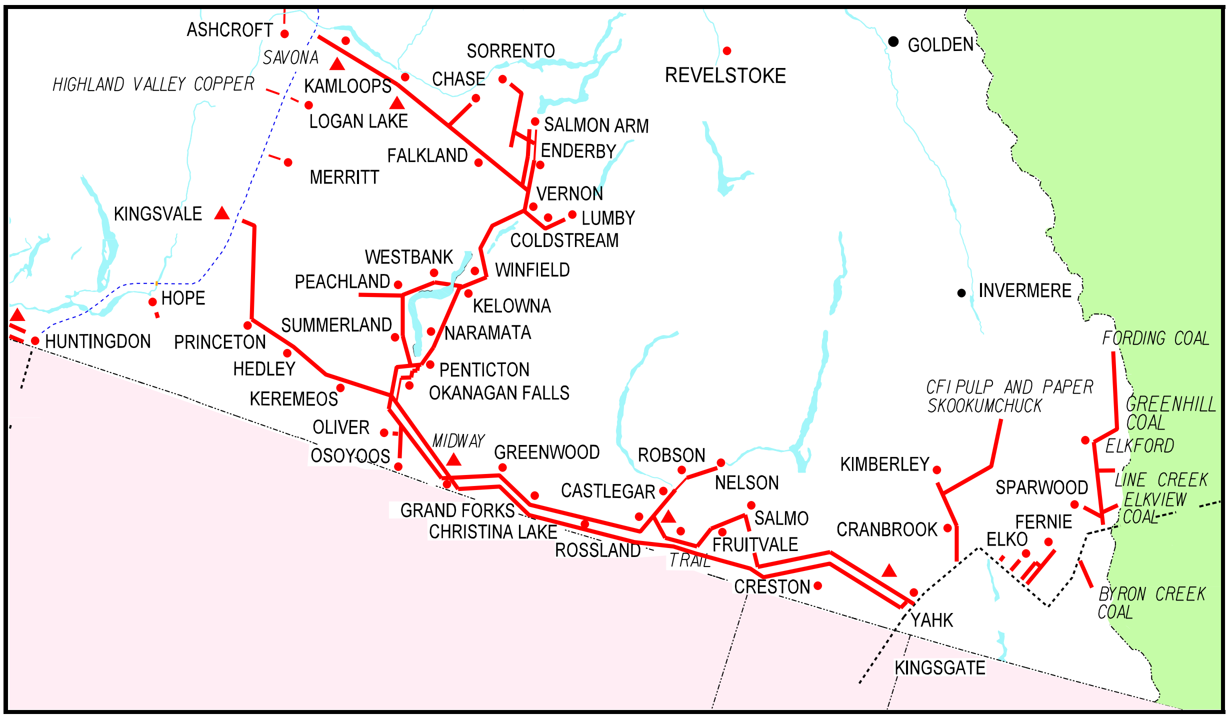


1.2.2 Interior Transmission System

Natural gas for Terasen Gas' Interior region customers is delivered from sources in British Columbia via the Duke Energy 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 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 TCPL system at Yahk.

The Kingsvale and Yahk interconnects are capable of both receipt and delivery allowing bi-direction flow between these two points. Figure 1.3 shows the various pipeline components that make up the ITS.

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"[2], setting out the requirements under the Act for utilities to complete Resource Plans. In December 2003, the BCUC issued *Resource Planning Guidelines* 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 – planning horizon of 15 to 20 years.

2 Energy For Our Future: A Plan for BC - http://www.gov.bc.ca/em/popt/energyplan.htm#eof

2. Develop a range of gross (pre-DSM[3]) demand forecasts.
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 (Appendix A) form the basis of the Resource Planning processes undertaken by Terasen Gas 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. Terasen Gas has recently completed a Regional Resource Planning study[4] that 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 the ability of the infrastructure to reliably serve the needs of the market. The Regional Resource Plan forms the broader context in which Terasen Gas operates and in which this Resource Plan was developed. 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.

3 DSM = Demand Side Management

4 A copy of the Regional Resource Planning study can be obtained by visiting www.terasengas.com

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 a key 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 (20 years), together with a detailed four-year action plan for acquiring resources to meet customer requirements in the near term. It is a planning document that analyzes financial, environmental and social impacts and incorporates stakeholder input. The last formal Integrated Resource Plan for the Mainland was filed in July 1995 by B.C. Gas.

1.4.1 Overview of the Resource Planning Process

The Resource Planning process at Terasen Gas 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.

2. Review the Regional Context

Terasen Gas 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 the Terasen Gas Resource Plan, Terasen Gas also reviewed the *Integrated Electricity Plan* submitted by BC Hydro to the Commission in March, 2004.

3. Develop a Range of Possible Demand Forecasts

Terasen Gas employed a range of alternative assumptions related to new generation loads and residential and commercial customer additions in developing a range of demand forecasts which bracket the possible future service requirements on the Terasen Gas system. Three forecast scenarios are used to assess and compare alternative resource portfolios.

4. Identify Potential Supply and Demand Side Resources

The Terasen Gas system is connected to potential supply sources throughout North America. While this ensures access to sufficient supplies of gas, increased demand for gas service on the Terasen Gas system has resulted in the need for additional capacity to transport gas from the supply regions to the consumption areas. Providing sufficient capacity to meet future customer demand can be accomplished through combinations of additional piping, compression and 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 of the long term planning period addressed by the Resource Plan (normally 20 years).

1.4.2 Terasen Gas Resource Planning Objectives

Terasen Gas' 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 Utility's commitment to providing the highest level of quality energy services to its customers. Terasen Gas' Resource Planning objectives are outlined below.

Ensure reliable and secure gas supply.

A secure energy supply is essential for all of Terasen Gas' 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 Utility 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.[5] Table 1.1 provides a summary of the objectives, associated attributes and measures used to assess alternative resource portfolios against those objectives.

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

5 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.

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 Resource Planning objectives table, 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[6] (TRC) is used for conservation and efficiency programs; the Ratepayer Impact Measure[7] (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; 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. The results of the trade-off process for Terasen Gas and selection of a preferred Resource Portfolio are discussed in detail in Section 6, Resource Portfolio Development and Evaluation.

1.4.3 Resource Planning Process Timeline

During 2004 and 2005, each one of the Terasen Gas group of companies has filed Resource Plans for their service territories. The timeline for stakeholder consultation and Resource Plan submission for each company is provided in Figure 1.4 and summaries of the findings of the TGVI and TGW Resource Plans are provided in Sections 1.4.2.1 and 1.4.2.2 below. On June 18, 2004, TGVI filed its Resource Plan highlighting the growing demand for natural gas on Vancouver Island and the proposed system expansion of an LNG facility. On August 31, 2004,

[6] 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.

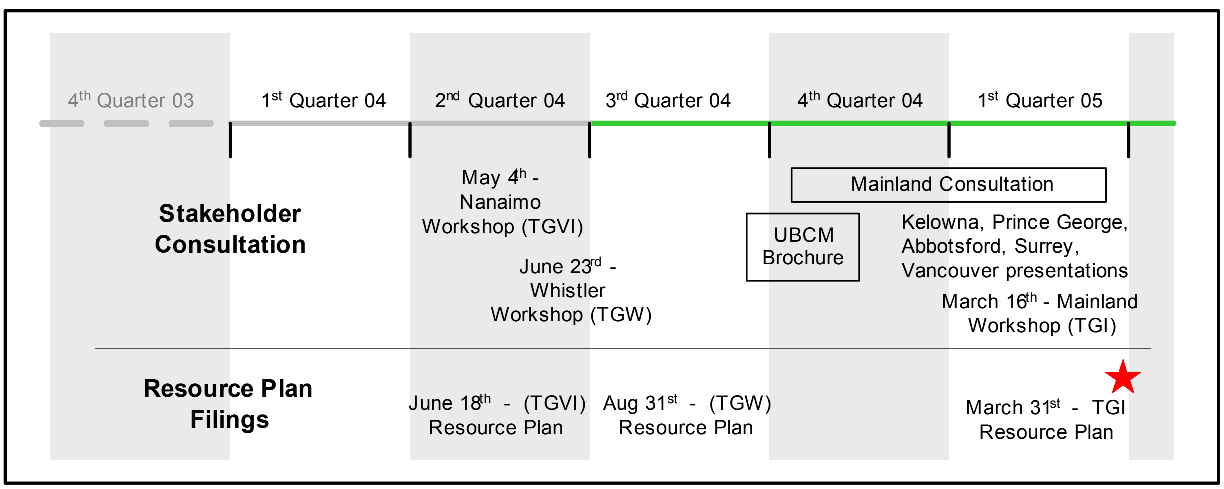
[7] Ratepayer Impact Measure (RIM) Test – a measure of the distribution of equity impacts of DSM programs on non-participating rate-payers. From this perspective, a program is cost effective if it reduces a utility's rates. This can be expressed as a ratio or in dollars of net benefits

TGW submitted its Resource Plan to the Commission outlining the propane system constraint for Whistler region customers. The TGW Resource Plan identifies several alternative energy options, including providing natural gas service to the Resort Municipality of Whistler ("RMOW").

Early in 2004, Terasen Gas agreed to file a Resource Plan for its Mainland regions by year's end, and subsequently received an extension for the filing date to March 31, 2005. Stakeholder consultation undertaken in the Mainland regions for the Terasen Gas Resource Plan is also highlighted in Figure 1.4. Section 7 of this report discusses this stakeholder consultation in detail.

Going forward, the Terasen Gas group of companies will undertake regular review and filing of updates to these Resource Plans with reference to the most current Annual Review materials that are part of any multi-year negotiated settlement. In addition, five year capital plans with capital expenditure schedules and a summary of justification will be referenced in the Resource Plan. Wherever possible, the timing of these updates will be consistent with the internal planning timeline for the Annual Contracting and Price Risk Management Plans for gas supply, which are normally completed through the fourth quarter and the first quarter of the following year. In addition, the companies will look for opportunities to streamline its filing dates by coordinating and synchronizing with other major utilities in British Columbia, such as BC Hydro.

Figure 1.4 2004 Resource Planning Timeline - Terasen Gas Group of Companies



UBCM = Union of British Columbia Municipalities

1.4.3.1 Terasen Gas (Vancouver Island) Inc. Resource Plan

In its submission on June 18, 2004[8], TGVI outlined the growing demand for natural gas in its service territory. Demand for natural gas on Vancouver Island and the Sunshine Coast has seen considerable growth since the construction of the distribution system, with growth expected to continue in the future. The TGVI system currently operates at full capacity with a capacity shortfall expected to occur by 2007. The Resource Planning process has reviewed options for addressing this shortfall and concludes that expansion of the existing pipeline system will be required. TGVI believes that the preferred solution to managing the projected shortfall is to construct an LNG facility on Vancouver Island. Without system expansion, the shortfall in 2007 would extend for more than one third of the year, almost an entire winter heating season.

When evaluated against the four Resource Planning objectives (refer to Table 1.2), the LNG Storage resource portfolio is the preferred portfolio. LNG Storage ranks first in reliability and security of supply, cost, and rate impact. LNG is also preferred in terms of employment and land use impacts, and ranks favourably with the other portfolio options in air emissions impacts across the range of demand forecasts.

As a result, TGVI submitted an application for a Certificate of Public Convenience and Necessity ("CPCN") to the BCUC for the development and construction of the LNG facility. The application initiated public hearing proceedings, which took place in the fourth quarter of 2004 and early in the first quarter of 2005, to review both the Resource Plan and CPCN filings. In a decision dated February 15, 2005, the BCUC agreed with TGVI's Resource Plan findings and approved the CPCN application subject to conditions. A summary of the 2004 TGVI Resource Plan evaluation follows.

Table 1.2 Evaluation Summary - TGVI Resource Plan

TGVI Planning Objective	LNG Storage	Pipe Compression	Pipe Compression Curtailment
Ensure reliable secure supply	✓		
Lowest delivered cost	✓		
Reduce long term volatility	✓		
Balanced impacts	✓	✓	

Financial evaluation of the different resource portfolios to meet the demand requirements supports the LNG Storage portfolio as the preferred alternative to meet the objective of providing service to customers at the least delivered cost. For the most likely demand forecast

8 Visit www.terasengas.com for copy of the 2004 Terasen Gas (Vancouver Island) Inc Resource Plan.

scenarios, the LNG Storage portfolio results in the lowest incremental cost and is not dependent on the outcome of BC Hydro's call for new generation capacity on Vancouver Island.

The Resource Planning objective *Balance Socio-Economic and Environmental Impacts* involves measurement and evaluation of emissions factors, land use impacts, and employment impacts for each of the portfolios. The emissions measures for carbon dioxide (CO_2), nitrogen oxide (NOx) and sulphur dioxide (SO_2) are similar for all three portfolios across all forecast scenarios. The land use and employment impacts favour the LNG Storage portfolio across all forecasts.

The Resource Planning objective *Ensure Reliable and Secure Supply* was evaluated qualitatively for each of the three resource portfolios. While TGVI is confident that any of the portfolios would deliver an adequate level of reliable and secure supply of gas service to customers, a storage facility on Vancouver Island provides additional protection should an upstream failure occur on the Duke, Terasen Gas mainland or TGVI systems. Storage in close proximity to the Utility's major market area adds diversity to the resources available to TGVI.

The Resource Planning objective *Reduce Rate Volatility* measures the relative rate impact of each portfolio and was measured qualitatively. A large storage facility close to the major market helps mitigate commodity price increases during peak demand periods. An LNG storage facility would increase regional supply capacity and decrease the risk of a regional price disconnect. Storage can provide a dampening effect on summer versus winter price differentials.

1.4.3.2 Terasen Gas (Whistler) Inc. Resource Plan

In its submission on August 31, 2004[9], TGW outlined the growing demand for propane service in its service territory. TGW has provided distributed propane service to residential and commercial customers in Whistler since 1987. To date demand growth has been met through periodic expansions of the propane system. The existing system is nearing capacity and will require a major expansion including the development of a new propane storage site. TGW has identified several alternative energy options, including expansion of the existing propane system or providing natural gas service to the RMOW.

The anticipated development of additional housing and sport facilities associated with the 2010 Winter Olympics along with the Sea to Sky Highway Upgrade project presents a unique opportunity to consider extending natural gas service to Whistler as an alternative to expanding the propane system. TGW is working closely with both the Resort Municipality of Whistler and BC Hydro to examine and assess the energy alternatives available to the municipality as it identifies its community energy plan out to the year 2020. TGW believes that a natural gas pipeline connecting Whistler to the gas transmission system in Squamish is the preferred solution to addressing the future energy requirements and sustainability goals of Whistler and the Sea to Sky Corridor.

Resources considered by TGW to increase the capacity of the system include expansion of the propane system and conversion to natural gas:

9 Visit www.terasengas.com for a copy of the Terasen Gas (Whistler) Resource Plan.

1. Propane System expansion: Increase the liquid propane transport, receipt, storage, and vaporization capacity.
2. Liquefied natural gas (LNG) - road or rail transport of LNG to a local LNG storage and vaporization facility.
3. Compressed natural gas (CNG) - road or rail transport of CNG to a local CNG storage and pressure regulating facility.
4. Natural Gas Pipeline - construction of a natural gas pipeline and pressure regulating facilities connecting the existing distribution system to the Vancouver Island Natural Gas Pipeline near Squamish.

As summarized in Table 1.3, the pipeline option scored high against all Resource Plan objectives for TGW.

Table 1.3 Evaluation of Alternatives Against Resource Planning Objectives - TGW

TGW Planning Objective	Propane Expansion	Natural Gas Pipeline
Least Delivered Cost	• Lower fixed costs • Higher operating & commodity costs	• Competitive alternative to propane • Greater potential to meet new demands and reduce costs further
Ensure reliable and secure supply	• High system reliability and secure supply sources	• High system reliability and secure supply sources
Reduce rate volatility		• Lower commodity costs • Benefit from Terasen Gas' diversified gas supply portfolio
Balanced impacts	• Lower land impacts • More permanent employment	• Reduced GHG and air pollutant emissions • Facilitates NGV strategy further reducing emissions • More construction employment • Whistler Council support

2 TERASEN GAS - GAS SUPPLY OVERVIEW

2.1 Terasen Gas - Gas Supply Obligations

Terasen Gas through its Midstream management group ("Midstream Manager") is responsible for contracting of all Midstream[10] resources needed to move gas from market (supply) hubs to the distribution system and to provide balancing and peaking services for all customers. Terasen Gas uses pipeline, storage, seasonal, spot peaking, hedging and sale activities to manage load variability and resultant cost variances.

Terasen Gas has two types of customers: distribution and transportation customers. Distribution customers consist of Residential, Commercial, Seasonal, Small Industrial customers and Natural Gas Vehicles (Rate Schedules 1 – 6) that have gas delivered to their home or business. These bundled sales customers are also referred to as "Core Sales" or "Core Market" customers. On behalf of Core Market customers, Terasen Gas currently purchases all the natural gas and recovers this cost in bundled sales rates. This requires holding natural gas pipeline and storage assets upstream and downstream of the Terasen Gas system on behalf of these customers.

Core Market customers typically use a significant portion of their gas requirements for heating applications. Consequently, gas demand for the Core Market is weather sensitive. Due to the weather dependency, sufficient gas supplies must be purchased to meet the requirements for the Core Market based on the coldest day of each year. Gas is primarily consumed during the winter requiring gas purchasing throughout the year to be shaped to meet these demand characteristics.

As of November 1, 2004, Small and Large Commercial customers, Rate Schedules 2 and 3 have the choice of buying natural gas from either a gas marketer, licensed by the BCUC, or continue buying their gas from Terasen Gas as part of Terasen Gas' Commodity Unbundling program[11]. This program provides small volume commercial customers with more options for buying fixed price natural gas commodity. However Terasen Gas will continue to maintain responsibility for managing the Midstream resources and delivering gas to customers whether they buy their gas direct from Terasen Gas or from a licensed gas marketer.

The second type of customer is transportation customers. These customers are large commercial and industrial customers who manage their own gas supply requirements. Transportation customers purchase their own gas in the wholesale market and provide it to Terasen Gas located at the inter-connect of Duke's pipeline and the Terasen Gas system near

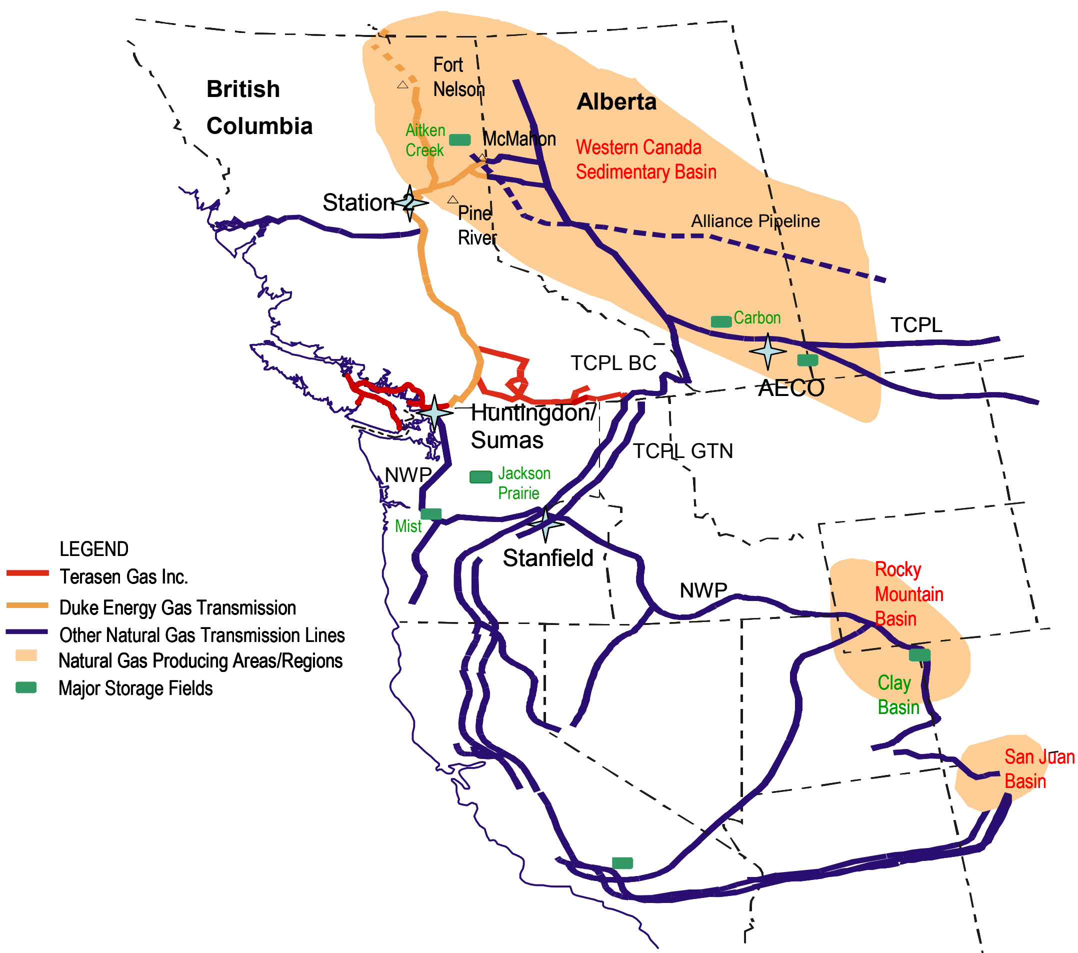
[10] Midstream refers to those resources owned or leased by Terasen Gas Inc. that help to store, transport and manage the gas Terasen Gas purchases and provides to customers before it reaches Terasen Gas' distribution system.

[11] The Commodity Unbundling program is open to all commercial customers (Rates 2, 3 and 23) except those in Squamish, the Sunshine Coast, Vancouver Island and Fort Nelson which operate under different regulatory agreements.

Huntingdon, B.C. or at the various interconnects between Duke and Terasen Gas on the Inland delivery area. Terasen Gas then transports the gas to the customers' facilities. Currently, Terasen Gas has the option to interrupt service to some of these customers on the coldest days and divert their gas to the Core Market. This provision limits the need to build pipeline capacity to serve Core Market demands that are only required on the coldest days.

Natural gas supply serving the B.C. market primarily originates from the Western Canadian Sedimentary Basin (Northeast British Columbia and Alberta) and is transported to B.C. customers via Duke's T-South pipeline from Northern B.C. and TransCanada's B.C. pipeline in South-eastern B.C. Natural gas can also be sourced from the Stanfield market hub and Rocky Mountains and be delivered via Williams' North West Pipeline ("NWP") through the Columbia Gorge to Huntingdon, B.C. This network of gas pipelines and storage facilities is shown in Figure 2.1. Terasen Gas primarily receives gas at three supply / market hubs: Huntingdon, Station 2 and AECO.

Figure 2.1 Western Gas Supply Region and Pipeline Layout



2.2 Market Considerations for Gas Supply Availability

Gas supply considerations are a key component in long term Resource Planning for Terasen Gas. Factors such as supply / demand competition, resource availability, and restrictions or constraints are evaluated to provide secure delivery to our customers. The challenge to load serving entities like Terasen Gas is meeting customer demand with supply resources which are dependent on the physical capacities of the region. In meeting future demand growth and to ensure adequate supply is available, timely infrastructure additions are essential.

2.2.1 Gas Supply Reserves

When Terasen Gas purchases gas for delivery to its bundled sales customers, it must consider not only the local natural gas market within the Lower Mainland or Interior, but also the regional market in British Columbia, the U.S. Pacific Northwest and the continental market of North America. The continental gas supply perspective is important when evaluating the requirement for new facilities which are to be used over their lifetime of thirty or more years. When resources reach the end of their useful life, significant lead time must be taken into consideration to build facilities and bring the resources to the market to meet existing and new demand in the region. Terasen Gas has reviewed the latest forecasts for gas reserves from a variety of sources and, as described below, is satisfied that ample supply exists to serve Terasen Gas markets over the planning period.

2.2.1.1 Regional Perspective

The regional market is centred on the Huntingdon / Sumas market hub at the B.C. / Washington border, southeast of Vancouver. Most of the gas used in the region originates in from Duke's T-South pipeline or from the Stanfield market hub and Rocky Mountain supply region via Williams' NWP through the Columbia Gorge.

The Pacific Northwest can be characterized as being rich in resources due to its access to supply sources in the Rockies, Alberta and Northern B.C. Estimates by the National Petroleum Council ("NPC")[12] are 272 trillion cubic feet ("Tcf") (7,706 10^9m^3) of proven reserves in North America or roughly 10 years of supply at current demand levels. Further, the study estimated 1,970 Tcf (55,810 10^9m^3) of total technical resource or 73 years of supply at current production levels. Proven reserves are those that have been drilled and are awaiting production and are similar to the inventory that most businesses maintain, while the total technical resource includes those resources that remain to be discovered and/or developed.

12 National Petroleum Council, "Balancing Natural Gas Policy – Fuelling the Demands of a Growing Economy", 2003.

2.2.1.2 North American Perspective

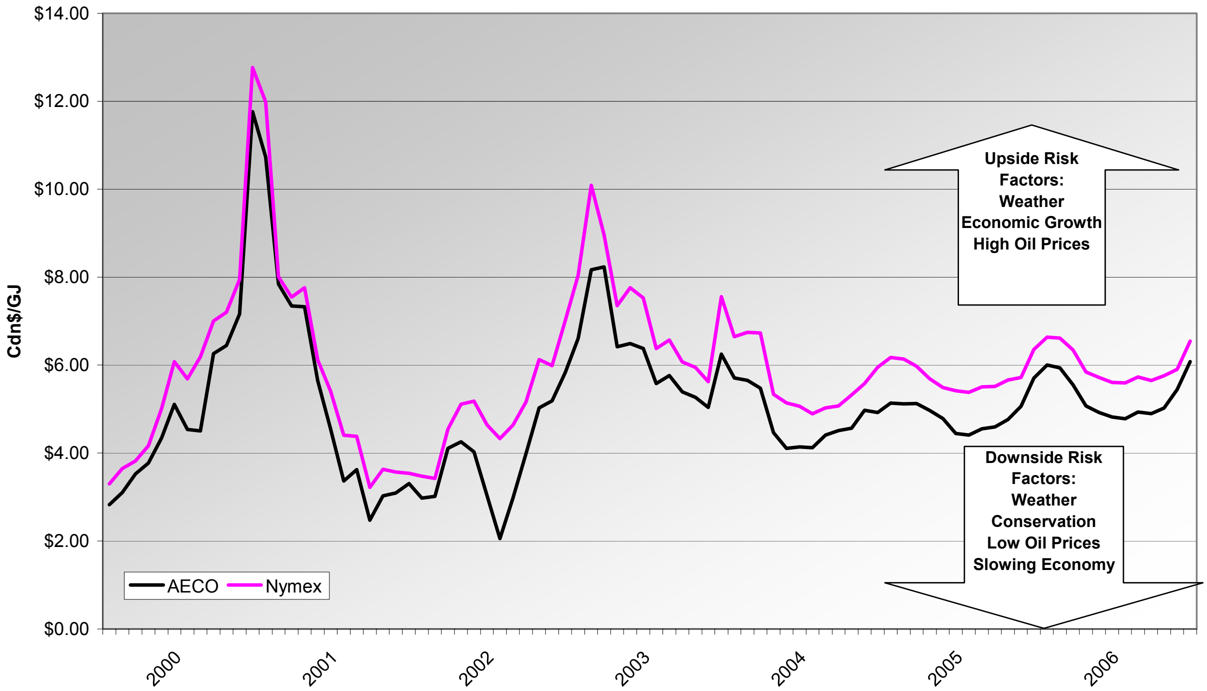
A report by the National Energy Board ("NEB") released in 2003[13] identifies some uncertainty regarding long-term gas supply in the region. Through scenario analysis, the report suggested a tight supply-demand balance would likely exist between supply and demand in the region, and that natural gas prices would be relatively high and volatile until new supply or a reduction in consumption were to occur. In August 2004, the NEB released a follow up paper[14] detailing a series of round-table discussions of the foreseeable evolution of the gas supply market through to 2010 with market participants across Canada. Market participants commonly agree that the supply and demand balance will remain tight through to 2010 and that gas supply will be challenged to meet expected growth in gas demand. While incremental supply resources are likely to come from Mackenzie Delta and imported liquefied natural gas, these sources will become available to the market closer to the end of the decade. Alaskan gas is also expected to bring additional supply to market; however, this resource is not expected until post 2010.

The North American natural gas industry has been faced with a sustained period of high prices and extreme volatility over the last couple of years. Figure 2.2 below illustrates the impact on the Alberta AECO daily prices which averaged $6.211 Cdn/gigajoule ("GJ") in 2004, a decrease of 1.2% from 2003 prices versus a 38% increase from 2002 average. Variances in natural gas production and storage levels, extreme weather conditions, rising oil and competing fuels prices have led to the rise and fall of energy costs.

[13] National Energy Board, "Canada's Energy Future – Scenarios for Supply and Demand to 2025", July 2003.

[14] National Energy Board, "Looking Ahead to 2010 Natural Gas Markets in Transition, An Energy Market Assessment", August 2004.

Figure 2.2 Alberta AECO and Nymex Natural Gas Prices



Source: Cambridge Energy Resource Associates
Note: The above information is for purposes of discussion and not intended as a forecast.

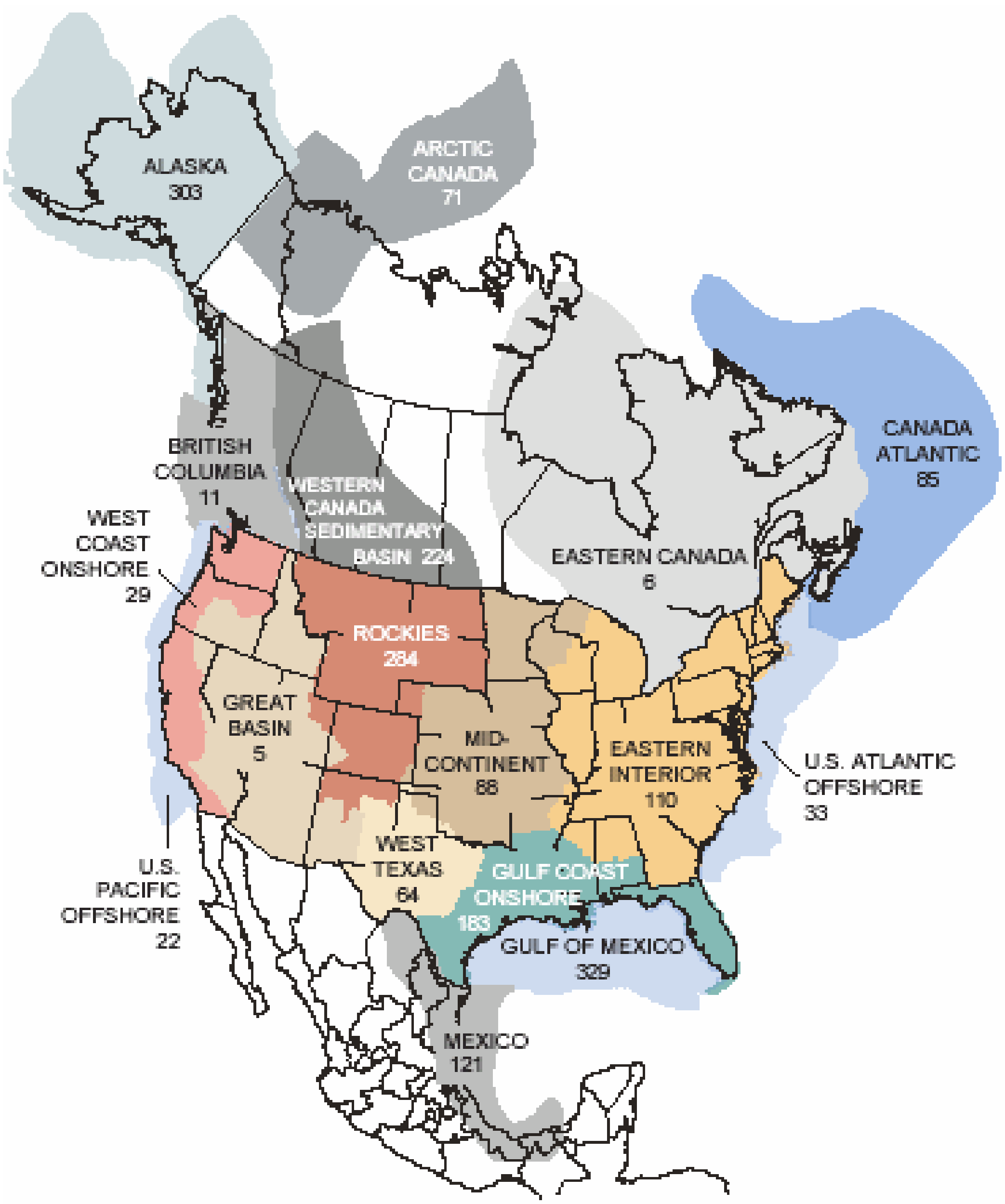
A review of Canada's conventional resources released by the NEB in 2004 concluded that Canada has an ultimate potential of over 14,165 $10^9 m^3$ (500 Tcf) of conventional marketable gas.[15] Conventional marketable gas is defined as gas that using current or expected technology could be produced and brought to market. This estimate excludes unconventional resources such as gas offshore of British Columbia[16] or coal bed methane. In North America, a migration to newer supply areas is taking place as supply is exhausted in heavily exploited areas such as the U.S. inshore Gulf coast and mid-continent. Areas where gas supply is continuing to build include the U.S. Rocky Mountain region and North-eastern B.C. Frontier or new areas include the McKenzie Delta, Alaska North Slope and Sable Island[17]. North American gas supply estimates do not include liquefied natural gas imported to North American via tanker ships, another potential sizable resource. Figure 2.3 below illustrates the distribution of existing supply resources in North America.

15 National Energy Board, "Canada's Conventional Natural Gas Resources: A Status Report", April 2004.

16 The Government of Canada is currently conducting a review of the federal moratorium in place preventing drilling in this region. Initiated in 2004, a Review Panel will assess economic, social and environmental impacts involved in lifting the moratorium.

17 The Mackenzie Delta and Alaska resources are currently under great scrutiny, both of which are not expected to enter the marketplace until late 2009 and into the next decade.

Figure 2.3 North American Supply Resources (in Trillion Cubic Feet)



(Source: National Petroleum Council)

2.2.1.3 World Perspective

Proven gas reserves worldwide are vast. The U.S. Department of Energy's World Energy Outlook published in April 2004 estimates world proven (discovered) reserves at approximately 169,980 $10^9 m^3$ (6,000 Tcf) or more than 60 years of supply at current production levels.

2.2.2 Exploration and Drilling

Total US drilling activity increased approximately 13% from 2003 to 2004 and is expected to continue expanding through 2005. As well, completions continue to grow and are expected to reach 22,000 – 23,000 per year over the next 2 years. Canadian rig counts for the month of December 2004 were 440, a 5% increase from the same time in 2003; however annual rig counts were roughly the same in 2003 and 2004.[18] It should be noted that decline rates in the Western Canada Sedimentary Basin ("WCSB") have increased from 13% in 1992 to 23% in 2002, while initial well productivity for a typical gas well completion has fallen from 19.8 10^3m^3 (0.7 MMcf/d – million cubic feet per day) in 1997 to 8.5 10^3m^3 (0.3 MMcf/d) in 2003.[19] The reason for this decline is partially a function of maturity of the basin and partly a function of new technology such as directional drilling, allowing quicker depletion of reservoirs. As the average initial productivity of new well connections in the WCSB continue to trend downwards, an increasing number of new gas well connections are needed each year to maintain conventional deliverability.

There has been a rise in production from oil sands projects in western Canada and plans for further expansion of these projects. Natural gas is intensively consumed in the processing of oil sands. Despite higher natural gas costs, demand for natural gas for use in oil sands production is expected to rise from 20,539 10^3m^3 (725 MMcf/d) in 2002 to a projected 51 10^6m^3 (1.8 Bcf/d) in 2015.[20]

While basins in Western Canada are maturing, a number of factors will likely act to increase the overall deliverability of Canadian gas. These include advances in drilling technologies to access smaller pools, new supply resources from the North, the Rocky Mountains and other regions, and the anticipated onset of new LNG resources. Canadian gas deliverability is expected to rise from 11% from 481.6 10^6m^3 to 538.3 10^6m^3 (17 to 19 Bcf/d) by 2015.[21]

2.2.3 Other Supply Sources

The NEB estimates the ultimate potential of west coast offshore resources at 255 10^9m^3 (9 Tcf) with the majority of the offshore natural gas expected to exist in the Queen Charlotte Basin. Since 1972, this region has been protected by a moratorium on exploration and development. The moratorium is currently under review by the Province of British Columbia and Natural Resources Canada to determine how offshore oil and gas development can occur in British Columbia in a scientifically sound and environmentally responsible manner. Currently there is no commercial production of this resource. Unconventional natural gas resources such as coal bed methane represent additional resource potential, however it is unclear how much may eventually be produced.

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18 Baker Hughes, Rig Counts

19 National Energy Board, "Short Term Natural Gas Deliverablity 2004-2006", November 2004

20 CERA, "Canada's Oil Sands: Strong Growth Despite a Tight Gas Market", 2003.

21 National Energy Board, "Canada's Energy Future – Scenarios for Supply and Demand to 2025", July 2003.

Import LNG is anticipated to play an increasing role in the overall North American market. Many LNG terminals have been proposed for locations in Canada and the United States, however it is speculated that out of the forty current proposals, only two or three will likely be in service by 2010[22]. These new projects could increase total LNG import capacity by 85 10^6m^3 (3 Bcf/d), for a total capacity of approximately 283.3 10^6m^3 (10 Bcf/d).

2.3 Market Considerations for Competing Demands and Infrastructure

In planning for future gas supply requirements, it is important for Terasen Gas to know what the competing demands are in other areas that could impact Terasen Gas' ability to secure supply to meet future demand. Along with those competing demands is the competition for use of the infrastructure to transport natural gas to British Columbia. The following sections discuss the competing demands and the availability and status of the infrastructure Terasen Gas relies on.

2.3.1 Power Generation

The power generation sector has a significant role in the energy market due to its potential to exert a significant amount of demand. Power generation represents an increasing percentage of the Pacific Northwest region's overall demand. Between 2000 and 2003, roughly 24,000 MW of new generation capacity was added to the jurisdiction of the Western Electricity Coordinating Council[23], of which 95% was gas-fired.

In the I-5 Corridor, only 3,230 MW of gas-fired generation capacity existed prior to 2000. Gas fired generation has historically been used in the region to compliment hydroelectric capacity and provide a displaceable source of reliable energy during periods of reduced hydroelectricity capability or in peak periods when regional demand exceeded hydroelectric capacity. Since 2000, 2,020 MW of new capacity has come into service, of which 375 MW is peaking generation, 1,265 MW is combined cycle generation and 380 MW is cogeneration. Appendix B contains a list of gas-fired facilities that have been constructed in the region since 2000.

The forecast total potential gas demand for generation (both existing and expected new generation) within the US portion of the I-5 Corridor ranges between 15,015 10^3m^3 and 16,299 10^3m^3 (530 and 575 MMcf/d) for 2005, while that for 2009 ranges between 19,406 10^3m^3 and 27,197 10^3m^3 (685 and 960 MMcf/d). This total does not include the entire capacity of several existing projects for which their owners / operators have indicated that design day demand will be significantly less than capacity (Point Whitehorn, Frederickson and Fredonia) as well as

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22 National Energy Board, "Looking Ahead 2010 Natural Gas Markets in Transition", August 2004.

23 Electricity generation and transmission in the Pacific Northwest of the United States falls under the jurisdiction of the Western Electricity Coordinating Council ("WECC"). The WECC region encompasses an area stretching as far north as British Columbia and Alberta, as far south as Baja, California Norte, Mexico and east to South Dakota. The WECC is one of ten regional members of the North American Electric Reliability Council ("NERC"), a non-profit corporation the coordinates virtually all the electricity supplied in the United States, Canada and portion of Mexico.

several small facilities supplied by load serving entities as industrial / transportation customers. Appendix B also contains a further list of proposed electrical generation capacity additions in the I-5 corridor.

2.3.2 Demand and Infrastructure in the Pacific Northwest Region

By North American standards, the Pacific Northwest regional market known as the I-5 corridor is relatively small with design-day demand estimated at between 4 and 5 petajoules (PJ)/day.[24] In comparison, the Alberta market hub is approximately 15 PJ/day with total demand across North America averaging approximately 70 PJ/day. The region itself is also characterized by a tight supply / demand balance that have contributed to price volatility during periods of high demand.

In their 2004 study on the B.C. natural gas market (see Appendix C), the NEB concluded that B.C. has experienced the rising gas prices that have occurred elsewhere in North America and that in response, producers have increased exploration for gas to serve the region. Consumers, particularly industrial costumers, have responded to higher prices by changing their fuel use and adopting energy conservation measures.

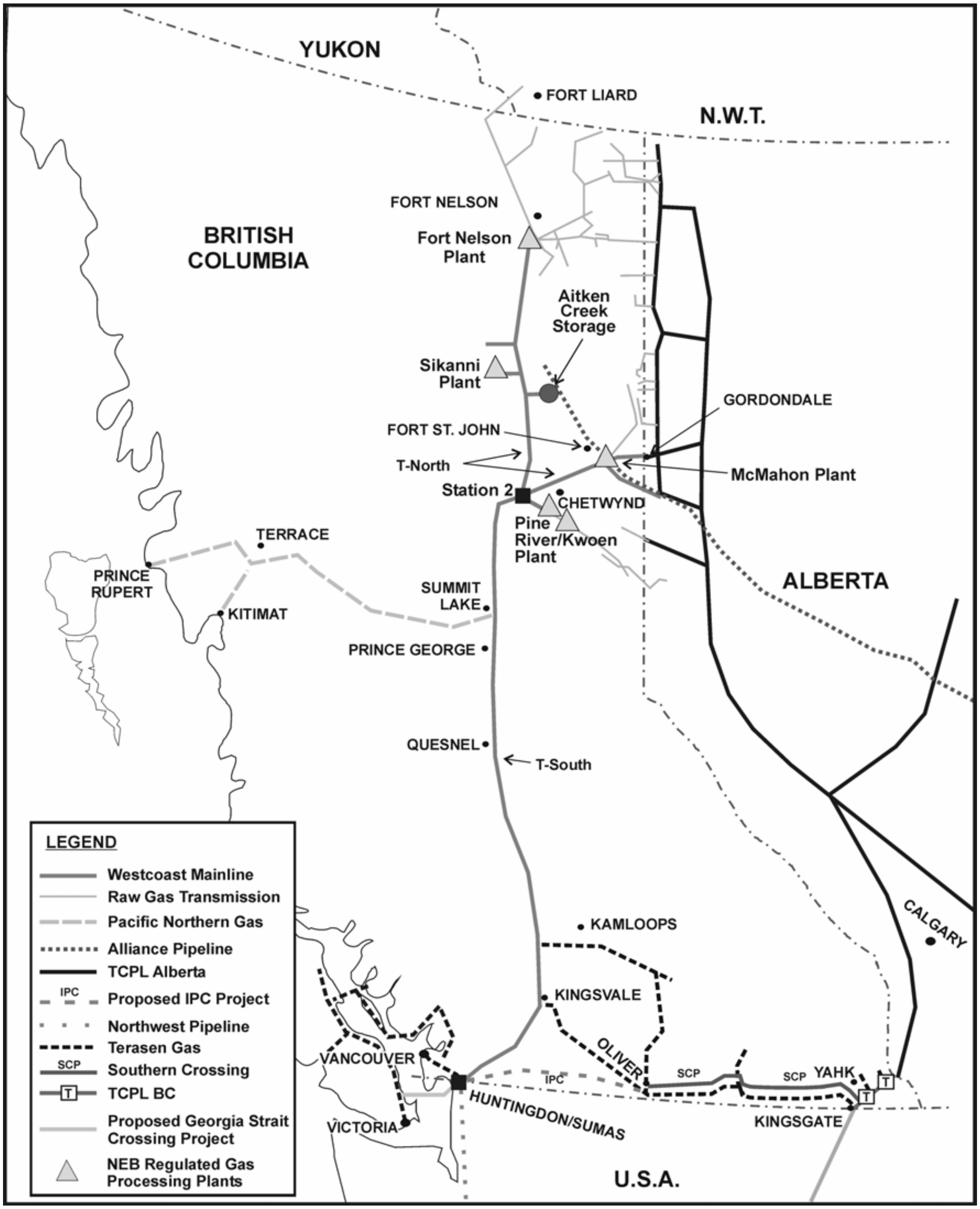
The major demand centres in the region run along the I-5 corridor, from South-western B.C. to Portland Oregon with four major gas supply pipeline routes delivering gas to the region. As discussed earlier and shown in Figure 2.4 below, the pipelines are Duke's T-South pipeline bringing gas from North-eastern B.C., Terasen Gas' Southern Crossing pipeline transporting gas from Alberta, TransCanada Pipeline's Gas Transmission Northwest ("GTN") pipeline from Stanfield and Williams' NWP transporting gas from the US Rocky Mountain Region.

The regional market is centred on the supply hub at the Huntingdon / Sumas border crossing where Duke's capacity to deliver to Terasen Gas' Lower Mainland, Vancouver Island and the Pacific Northwest region is approximately 48.2 10^6m^3 (1.7 Bcf/d). This supply hub allows access to downstream storage resources such as Jackson Prairie Storage ("JPS"), Mist and gas from the Stanfield supply hub.

As discussed, the majority of the gas delivered to the region comes from Northeastern B.C. and is shipped south from Station 2 on Duke's T-South pipeline. In the winter, production in Northeast B.C. is augmented with gas from the Aitken Creek storage facility. Terasen Gas' and Williams' NWP provide smaller quantities of supply to the region and play an important role in providing supply diversity to the region. Further, this network of pipelines is important in establishing security of supply to the region. In addition to gas pipelines, gas storage is used to meet the variances or peaks in demand characteristic of the residential / commercial heating market.

24 The "I-5 Corridor" encompasses the regions of lower mainland British Columbia, Vancouver Island, Western Washington and Western Oregon.

Figure 2.4 Regional Pipelines



Source: National Energy Board

2.3.2.1 Natural Gas Storage

Storage is most efficient when it is located in proximity to the load it serves, thus reducing the required facilities that must be put in place to bring gas to the market. There are two forms of storage commonly in use, underground and LNG storage.

Underground storage like Aitken Creek in Northeast B.C., and Carbon in Alberta are located in production areas and serve the seasonal load of the Core Market, whereas facilities like JPS in Chehalis, Washington State and Mist in Beaver, Oregon are located near markets and are used as peaking resources. Underground storage typically makes use of existing gas or oil reservoirs to store gas. Suitable geological conditions for an underground storage facility have not been confirmed in southern British Columbia; therefore options for storage within the Terasen Gas service area are currently limited to LNG facilities where pipeline gas is transported to the site, liquefied and stored for use during high demand periods.

LNG storage is used primarily on peak or high demand days and is very flexible in terms of where it can be located. LNG facilities in the Pacific Northwest include Tilbury Island (located in Delta) on the Terasen Gas system, Williams facility at Plymouth Washington, and Northwest Natural facilities at Portland and Newport, Oregon.

A situation of temporary tight supply / demand is typically mitigated by development of storage resources that provide supply during periods of high demand. Storage allows a balancing of supply and demand between low summer demand months where supply is put into storage and high winter demand months where it is withdrawn. However, there is no expectation of any new large underground storage reservoirs being developed in the region. Further, there is limited opportunity to expand capacity at Mist and JPS.

2.3.3 Regional Planning Efforts

In July 2004, Terasen Gas produced a "Regional Resource Planning Study" which provided an outlook for natural gas demand in the region served through the Sumas market trading point referred to as the I-5 Corridor. The objectives of the study were to assess the supply resources available to the market and develop high-level recommendations as to what solutions would optimally address any existing or expected future capacity shortfalls. Analyses showed that existing resources are sufficient to meet normal expected loads in 2007. However, review of weather sensitivity and physical interruptions from pipeline outages suggests a need for additional capacity resources to meet peak day regional demand in the incidence of a moderately cold or low hydro year.

In addition, the Northwest Gas Association ("NWGA") working in partnership with Terasen Gas, created a similar report in June 2004 entitled the "Northwest Gas Outlook", providing a consensus industry perspective of the region’s current and projected natural gas supply and delivery capabilities as well as customer demand projections and drivers for the Pacific Northwest. The Northwest Gas Association is a trade organization of the Pacific Northwest natural gas industry, whose membership includes six natural gas utilities and three transmission pipeline companies. Similar to Terasen Gas' findings, the Northwest Gas Association's analyses showed that under peak day demand conditions, the region may require additional capacity as soon as 2006 – 2007. Terasen Gas endorses the analyses done by the NWGA and will continue to work with the Association and other market participants in the region to encourage coordinated planning.

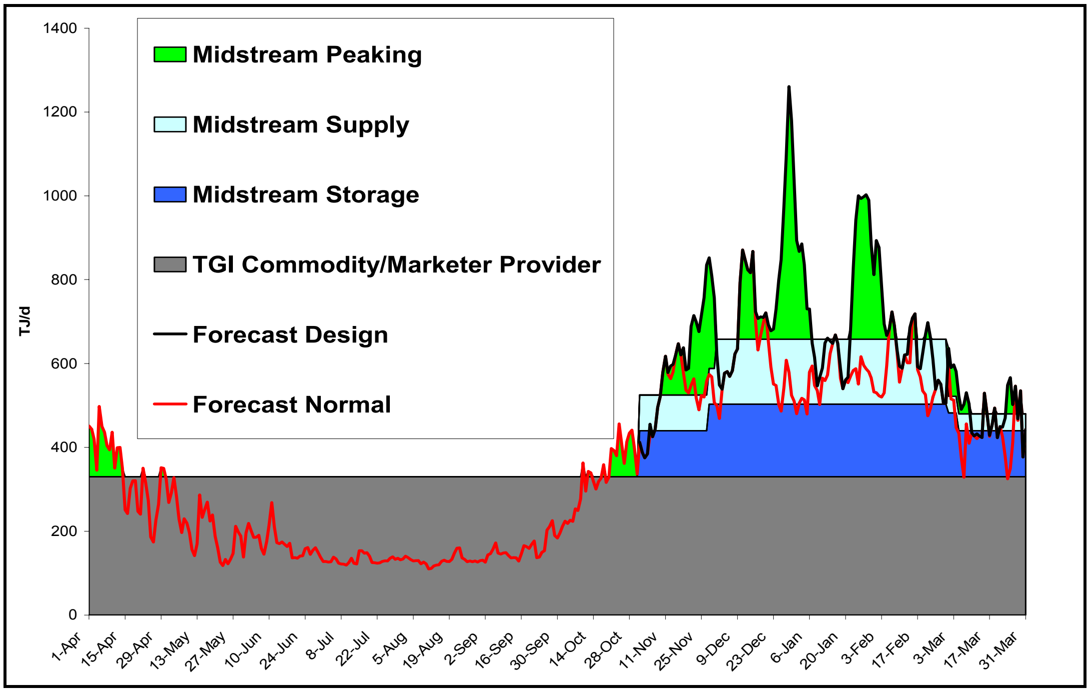
2.4 Gas Supply Portfolio Planning

2.4.1 Gas Supply Portfolio Planning

A gas supply portfolio is the package of contracted supply resources that ensure a reliable supply of natural gas to a gas Utility's customers over the course of a year and long-term. Generally, Terasen Gas' supply portfolio consists of a range of gas purchase contracts to meet forecasted design day demand for its Core Market customers. Terasen Gas uses third-party pipeline capacity to access contracted natural gas resources throughout the year, including peaking resources that allow the interruption of gas supply to specific customers during periods of high demand (known as curtailment).

In planning the gas supply portfolio for Terasen Gas, resources must be in place to manage the varying demand for gas on an annual basis. Terasen Gas' supply portfolio must also meet reasonable elevated demand levels over extended periods of colder weather, and mitigate any interruptions in delivery capacity. Terasen Gas' Midstream Manager relies on base load supply from Commodity and Market Providers, as well as Terasen Gas' own storage supply, seasonal and spot supply from Station 2, Huntingdon and Alberta. Figure 2.5 shows the forecasted normal and design day demand throughout the year. As shown below, gas supply requirements vary significantly through the year, reflecting the significance of weather sensitive demand inherent to Terasen Gas' Core Market customers. Terasen Gas looks at both the design day and the normal or expected demand for each day. The coloured areas below the lines represent types of resources used to meet the forecast demand.

Figure 2.5 Annual Supply Portfolio Profile 2004 - 2005



Terasen Gas' Midstream Manager conducts sensitivity analysis on it's portfolio of resources required to meet normal and design day load requirements. After reviewing the design day and various load profiles, Midstream has selected the resources identified in Table 2.1 as the recommended portfolio for 2005/06 and forecasted supply sourcing for the next three years.

Table 2.1 Midstream Contracting Portfolio - Contracting Volumes to 2007-08

	2004/05	2005/06	2006/07	2007/08
Commodity Supplier	330	333	336	339
Station 2 & Alberta Seasonal / Spot / Alberta	169-252	152-252	152-252	152-252
Huntingdon Seasonal / Peaking	54	45-80	50-95	45-100
Seasonal Storage	135-155	135-172	135-172	135-172
Jackson Prairie / Mist & Downstream Storage	217	203-236	203-237	203-238
SCP Peaking / Kingsgate	83	86	90	93
LNG	164	164	164	164
Industrial Curtailment	26	26	26	26
Total Supply	1260	1260	1276	1290

The majority of Terasen Gas' Midstream transportation, storage and supply contracts are short-term in nature, providing the flexibility to accommodate future market changes. The ability to re-evaluate and change the portfolio mix on a year to year basis provides Terasen Gas with the option to make portfolio adjustments that best respond to market factors and corporate objectives going forward.

While customers and regulators expect the Utility to procure and deliver energy in the most cost-effective manner possible, it is also Terasen Gas' responsibility to prudently identify, monitor and mitigate potential operational and market related risks. In assembling a gas supply portfolio to meet this demand, Terasen Gas balances the objective of least cost against objectives of reducing rate volatility and ensuring supply reliability and security.

Least Cost

Terasen Gas assembles a portfolio that, on an expected basis, represents least delivered cost. This is done by using a mix of gas purchasing and supply resources that minimize the assets required to serve the load. Terasen Gas uses a linear programming and optimization model called 'Send-out' as well as industry knowledge and experience to establish least-cost portfolio and asset planning.

Supply Reliability and Security

Two of the major risks affecting supply reliability and security are infrastructure failure and supplier failure. Infrastructure failure can occur for a variety of reasons due to the mechanical nature of the gas delivery system. Problems can occur with pipelines, compressors, gas wells, or gas plants. Suppliers can fail for a variety of reasons including financial difficulties and lack of reserves. Terasen Gas addresses these risks by diversifying its supply portfolio to the extent possible.

Rate Volatility

Rate volatility is a result of both increases in absolute prices and in daily or seasonal price volatility related to short term events. Terasen Gas manages price risk by diversifying its portfolio through the reduction of exposure at any one pricing point, minimizing exposure at trading points having less liquidity and managing overall price volatility. Midstream optimizes and diversifies its portfolio by the following practices:

- Diversifying gas pricing among many pricing indices (for example, Huntingdon, AECO, and Station 2 priced gas supplies).
- Purchasing physical supplies at daily, monthly and fixed prices.
- Injecting supply into storage in the summer, which is a physical winter hedge tactic by locking in the value of summer gas, to meet load requirements in the winter.
- Purchasing contracts, pipeline and storage resources with varying expiry dates.

2.4.2 Gas Purchasing

Terasen Gas' Midstream Manager develops an optimal portfolio to meet design day load. Midstream holds and manages storage resources, spot and peaking resources (accessed through third-party pipeline capacity), hedging and sale activities (as approved within the Annual Contracting Plan to manage load variability and resultant cost variances). The Midstream Manager determines the allocation of gas to be delivered to the various hubs such as Station 2 via Duke's T-South pipeline, Kingsgate via TransCanada Pipeline and Huntingdon via Williams' NWP. Midstream is also responsible for managing excess gas when variation between normal versus design demand occurs either by off system selling or injecting into storage. Midstream Manager is also allowed a limited amount of hedging activities.

The stacking of supply resources is grouped by type of contract with 100% load factor resources drawn first and flexible contracts, like storage, situated further up the supply stack. Accessed through third-party pipelines, supply resources in Terasen Gas' portfolio consist of:

- baseload (365 days in duration) and long term contracts greater than 1 year,
- seasonal (60 – 214 days),
- a combination of leased underground storage (20 – 151 days) and LNG contracts (25 days or less),
- daily and monthly spot supply purchases,
- Huntingdon supply and Terasen owned peaking resources (10 – 25 days) for colder winters, and
- LNG and industrial curtailment for shorter interval weather events (less than 5 days).

2.4.3 Gas Price Risk Management and Cost of Gas

Terasen Gas has employed a Price Risk Management Plan for many years to manage the market risk inherent in its procurement of natural gas to serve customer load and the subsequent impact on customer rates. Though the key guiding principles have generally remained unchanged from year to year, Terasen Gas does, through an annual submission to the BCUC, re-examine 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 moderate the volatility of market gas prices and resultant rates for customers. Terasen Gas believes that the primary focus for load retention and load growth is to ensure gas rates stay competitive with electricity rates in the Province. In the context of Provincial policies in B.C. of low electricity rates and preservation of the BC Hydro Heritage Asset benefits for an extended period, Terasen Gas considers it an important focus of its price risk management activities to manage this objective. 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 on customer rates due to commodity price volatility.
3. Reduce the risk of regional price disconnects.

Terasen Gas believes that a primary focus for continued load retention and encouragement of new, economic load growth is to ensure rates stay competitive with electricity rates in the Province. With policies in the Provincial Energy Plan (and subsequent actions on these policies) targeting low electricity rates and preserving for an extended period the benefits of the low cost heritage electricity resources, small-volume electricity consumers will be sheltered for the most part from market prices or the marginal costs of their electricity load. Staying competitive with electricity will need to be a continuing focus of Terasen Gas' price risk management activities.

While improving the likelihood that natural gas remains competitive with electricity over the term of the plan is a significant objective, moderating the volatility of market gas prices and resultant rates for customers is also important. The magnitude of managing price volatility has become apparent over the last three years as both market volatility and prices have increased. In order to manage this market price volatility, Terasen Gas has employed a hedging program to create a portfolio mix that, used in combination with the existing gas cost pass-through mechanism, has assisted in managing customer rates. The hedging program employs a combination of fixed and option financial instruments that are implemented over a 24 – 36 month hedging window.

2.4.4 Managing Gas Supply Physical Resources

The basic physical resources that Terasen Gas has available are pipeline, underground storage, and LNG storage. Terasen Gas depends on the following pipelines; Duke Energy Gas Pipeline, Trans Canada Pipeline, Southern Crossing Pipeline and Northwest Pipeline. Pipeline capacity is best used for demand that exists 50-60% of the year, because this capacity is fixed and must be paid for based on the peak capacity that is reserved for the user. As such, using pipeline capacity frequently lowers the average cost.

Upstream supply includes northeast British Columbia and Alberta supply plus storage resources, while downstream supply sources include gas from Huntingdon, Kingsgate, and Stanfield. All storage facilities, except Terasen Gas' LNG facility located in Delta, are leased and not physically located within Terasen Gas Midstream's consuming areas. With the exception of LNG facility at Delta, they all require some form of associated third party transportation capacity to reach Terasen Gas. Terasen Gas uses upstream storage as a seasonal base load resource and downstream storage for peak day requirements.

TGVI recently received BCUC approval to build a 1 billion cubic foot LNG storage tank at Mount Hayes, near Ladysmith on Vancouver Island. The addition of this LNG resource provides

Terasen Gas the option of contracting for LNG storage capacity from TGVI. The proposal had been the subject of a CPCN application which was granted by the BCUC on February 15, 2005. With construction commencing by the end of 2005, the planned in-service date is for November 2007. The LNG storage tank will provide TGVI customers with the ability to avoid the cost of downstream storage, seasonal pipeline capacity or base load pipeline capacity that would otherwise be required. Since the minimum practical size of the LNG facility would be greater than TGVI's immediate needs, TGVI will offer storage services to Terasen Gas and others in the region at the market price of storage to defray some of the costs of the LNG facility. As such, both TGVI and Terasen Gas benefit through increased deliverability and supply security within the region.

LNG also serves to reduce the need for providing supply through displacement. Currently gas is delivered by displacement to TGVI and Terasen Gas from storage facilities south of Huntingdon such as Mist. Delivering by displacement means that gas destined for markets south of Huntingdon is diverted to TGVI and Terasen Gas and replaced further south by the gas from the storage facilities. This means that on a peak day, there is actually less gas available to flow south because it is being diverted for TGVI and Terasen Gas. For this reason, local LNG contributes to both higher liquidity and reduced price volatility at Huntingdon / Sumas on high demand days[25].

Terasen Gas supports this project and would be willing to purchase the excess LNG at an avoided cost of downstream storage of up to $70 - $80 per gigajoule. Terasen Gas sees LNG storage capacity as an important new resource and diversification of its short term portfolio.

2.4.5 Westcoast T-South Decontracting

The southern segment of the Duke Energy Westcoast Pipeline ("T-South") begins at Station 2 near Chetwynd, B.C., where it connects with the northern part of the system ("T-North"). T-North consists of 3 pipelines (Fort Nelson Mainline, Grizzly Valley Pipeline and the Fort St. John Pipeline) connecting the 3 main Westcoast gas processing plants (Pine River, Fort Nelson and McMahon) as well as a number of processing plants owned by third parties. From Station 2, T-South has the capability of delivering to Pacific Northern Gas Delivery Area ("PNG") at Summit Lake, to Terasen Gas' Inland Delivery Area ("IDA"), from Kingsvale SCP to the Huntingdon Delivery Area ("HAD") and from there, exported to the US south of Huntingdon.

Historically when T-South has been fully contracted, flows to the Huntingdon Delivery Area have been higher than the combined capacity from Station 2 and Kingsvale. As a result, physical volumes flowing north on Northwest Pipeline from Stanfield into the region have been nominal because of the relatively low costs of Westcoast supply. In other words, it was more economical to contract supply from Station 2 via T-South than to access gas from Stanfield via Northwest Pipeline.

25 The sendout from the LNG facility represents roughly 5% of the gas available at Huntingdon / Sumas on a peak day.

In 2005, contracted capacity on T-South has fallen by approximately 35% putting the price in the \$0.40 to \$0.43/Mcf range in 2006. Having fewer parties contracting for the capacity will cause the average shipping costs to rise for the remaining shippers. Beginning in November 2005, 29 10^3m^3 (1,021.5 MMcf/d) has been contracted on the Duke system to the border. Historically, flows on the Duke system have been higher - in the range of 1.4 to 1.6 Bcf/d. For the upcoming year, there will be a higher variable cost to move incremental volumes on the Duke system since it will be necessary to pay interruptible tolls rather than being able to purchase surplus firm capacity from existing shippers at a discounted rate. Unless the price of gas at Station 2 discounts sharply, these tolls are expected to rise. Further, Terasen Gas expects that volumes flowing north from Stanfield will increase and volumes from Station 2 will decrease except when demand is very high in the region and the pipe is full.

What this likely means is that the price at Huntingdon will be higher than normal, all other things being equal. From the customer's perspective, this could result in higher costs and increased price volatility depending on the amount of re-contracting on T-South and the influence of weather-driven demand.

2.4.6 Customer Curtailment

Curtailment or fuel switching can be used as a supply resource; however, some curtailment agreements are contractually limited, specifying the maximum number of days the customer can be curtailed within a given period of time. This involves interrupting a large customer and using their gas supply to meet peak demand. Typically, customers who can be curtailed have a backup fuel supply that can replace the lost gas supply. Curtailment is typically used to help offset very short duration peaks in demand. The reasons for a shorter duration include limitations in terms of the supply of the alternate fuel, the cost of the fuel, and local environmental concerns that limit the amount of alternate fuel that can be consumed. From a gas supply perspective, there must be confidence that the customer will have firm alternative fuel supply to be able to make their gas supply available and will in fact be in a position to switch when called upon.

2.5 Managing Infrastructure Disruption

The primary objectives of the short-term supply and price risk plan for Midstream resources are:

- Contracting of cost effective supply resources that ensure safe and reliable natural gas deliveries to meet Core Market customer design day demand while mitigating against upstream and downstream supply disruptions.
- Portfolio resource mix and price diversity that incorporates contracting flexibility for both the short and longer term.

Given the current infrastructure availability, the Midstream Manager's resource portfolio aims to lessen the impact of infrastructure disruption events that are likely to occur. The Midstream Manager evaluates scenarios that could lead to the disruption of gas supply, the potential impact of these events on the portfolio, and the Utility's ability to mitigate the impact of these events within the existing portfolio.

Shortfalls can either be pipeline or supply related, examples being pipeline outages, well freeze offs, or processing plant interruptions. Disruptions associated with infrastructure or associated supply sources will impact the Midstream Manager's ability to deliver to market and/or the portfolio costs.

Terasen Gas is increasingly concerned about the potential impact of unplanned outages and the aging regional infrastructure on the availability of supply. This concern in particular relates to force majeure plant outages at the major Westcoast processing plants. A three-day plant upset event occurred in mid July 2004 at Ft. Nelson. Hours later, the McMahon plant went down as well. The output at the Ft. Nelson plant was cut by 50% 8,500 10^3m^3 (300 Mcf) on the first of the three days alone. While Terasen Gas was able to meet all customer load requirements despite the interruption, had this occurred in the winter months this prolonged outage would have meant more serious implications.

Parts of both Duke and NWP's infrastructure are aging and with the first pipe and processing plants constructed in the mid 1950s, the likelihood of other capacity disruptions grows. Capacity interruptions inflict the greatest impact on Midstream's ability to meet customer load requirements and are exaggerated when combined with one or more of the following variables:

- Degree of infrastructure disruptions
- Weather severity
- Duration of weather event and infrastructure disruption

Given Terasen Gas' commitment as a Utility to be able to serve firm requirements of all it's customers on a design day, the following sections describe supply options for augmenting existing infrastructure to meet future deliverability expectations in the region.

2.5.1 Pipeline Options

Natural gas supply serving the Lower Mainland is transported by Duke's T-South pipeline bringing gas to Sumas from Northeast B.C., and Williams' NWP delivering gas through the Columbia Gorge from the Stanfield hub and Rocky Mountains. The current capacity of T-South is 48,246 10^3m^3 (1,703 MMcf/d), while NWP has a physical capacity of 15,958 10^3m^3 (528 MMcf/d) through the Gorge.

<u>Recent Expansions</u>

Completed in December 1999, Terasen Gas' Southern Crossing Pipeline project added 8,500 10^3m^3 (300 MMcf/d) of capacity from Alberta to the Southern B.C. Interior and through Duke to Sumas. Duke completed a small expansion of added compression, adding 2,408 10^3m^3 (85 MMcf/d) from Kingsvale to Huntingdon and 992 10^3m^3 (35 MMcf/d) from Station 2 to Kingsvale.

In 2003, NWP completed a 1,417 10^3m^3 (50 MMcf/d) expansion of physical capacity through the Columbia Gorge and completed a 6,006 10^3m^3 (212 MMcf/d) expansion south of Sumas to Chehalis – also known as the Evergreen project. Due to two pipeline failures in the fall of 2003 on the NWP 26 inch mainline, an order from the U.S. Office of Pipeline Safety in December 2003 effectively removed the 26 inch line from service, and with it approximately 10,200 10^3m^3 (360 MMcf/d) of capacity between Sumas and Portland. The 26" pipeline is approximately 40 years old. NWP plans to replace most of the capacity of the 26" line through a combination of compressor and pipeline additions in the coming years.

Future Expansions

Numerous capacity expansions are proposed for the region, however the estimated in-service dates are unknown. These projects include TransCanada Pipeline's connector from Kingsgate to Seattle (known as the Washington Lateral); Duke's expansion from Station 2; NWP through the Columbia Gorge; Terasen Gas' Inland Pacific Connector; and Gas Transmission Northwest's pipeline Oregon Lateral[26].

The Inland Pacific Connector ("IPC") project is being proposed by Terasen Gas to provide additional pipeline capacity to serve Southwestern B.C. and the Pacific Northwest. The IPC will connect Huntington via the Southern Crossing pipeline from Oliver to Huntington. The project could add 5,666 10^3m^3 to 9,916 10^3m^3 (200 to 350 MMcf/d) of capacity to service the Huntingdon / Sumas market hub, connecting directly back to the Alberta supply basin. The earliest foreseeable filing for approval is the summer of 2005 and pending BCUC approval, the earliest practical in-service date would be November 2007.

2.5.2 Storage & LNG Options

Terasen Gas' downstream storage resources currently consist of JPS and Mist Storage. JPS currently holds up to 538.3 10^6m^3 (19 Bcf) of working gas deliverable at a maximum rate of 24,081 10^3m^3 (850 MMcf/d). Expansions to JPS of 28.3 10^6m^3/year (1 Bcf/year) have been planned for the next four years. The Mist facility was expanded in 2004 to 11,500 10^3m^3 (390 MMcf/d) of deliverability and 362.6 10^6m^3 (12.8 Bcf/d) of working gas.

Three LNG plants are located within the Pacific Northwest. Terasen Gas' Tilbury LNG can deliver up to 4,250 10^3m^3 (150 MMcf/d) and holds 16,998 10^3m^3 (600 MMcf). Newport LNG holds 25,497 10^3m^3 (900 MMcf) and can deliver up to 1,700 10^3m^3 (60 MMcf/d). Gasco LNG can deliver 3,400 10^3m^3 (120 MMcf/d) and holds 16,998 10^3m^3 (600 MMcf). In addition, Puget Sound Energy in Washington owns a Propane Air facility that can supply the equivalent of 29 MMcf/d of gas for 4 days. Storage can also be drawn from an LNG facility in Stanfield, Oregon if required.

26 Gas Transmission Northwest (GTN) was recently acquired by TransCanada Pipeline in November 2004. GTN system extends from TransCanada's facilities near Kingsgate, British Columbia, on the British Columbia-Idaho border, to a point near Malin, Oregon on the Oregon-California border. The natural gas transported on this pipeline originates primarily in Canada and is supplied to customers in the Pacific Northwest, Nevada and California.

As described in Section 2.4.4, TGVI recently received BCUC approval to build a 1 billion cubic foot LNG storage tank at Mount Hayes, near Ladysmith, on Vancouver Island. This plant would have a delivery capacity of 2,833 10^3m^3 (100 MMcf/d). The LNG storage tank will provide Terasen Gas customers with some ability to avoid the cost of downstream storage, seasonal pipeline capacity or base load pipeline capacity that would otherwise be required.

There have been several locations proposed for LNG import terminals in the Pacific Northwest including Columbia River, Kitimat and the Prince Rupert area. While these projects are currently in very preliminary stages, they represent possible supply options for the future. At issue is the size of the facilities and whether the supply can be absorbed into the region.

2.5.3 Market Valuation of Resource Options

To provide insight to how the resource options are valued, the following is an example illustrating valuation of the different resource options.

<u>Annual infrastructure carrying costs (for 1 GJ of supply)</u>

- Pipeline - 365 days x \$0.40/GJ/day = \$150 per year
- Underground Storage - 30 days x \$3.50/GJ/day = \$115 per year
- LNG Storage - 10 days x \$10/GJ/day = \$100 per year

<u>Costs by Load Duration - $/GJ</u>

Required (days)	Pipeline	Downstream Storage	LNG Storage
6	25.00	19.20	16.70
10	15.00	11.50	10.00
30	5.00	3.50	-
150	1.00	-	-
365	0.40	-	-

*Note: above costs are estimates only

This cost breakdown illustrates the cost effectiveness of the respective resources for various days of service required to meet expected load. One of the key planning criteria for Terasen Gas' gas supply portfolio requires that resources be in place to meet design day demand. As discussed in Section 2.4.1, Terasen Gas' Midstream Manager uses resources such as pipeline, underground storage, LNG storage and peaking resources to manage load variability for each day of the year. The cost and characteristics of each resource dictate where they best fit in the supply portfolio.

While pipeline is the most cost effective resource for base load supply 365 days of the year, shorter-term storage contracts (30 days duration) are typically more cost effective to meet winter load. For peak day gas requirements 10 days and under, LNG storage is the most cost effective asset which provides operational flexibility to meet loads in periods of high demand.

2.6 Conclusions

Future gas supply requirements for Terasen Gas are driven by Core Market customer growth. In the past and for the future, Core Market growth means design day requirements will grow at higher rates than the average daily requirements. Additional pipeline capacity will be required to meet average daily demand growth, but the majority of required infrastructure will be local storage for the winter to meet design day demand. As demand increases, relatively scarce local storage is expected to become even more important and therefore more costly.

While Terasen Gas contracts a diverse resource portfolio mix to ensure safe, reliable and cost effective delivery of natural gas to Core Market customers, disruptions due to aging infrastructure or interruption from supply sources impact the Midstream Manager's ability to deliver to market, and / or portfolio costs. Terasen Gas supports the coordinated planning efforts between industry players and the Northwest Gas Association to monitor infrastructure requirements to meet growing demand in the region. Terasen Gas will continue to evaluate potential risks and shortfalls through scenario analysis to encourage proactive planning in the near and long term, and focus on its objectives of long term access to secure, reliable, competitively priced supply to meet its Core Market customer requirements.

3 ENERGY OUTLOOK

In explaining how Terasen Gas manages the supply of natural gas to serve its customers, Section 2 of this document describes the regional, North American and World gas reserves available to meet future energy needs. This section considers the competitiveness of natural gas and electricity and discusses other energy use trends, since these factors play a role in Terasen Gas' demand forecasts, which are presented in Section 4.

3.1 Natural Gas and Electricity Prices

Trends in natural gas and electricity prices send signals to consumers in making buying decisions on energy system equipment and fuel choices. Since these are the two primary energy choices for consumers, expectations by consumers of future price increases in the supply of either energy type relative to the other can have a significant impact on 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. Information reviewed by Terasen Gas in preparing this Resource Plan points toward the continued competitiveness of natural gas prices as upward pressures on electric rates continue. Currently, natural gas continues to enjoy a price advantage over electricity in British Columbia.

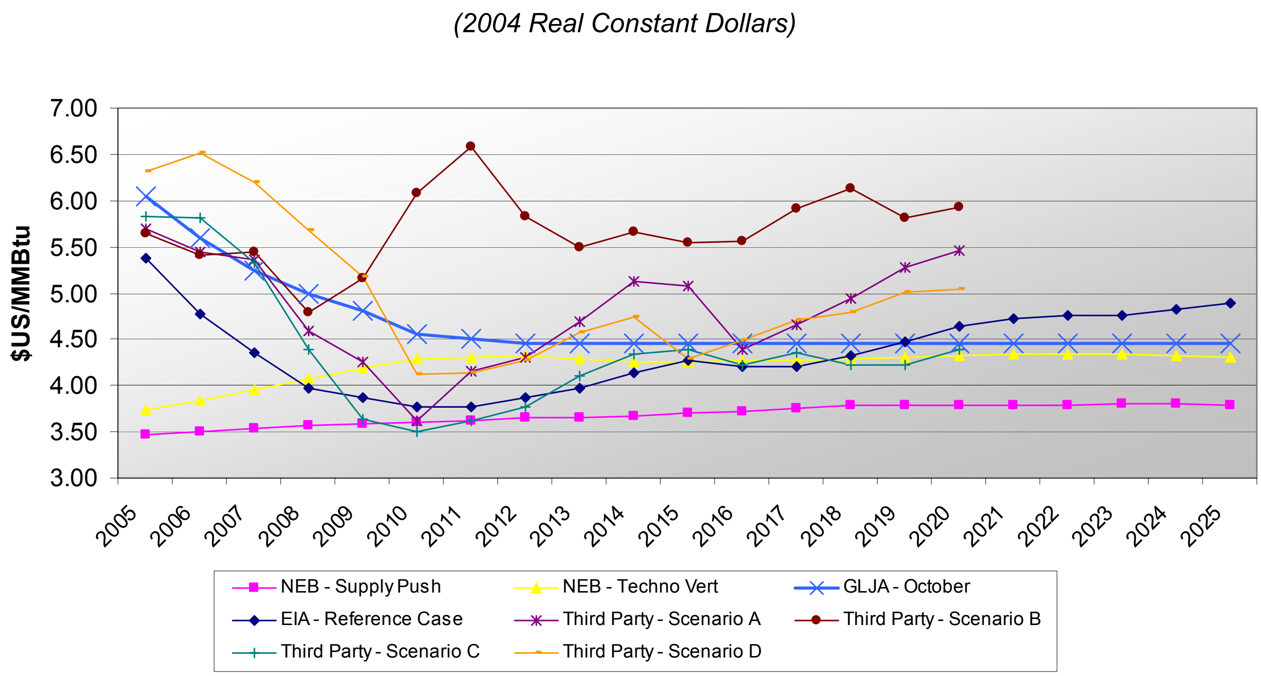
3.1.1 Natural Gas Price Forecasts

Terasen Gas does not forecast natural gas prices, but instead reviews the price forecasts of other industry experts when analyzing likely future gas consumption for its own customers. Gilbert, Laustsen, Jung and Associates ("GLJA") are a private petroleum industry consultancy that prepares natural gas and oil price forecasts on a quarterly basis. Terasen Gas has used forecasts generated by GLJA in evaluating customer growth and system resource activities. The GLJA October 2004 forecast is provided in Figure 3.1. GLJA expectations benefit from tracking recent trends in oil and gas supply, as well as other trends in the natural gas industry and the cost of competing fuels.

GLJA forecasts that within the next 5 years, new sources of gas supply such as imported LNG and possibly Arctic gas will have a moderating effect on near future gas prices, but that over the long term, gas prices will continue to maintain a relationship to the price of oil. The industry outlook on the price of oil, as evidenced by the futures market, is that oil prices will be flat to declining in real terms over the next 5 to 10 years since currently, the cost of new production is generally less than the current market price. The GLJA forecast shows a declining price in natural gas over the next 5 years, followed by a flattening of prices (in real, constant dollars) over the long term.

For comparison, Terasen Gas has reviewed price forecasts generated by the National Energy Board, the Energy Information Administration ("EIA") and by an independent Third Party[27]. The National Energy Board has developed two scenario forecasts based on the advancement of technology and the environment: Supply Push and Techno-Vert.[28] The EIA has produced seven price forecasts where each scenario models different social, economic and political trends affecting the price of natural gas, however only their reference case is depicted below.[29] The four scenarios developed by the Third Party from years 2005 to 2020 are also based on a different set of socio-economic and political assumptions. All price forecasts are discussed in greater detail in Appendix D.

Figure 3.1 Natural Gas Price Forecast Comparison at the Henry Hub



27 For confidentiality and proprietary reasons, the name of the Third Party cannot be disclosed.

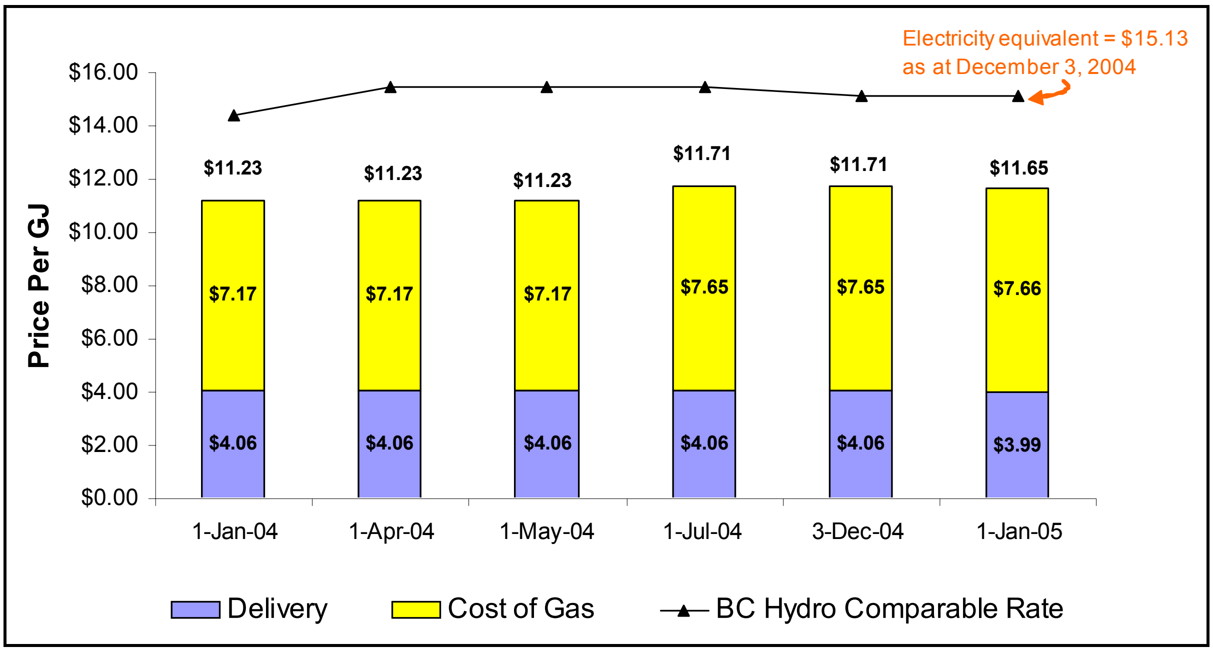
28 NEB, "Canada's Energy Future – Scenarios for Supply and Demand to 2025", July 2003.

29 EIA, "Annual Energy Outlook 2005".

3.1.2 Electricity Prices

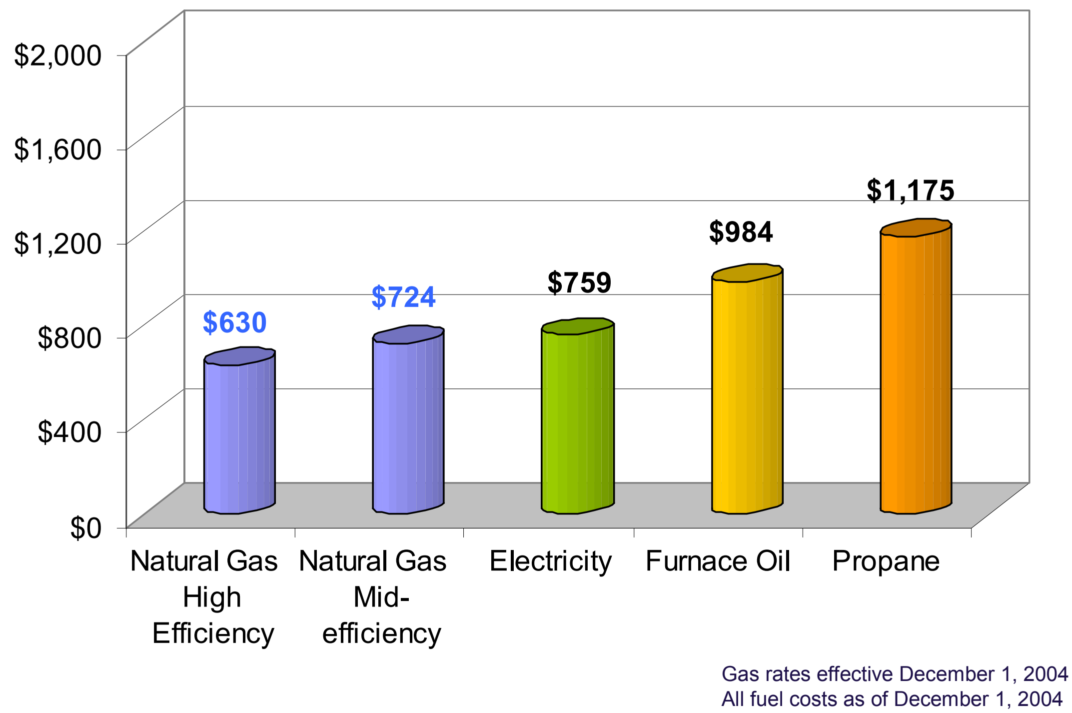
Two electric utilities provide electrical service in British Columbia. FortisBC Inc. supplies electricity within south Central B.C., while BC Hydro serves the vast majority of the Province. In both service areas, B.C. enjoys some of the lowest electricity rates in Canada and North America. For each organization, electricity rates are set for the entire service area irrespective of regional differences in the cost of supplying the electricity. Figures 3.2 and 3.3 show that while electric rates in B.C. are low compared to other jurisdictions, natural gas still enjoys a competitive advantage on an annual energy use basis within the Province.

Figure 3.2 Lower Mainland Residential Bill History per GJ, Gas vs. Electric Comparison Terasen Gas Delivery and Commodity Charges



Assumes: Natural gas use of 110 GJ Terasen Gas amount includes basic charge
Efficiency of gas equipment is 90% relative to 100% for electricity
BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Figure 3.3 2004 Annual Fuel Cost Comparison for Space Heating - Lower Mainland Service Area



For BC Hydro, electricity rates have been held constant from 1993 until April, 2004. In 2004, B.C. Hydro applied for an increase of 8.9%, citing that costs to produce electricity have been rising: "As demand for electricity grows, BC Hydro will need to upgrade its infrastructure and bring on new, additional power supplies to meet that demand."[30] According to BC Hydro's web site, electricity rates have actually dropped by 14% against inflation – a trend that is not expected to be sustainable. The BCUC subsequently approved a 4.84% increase in October 2004.

BC Hydro has also stated in their 2004 Integrated Electricity Plan ("IEP") that new generating facilities will be required within the next 10 years in order to meet their commitment to be able to supply the domestic electricity needs of the Province[31]. Further, an earlier in-service date for a solution to Vancouver Island's impending electricity capacity shortfall is required by 2007. These impending costs, in addition to market rates for electricity that are typically higher than B.C. rates, suggest significant upward pressure on future electricity rates.

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30 Statement from BC Hydro's Web Site: http://www.bchydro.com/policies/rates/rates756.html

31 BC Hydro, 2004 Integrated Electricity Plan, Part 6 – Portfolio Evaluation Results. At a workshop to prepare their 2005 IEP, BC Hydro stated that this objective has been revised to provide new generation facilities by 2012 with effective Power Smart programs and by 2007 without Power Smart, sooner than described in the 2004 IEP.

3.2 Hog Fuel

As of 2002, British Columbia had an installed electricity capacity of 14.1 GW[32]. Eighty-nine percent (89%) of the total electrical capacity is supplied by renewable energy sources. Renewable energy resources consist of naturally regenerating energy resources such as the sun, wind, moving water, earth energy, and biomass (i.e. wood waste). 76% of B.C.'s renewable energy power capacity is standard hydroelectric with about 24% derived from biomass wood residue sources (both electrical and thermal).

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. 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. Biomass energy is also commonly referred to as "hog fuel" because of the mechanical shredder, called a "hog", used to process the wood waste. Since use of hog fuel 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 friendly.

Until recently, wood biomass energy or hog fuel was 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. However, recent developments in the past few years make hog fuel more of a threat to natural gas and other fossil fuels in industrial applications. With the rising price of natural gas and oil, the cost of producing hog fuel is becoming more attractive, providing a larger incentive to industries to utilize hog fuel 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 probably most 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 is changing 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.

3.3 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

[32] Source - Energy Consumption and Supply in British Columbia: A Summary and Review. The British Columbia Ministry of Energy and Mines, June 2004 - CIEEDAC Renewable Energy Database, 2003.

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.

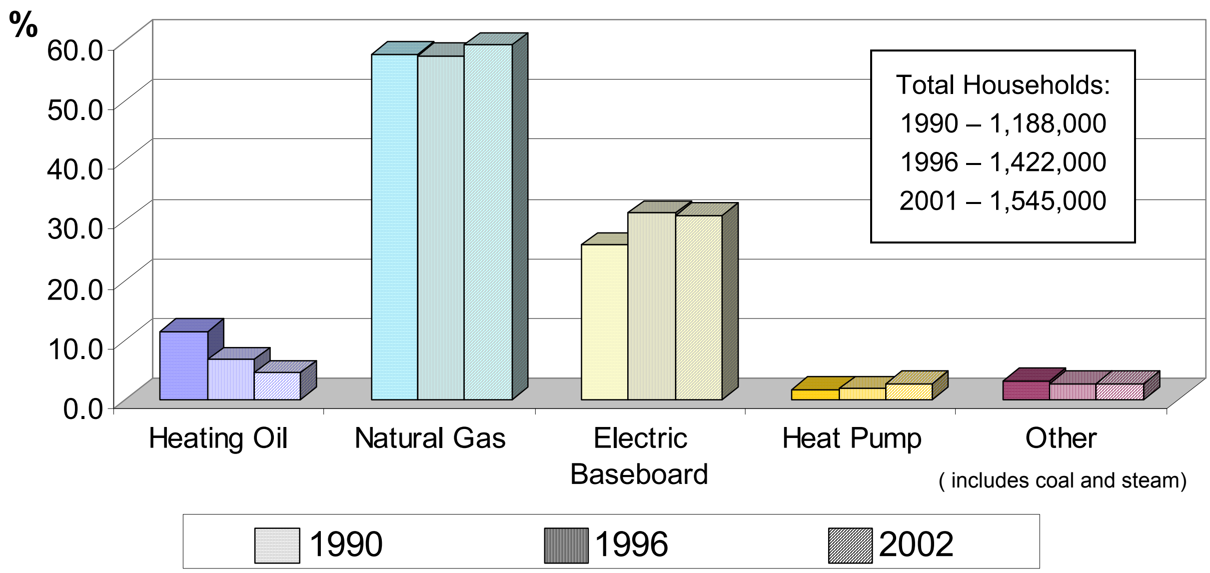
3.4 The Role of Natural Gas in Community Energy Planning

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.

3.4.1 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 3.4 shows the relative mix of residential energy systems in 1990, 1996 and 2002.

Figure 3.4 History of Residential Heating Systems in B.C. by Percentage



Similarly, Figure 3.5 shows the relative mix of energy systems, in this case specifically for multi-family residential households. Figure 3.6 shows the energy use trends for domestic hot water in multi-family households in the Province.

Figure 3.5 History of Apartment Heating Systems in B.C. by Percentage

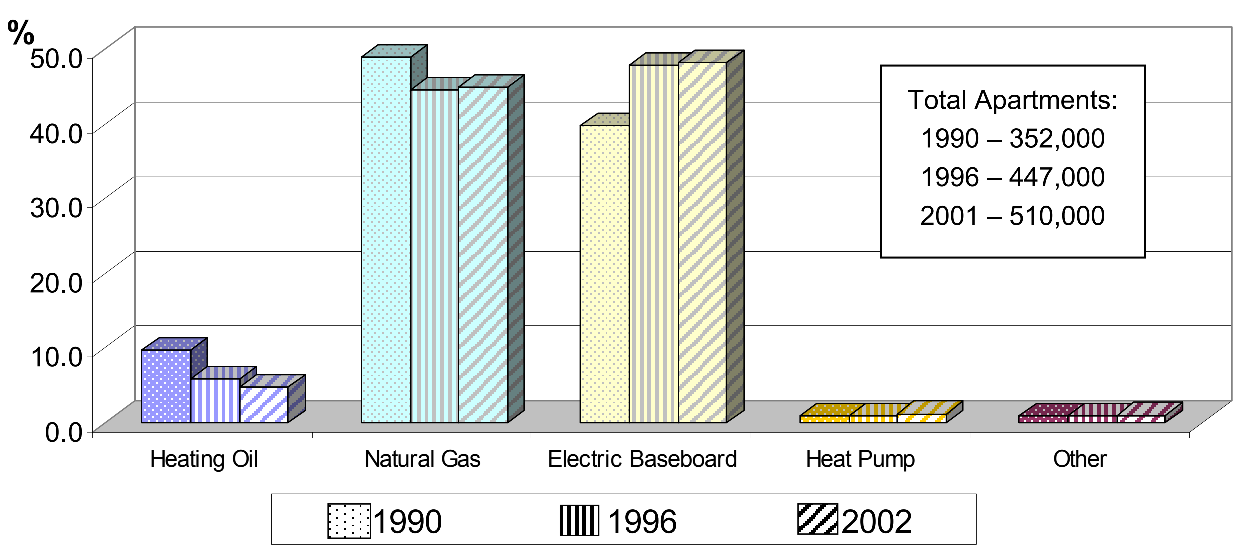
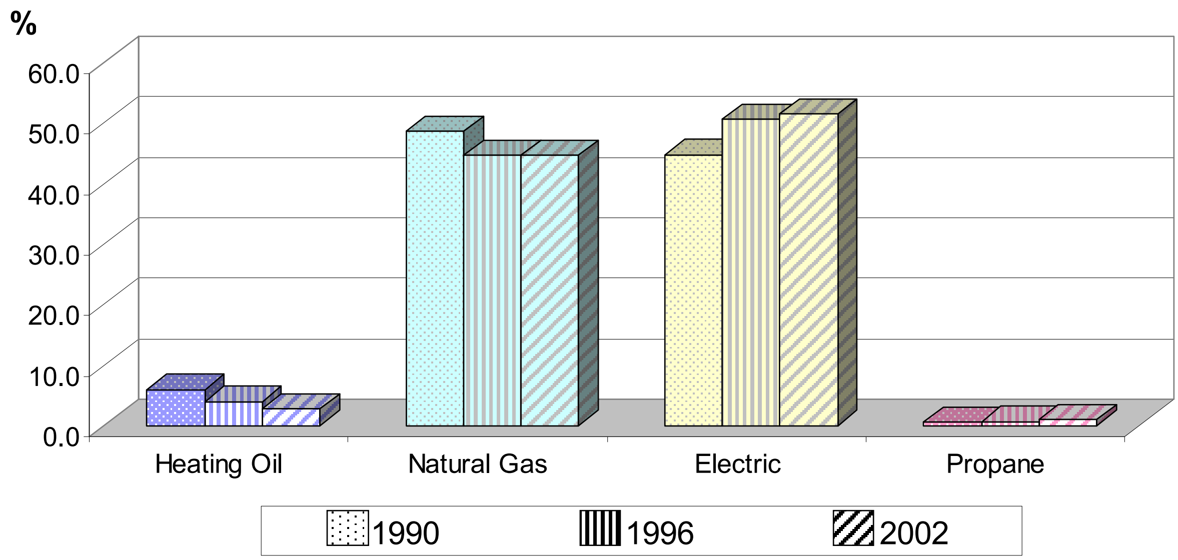


Figure 3.6 History of Energy Use for Domestic Hot Water in Apartments in B.C.



Heating Oil

Since 1990, heating oil has had only a small portion of the market for residential heating and hot water. The cost, convenience, reliability and environmental aspects 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 likely to continue.

Natural Gas

The NRCan data (Figure 3.4) 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 3.5 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 is also seen in the energy choices for hot water heating.

Electricity

Electricity, on the other hand, has enjoyed a jump in market share over the 1990 to 2002 period. This trend can also be largely attributed to growth in the apartment, or multi-family segment. The reason for this switch to electricity 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. This is a phenomenon that appears short-sighted and overlooks the long-range value of choosing more efficient energy technology.

Heat Pumps

Ground and air source heat pumps are considered a form of electric heating and cooling since they require electricity to access and circulate the thermal energy they are drawing on. These systems have gained slightly in market share in certain areas of the Province, particularly Ground Source Heat Pump ("GSHP") technology. Many of the conditions for successfully implementing GSHPs are very regional and site specific. As well, the systems are generally more complex, with higher initial capital costs. However, more independent research is underway to investigate the benefits and pitfalls of GSHPs as well as the types of applications and regions that are most appropriate for implementing this technology. As more experience is gained with GSHPs, technology, construction procedures and operation of these systems is likely to improve.

Currently, GSHPs are often installed along with a second energy system that is typically either an electric or a natural gas system. More and more, developers and community planners appear to be looking at hybrid systems that combine GHSP 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. Many communities in B.C. 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.

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. While heat pump technology appears to have substantial benefits under specific conditions, more data is needed on their long-term performance, full life cycle costs and regional success factors. However, as energy costs rise, these systems are gaining more attention.

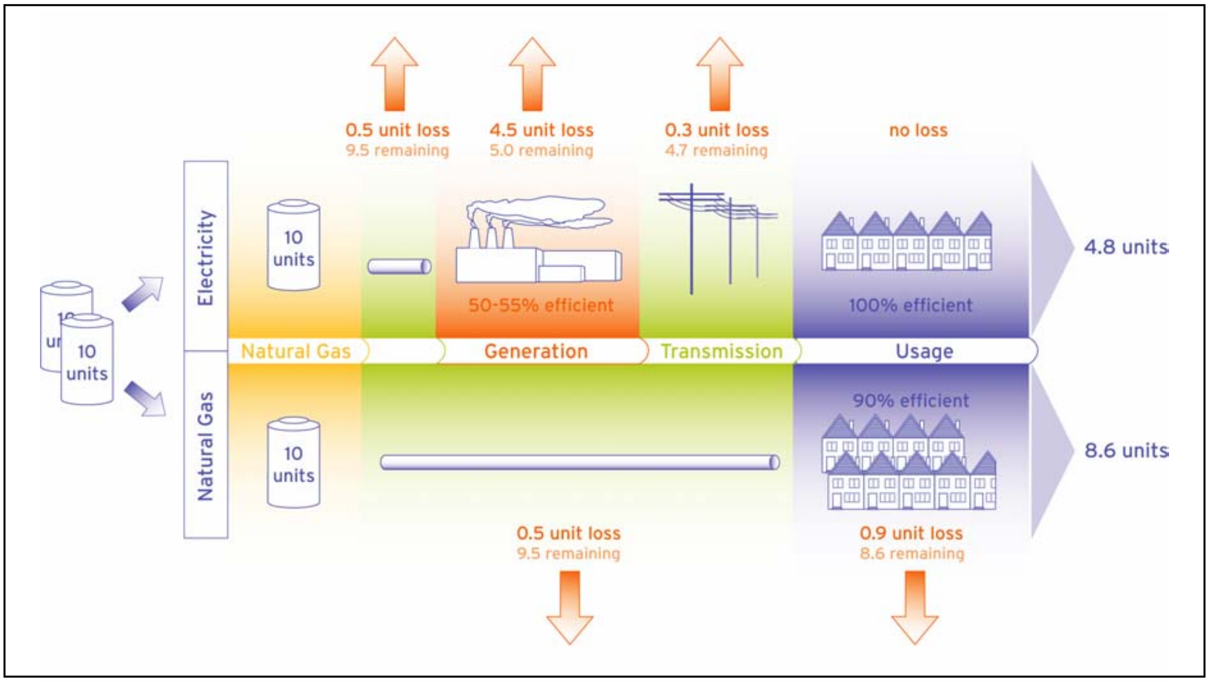
3.4.2 Energy Efficiency

Mixed into the energy choice decision is the issue of overall energy efficiency. Wise and efficient energy choices now mean that the fuel resource will go further in the long-run. When the incremental costs of acquiring that energy can be spread among a greater number of energy users, competitive pricing and energy efficiency can co-exist. Adding new energy loads that are based on high efficiency technologies helps to minimize incremental infrastructure costs for both natural gas and electrical delivery systems.

Furthermore, natural gas is the cleanest burning of the traditional fossil fuels. Where high efficiency natural gas energy systems can replace older, less efficient systems or systems that run on dirtier burning fossil fuels such as coal or fuel oil, significant improvements in air emissions result. These types of benefits are discussed further in Section 5, Core Market Demand Side Management.

The diagram in Figure 3.7 compares the efficiency of using natural gas to generate electricity, which is then used in the home - to the efficiency of supplying natural gas directly to the home for the same end use. These energy sources can be compared in this way, since existing hydro generating facilities are operating essentially at supply capacity and therefore any new electricity load must rely on incremental supply generated at the margin. A substantial portion of marginal electricity supply, whether imported or produced in-Province, is generated using natural gas or other fossil fuels.

Figure 3.7 Natural Gas Efficiency for Home Heating – Electric Generation versus Direct to Home Supply

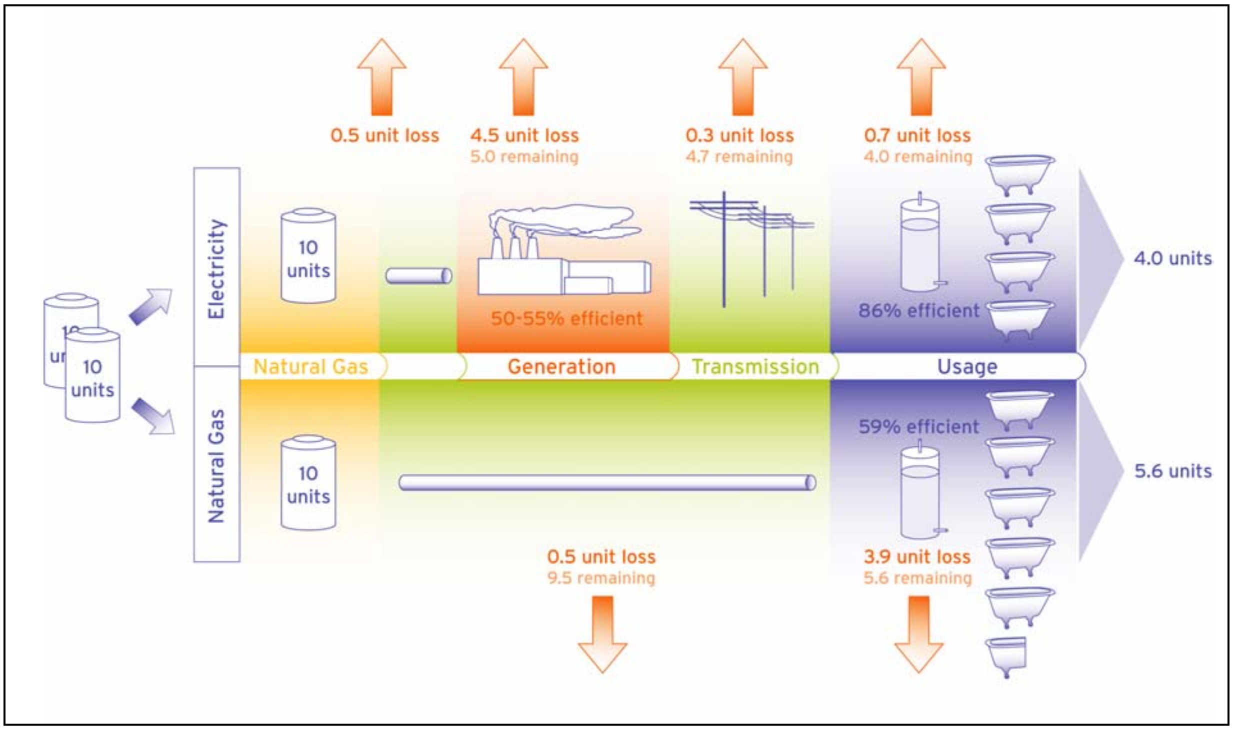


The above diagram accounts for losses in the transmission of the energy from the point of production (through either pipelines or electrical transmission lines) to the end use, as well as for the efficiency losses at the point of use. The 50% to 55% efficiency rating for electrical generation represents current, high efficiency technology, notably combined-cycle natural gas fired generating plants. While some co-generation facilities can attain much higher efficiencies, other in-use, legacy facilities operate at much lower efficiencies.

Figure 3.7 points out how the improved efficiency of using natural gas for home heating directly in the home can heat almost twice as many houses - as would the same amount of natural gas used to generate electricity sufficient to heat homes. Alternatively, the same number of homes could be heated for almost twice as long using natural gas directly in the homes.

Similarly, using natural gas directly in the home for domestic hot water has efficiency benefits over using gas to generate electricity and then delivering electricity to the home to heat the water. Figure 3.8 demonstrates this efficiency comparison. The relative difference is not as large as in the home heating case, but the benefits are multiplied when both uses are implemented together. Considering the trend toward electric baseboard heating in higher density residential developments discussed in Section 3.4.1, these energy efficiency comparisons suggest that energy use is increasingly becoming less efficient and will in turn put upward pressure on energy rates over the long run.

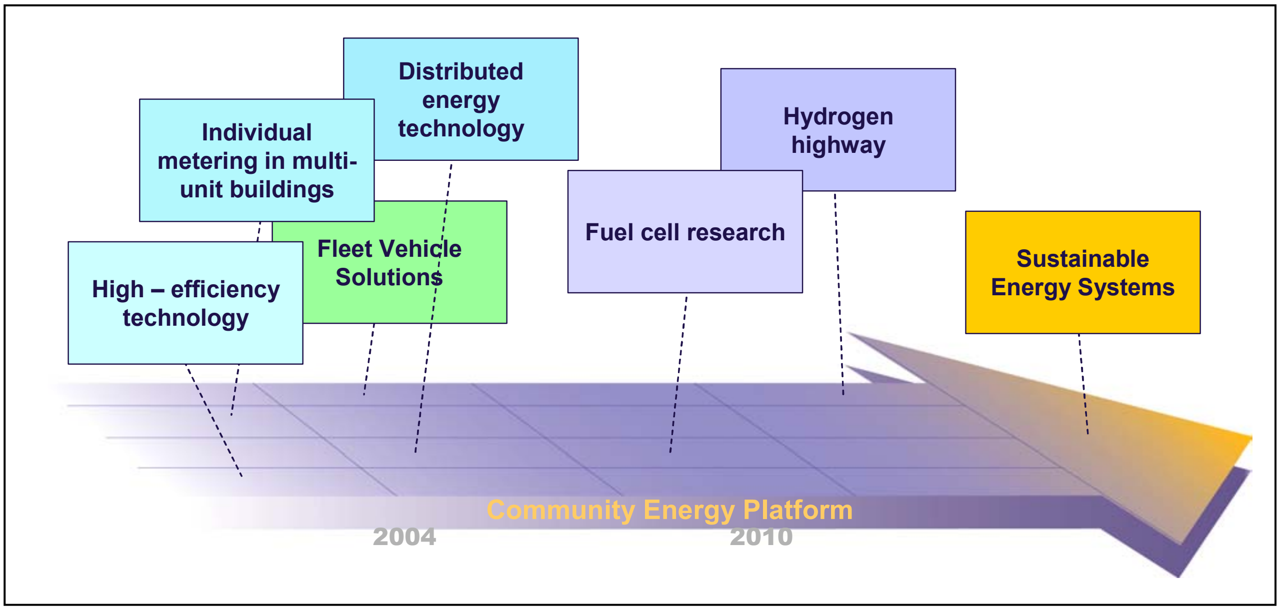
Figure 3.8 Natural Gas Efficiency for Domestic Hot Water – Electric Generation versus Direct to Home Supply



3.4.3 Making Natural Gas an Integral Part of Community Energy Planning

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 3.9 below helps explain five ways that natural gas can benefit communities now and going forward.

Figure 3.9 The Role of Natural Gas in Community Energy Planning Now and in the Future



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 as discussed above.

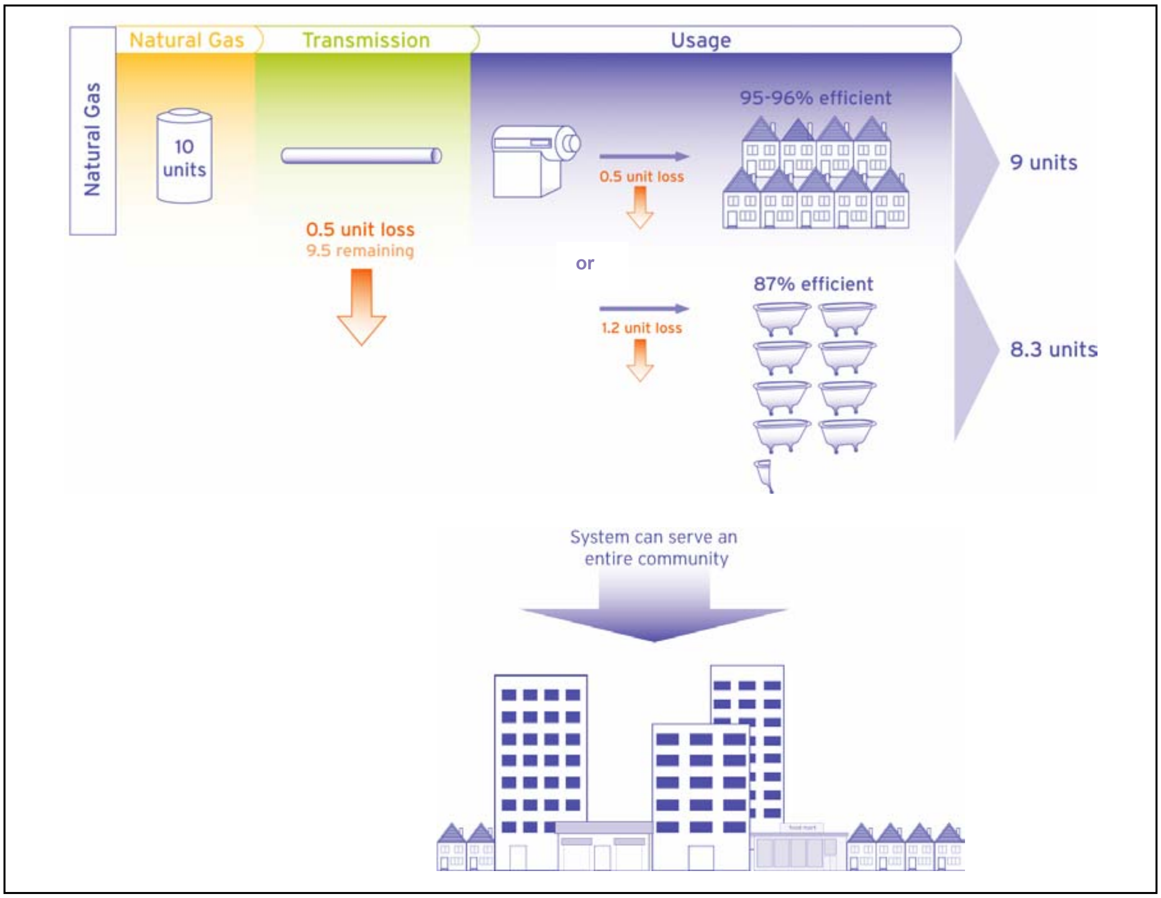
Individual Metering for Multi-tenant Developments

Terasen Gas 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. Implementing these types of solutions into new construction will help reverse the trend toward less efficient energy choices discussed in Section 3.4.2. Terasen Gas has initiated discussions with other utilities and stakeholders to help facilitate this type of energy choice. Stakeholder consultation efforts are more fully described in Section 7.

High-Efficiency Distributed 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.[33] Figure 3.10 illustrates the efficiencies that can be achieved with this type of system.

Figure 3.10 Natural Gas Efficiency for Distributed Energy Systems



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

Fleet Vehicle Solutions

Today, natural gas can fuel vehicles with the transportation advantages of lower fuel costs and decreased emissions compared to conventional diesel or gasoline engines. The largest existing market for this type of vehicle fuel system is in fleet vehicles for cost and air quality conscious organizations. Successful natural gas vehicle ("NGV") fleet programs in place in B.C. include a growing pilot at the City of Victoria[34], Lordco Auto Parts[35] boasting 50 NGVs among its fleet in 2004 and Novex Courier[36] who call themselves the Clean Courier and count NGVs as an essential component of their clean vehicle fleet. NGVs present one of the biggest opportunities in the Province to reduce GHG and pollutant emissions from automobile transportation. Incentive programs exist to help with natural gas fleet vehicle projects[37].

Fuel Cell 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. Natural gas is an important and efficient feedstock for the production of hydrogen for use in these fuel cells.

One of the major hurdles in bringing fuel cell technology to mainstream use is the lack of infrastructure required to support refuelling. Terasen Gas is part of an initiative to study whether hydrogen generation through energy recovery at natural gas regulating stations is feasible. The Company has not entered into a formal partnership, but has agreed to help fund portions of the study being carried out among a host of interested organizations including:

- U. Vic Integrated Energy Systems Institute
- U. Vic Innovation & Development Corporation
- Greenleaf Integrated Energy Systems Inc.
- BC Ministry of Energy & Mines
- Fuel Cells Canada
- Victoria Node Committee, BC Hydrogen Highway
- BC Hydro
- BC Transit
- Westport Innovations
- Terasen Gas

This system concept may offer an accessible bridge to solving the hydrogen fuel cell – refuelling infrastructure gap, potentially providing early adopters of fuel cell technology with a cost effective, modest volume, hydrogen refuelling network. If the technology and systems are adopted, potential benefits in air emissions and early steps toward much needed infrastructure development could result.

34 http://www.city.victoria.bc.ca/common/index.shtml

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

36 http://www.novexclean.ca/clean_courier.htm

37 Natural Resources Canada (www.oee.nrcan.gc.ca/), the Canadian NGV Alliance (www.ngvcanada.org), and a company called Clean Energy (www.cleanenergyfuels.com) are sources of additional information.

Hydrogen Highway Initiative

The hydrogen highway takes this fuel cell research one step further. In B.C., a hydrogen highway initiative has been advanced to pilot hydrogen fuel and infrastructure projects between Victoria and Vancouver and continuing northward along the Sea to Sky corridor to Whistler. This work can link existing natural gas fleet vehicle solutions to fuel cell research and the potential hydrogen highways of tomorrow. In addition to providing an efficient hydrogen feedstock, natural gas infrastructure of today has the potential to be converted to hydrogen infrastructure of tomorrow – adding to the long-term value of capital investments in natural gas alternatives. Representatives from Terasen Gas currently sit on B.C.'s Hydrogen Highway working committee.

4 GROSS DEMAND FORECASTS

4.1 Introduction to Demand Forecasts

Forecasted demand scenarios have been prepared for a planning horizon of 20 years, in accordance with the requirements of the Resource Planning process outlined in a previous section of this report, reflecting the long term nature of Resource Planning. In addition, to reflect the uncertainties about the future associated with a long planning horizon of 20 years, Terasen Gas has prepared a range of forecasted gross demand scenarios to account for such uncertainties and to facilitate a comprehensive understanding of the potential resource portfolios that it might employ to balance supply and demand.

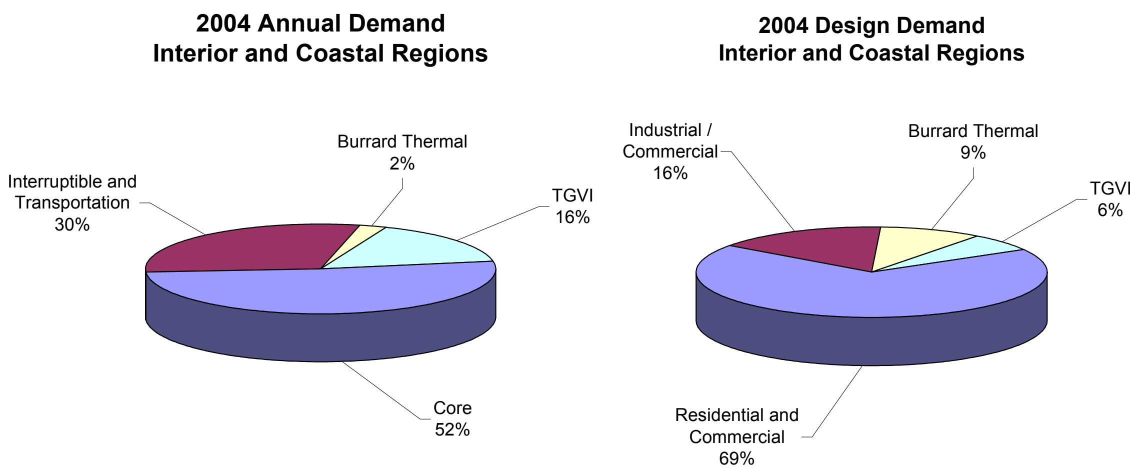
As noted earlier, Terasen Gas provides natural gas transmission and distribution services to approximately 789,000 residential, commercial, industrial and transportation customers in more than 100 communities in the Province of British Columbia. Terasen Gas provides natural gas service including both delivery and commodity to most of these customers. A small number of these customers, approximately 1,500 customers, receive only transportation service. These transportation service only customers are represented by large volume end-users, including a local distribution Utility – Terasen Gas Vancouver Island, that procure their own natural gas commodity themselves or through gas marketers. Of these transportation service only customers, a large volume transportation customer of significance is the Burrard Thermal Generating Station ("Burrard"), with a potential demand of approximately 230 TJ/day and a 2004 total recorded delivery volume of approximately 2,400 Terajoules.

Burrard is a natural gas-fired steam turbine generating station located in the Lower Mainland. The plant comprises six units, which were constructed in the 1960s and 1970s. Burrard's output (net of its own energy requirements) is 913 megawatts ("MW"). The 2004 BC Hydro Integrated Electricity Plan supply reflects a base case in which three units at Burrard are assumed to be available for operation in fiscal year 2004 to fiscal year 2006, and all six units available over the remainder of the 20-year planning horizon.[38] In March 2005, BC Hydro filed its 2005 Resource Expenditure and Acquisition Plan ("REAP"), with an updated set of operating assumptions for the Burrard facility. On page 2 - 13 of their REAP, BC Hydro states "*for planning purposes, BC Hydro is assuming that beyond 2014, Burrard will no longer be relied upon for firm energy or dependable capacity. This is based on the current operating regime and that capital expenditures can be minimized by managing the facility to a fiscal year 2014 end-of-useful life. This is a change from the 2004 REAP, where the plant was assumed to be available through the end of the planning period."* The demand scenarios Terasen Gas is using for planning incorporates this new set of planning assumptions by BC Hydro.

Figure 4.1 provides the profiles of the Annual Demand and Design Demand for customers of Terasen Gas.

[38] From page 27 Part 6: Portfolio Evaluation Results Hydro Integrated Electricity Plan, April 2004

Figure 4.1 Customer Profiles – 2004 Annual Demand and Design-Day Demand



For the purpose of this Resource Plan, a gross demand forecast scenario is comprised of the sum of the different individual customer demand components that make up the gross demand. The individual customer demand components are Core Sales Customers which receive both delivery and commodity service (Residential, Commercial, Small Industrial, Seasonal and Natural Gas Vehicles; Rate Schedules 1 to 6), Interruptible and Transport Customers (Rate Schedule 7 General Interruptible Service, Rate Schedule 22 Large Volume Transportation, Rate Schedule 23 Large Commercial Transportation Service, Rate Schedule 25 General Firm Transportation Service and Rate Schedule 27 General Interruptible Transportation Service), BC Hydro for gas-fired generation of electricity at Burrard, the Vancouver Island Cogeneration Plant ("ICP") and the potential Duke Point Power plant ("DPP") along with demand from TGVI pursuant to a wheeling arrangement.

For design demand planning, interruptible customers including Rate Schedule 7 General Interruptible Service, Rate Schedule 27 General Interruptible Transportation Service, Interruptible Rate Schedule 22 Large Volume Transportation and Rate Schedule 4 Seasonal customers are excluded from the design demand analysis.

Figure 4.2 below provides a matrix showing the components of the three gross demand forecast scenarios that have been developed for the Coastal Transmission System:

- **High Customer Growth**
    - Includes high Core Market customer growth as well as the following BC Hydro demand; the 275 TJ/d requirement of the BC Hydro Bypass Transportation Agreement (BTA) is maintained despite BC Hydro's expectation that only 3 units may be required at Burrard until 2009. An increase in contract demand in 2009 from 275 TJ/d to 321 TJ/d for the remainder of the planning period is assumed for dependable service to ICP, DPP, and Burrard Thermal.

- **Base Customer Growth**
  - Includes the base scenario level of Core Market demand as well as the following BC Hydro demand; the requirements based on the stated operating context for Burrard. An increase in contract demand in 2009 from 275 TJ/d to 321 TJ/d is also assumed but only until 2014, after which only 90 TJ/d is included for ICP and DPP.

- **Low Customer Growth**
  - Includes low Core Market demand (10% below Base case growth levels) as well as the following BC Hydro demand; Burrard continues to operate with only three units on standby until 2014 and only service to ICP is required.

The transportation demand from TGVI is based on requirements outlined in the TGVI LNG Certificate of Public Convenience and Necessity application decision dated February 15th, 2005. In the high and low scenarios where both ICP and DPP are expected on Vancouver Island, the requirement for transport across the CTS assumes that an LNG facility is added to the TGVI system at Mt. Hayes. In the low scenario, where ICP but not DPP demand is assumed on Vancouver Island, the requirement for transport across CTS assumes TGVI system expansion with compression, pipeline looping and continued reliance on curtailment. Demand from the ICP remains the same at 45 TJ/day in each of the scenarios.

Figure 4.2 Matrix of Gross Demand Scenarios for the Coastal Transmission System

Terasen Gas Inc. Gross Demand Forecast Scenarios for the Coastal Transmission System	Demand Forecast Components (TJ/day)													
			BC Hydro Transportation Forecast Components and Potential Timing for Changes in Demand											
			2005 Component Demand			2007 Component Demand			2009 Component Demand			2015 Component Demand		
	TGI Core +	TGVI * Transportation +	ICP +	DPP +	Burrard Thermal	ICP +	DPP +	Burrard Thermal	ICP +	DPP +	Burrard Thermal	ICP +	DPP +	Burrard Thermal
TGI High Forecast	High	Base	45	0	230	45	45	185	45	45	231	45	45	231
TGI Base Forecast	Base	Base	45	0	120	45	45	120	45	45	231	45	45	0
TGI Low Forecast	Low	Base	45	0	120	45	0	120	45	0	120	45	0	0

TGI = Terasen Gas Inc.
TGVI = Terasen Gas Vancouver Island Inc.
ICP = Island Cogeneration Plant
DPP = Duke Point Power plant
* High and Base forecasts of TGVI transportation across the Coastal Transmission System are based on requirements of the TGVI Revised Base +45 LNG Storage Portfolio. The Low forecast is based on the TGVI Revised Base + 0 PC&C (53 hours) portfolio. For more information refer to: TGVI 2004 Resource Plan and LNG Storage Project CPCN Application, Exhibit B8, Response to BCUC IR 48.1 and 48.2, November 2004

For the Interior Transmission System, the gross demand scenarios have been limited to three also; High, Base and Low reflecting different scenarios for customer additions only over the 20 year planning horizon.

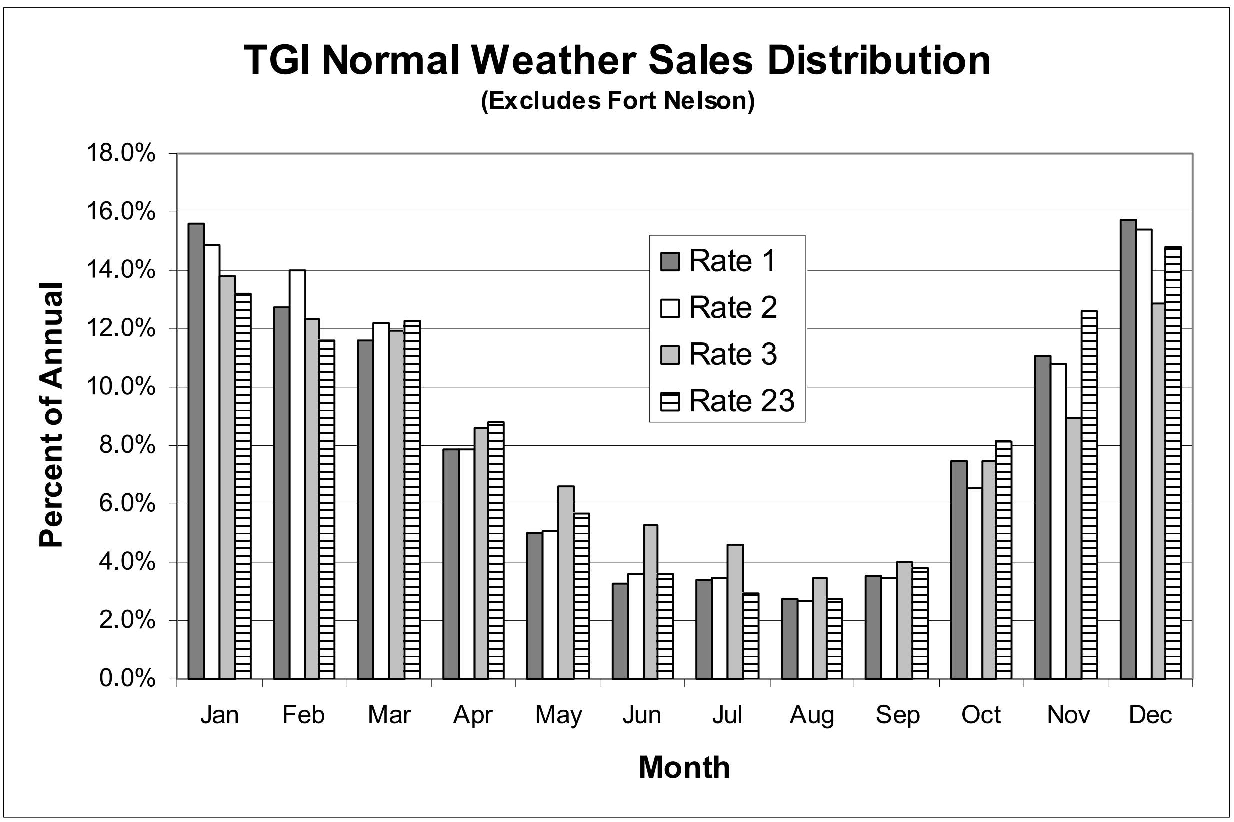
The next sections of this report discuss the different customer demand components of the forecasted demand scenarios, key drivers of the forecasts and the assumptions incorporated.

4.2 Customer Demand Components

4.2.1 Core Market Sales Customers

In 2004, Core Market customers' consumption represented approximately 52% of the annual gas volumes and approximately 69% of the design-day demand (see Figure 4.1). Residential and commercial customer annual consumption profiles are illustrated in Figure 4.3. The profile illustrates the "peakiness" of the Rate Schedules 1 to 3 and Rate Schedule 23 customers' consumption and their high correlation to colder temperatures usually experienced during the winter period.

Figure 4.3 Residential and Commercial Customer Annual Consumption Profile



Factors or drivers affecting the Core Market customers' forecasted demand for gas are:

- growth in the number of customers
- usage patterns of the customers, impacted by technology and economic factors
- weather

Variations in the first two drivers can lead to a number of potential outcomes with growth in the number of Core Market customers being the primary determinant of the demand forecast. To address this uncertainty, three forecast scenarios were developed to bracket the probable combinations. A Base forecast was developed to represent the expected outcome, as well as a High and a Low forecast to bracket the range of probable outcomes. The variability of the third factor, weather, was accounted for by utilizing design conditions for determining design day requirements and normal weather conditions for determining annual demand requirements.

4.2.1.1 Weather Sensitivity

Depending on the system, load planning for the purpose of Resource Planning is driven primarily by the design-day demand or design-hour demand[39] For the CTS and Transmission Pressure ("TP") laterals, design hour demand is used since the CTS and TP laterals cover a much smaller geographic area with less climatic diversity and have a higher portion of heat sensitive load. The CTS also has a lower maximum operating pressure. These factors combine to limit the capacitance of the system, as linepack is not sufficient to moderate intra-day demand peaks. Because of the relative differences, the ITS uses design day demand as a design requirement with the CTS and TP laterals using design hour demand.

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 Terasen Gas system. For Terasen Gas, since Core Market customers' demand is primarily weather dependent, design-day or design-hour demand is forecast based upon the coldest weather using a statistical approach called Extreme Value Analysis with a 1 in 20 year return period for the coldest day weather event occurring. This results in a design-day temperature, for example, of 30.8 heating degree days (HDD)[40] or -12.8 degrees Celsius for the Lower Mainland region, 44.1 HDD or -26.1 degrees Celsius for the Inland region and 49.4 HDD or -31.4 degrees Celsius for the Columbia region. To estimate the design day requirements[41], actual daily send-outs for the prior years' winter period November 1st through the end of February are regressed against the weather variable temperature.

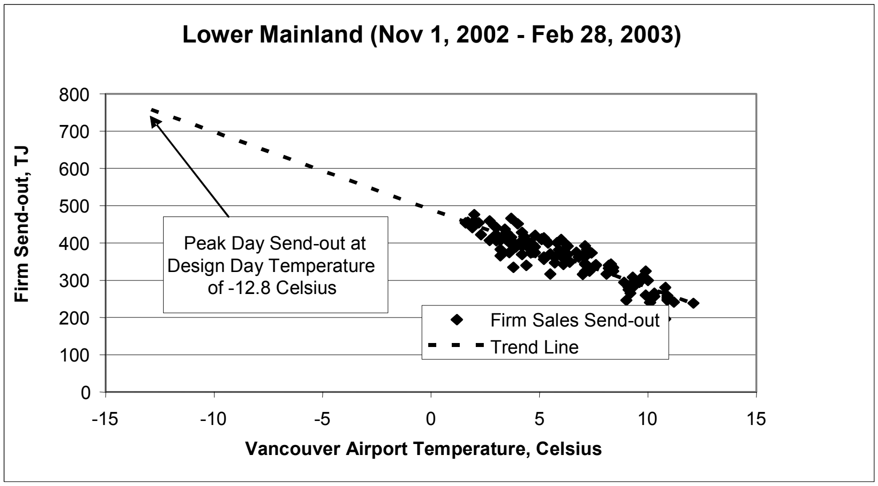
Recent experience in 2003 and early 2004 provides support to the validity of the existing design-day demand model. Figure 4.4 illustrates the observed relationship in the Lower Mainland between Core Market (Rate Schedules 1 – 6) customer load and heating degree days recorded during the past two winters. For this illustration, temperature is used and at the time the analysis was done, only history up to January 31st, 2004 was available.

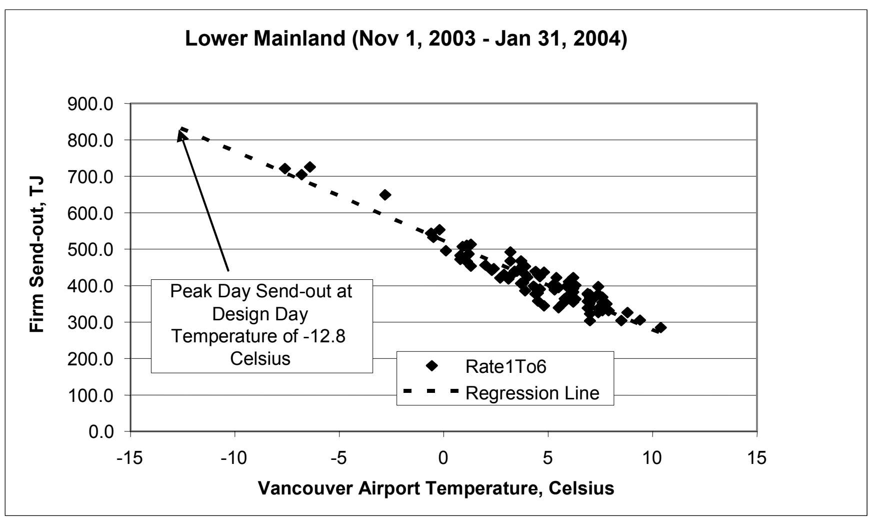
39 Design Day / Design Hour Demand - the maximum demand for natural gas a utility expects it must provide over a single day or hour as the case may be.

40 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, 18 degrees Celsius.

41 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.

Figure 4.4 Terasen Gas Core Market Consumption to Heating Degree Days – Lower Mainland Design Day – Last Two Winters





This figure also illustrates the difficulty of assessing the design day demand in warm weather years. In the winter of 2002/03, the coldest winter day temperature at the Vancouver Airport did not exceed 1.6 Celsius on a 24 hour average basis. The design day is extrapolated using values well beyond those actually experienced. Minor errors in the data will have a significant influence on the design day value.

Referring to the 2003/04 chart, the coldest day occurred on January 4, 2004 when a 24-hour average temperature of -7.6 Celsius was measured at the Vancouver Airport. There were 5 such days in total when the average temperature fell below freezing. With these cold-snap days, the extrapolation to the design day is much less susceptible to any errors in the warmer weather values.

4.2.1.2 Core Market Customer New Account Growth Forecast

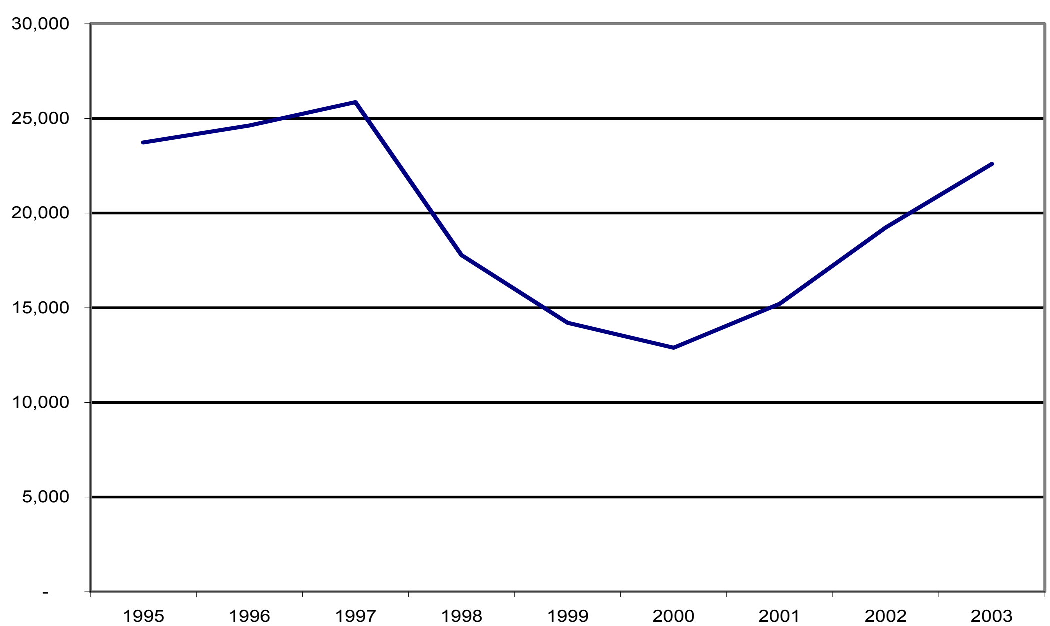
Three forecast scenarios – Base, High and Low were developed to reflect the range of possible outcomes in anticipated Core Market customer growth rates over the forecast horizon. Following is a discussion of history of Terasen Gas' customer additions and the assumptions used to generate these three forecast scenarios.

History of Account Additions

Since the mid 1990s, Terasen Gas has witnessed a gradual decline in the number of new customers connecting to its pipeline system annually. In 1995, new customers recorded totalled approximately 18,000 compared to only 5,700 new customers observed for 2003, a decline of 12,300 or 68% over the period 1995 – 2003. Housing starts illustrated in Figure 4.5 varied and declined during the same time period reaching a low of 13,000 in the year 2000, as the provincial economy softened. This negatively impacted the number of new gas customers added to Terasen Gas' system.

During the last several years, an improving provincial economy and higher new housing starts have correlated with a slight rebound in new gas customers but not as much as would have been expected based on the experience during the mid 1990s. More aggressive enforcement of overdue account collections led to a significant increase in the number permanent customer disconnects. This coupled with process redesign and changes to the order fulfilment process related to installation of new services negatively impacted overall net customer additions. These "losses" are considered one-time and are not forecasted to continue into the future.

Figure 4.5 Canadian Mortgage Housing Corporation – New Housing Starts



Comparison of Terasen Gas Account Additions to Other Jurisdictions

To provide context to Terasen Gas' recent and forecast customer growth rates and to examine what Terasen Gas could potentially achieve for customer additions, the histories of customer additions for other gas distribution utilities in the Pacific Northwest have been compiled for comparison. Relative to these other gas distribution utilities in the Pacific Northwest, Terasen Gas' account addition growth rate is considerably lower, both in terms of the absolute number of customer additions and the percentage growth rate. Figure 4.6 compares Terasen Gas' account addition history for the period 1995 – 2003 to other utilities in the Pacific Northwest. In comparison to Atco Gas and Puget Sound Energy, utilities of similar customer base size (i.e. approximately 700,000 to 800,000 customers), Terasen Gas account growth record has lagged.

Figure 4.6 Customer New Account Additions – Comparison to Other Jurisdictions

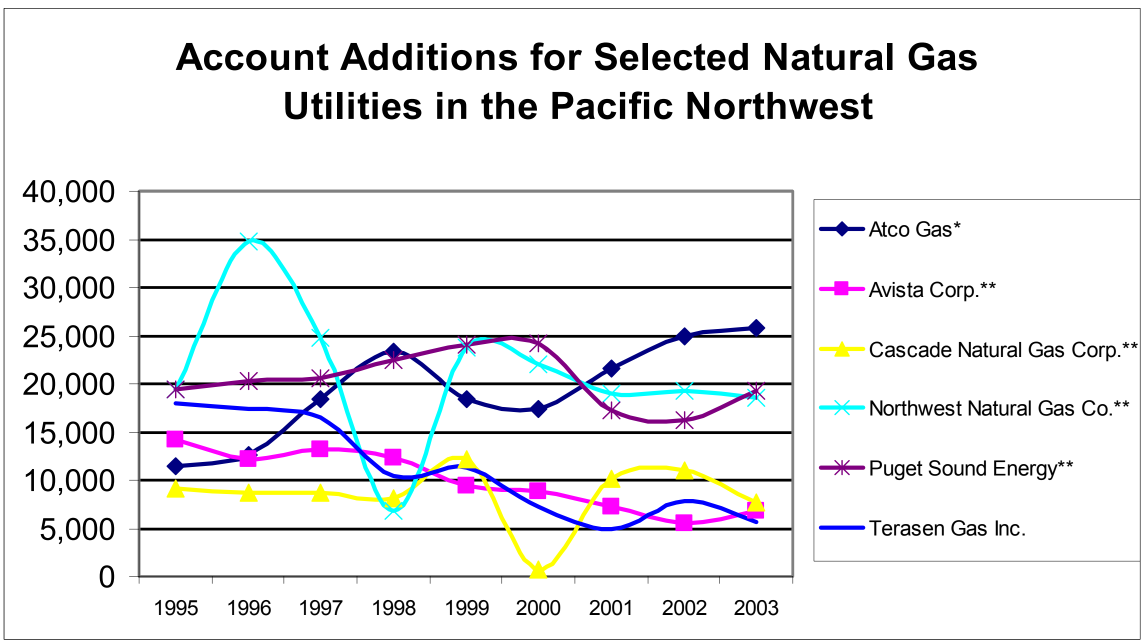
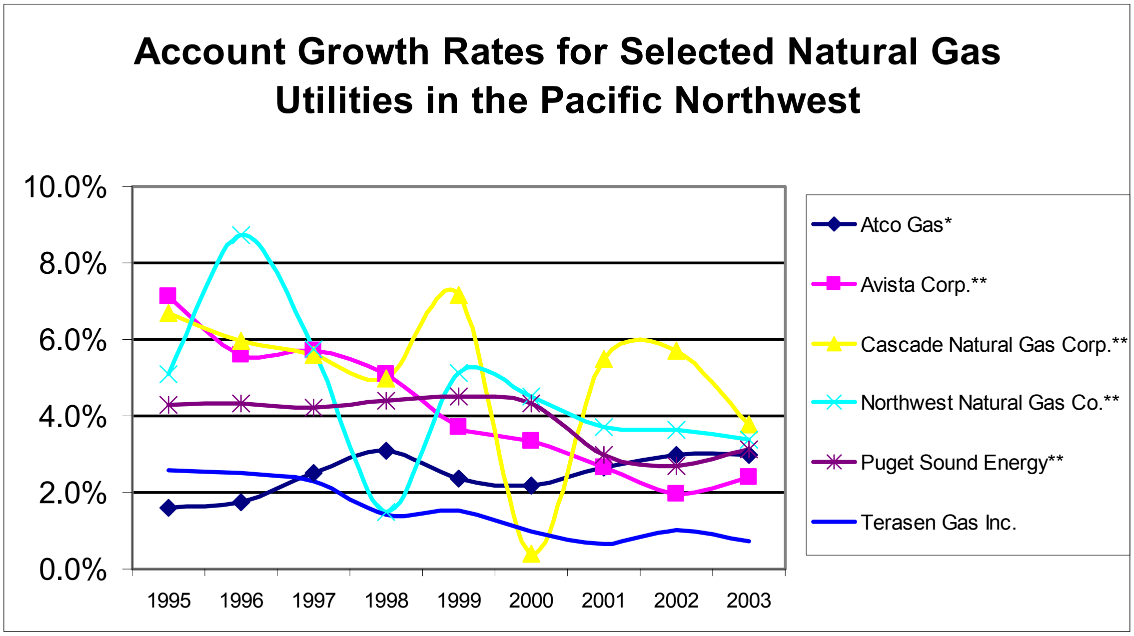


Figure 4.7 compares Terasen Gas' account addition percentage growth history to that of other utilities in the region. In all cases, Terasen Gas' annual account growth percentages lag that of all utilities noted on the chart. The information in Figures 4.6 and 4.7 indicate that Terasen Gas should be able to achieve significant improvements in growth rates for capturing new natural gas customers.

Figure 4.7 Customer New Account Additions Percentage – Comparison to Other Jurisdictions



Customer Account Growth Forecasting Methodology

Terasen Gas' 20 year Official Account Forecast provides an estimate of account additions by community and rate class in the Company's service territory. For the purpose of the Official Account Forecast, account additions are assumed to affect only Rate 1 Residential, Rate 2 Small Commercial, Rate 3 Large Commercial and Rate 23 Transport only Commercial customers. The total number of accounts for all other rate classes is assumed to remain unchanged over the forecast period. Analysis of historical account additions shows that account growth is limited primarily to Rates 1, 2, 3 and 23 customers with the total number of accounts not changing materially for the other rate classes.

The primary predictor variable used in the account growth model is household growth rate by Provincial Health Region, which is used to calculate account growth. This variable is chosen because it is highly correlated with account growth and may be used for both short-term and long-term forecasts.

Account growth for the shorter term (i.e. the next five years) is calculated using an econometric model wherein household formation growth rates and commodity prices are the main predictor variables. The results from this model are validated and adjusted if needed by the effect of known changes in the proportion of single–detached family to multiple family housing and economic dependency of a community on a single industry. For the forecast period after 2008, the household formation forecast prepared by B.C. Stats provides the input for the main predictor variable.

The yearly household growth rate by Health Region is derived from the household formation forecast by calculating the percentage change in household totals for each forecast year. Each Terasen Gas community is mapped to the Health Region in which it is located, and the corresponding household growth rate becomes an input for the equation at the community level. Table 4.1 shows that there are currently 69 communities mapped to 39 health regions.

Table 4.1 Communities to Health Regions

Terasen Gas Service Area	No. of Communities	No. of Health Regions
Lower Mainland	14	13
Inland	48	21
Columbia	6	4
Fort Nelson	1	1
Total	69	39

Description of the Base Forecast Conditions for Core Market Customer Additions

For the Base forecast scenario[42], the price of natural gas commodity[43] remains relatively competitive to its primary alternative fuel, electricity, over the forecast horizon. Price volatility for natural gas will continue and be similar to that experienced in recent years. The housing type mix, single family dwelling ("SFD") versus multi family dwelling ("MFD"), is not expected to change materially over the forecast period from the recent average of 45% SFD and 55% MFD. The primary predictor variable used in the account growth model is household growth rate by Provincial Health Region, which is used to calculate account growth rates for the reasons discussed above. In addition, the effects of economic performance, such as the dependency of a community on a single industry, are assumed to be reflected in the household formation forecast.

New gas accounts due to conversions from alternate fuels are assumed to be negligible as conversion activity during the last couple years has averaged only approximately 300 per year. Annual growth rates for the planning period 2004 – 2026 average 2% per year.

42 For the purposes of the forecast consistency, the account additions for 2004 – 2008 matches those filed in the recent 2004-2008 multi-year PBR filing.

43 Refer to section 3 for gas price forecast used in modelling account additions for the planning horizon.

Description of the High Forecast Conditions for Core Market Customer Additions

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. The competitiveness of natural gas remains relatively competitive to its primary alternative fuel, electricity, over the forecast horizon. In addition, Terasen Gas is able to capture a significantly higher proportion of new housing starts compared to recent experience, particularly in the MFD market segment. Annual growth rates for the planning period 2004 – 2026 average approximately 3% per year. This expected growth is similar to the growth rates experienced by other utilities in the Pacific Northwest in recent past (refer back to Figure 4.7).

The High forecast scenario supports Terasen Gas' objective of achieving one million customers for its gas Utility entities by 2010, primarily through residential customer additions. This growth is expected to be achieved primarily through new construction attachments. Marketing efforts will focus on capturing as much new construction starts as possible to see that they are piped for natural gas heating and appliances. Managing relationships with builders, developers and communities will be important.

Description of the Low Forecast Conditions for Core Market Customer Additions

For planning purposes, the Low forecast reflects a reduction of 10% of the annual customer additions 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 MFD, a market segment in which Terasen Gas is unable to increase its capture rate. Approximate annual growth rates for the planning period 2004 – 2026 are expected to average less than 2% per year.

Figure 4.8 shows the forecasted Core Market customer additions for Terasen Gas, as well as the correlation of customer additions to household formations as discussed above. Note the historic correlation of household formations to customer additions from 1995 to 2003.

Figures 4.9 and 4.10 break this customer addition forecast into Coastal and Interior region components. The primary difference for customer addition expectations for each region is that more growth is expected to occur in the Lower Mainland of the Coastal region, and this is where Terasen Gas expects to capture the most residential customers over the forecast period – particularly in the multi-family sector.

Figure 4.8 Terasen Gas Customer Additions

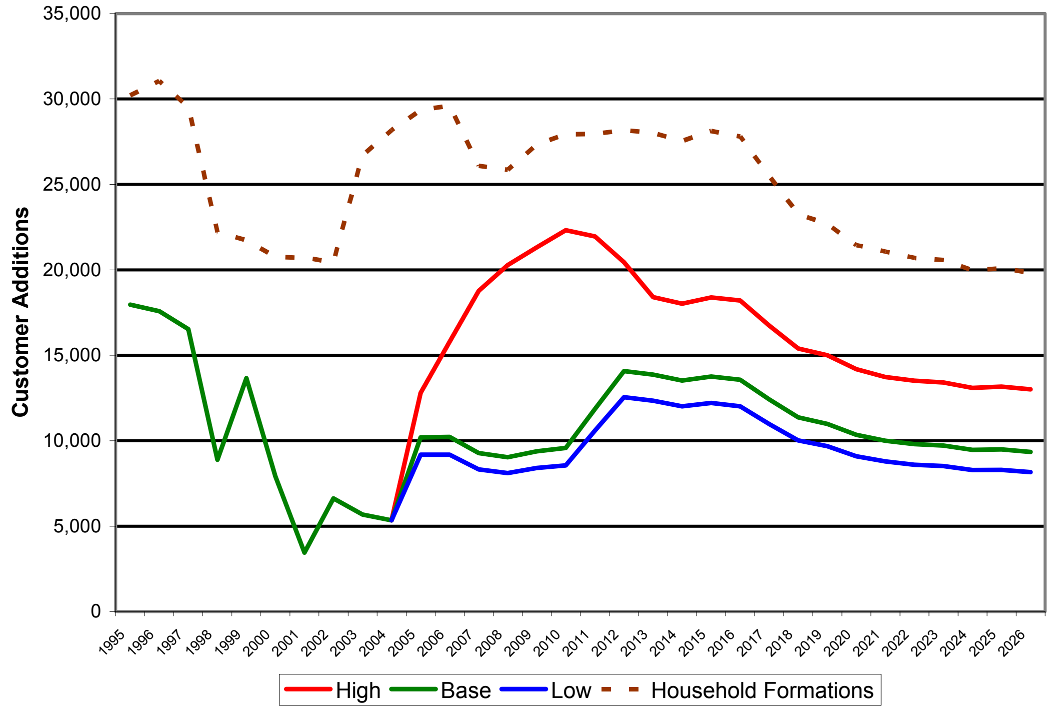


Figure 4.9 Terasen Gas Customer Additions – Coastal

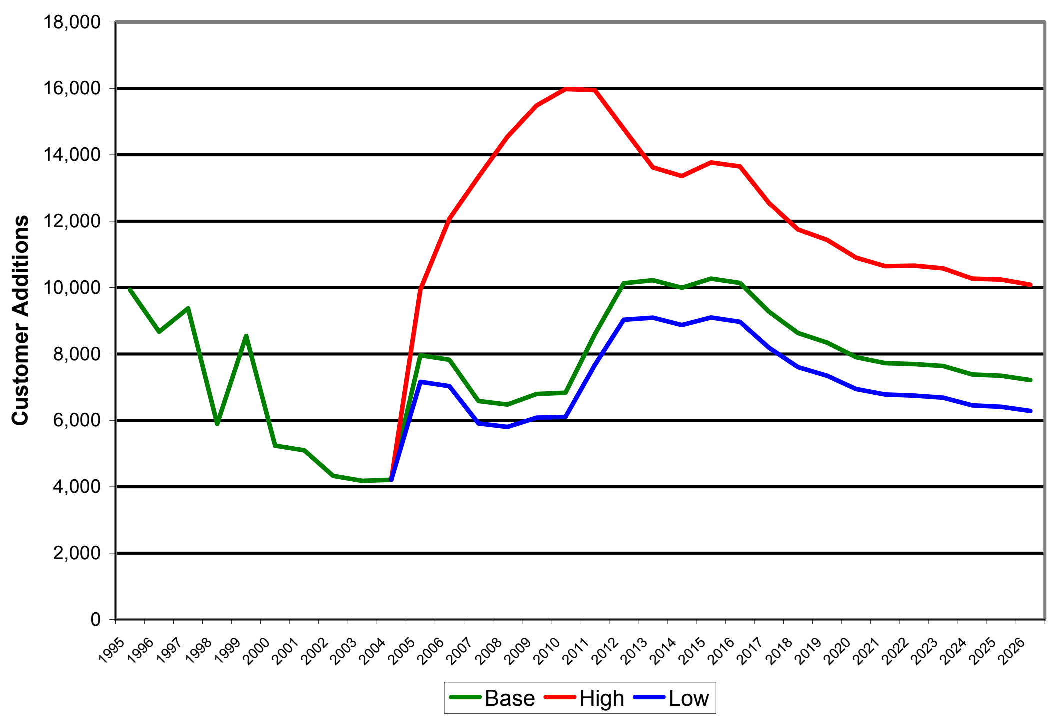
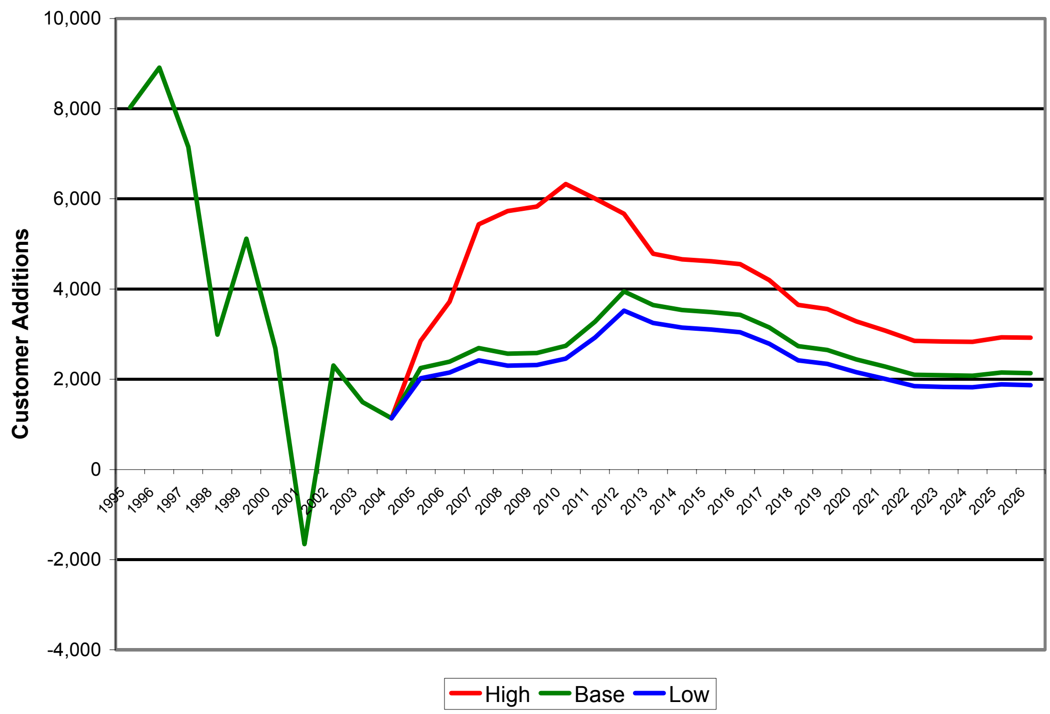


Figure 4.10 Terasen Gas Customer Additions – Interior



4.2.2 Interruptible and Transportation Customers

Interruptible and transportation customer requirements excluding Burrard Thermal and TGVI represent approximately 30% of the annual gas volumes and with firm transportation customers approximately 12% of the design demand. There are approximately 1,500 interruptible and transportation market customers with the majority of them (i.e. ~1,000) Rate 23 Transport only Commercial customers.

Generally, customers in this category find it economical to obtain their supply through third parties as a result their high load factor. Typical customers are process load customers (non-space heating) such as laundries, greenhouses, light industrial and manufacturing. Rate 23 Commercial Transport customers are typically residential (strata or multifamily), commercial or institutional operations.

4.2.3 Gas- Fired Generation Customer (BC Hydro)

BC Hydro currently uses thermal generating technology in the Province to help meet its customers' demand for electricity. BC Hydro operates a thermal generating facility called Burrard Thermal in Port Moody, British Columbia and supplies gas to a cogeneration facility, the ICP located at Elk Falls near Campbell River on Vancouver Island. Calpine Canada owns and operates the facility however BC Hydro has a long term electricity purchase agreement in place whereby BC Hydro provides the gas supply and contracts for all of the electricity output.

In its recent Integrated Electricity Plan, BC Hydro views the ICP capacity as a long term resource for meeting the electricity requirement for Vancouver Island. Consequently, although BC Hydro currently has a short term contract for gas transportation service to the ICP, it is expected that TGVI will continue to serve the ICP load over the long term. It is also expected that ICP's firm contract demand will increase from 38 TJ/day to 45 TJ/day which is representative of the full operating requirement of the plant.

BC Hydro also identified a gap between electricity supply and demand in the future on Vancouver Island of between 150 MW and 300 MW. In order to fill this supply gap, BC Hydro issued a Call for Tender ("CFT") in 2004 for competitive bids from independent power producers. The outcome of the CFT process was announced in late 2004 with BC Hydro contracting for 252 MW from the DPP plant project, a gas-fired combined cycle power plant to be located near the Duke Point industrial area of Nanaimo, B.C. The BCUC reviewed the proposed electricity purchase agreement between BC Hydro and Duke Power Point in a public hearing process in early 2005. On February 17, 2005, the BCUC accepted the contract between BC Hydro and DPP for the purchase of electricity beginning in 2007. Currently, the decision is being appealed. For the purposes of planning for the CTS, Terasen Gas has assumed a DPP demand outcome of 45 TJ/day for the High and Base cases with 0 TJ/day demand for the Low Case should the DPP project not proceed.

The Burrard Thermal Generating Station is a conventional natural gas-fired steam turbine station with six generating units, each about 150 MW. The plant is configured with three units on the east side and three on the west side. Located close to BC Hydro's main load centre in the Lower Mainland, Burrard helps to lower transmission system losses, increase the Interior-to-Lower Mainland peak transfer capability, maintain reactive voltage (VAr) support, and provide local capacity in the event of a loss of transmission to the region. Burrard has a net output of 913 MW and with all six units in operating condition can generate up to approximately 6,100 GWH per year.

Historically, BC Hydro has used Burrard to generate 2,100 GWH per year and has never exceeded 4,190 GWH per year. Burrard has had, and to some extent continues to have, an important role in providing discretionary and dispatchable energy, which is useful in low water years. The use of Burrard is highly variable and depends on both the water inflows at BC Hydro's hydroelectric facilities and market prices of natural gas and electricity. BC Hydro dispatches the plant when it is economic to do so, or when the energy is required for domestic load.

The current operational plan for Burrard is to have three units in generation standby mode for fiscal years 2004, 2005 and 2006, while the other three units are left in VAr support mode (does not require firing of natural gas) and can be recalled for generation if required. The Provincial government has announced a technical review by members of the legislative assembly ("MLA") of the future of Burrard. The MLA review committee has drafted a report, and the government's response to it may affect future options for Burrard.[44]

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44 Description of Burrard Thermal facility obtained from BC Hydro's 2004 Integrated Electricity Plan.

Due to the uncertainty surrounding the future use of the Burrard facility, Terasen Gas has chosen to model three different possible scenarios for the Burrard facility (refer to Figure 4.2), accounting for the assumptions contained in BC Hydro's 2005 REAP document regarding the projected use of the Burrard facility.

For the Low forecast scenario, demand from BC Hydro generation facilities including Burrard are constrained to not exceed 275 TJ/day, the maximum allowed under an existing Bypass Agreement. To supply natural gas to its thermal generation facilities on the Lower Mainland and on Vancouver Island, BC Hydro has a Bypass Agreement with Terasen Gas[45] for firm, non-recallable daily gas transportation service across the CTS to either Burrard or Eagle Mountain at a contract quantity of 275 TJ/day, for an initial term of 30 years (November 1, 1999 to November 1, 2029). BC Hydro holds an option to terminate the agreement on or after 2009. In the Base and High forecast scenarios where six generating units are operating at Burrard, an expansion of capacity under the existing Bypass Agreement would be required.

4.2.4 Terasen Gas (Vancouver Island) Inc.

Terasen Gas (Vancouver Island) Inc. is a wholly owned subsidiary of Terasen Inc. serving the Vancouver Island and Sunshine Coast regions. Currently, TGVI is a transportation customer of Terasen Gas and has a wheeling arrangement with Terasen Gas to provide transportation of gas from the Mainland to Vancouver Island. The wheeling arrangement is an agreement between TGVI and Terasen Gas for transportation of gas from Huntingdon to Eagle Mountain. Figure 4.2 includes the assumptions for gas amounts needed to supply TGVI's Core Market customers and the Vancouver Island Gas Joint Venture[46] under the various demand forecast scenarios. These are also explained in more detail in section 6.3.1.

4.2.5 Gross Energy Demand Forecast

This section includes a discussion of the methodology of determining both types of demand that Terasen Gas needs to plan for: design demand and annual demand.

4.2.5.1 Design Demand Methodology

In order to determine design demand requirements on the transmission system, design day for the ITS and design hour for the CTS, a statistical technique called regression analysis is utilized to establish the relationship between Core Sales customers consumption and temperature data (refer to previous discussion in Section 4.2.1.1 Weather Sensitivity). The Core Market customer (Rate Schedules 1, 2, 3 and 23) account forecast is employed as the primary predictor of

45 Refer to Rate Schedule 22 Supplement approved in Order G-78-99.

46 A joint venture of industrial customers (primarily large mills) on Vancouver Island who purchase energy as a single bargaining unit.

expected growth in design demands on the transmission system. Based on the 20 Year Official Account Forecast, the previous year's design demand load forecast by rate class and gate station[47] is analysed and used to determine the rate of peak demand load growth by rate class for each gate station. The rate of design demand load growth is then applied to the design demand load estimate for the current year to produce a long term design demand core load forecast by rate class and gate station. In addition, firm industrial demand (Rate Schedules 5 and 6) plus non-core firm contract capacities (i.e. Rate Schedule and 25 General Firm Transportation Service customers) are then included at the local network or gate station level. Expected growth in design load is directly proportional to account growth. The result is a long-term design demand forecast at the local network or gate station level.

The design demand is highly correlated to the coldness of weather conditions experienced and is highly price inelastic, meaning that during the design day or hour, the demand is insensitive to price, driven primarily by the weather. As mentioned earlier, the design day or hour is a single event based upon the coldest weather observed using a statistical approach of Extreme Value Analysis of a 1 in 20 year return of the coldest day weather event occurring. Terasen Gas must plan to be able to serve the firm requirements of all customers on such a day.

4.2.5.2 Annual Use Rate Methodology

In addition to design demand, annual demand (defined as the total gas forecasted to be consumed each day over a year) is required for gas supply planning purposes. The relationship between the design demand and annual demand is called the load duration. As mentioned in Section 2.4, Gas Supply Portfolio Planning, in planning the gas supply portfolio for Terasen Gas, resources must be put in place to meet the projected design-day demand and manage the varying demand for gas on an annual basis.

Individual use per account projections for Residential and Commercial customers (Rates 1, 2, 3 and 23) are developed for each service area and rate class by considering the following factors:

- The most recent historical normalized use per account (Table 4.2);
- Customer migration between rates;
- Forecast use for new customer additions;
- Appliance conversion or replacement effects where applicable; and
- The estimated impact of demand side management programs over the forecast period.

[47] A gate station is placed at pipeline locations where gas is taken from transmission pressure piping into intermediate pressure piping or distribution networks.

Table 4.2 Historical Annual Use Rates

	2001 NORMAL	2002 NORMAL	2003 NORMAL	2004 NORMAL
Rate 1	101	106	103	103
Rate 2	305	302	304	317
Rate 3	3,332	3,378	3,292	3,426
Rate 23	5,802	5,281	4,883	4,975

* units - gigajoules

Use rates for industrial customers (Rates Schedule 5, 7, 22, 25, 27) are determined primarily using a customer survey process. Industrial customers are asked annually to what extent they expect their firm's natural gas consumption to change from the previous year, and then to estimate their consumption over a forecast period. The industrial energy forecast is then updated to include these demand estimates and other pertinent feedback.

4.3 Gross Demand Scenarios

The sum of the different customer demand components of design demand for each of the three gross demand scenarios High, Base and Low for the CTS and the ITS are outlined in Figures 4.11 and 4.12.

Figure 4.11 CTS Gross Design-Hour Demand Scenario Forecasts

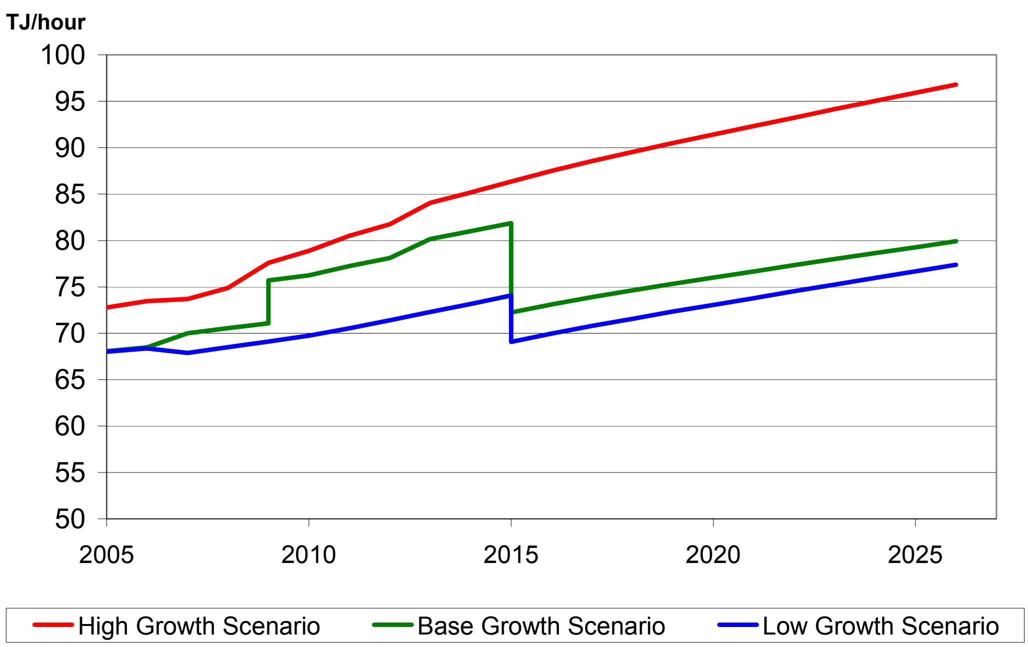
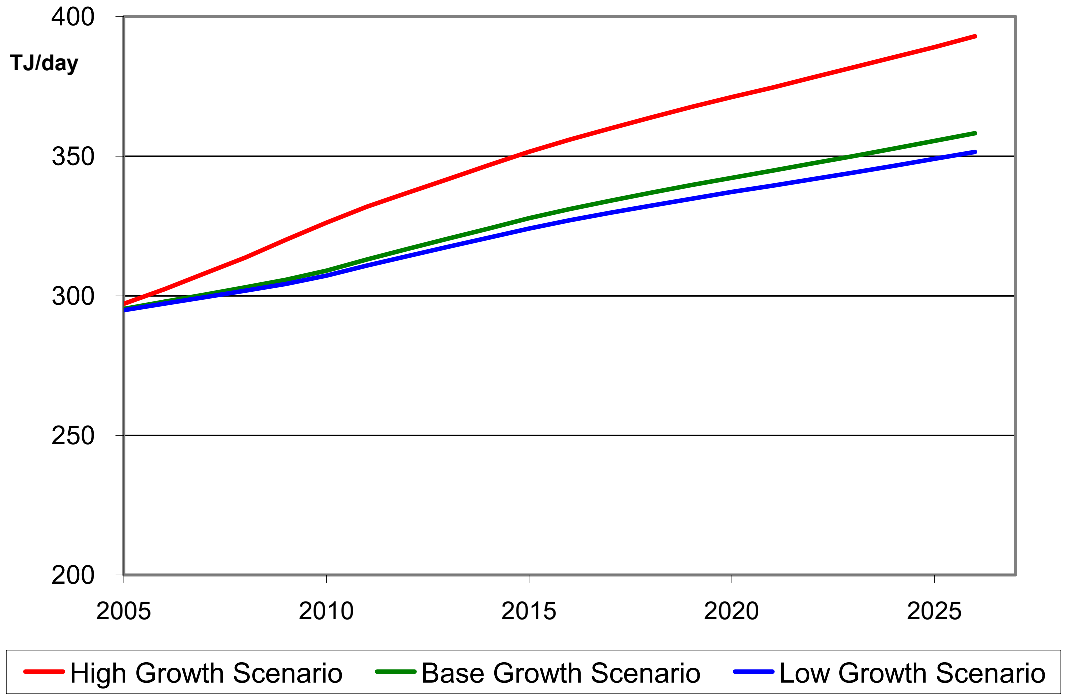


Figure 4.12 ITS Gross Design Day Demand Scenario Forecasts



4.4 Conclusions

At Terasen Gas, the demand for natural gas is growing and is expected to continue growing, driven by demand from Core Market sales customers in both the Coastal and Interior service regions. High growth will occur if housing starts and household formations meet experts' forecasts and Terasen Gas is successful at capturing a high proportion of both the single and multi-family residential sectors. Terasen Gas has also provided a low demand scenario forecast to examine the impacts from less than expected demand growth.

5 CORE MARKET DEMAND SIDE MANAGEMENT

Demand Side Management ("DSM") refers to "utility activity that modifies or influences the way in which customers utilise energy services". Terasen Gas offers demand side management programs targeted at improving the energy efficiency of residential and commercial customers. In the past four years, over 85,000 customers have participated in DSM programs. This section describes the company's proposed DSM programs and their role as a resource option in Resource Planning.

5.1 Background

Terasen Gas has pursued a number of customer programs since Resource Planning came to the Utility forefront in the mid 1990s. The objective in all of the programs has been to influence the way in which customers utilised the gas delivery network.

Natural gas has been available to the Terasen Gas service area for over 50 years. As a result, the Terasen Gas market has a mix of both old and new energy consuming equipment and a significant proportion of older building stock. Older equipment and building stock represent opportunities to improve customer energy use efficiencies through cost-effective DSM programs. Energy efficiency programs can play an important role in reducing peak day impacts reducing customers' overall cost of gas commodity and delivery services.

Among Terasen Gas' responsibilities is the need to help ensure that the region remains attractive to new businesses from a relative energy cost and supply reliability perspective. For industry, this means promoting a level playing field with other regions and avoiding the flight of businesses driven by high relative energy costs in this region. For residential consumers, opportunities exist to encourage energy efficient gas appliance choices, 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 DSM initiatives can be as important as the programs themselves. Furthermore, such resources also need to be considered within the Resource Planning context across all energy alternatives using an integrated energy approach.

Terasen Gas is committed to working with industry partners, other utilities and all levels of government to ensure cost effective delivery of its programs and consideration of interdependencies among fuel choices. Through this Resource Plan, TGVI supports a number of provincial initiatives: market transformation relating to more efficient heating systems in residential and commercial applications, fireplace efficiency upgrades, and improvements to building envelopes.

Alongside Terasen Gas' efforts to encourage energy efficiency, there has been a growing interest by governments to reduce the 30 billion tonnes of world-wide annual Greenhouse Gas ("GHG") emissions. With Canada emitting 682 tonnes of GHGs (nearly 27 tonnes per person in

1997), the Canadian government has challenged the provincial and municipal governments to look for ways to meet the targets set out in the federal Kyoto commitments[48]. Terasen Gas is committed to working with government, utilities and industry partners to coordinate efforts to encourage energy efficiency resulting in the corresponding reductions of GHGs.

5.2 Role of Demand Side Management

From Terasen Gas' perspective, the primary objective of DSM is to increase the overall economic efficiency of the energy services it provides to customers. Table 5.1 below, however, outlines the many benefits that DSM programs can generate.

Table 5.1 Benefits of Demand Side Programs

Benefits of DSM
• 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. • Enhance the safety and improve the operating characteristics of customer's energy utilization systems. • Support climate change initiatives. • Overcome barriers to market transformation of efficient technology. • Support job creation. • Defer transmission facility improvements through targeted DSM.

5.3 Load Management Strategies

There are four primary load shaping strategies that DSM can employ to meet various Utility objectives as shown in Figure 5.1. The following diagrams represent the role of DSM in changing customer gas demands throughout the year:

A specific market's DSM portfolio provides a collection of targeted "load shaping" programs. It therefore needs to be developed in the context of the existing market considering the customer classes, the age of existing buildings and HVAC systems, the existing technologies, and the projected growth. When considering the Terasen Gas service territory, the following opportunities exist for each of the load shaping strategies:

<u>Peak Shaving</u>: All of the planned 2005 DSM Programs fall into this load shaping strategy. Customers with natural gas heating equipment can typically benefit the most from peak shaving programs.

48 In 1997, the Kyoto Protocol was established as the first global step to address the challenges of climate change and established an overall target for GHG emissions reductions for developed countries of 5.2% below 1990 levels for 2008 – 2012.

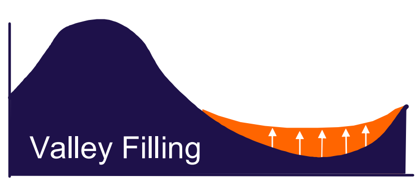
Valley Filling: Although there have been some past programs promoting the shifting of loads to the off-season, no valley-filling programs are planned for 2005. The current Conservation Potential Review (CPR) is examining summer load potential such as BBQ hook-up and pool-heater programs.

Strategic Load Building: No programs currently fall into this category although the CPR is evaluating the benefits of fuel substitution programs that could add load.

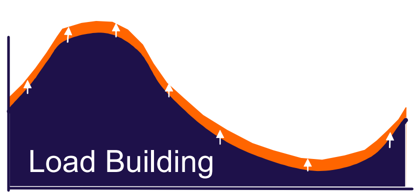
Strategic Conservation: This strategy is applicable for programs targeted at specific communities or areas on the gas delivery system where resources are constrained. The programs which have been developed and outlined in this Resource Plan are open to all eligible customers in Terasen Gas' service areas. Special application of these programs targeted at areas with resource constraints can be used to delay or reduce the need to capital improvements. Special applications may include the use of modified incentive payments and local marketing initiatives to enhance the level of customer participation. As with any of the DSM programs offered by Terasen Gas, targeted applications must pass the evaluation tests.

Figure 5.1 Primary Load Shaping Strategies

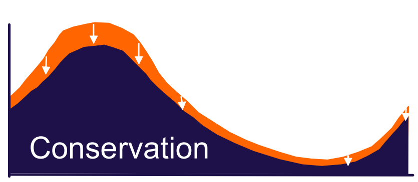
Peak Shaving reduces design day load requirements. Customer energy costs are reduced by decreasing demand on the delivery system, thereby reducing the need to expand the system. In addition, the need to purchase the most expensive gas is reduced.



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.

Terasen Gas formulates its annual DSM portfolio in the context of the load shaping strategies and based on the criteria provided in Table 5.2.

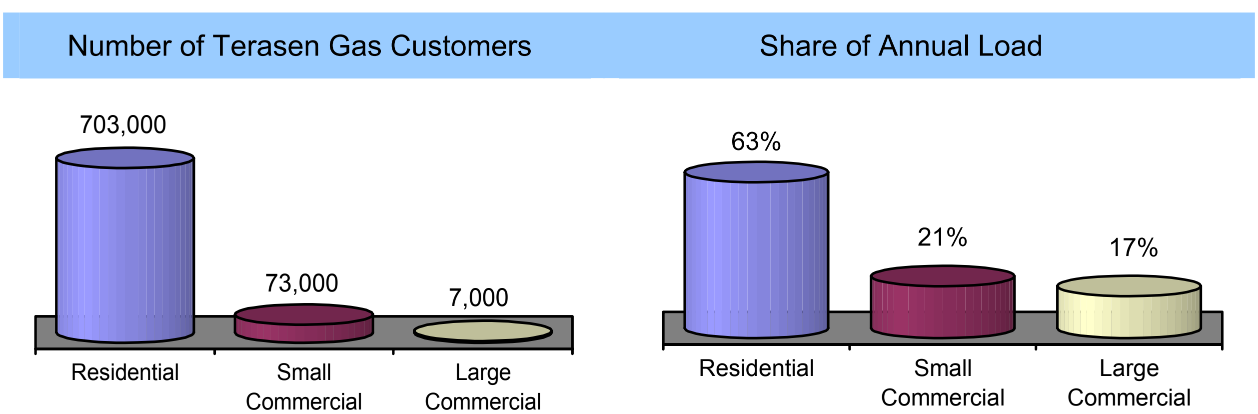
Table 5.2 Criteria for DSM programs

Annual DSM Portfolio Development Criteria
• Cost Benefit testing results. • Previous DSM experience, program evaluations and market research. • Customer responsiveness to DSM incentives for specific measures. • Provincial and federal initiatives that DSM programs could support. • Existing DSM budget framework. • Impact on load shape particularly in capacity constrained communities. • Continuous improvement – testing of new or modified programs.

5.3.1 Customer Segments

The customer base identifies the size of the market opportunity and assists in planning marketing programs. Figure 5.2 indicates that although 90% of the 789,000 Terasen Gas natural gas customers are residential, they represent only 63% of the load applicable to DSM (Large industrial transportation customers are excluded from this DSM analysis[49]).

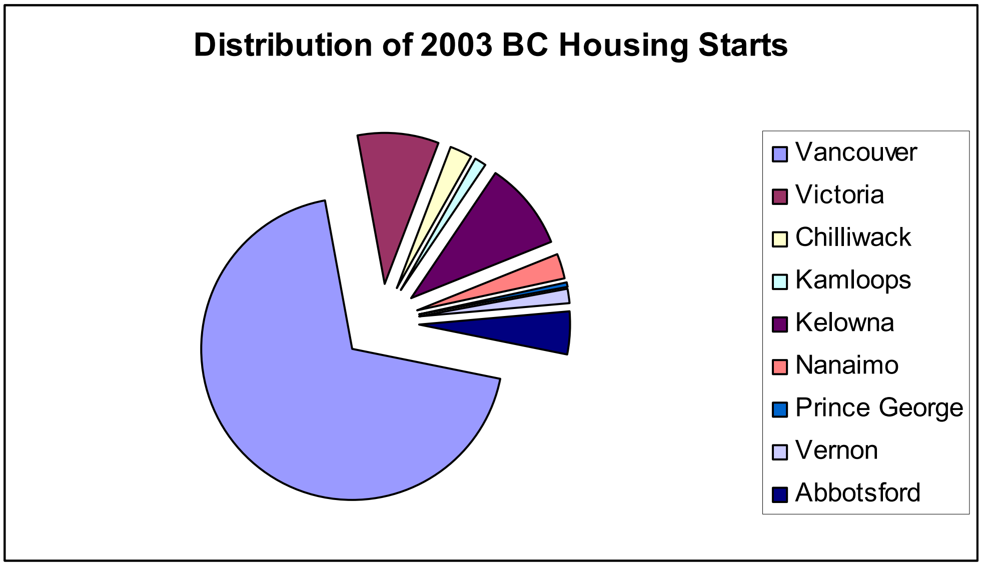
Figure 5.2 Customers by Rate Class



49 Terasen Gas Inc. experience has shown that gas is utilized efficiently in the industrial sector, with many firms retaining qualified personnel to oversee their energy operations

For DSM programs that are designed to target new construction, the market opportunity for each community is based on housing starts. Figure 5.3 illustrates the distribution of 26,000 new construction starts provincially in 2003 with the Lower Mainland providing the largest new construction market share. There was notable growth also in Victoria, Kelowna and Abbotsford.

Figure 5.3 Provincial Distribution of Housing Starts



Source: Canadian Mortgage and Housing Corporation

As shown in Table 5.3, the Terasen Gas service area has experienced a decline in normalized average use per account. The significant natural gas price increase in 2001 led to a sudden decline in average use demonstrating a correlation between use rate per account and changes in natural gas prices.

In the longer term, other factors can influence average use. Terasen Gas is undertaking a detailed market study (the Conservation Potential Review discussed in the next section) which will quantify the degree to which the following factors have a role in the declining use:

- Electricity price caps versus natural gas as a market based fuel.
- New construction (more efficient homes) increasing in market share.
- Increasing market share of multi-family housing with only fireplace load (market shift to electric baseboard).

Table 5.3 Normalized Average Use per Residential Account

Use Per Residential Account (GJ/Year)	1998	1999	2000	2001	2002	2003
Lower Mainland	122.8	121.9	116.9	105.2	113.0	111.6
Inland	102.2	104.0	98.9	87.5	88.0	88.7
Columbia (East Kootenays)	109.8	113.4	108.0	112.9	95.5	96.0
All Regions	**116.8**	**116.7**	**111.6**	**100.5**	**105.6**	**103.1**

5.4 DSM Opportunities

5.4.1 New and Existing DSM Programs for 2005

The Conservation Potential Review, discussed in Section 5.4.2 below, is intended to provide a framework upon which to build future DSM portfolios for 2006 and beyond[50]. For 2005, the planned DSM portfolio is shown in Table 5.4.

Table 5.4 Planned 2005 DSM Portfolio

Rate Class	Program Title	Projected Participants	Program GJ Savings based on measure life	GHG Reductions Tonnes of C02e
Residential	Energy Star Heating Upgrade	3,000	1,035,000	52,000
Residential	New Construction Heating Upgrade	1,500	475,875	24,000
Residential	Fireplace Upgrade Program	1,500	543,750	28,000
Commercial	Utilisation Advisory	50	495,750	25,000
Commercial	Efficient Boiler Program	60	2,068,500	105,000
Commercial	Destination Conservation	30	18,380	1,000
Commercial	CHBA Project	TBD	TBD	TBD
	Total for 2005	**6,140**	**4,637,255**	**235,000**

A description of each of the proposed programs is provided in Section 5.7.

50 Depending on the nature of the opportunities identified, Terasen Gas may also re-prioritise its 2005 portfolio to maximize benefits arising from its DSM activities.

5.4.2 Requirement for a Conservation Potential Review

In October 2004, Terasen Gas initiated a CPR. A CPR examines available technologies and determines their "conservation potential" over the study period through economic screening. The CPR compares the economic and achievable potential of viable measures to a base case scenario.

Terasen Gas last conducted this type of study in 1994[51]. In the past decade, there have been significant changes in the market that suggested a current conservation potential review is appropriate:

- technology and appliance efficiencies have improved
- utilities and industry have gained experience with DSM
- energy costs have risen substantially
- customer interest in conservation has changed dramatically as a result of higher energy costs
- the Vancouver Island and Sunshine Coast gas distribution system was acquired by Terasen Gas (Vancouver Island), providing a key challenge. There is a unique interdependence between electricity and natural gas where the marginal source of electricity is provided by gas fired generation.
- Terasen Gas (Whistler) Inc. acquired the propane system serving Whistler
- BC Hydro is evaluating all economic forms of electricity conservation creating interest in the potential viability of fuel substitution programs
- Kyoto and other climate change initiatives have led to significant federal, provincial and municipal interest and support for Utility conservation programs providing GHG reductions

In order to provide future Resource Plans that can adequately address the market changes as well as identify and prioritise potential opportunities, the CPR has three key objectives:

(a) Characterization of available natural gas technologies inclusive of energy efficiency and fuel substitution.

(b) Identification of the size of the potential opportunities over a set study period.

(c) Economic modelling of DSM programs, fuel substitution and energy efficiency measures.

The CPR results will form the basis for future program development within a comprehensive DSM portfolio. It is anticipated that the CPR will be completed by mid 2005.

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51 *Characterization of DSM Efficiency Measures*, Marbek, 1994.

5.5 DSM Portfolio Link to Provincial Strategy for Energy Efficiency in Buildings[52]

Terasen Gas has been engaged stakeholder in the Province's Review of Energy Performance Measures for Buildings in B.C. The review culminated in a series of recommended actions currently being reviewed by the relevant industry sectors. A number of initiatives within Terasen Gas' 2005 DSM portfolio directly support these recommended actions. Table 5.5 outlines how each of the proposed DSM programs supports the Province's Strategic Plan. A number of additional measures have also been identified in the Province's Strategic Plan:

- Community action on Energy Efficiency Pilot Program.
- Residential / developer/trades training and capacity building programs.
- Multi-unit residential building market transformation strategy.
- Building energy system operator training and certification program.

These measures will be considered in subsequent Resource Plans.

Table 5.5 DSM Portfolio Link to Provincial Strategy for Energy Efficiency in Buildings

Provincial Strategic Plan Recommendation	Action	Program/initiative	Measure
Update and expand Energy Efficiency Act, including building components	Support market transformation efforts to High Efficiency equipment	Energy Star Heating System Upgrade	Energy Star residential furnaces and boilers for existing buildings
		New Construction Energy Star Heating System Upgrade	Energy Star residential furnaces and boilers for new construction
		Fireplace Upgrade Program	High efficiency fireplaces – existing buildings
		Efficient Boiler Program	Mid and high efficiency commercial boilers – new and existing buildings
B.C. Government wide leadership for new and existing buildings and equipment	Improve energy utilization efficiency	Efficient Boiler Program	Mid and high efficiency commercial boilers – new and existing buildings
		Commercial Utilization Advisory	Energy assessments for existing commercial customers

52 Strategic Plan for Energy Efficiency in Buildings, Andrew Pape-Salmon, Ministry of Energy and Mines; Innes Hood, the Sheltair Group, March 26, 2004

5.6 DSM Portfolio Impact

The 2005 portfolio provides forecast savings of 4.6 million GJs and 235 kilotonnes of GHGs and offers significant TRC[53] net benefit. Rigorous econometric modelling in evaluations has also demonstrated DSM's contribution to market transformation.

In some cases, DSM programs can also play a role in deferring system improvements by reducing system design day. However, the current portfolio represents only approximately 0.1% of design day system demand and would be even smaller if evaluated in terms of impact on a specific community's distribution system. When considering the current CPR, a significant expansion of conservation activity has the potential to defer the need for system improvements, with two primary considerations:

- Customer participation in future DSM programs (and the corresponding savings) cannot be guaranteed. With the long lead time required for system improvements, the actual savings from DSM programs are better measured retrospectively, long in advance of the system improvements, to effectively mitigate the risk associated with relying on DSM to offset growing demand.
- The CPR will be evaluating conservation options from a multi-utility perspective in that fuel-substitution ("energy choice") alternatives will be quantified. It is possible that a portfolio of economic electric-to-gas fuel-substitution opportunities will, in effect, offset any reductions resulting from a long list of natural gas conservation measures. As an outcome of the CPR, future DSM portfolios may contain a mix of conservation and fuel-substitution or energy choice programs that provide quantified benefits to "all participants" but with only a limited reduction in design day natural gas demand.

5.7 Funding Requirements for 2005

Partnering Opportunities

Terasen Gas has attempted, whenever feasible, to partner with other organizations to leverage Utility DSM funds; Natural Resources Canada, BC Hydro, FortisBC, and appliance manufacturers have all participated in Terasen Gas programs providing benefits to its customers. Looking ahead, the Alternative Energy Policy Branch of the Ministry of Energy and Mines ("MEM") has received approval for its application to the federal "Opportunities Envelope" for $11 million over a two year period for energy efficiency measures of which $3 million is earmarked to support Terasen Gas' DSM programs. They will become the primary partner for a number of the Terasen Gas' DSM initiatives proposed for 2005 through 2007.

[53] **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.

The approach of the MEM proposal was to leverage existing programs and delivery channels to support a Province wide market transformation strategy. Table 5.6 shows a summary of the MEM's funding proposal - $118 million available through all sources to support energy efficiency programs and training in B.C.

Table 5.6 MEM Funding Sources for Market Transformation Strategy

Incentives recorded in MEM application (Fiscal year ends March 31)	**Funding Source (Thousand $)**				
	BC Gov't	**Utilities**	**Industry Sources**	**Opportunities Envelope**	**Total**
2004-05 Programs	$2,477	$26,264	$1,360	$1,640	$31,741
2005-06 Programs	$8,246	$27,302	$1,448	$5,022	$42,019
2006-07 Programs	$11,365	$27,727	$1,287	$4,338	$44,717
Total Joint Programs	**$22,089**	**$81,294**	**$4,094**	**$11,000**	**$118,476**

Anticipated Costs

Table 5.7 provides an overview of the programs planned by Terasen Gas, showing anticipated participation and costs providing close to $7 million in net benefit based on the Total Resource Cost test. The program costs are net of any partner contributions. It is anticipated, however, that the CPR will identify new opportunities which may result in modifications to the programs planned for late 2005.

Table 5.7 Planned DSM Programs

Program Title	Projected Participants	Total Incentive	Program Costs (Net or partner contributions)	Total Resource Cost (TRC[54]) Net Benefit
Energy Star Heating Upgrade	3,000	$450,000	$300,000	$1,138,918
New Construction Heating Upgrade	1,500	$225,000	$300,000	$537,703
Fireplace Upgrade Program	1,500	$150,000	$100,000	$33,147
Utilisation Advisory	50	$0	$75,000	$1,272,384
Efficient Boiler Program	60	$720,000	$250,000	$3,826,278
Destination Conservation	30	$0	$45,000	$175,346
CHBA Project	TBD	TBD	TBD	TBD
Total for 2005	**6,140**	**$1,545,000**	**$1,070,000**	**$6,983,776**

Cost Benefit Tests	TRC	RIM[55]
Portfolio of 2005 Programs	1.97	0.61

Residential Programs

New Construction Energy Star Heating Systems

This new program targets the installation of Energy Star qualified natural gas furnaces and boilers in new construction with an incentive payable to residential builders. Builders are required to apply to funding after which they have two years to install the equipment. The intent of the program is to alter the existing market where only 5% of new homes currently have high-efficiency equipment installed.

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. Possible partners include NRCan, MEM, appliance suppliers, and BC Hydro if a furnace fan motor incentive is offered.

54 **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..

55 **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.

Fireplace Upgrade Program

A program evaluation is currently underway for the 2004 program. Participation was nearly 1/3 of the forecast so specific attention is being given determine the possible cause. Based on the results of the evaluation, Terasen Gas will tailor a program to either the new construction or retrofit market. In either case, a Utility incentive would be paid to participants who select a fireplace with an EnerGuide Fireplace Efficiency rating of 55% or higher. Depending on the results of the 2004 evaluation, upgrade from wood burning fireplaces may also be included. Possible partners would include NRCan, MEM, appliance suppliers, and BC Hydro.

Commercial Programs

Efficient Boiler Program

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.

Commercial Utilization Advisory

The continuation of this program is proposed for 2005 along with an expanded set of web tools to provide commercial customers with comparative natural gas usage information against which their facilities can be benchmarked.

CHBA-BC Project

The Canadian Home Builders Association of B.C. (CHBA-BC) is bringing together multiple partners to work with builders and contractors to develop energy efficient neighbourhoods. It will facilitate the development of an EGH-80[56] community where all houses demonstrate such performance. It assists engagement of all trades with an aim to alleviate barriers to energy efficient new housing design in a systematic fashion, including the first cost barrier. The incentive is still under negotiation by the various partners but will contribute towards the energy savings and emission reductions.

Destination Conservation

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.

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56 NRCan's EnerGuide for Houses (EGH) rating system. A rating of 80 is equivalent to the energy performance of an R-2000 home.

6 RESOURCE PORTFOLIO DEVELOPMENT AND EVALUATION

6.1 Introduction

Natural gas is moved from producer to end user through a pipeline system. The capacity of a pipeline system is limited by the pipeline size, design pressure, and the length of the pipeline. To overcome friction and allow gas to flow through the pipeline, a pressure differential between the inlet and the downstream delivery points is required. Compressors are used to create the pressure differential and move large volumes of natural gas at high transmission pressures to major delivery points. The end pressures, which vary with flow, are controlled by pressure regulating stations before the natural gas enters the pipeline distribution system.

Generally, there are three types of 'supply side resources' that can be used to increase the physical capacity of a pipeline system: pipeline looping, compression, and on-system storage. In addition, 'demand side resources' such as industrial curtailment can be used to limit demand during peak periods. A brief summary of each of these resources is provided below.

Pipeline Looping

A pipeline loop is the addition of a second pipeline which is usually in parallel to an existing one. This increases the effective cross-section area of the pipeline serving the region and thus, allows a greater flow rate for a given pressure differential.

Compression

Compressors can be added to increase capacity in one of two ways; additional or larger compression units can be added to increase the pressure differential across an existing station, or additional stations can be added along the pipeline to maintain a higher average system pressure.

Storage

Storage allows natural gas to be put away in times of low demand, such as the summer months, to be used later during periods of high demand to augment the capacity of the pipeline. There are generally two types of storage facilities. Underground faculties use salt caverns or depleted gas wells to store large amounts of natural gas in the earth. LNG facilities cool natural gas until it condenses into a liquid and store it in an insulated tank. During peak demand periods, the liquid is vaporized and pushed back into the pipeline. To augment the capacity of the pipeline system the storage facility must be located downstream, adjacent to the demand the pipeline is meant to serve.

Curtailment

Industrial curtailment is the right to recall firm transportation service from large industrial customers under specific conditions. Terasen Gas uses this recalled capacity to ensure firm service to its Core residential and commercial customers during periods of peak demand. Curtailment arrangements are usually based on the transport customer’s ability to switch to an alternative fuel and it may or may not include rights to the customer's gas supply during the curtailment period. The value of the curtailment service is recognized through direct fixed and variable charges paid by the utility or through reduced transportation costs relative to the transport customer's firm or interruptible alternatives. Utility customers realise value for curtailment through avoided expansion or gas supply costs.

6.2 Description of the Terasen Gas Service Region

Figure 1.1 in Section 1 illustrates the pipeline systems for the Terasen Gas group of companies, including Terasen Gas that serves communities and industrial users off the Duke Energy transmission pipeline from Northeastern British Columbia and the TransCanada pipeline from Alberta. Terasen Gas operates and maintains two major high pressure transmission systems, namely the CTS and the ITS.

6.2.1 Coastal Transmission System

Section 1.2.1 provides a plan (Figure 1.2) and description of Terasen Gas' CTS. While it covers a relatively small geographic area, the CTS serves the largest customer base in the Terasen Gas system. Approximately 550,000 of Terasen Gas' 789,000 customers are located in the Coastal service region. In addition to meeting the requirements of Terasen Gas' Core customers (includes bundled sales and firm commercial and industrial transport service customers), the CTS provides transportation service for TGVI from Huntingdon to Eagle Mountain[57] and for BC Hydro from Huntingdon to Eagle Mountain and the Burrard Thermal Generating station.

The CTS delivers gas to the Coastal distribution network via 163 gate stations in the Fraser Valley and Metro-Vancouver area. Pressure is reduced at these stations to 300 psig or less depending on system requirements.

6.2.2 Interior Transmission System

Section 1.2.2 provides a plan (Figure 1.3) and description of Terasen Gas' ITS. The ITS consists of 2,100 km of pipe ranging from 6 inch to 20 inch in diameter and operating in pressures between 700 and 1440 psig. Compressors are located at Savona, Kingsvale, Hedley, Midway, Trail, and Kitchener. Natural gas is distributed to various metering and regulating stations located near customers and communities. Operating pressure is reduced at these stations to 300 psig or less, depending on load and customer requirements.

57 The ‘Eagle Mountain’ delivery point is known as V1-Coquitlam on the TGVI system.

6.3 Resource Portfolios

One of the primary roles of Resource Planning is to assess expansion alternatives over a range of expected demand scenarios to determine the preferred resources required to meet demand over the long term. The first step in this process is to determine when demand growth will trigger the next capacity expansion on the existing pipeline system. Once this is established, multiple long-term system plans are assembled to address the requirements of each gross demand forecast discussed in Section 4. Each plan identifies a portfolio of investments in capacity resources over the planning period differentiated by the type and timing of resources used.

Components of these portfolios are identified using computer modelling that simulates the hydraulic characteristics of the Terasen Gas transmission system and planning criteria that address the design limitations and operating requirements of the systems. Considerations addressed by the planning criteria include:

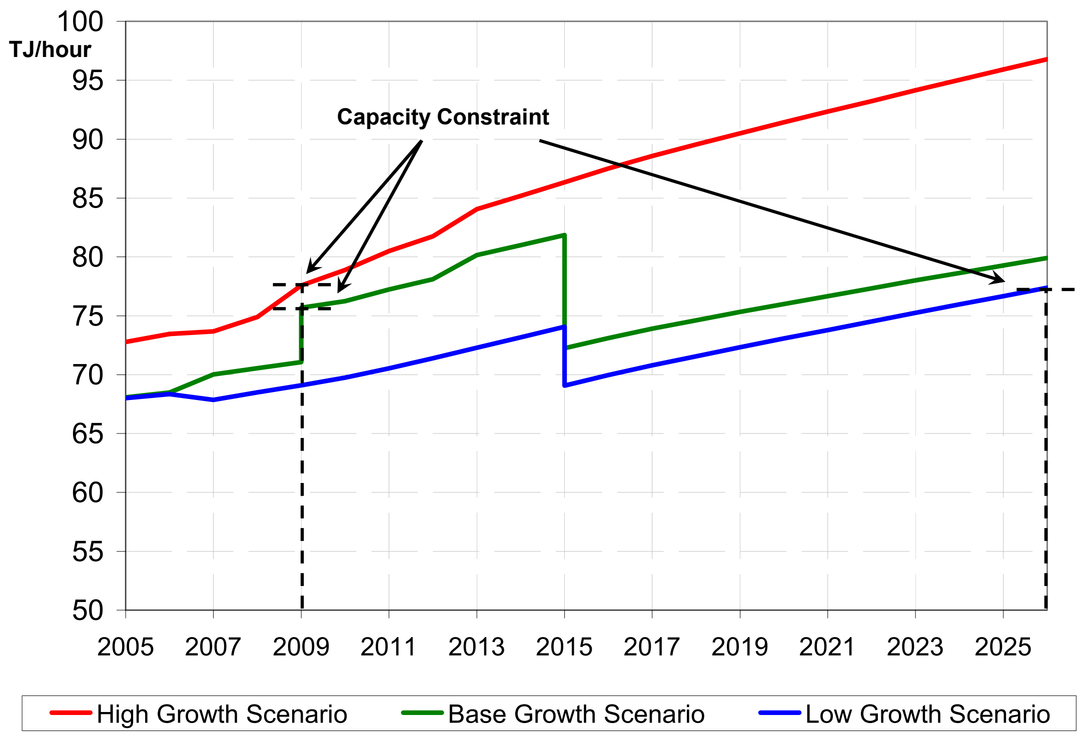
- Optimization of resource additions to meet the requirements over a 20 year planning period.
- Life cycle costs over the planning period of any new facilities as measured by the associated cost of service that must be recovered through customer rates.
- Capacity requirements under design day and normal day demand conditions.
- Construction and operating logistics are considered when assessing the feasibility and timing of alternative resource additions.

6.3.1 CTS Resource Portfolios

6.3.1.1 CTS Upgrade Project Timing

In all forecasts the first constraint to occur on the CTS is a shortfall of capacity north of Nichol Station on the part of the system that supplies Coquitlam Gate Station, Eagle Mountain, and Burrard Thermal. In addition to serving Core customers (includes bundled sales and firm commercial and industrial transport service customers) demand, this northern leg of the CTS is used to provide transportation for BC Hydro and TGVI. Hydraulic modelling results indicate that the assumptions used for BC Hydro transportation demand have the greatest effect on timing of this constraint. Figure 6.3 shows the onset of the initial constraint under the High, Base, and Low CTS forecasts.

Figure 6.1 CTS Capacity Constraints Reflected on the Demand Forecast Summary



In contrast to the supply base case presented in the 2004 BC Hydro Integrated Electricity Plan (IEP) BC Hydro's 2005 REAP indicates that:

- While the current operating context, that of having three units available on standby to provide capacity and three units available for later on recall, is expected to continue the timing for recalling the three units is now shown deferred from F2007 to F2009.[58]
- While Burrard Thermal was previously assumed to remain in-service beyond the end of the planning period, the current assumption is that Burrard is no longer relied on for dependable capacity and firm energy starting F2015.[59]

The 2005 REAP assumes dependable capacity from the DPP plant although approval for this project is still subject to appeal. To reflect variations in BC Hydro demand, the High, Base, and Low forecasts are based on the assumptions set out in Section 4.1 of this document.

58 BC Hydro, 2005 Resource Expenditure and Acquisition Plan (REAP), March 2005.

59 BC Hydro, 2005 Resource Expenditure and Acquisition Plan (REAP), March 2005, page 2 – 15.

These assumptions are included in the demand forecast component descriptions in Table 6.1, which shows there is a 156 TJ/day or approximately 100% difference between the Low and High assumptions in 2009 for BC Hydro transport demand. In comparison, there is a 34 TJ/day or 4% difference between the Low and High forecasts in the 2009 for Terasen Gas' Core demand (includes bundled sales and firm commercial and industrial transport service customers). For Core demand, the Low forecast assumed growth rates 10% lower than the Base forecast scenario. In the High forecast, it is assumed that Terasen Gas group of companies will obtain one million customers by 2010.

Table 6.1 Summary of Gross Demand Scenario Forecasts for CTS

Terasen Gas Inc. Gross Demand Forecast Scenarios for the Coastal Transmission System	Demand Forecast Components (TJ/day)																							
					BC Hydro Transportation Forecast Components and Potential Timing for Changes in Demand																			
					2005 Component Demand					2007 Component Demand					2009 Component Demand					2015 Component Demand				
	TGI Core	+	TGVI Transportation	+	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal	ICP	+	DPP	+	Burrard Thermal
TGI High Forecast	**High**		**Base**		**45**		**0**		**230**	**45**		**45**		**185**	**45**		**45**		**231**	**45**		**45**		**231**
TGI Base Forecast	**Base**		**Base**		**45**		**0**		**120**	**45**		**45**		**120**	**45**		**45**		**231**	**45**		**45**		**0**
TGI Low Forecast	**Low**		**Base**		**45**		**0**		**120**	**45**		**0**		**120**	**45**		**0**		**120**	**45**		**0**		**0**

TGI = Terasen Gas Inc.
TGVI = Terasen Gas Vancouver Island Inc.
ICP = Island Cogeneration Plant
DPP = Duke Point Power plant

TGVI's requirement for transportation across the CTS for the Vancouver Island Gas Joint Venture ("VIGJV") and TGVI Core demand is based TGVI's Revised Base forecast which was reviewed during the recent CPCN application for the Mt. Hayes LNG facility. In the High and Base forecasts used here, the TGVI requirements are from the Revised Base + 45 LNG portfolio and in the Low forecast is from the Revised Base + 0 PC&C (53 hr) portfolio.

6.3.1.2 CTS Resource Options

Common to all CTS forecasts is the need to increase capacity on the northern leg of the system serving Coquitlam, Eagle Mountain, and Burrard Thermal. The results of hydraulic modelling conducted to date suggest that the preferred solution to this constraint will be a program of 30 inch looping from Nichol to Noons Creek. The loop would be constructed in three phases; Nichol to Port Mann[60] (4.3 km), Cape Horn to Coquitlam (5.1 km), and Coquitlam to Noons Creek (4.3 km).

Capital solutions that employ compression as means to avoid segments of the loop are not cost effective. In the absence of the Nichol-Coquitlam loop, there would be little benefit to adding power at Langley due to limited pipeline capacity downstream of the compressor. In the Base

60 The original 24 inch crossing of the Fraser River between Port Mann and Cape Horn was recently replaced with a new 30 inch line.

forecast, for example, two additional compressor units at the Langley compressor station as well as the addition of a three unit compressor station near Nichol would ultimately be required. In Table 6.2 a comparison of capital expenditures required to meet 2026 Base forecast demand shows that pipeline looping is ultimately less expensive than a compression based alternative.

Table 6.2 Capital Expenditures Required for CTS Base Scenario Forecast Demand to 2026

Base Forecast Capital Requirements for 2026	Looping 2004 $million	Compression 2004 $million
Nichol – Port Mann	$14	
Cape Horn – Coquitlam	$17	
Langley Unit Additions		$35
Nichol Compressor Station		$50
Total Capital	$31	$85

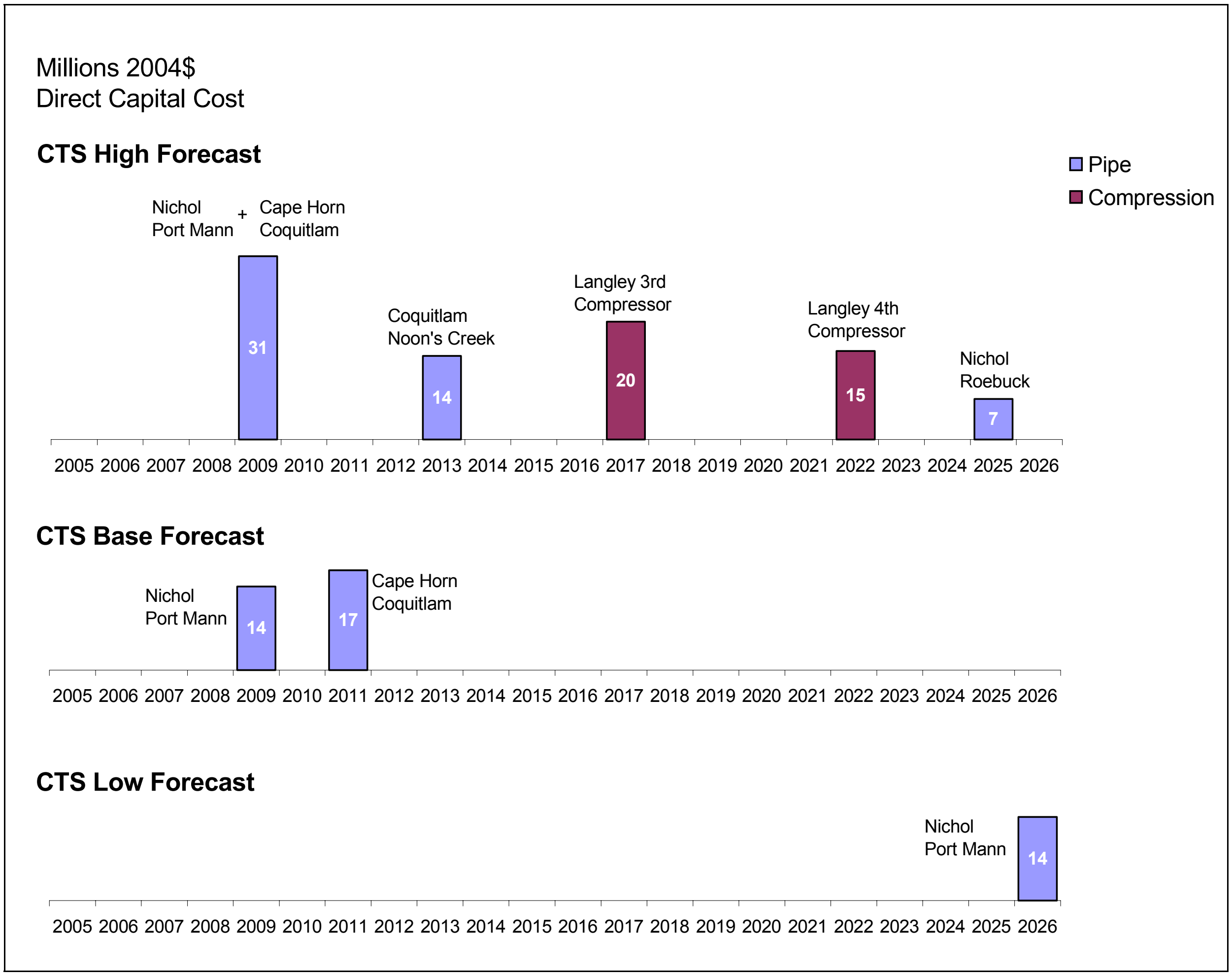
With the completion of looping downstream of Nichol, subsequent demand growth would be met with the addition of compression at Langley and a 2 km loop between Nichol and Roebuck Stations depending on the forecast. Figure 6.4 shows the expansion requirements for each of the Low, Base, and High forecasts. These preliminary costs for looping are based on 1995 estimates adjusted for inflation.

For the High forecast, the Nichol – Port Mann and Cape Horn – Coquitlam loop will both be required in 2009. The timing of subsequent expansion shown in Figure 6.4 assumes that capacity for six units at Burrard is maintained to the end of the planning period. If however, the requirement for firm capacity to Burrard is eliminated after 2014 the Coquitlam – Noons Creek loop could be deferred outside the planning period.

In the Base Forecast, the Nichol – Port Mann and Cape Horn – Coquitlam loop is required for 2009 and 2011 respectively. Subsequent expansion is avoided because no firm capacity is assumed for Burrard after 2104.

In the Low case where only three Burrard units are maintained until 2014, the Nichol – Port Mann loop is required in 2026.

Figure 6.2 Timing and Relative Costs of CTS Expansion Requirements



While the analysis shows that the first phase loop is expected in 2009, the timing will ultimately depend on the rate of Terasen Gas Core Market customer growth realized, resolution of the requirements for on-Island generation and subsequent TGVI expansion requirements, and the timing and extent to which additional Burrard units are recalled into service. The need for expansion prior to 2009 is considered unlikely and would only be expected to result from one or a combination of the following: a request for additional capacity under the BTA, Terasen Gas Core Market growth in excess of the High forecast, TGVI requirements exceeding those of the Revised Base + 45 LNG portfolio (either because of higher TGVI or VIGJV demand or because the expansion requirements are met without the Mt. Hayes LNG facility). Based on conventional requirements for consultation, land acquisition, permitting, design and construction, implementation of the Nichol – Port Mann loop is expected to take two years.

6.3.1.3 CTS Portfolio Selection

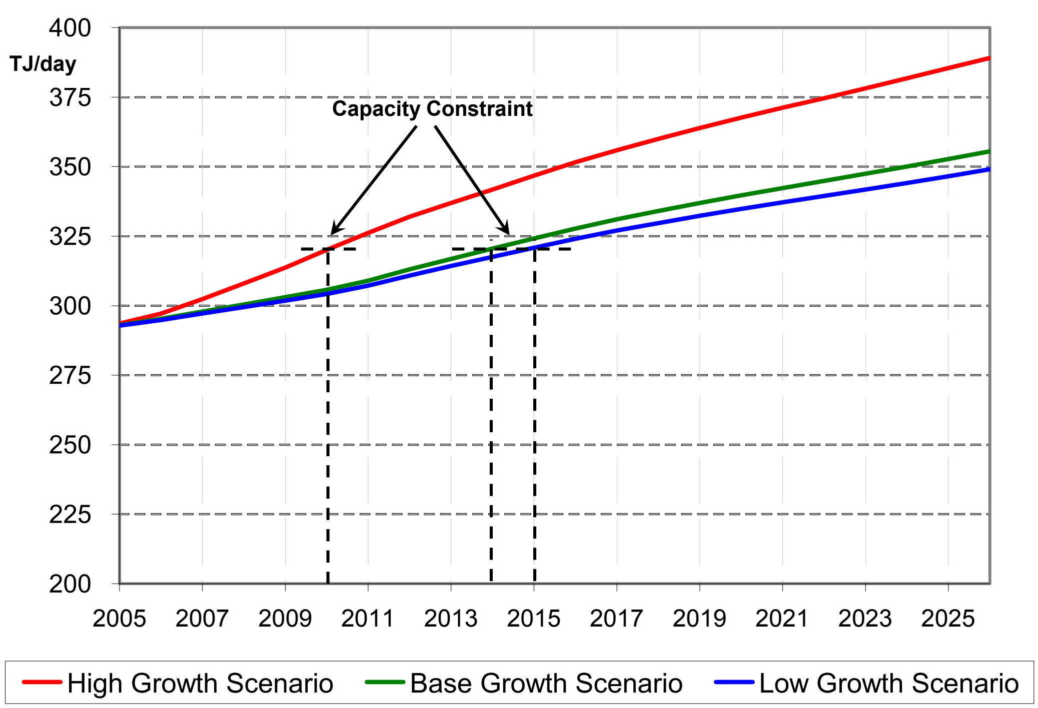
In anticipation of the 2009 requirement, Terasen Gas will continue to assess alternatives to defer the pipeline loop. These include contract demand reductions as well looping alternatives based on additional on-system storage. Beginning in 2008, Terasen Gas expects to contract for storage services from TGVI based on available capacity from the Mt. Hayes facility. There may be opportunity to use this service or an expansion of the existing Tilbury facility to defer the upgrade. Given BC Hydro's expectation that full Burrard capacity will only be required for 6 years, a storage based expansion may be more cost effective than the pipeline loop. Unlike pipeline looping which only provides capacity, on-system storage provides both capacity as well as benefits in terms of avoided gas supply costs and reduced stranded asset risk.

6.3.2 ITS Resource Portfolios

6.3.2.1 ITS Upgrade Project Timing

On the ITS, the first constraint is expected to result from Core Market demand growth in the Thompson – Okanagan region. Figure 6.5 shows the onset of the initial constraint under the High, Base, and Low ITS forecasts.

Figure 6.3 ITS Capacity Constraint Reflected on the Demand Forecast Summary



Of the 298 TJ/d design day requirement forecast for 2007 on the ITS, 273 TJ/d is attributed to residential and commercial customers. Firm transportation for large industrial customers only accounts for 25 TJ/d of the total. Since no growth is forecasted for large industrial customers in the three scenarios, differences in timing result entirely from the Residential and Commercial customer growth forecast.

6.3.2.2 ITS Resource Options

The results of hydraulic modelling conducted to date have identified two alternatives to resolve the forecast capacity constraint; a phased program of 20 inch 1035 psig looping between Penticton and Winfield, or the addition of a LNG storage facility near the existing pipeline between Falkland and Vernon. A discussion of each alternative follows.

The loop would be constructed in three phases starting from the Ellis Creek station near Penticton; the first phase would end just north of Naramata (23.7 km), the second just south of Mission (15.0 km) and the final phase would be a bypass of Kelowna ending at Winfield Station (30 km). Effectively, each phase of the loop is an extension of the Southern Okanagan Pipeline (SONG), built in 1997, which delivers high pressure supply into the Okanagan from the Southern Crossing Pipeline (SCP) interconnect south of Oliver.

In the High forecast, requirement for the first loop is not expected until 2010 and in the Base and Low forecast not until 2014 or 2015. The second phase loop would be expected to follow about 10 years after the first. Only in the High forecast might the third phase loop be expected within the planning period. In addition to resolving the capacity shortfall, the looping program provides other benefits which would also be considered when establishing the timing of the expansion requirement:

- Increased capacity to access the AECO market for Alberta gas supply. This would result in greater supply diversity and may possibly lower gas supply costs depending on differential from Station 2 based supply.
- Resolution of pressure restrictions due to development adjacent to the original pipeline (class location changes). These pressure restrictions reduce capacity available to serve the region. Increased development activity could advance the need for expansion.

As an alternative to the looping program, phased addition of LNG storage has also been considered. In this case, a one bcf facility similar to that proposed for Mt. Hayes would be constructed to meet the initial requirement (2010, 2014, or 2015 depending on the forecast). Only in the High forecast might an expansion of this facility be expected late in the planning period. In addition to resolving the capacity shortfall, the LNG alternative provides other benefits which would also be considered when establishing the timing of the expansion requirement:

- Additional on-system storage increases supply diversity for Terasen Gas and allows the cost of incremental third party storage to be avoided.
- Unlike the pipeline looping, alternative available capacity has market value. Terasen Gas could use the facility to provide storage services to others, generating mitigating revenue to offset cost and lower stranded asset risk.

The conventional schedule for implementing pipeline looping and compression projects is two years, which includes time for consultation, land acquisition, permitting, design, and construction. The conventional schedule for adding an LNG storage facility is about three years.

It is assumed that current arrangements with interruptible customers will continue into the future. For rate 22A customers, Terasen Gas can curtail transportation services up to half of the customer's firm transportation capacity for five days in a contract year. However, given the relatively small size of this gross demand component, it is unlikely that increasing the level of curtailment will offer a means to avoid expansion requirements.

6.3.2.3 ITS Portfolio Selection

Since the ITS requirements fall outside the both the development schedule and action plan window, final analysis of these resource options has not yet been completed. Terasen Gas will continue to monitor demand growth in the region and development activity along the ITS.

6.3.3 Evaluation of CTS and ITS Options under Resource Planning Objectives

Detailed evaluation of the options discussed in sections 6.3.1 and 6.3.2 against the planning objectives identified in section 1 are not yet included as part of the Resource Plan for three reasons. First, the number of options available to solve the capacity shortfalls in each of the Coastal and Interior regions is limited, as discussed above. Second, the timing of the capacity constraints remains outside the four-year action planning window of the Resource Planning process. Finally, for the CTS, the timing and full range of options available to Terasen Gas is in part dependent upon BC Hydro decisions for the operation of its thermal generating stations. The need for continued assessment of these factors is incorporated into the action plan and a full review of the Resource Planning objectives will be conducted as the issues are resolved.

6.4 Interior Transmission Laterals

Upgrades to the Terasen Gas laterals north of Savona and east of Yahk are expected over the planning period; however, none of these are currently expected to trigger the requirement for a CPCN application.

6.5 Terasen Gas Distribution System

Upgrades to the capacity of the distribution systems generally are smaller in scale and more frequent in nature than upgrades to the Transmission system. In its planning process, Terasen Gas will seek optimal solutions to meet customer demand on the distribution system over the long term with solutions that are both cost effective and that minimize impact on the local community.

7 STAKEHOLDER CONSULTATION

7.1 Stakeholder Consultation to Date

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 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.

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. A preliminary review of the CTS and ITS transmission systems showed no immediate impacts on local communities. Significant system expansion would likely not be required until the year 2009. With no immediate system expansion that would impact communities, stakeholder interest was anticipated to be mild to low. Given this, Terasen Gas instead developed a stakeholder consultation process that targeted high growth municipalities (i.e. high number of new housing starts in recent years) with the focus on engaging municipal representatives in discussing the *Role of Natural Gas in Community Energy Planning* and communicating to them the *Resource Planning Process* Terasen Gas employs to ensure natural gas service is provided safely, reliably and cost effectively over the long term.

Consultation events also included a stakeholder workshop aimed at a broad range of stakeholders from around the Province and a separate meeting with BC Hydro to facilitate understanding and, where possible, integration between BC Hydro and Terasen Gas.

With this targeted approach, Terasen Gas believes that municipal representatives, key influencers in communities' choice of energy will be better informed and able to assess the merits of natural gas compared to its alternatives. Topics discussed at the municipal meetings included:

- The role of natural gas in a sustainable energy future
- Efficient use of energy resources
- Natural gas compared to other energy systems
- Provincial / regional growth and energy use trends
- Terasen Gas programs for efficient energy use
- Resource Planning at Terasen Gas

For a copy of the presentation material, refer to Appendix E.

Table 7.1 presents a summary of stakeholder consultation events associated with the Terasen Gas Resource Planning.

Table 7.1 Summary of Stakeholder Consultation Events

Event & Date	Issues Presented / Discussed	Audience	Attendees / Respondents
2004 Union of British Columbia Municipalities (UBCM) Convention in Kelowna between **September 21 - 24**	Resource Planning process at Terasen Gas and distributed brochure with invitation to contact Terasen Gas for more information on the Resource Plan and to discuss community and energy options.	Local government representatives and staff	Over 900+ in attendance at 2004 Kelowna convention
Meetings with Municipalities: **November 22, 2004** – Prince George **November 22, 2004** – Kelowna **January** 17, **2005 –** City of Vancouver **February 15, 2005 –** City of Abbotsford **February** 18, **2005 –** City of Surrey	- The role of natural gas in a sustainable energy future - Efficient use of energy resources - Natural gas compared to other energy systems - Provincial / regional growth and energy use trends - Terasen Gas programs for efficient energy use - Resource Planning at Terasen Gas	Municipal staff in high level roles in development and social planning, engineering, municipal operations and energy and environmental committees In some cases, elected officials attended these meetings as suggested by senior municipal staff	Meeting attendance ranged between 8 and 15 municipal representatives at each municipality
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 approximately 45 separate stakeholders and stakeholder groups: - 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
BC Hydro Consultation – Ongoing Terasen Gas RP Meeting **March 18, 2005**	Same as above	BC Hydro technical staff and management	Not applicable

7.2 Comments from Stakeholder Consultation

7.2.1 Meetings with Municipalities

Communication with municipalities and other stakeholders for the 2004 Terasen Gas Resource Plan began in September 2004 with Terasen Gas providing a booth at the 2004 Convention for the Union of BC Municipalities and information on hand regarding Terasen Gas' Resource Planning process. Stakeholder response to this information was minimal, confirming Terasen Gas' expectation that without large projects on the immediate horizon, broad interest in the 2004 Resource Plan would be mild to low. This finding, in part, confirmed Terasen Gas' need to focus Resource Planning messages and communication opportunities carefully.

For the 2004 Terasen Gas Resource Plan, Terasen Gas recognized that it could not complete a large number of individual meetings with municipalities. A shorter list was developed targeting selected municipalities experiencing high levels of urban growth and whose needs for informed community energy planning would therefore be greatest. Of those municipalities contacted, five municipalities expressed a desire to meet with Terasen Gas as noted in Table 8.1.

Municipal representatives generally agreed that high efficiency natural gas systems were a preferred home heating energy solution over incremental electrical generation, where that generation was likely to be thermally generated from fossil fuels and until reliable renewable energy systems were more readily market available. An overwhelming interest for more information on high efficiency equipment and systems and Terasen Gas' energy conservation programs emerged during these meetings. At most of the meetings, municipal staff agreed in principal with Terasen Gas' desire to get these technologies and systems into the multi-family residential housing market where the efficiency benefits could make a significant impact.

No comments or questions were aimed directly at Terasen Gas' discussion of the Resource Planning process or Terasen Gas' methodologies for assessing future load growth and resource option alternatives. This low interest in Resource Plan specifics is again attributed to the lack of immediate projects arising from the 2004 Resource Plan. In all cases, municipal representatives were very interested in emerging energy issues and technologies and welcomed continuing communications with Terasen Gas.

7.2.2 Stakeholder Workshop

Invitations were sent out to a broad group of stakeholders representing different interests. Stakeholders invited included representatives from customers, businesses, municipal and provincial government, environmental organizations, BCUC and other interested stakeholders such as BC Hydro and energy industry organizations. Issues raised by stakeholders during the 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 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.

7.2.3 BC Hydro Consultation

Terasen Gas and BC Hydro are the two largest suppliers of energy and related services on the Mainland. As such, the actions of one Utility, very much impact the other. To ensure that both utilities are acting in the best interests of their customers while remaining fiscally responsible, a high degree of open and cooperative consultation is required during planning stages. Terasen Gas has sought input from BC Hydro during the Resource Planning process.

Consultation efforts with BC Hydro led to a presentation of Resource Plan details to date with BC Hydro staff on March 18, 2005. While Hydro staff generally supported the work presented, they had numerous technical and editorial comments and raised the following items for consideration.

- BC Hydro staff were interested in the Regional Supply aspects of Terasen Gas' business, the relevance of the Regional Resource Plan to the Terasen Gas 2004 Resource Plan, and in the measures in place and proposed to protect the secure and reliable delivery of natural gas as well as natural gas rates.
- The efficiency comparisons of using natural gas directly in the home versus using natural gas to generate electricity and the potential for integrating programs that could capture efficiency benefits for both organizations was noted.

- Discussion took place to ensure that Terasen Gas has appropriately accounted for all BC Hydro demand loads that need to be planned for in the Terasen Gas Resource Plan, in so far as they have yet been determined by BC Hydro. BC Hydro staff clarified their current position, just recently released, regarding the expected future operations and demand needs of Burrard Thermal Generating Station. This information has accordingly been incorporated into this Resource Plan.
- Terasen Gas also shared with BC Hydro the comments received by stakeholders during consultation efforts that were directly related to BC Hydro's portion of future natural gas demand. Both parties agreed that the uncertainty with respect to the future of Burrard Thermal remains one of the biggest challenges for planning infrastructure needs for Terasen Gas.

7.3 Future Consultation Opportunities for Stakeholders

The process of consulting stakeholders about Terasen Gas' future Resource Planning issues will continue after submitting the 2004 Resource Plan. CPCN application(s) to support the selection of individual resources within the preferred resource portfolio may be required at a future date. These application(s), submitted to the BCUC may also include a public hearing process and be subject to further consultation with stakeholders prior to the submission of the applications. For certain types of projects, design approvals, permits and land development applications under various Federal and Provincial Acts and under municipal planning bylaws may also be required. Effective stakeholder consultation is a key component of most of these approval processes.

8 ACTION PLAN

The preceding analysis shows that the earliest upgrade to Terasen Gas' natural gas transmission systems is an expansion in the Coastal region in 2009 under either a High or Base forecast demand scenario. In the Interior region, the earliest that an upgrade is required is in 2010 under a High forecast scenario. Since each of these potential projects is outside of the four-year action plan window of the 2004 Resource Plan, continued assessment of demand conditions and alternative solutions will instead be the primary focus of the Action Plan. The Action Plan describes the actions that Terasen Gas intends to pursue over the next 4 years based on the information and evaluation provided in this Resource Plan.

1. *Continue to monitor customer demand by:*

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

    b. Working with BC Hydro to understand their demand for natural gas at the Burrard Thermal generating station. As outlined in Section 6, the expected demand from Burrard Thermal significantly influences the timing of any system upgrades required to the CTS.

    c. Assessing the impact of distributed generation projects and other emerging energy trends and technologies on demand for natural gas.

    d. Validating 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 would therefore contribute to a higher demand forecast scenario.

    e. Assessing 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 to investigate the options available to Terasen Gas to address the future capacity shortfall in the CTS north of Nichol Station as set out in Section 6.3.1.*

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

    Review of weather sensitivity and physical interruptions from pipeline outages suggests a need for additional capacity resources to meet peak day regional demand in the incidence of a moderately cold or low hydro year.

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

    Terasen Gas will continue to engage key stakeholders regarding issues affecting the Resource Plan and encourage energy efficient choices for customers and communities. The results of these efforts will be incorporated into future Resource Plan updates.

5. *Report back on the outcomes and recommendations of the Conservation Potential Review.*

   The Conservation Potential Review results will form the basis for future program development within a comprehensive DSM portfolio. The CPR is expected to be completed by mid 2005.

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.*

   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 very competitive position for natural gas, benefiting the entire regional energy outlook in keeping with the Provincial Energy Policy.

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 Provincial body regulating utilities in British Columbia.

Call for Tenders (CFT) – 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.

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

Core customers – includes bundled sales and firm commercial and industrial transport service customers.

Core Market customers – 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.

Certificate of Public Convenience and Necessity (CPCN) – 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.

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-day demand – the maximum demand for natural gas a utility expects it must provide over a single day. As Core Market demand is weather dependent, design-day is forecast based upon the coldest weather using 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.

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.

FE rated – an official rating that verifies that the efficiency of vented gas fireplaces have been tested by the Canadian Standards Association.

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).

GWH – Giga-watt Hours.

Hog Fuel – Biomass fuel that has been prepared by processing through a "hog" - a mechanical shredder or grinder. If produced by primary forest industries, it usually consists of a mixture of bark and wood often with sawdust, shavings or sludge mixed in and is generally wet and fibrous with a high ash content.

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 Northwestern US. The I–5 Corridor includes B.C.'s Lower Mainland and Vancouver Island, Western Washington and Western Oregon.

Industrial curtailment – see curtailment.

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.

Integrated Electricity Plan – BC Hydro's 2004 Integrated Resource Plan.

Interruption – see curtailment.

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

Joint Venture – see Vancouver Island Gas Joint Venture.

Least delivered cost – the lowest cost for which natural gas can be supplied to a customer's home or facility where the gas is consumed.

Liquefied natural gas (LNG), LNG storage – natural gas contained 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.

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

Load duration, load duration curve – the load duration is the daily load over each day of the year, represented from the highest load to the 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 5.3 for further details).

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

Market saturation – the degree to which all the potential customers in a market or service area who could be natural gas customers, have been captured as actual customers.

Mist – the name and location of an underground, natural gas storage facility situated in Oregon, Northwestern US.

National Energy Board (NEB) – 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

Off-main potential – the market potential for customers that are currently not located near a gas supply main.

On-main saturation – similar to market saturation. The degree to which all of the potential natural gas customers who are near a gas supply main have been captured as actual customers.

O&M – operations and maintenance.

Peak day, peak demand, peak day demand – the maximum demand for natural gas a utility expects it must provide over a single day. As Core Market demand is weather dependent, design-day is forecast based upon the coldest weather using 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.

Tcf – Trillion cubic feet.

Terasen Inc. – the parent company of Terasen Gas Inc. and all other subsidiaries.

Terasen Gas Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas (Whistler) Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries. (Also referred to in the text of this report as Terasen Gas)

Terasen Gas (Whistler) Inc. (TGW) – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries.

Terasen Gas (Squamish) Inc. – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Whistler) Inc., Terasen Gas (Vancouver Island) Inc. and all other Terasen Inc. subsidiaries.

Terasen Gas (Vancouver Island) Inc. (TGVI) – a subsidiary and utility owned by parent Terasen Inc., and a separate corporate entity from Terasen Gas Inc., Terasen Gas (Squamish) Inc., Terasen Gas (Whistler) Inc. and all other Terasen Inc. subsidiaries.

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.

Vancouver Island Gas Joint Venture – a joint venture of industrial customers (primarily large mills) on Vancouver Island who purchase energy as a single bargaining unit.

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

---

[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.

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]

---

[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

Demand for Natural Gas from Electrical Generation Facilities in the Pacific Northwest

Recent and Proposed Gas Fired Generating Facilities in the Pacific Northwest:

Table B-1 Natural Gas Fired Electrical Generation Facilities Completed

Facility	Capacity (MW)	Peak Gas Use (MMcfd)	In-Service Date
Combined-Cycle			
Big Hanaford	248	38	Aug-02
Frederikson CC 1	249	38	Aug-02
Chehalis	520	80	Sept-03
Goldendale	248	38	Jul. 04
Cogeneration			
Wah Chang	14	3.1	Jul-01
Willamette Ind. – Albany GT Upgrade	6	1.3	Jan-01
Willamette Ind. – Albany ST Upgrade	45	10	Jan-00
Island Cogeneration	227	37	Apr-01
SP Newsprint	88	20	Oct. 03
Peaking			
Less than 100 MW in 2001	127	28.5	Mar-02
Less than 100 MW in 2002	11	2.4	Aug-01
Fredonia 3&4	106	24	Aug-01
Tesoro Ph 2	130	29	Jul-03

Table B-2 Proposed Gas-Fired Electrical Generation Capacity in the I-5 Corridor

Facility	Generation Capacity (MW)	Peak Gas Use (MMcfd)	Estimate In-Service Date
Under Construction - *Combined-Cycle*			
Mint Farm (Construction halted)	286	44	N/A
Satsop (Construction halted)	630 MW/ 720 MW w Duct Firing	100/127	N/A
Permitted - *Combined-Cycle*			
Everett Delta I / Preston Point	248	38	N/A
Everett Delta II	248	38	N/A
Longview	290	45	N/A
Summit Westward	520	80	N/A
Port Westward	400	100	Jun-07
Sumas 2	660	102	N/A
Permitted - *Cogeneration*			
Cowlitz Cogeneration	395	61	N/A
Permitted - *Peaking*			
The Cliffs	190	43	N/A
Permit Pending - *Combined-Cycle*			
Tahoma	270	42	N/A
Permit Pending - *Cogen*			
BP Cherry Point	720	111	N/A
Permit Pending - *Peaking*			
Beaver Upgrades	10	22	N/A
N.W. Hill (6-10)	10.5	24	N/A

APPENDIX C

NEB – The British Columbia Natural Gas Market An Overview and Assessment

National Energy Board

Office national de l'énergie

The British Columbia **Natural Gas** Market

An **O**verview *and* **A**ssessment

An **ENERGY MARKET ASSESSMENT** • April 2004

National Energy Board
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The British Columbia **Natural Gas** Market

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gas gas gas gas

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ACRONYMS

B.C.	British Columbia
BCUC	British Columbia Utilities Commission
CBM	coal bed methane
EMA	Energy Market Assessment
EnCana	EnCana Corporation
Enron	Enron Corporation
FERC	Federal Energy Regulatory Commission (U.S.)
GSX	Georgia Strait Crossing Pipeline Project
GTN	Gas Transmission Northwest Corporation
ICE	Intercontinental Exchange
I-5 Corridor	U.S. Interstate Highway 5 Corridor
LDC	local distribution company
LNG	liquified natural gas
M-KMA	Muskwa-Kechika Management Area
NEB or Board	National Energy Board
NGX	Natural Gas Exchange
NYMEX	New York Mercantile Exchange
PNG	Pacific Northern Gas Ltd.
PNW	United States Pacific Northwest (Washington, Oregon and Idaho)
SCP	Southern Crossing Pipeline
TCPL Alberta	TransCanada PipeLines Alberta system
Terasen	Terasen Gas Inc.
The Province	Province of British Columbia

U.S.	United States
VIGP	Vancouver Island Generation Project
WCSB	Western Canada Sedimentary Basin
Westcoast	Westcoast Energy Inc., which carries on business as Duke Energy Gas Transmission Canada

UNITS

Bcf	=	billion cubic feet
Bcf/d	=	billion cubic feet per day
GJ	=	gigajoule
m^3	=	cubic metres
m^3/d	=	cubic metres per day
mcf	=	thousand cubic feet
MMcf	=	million cubic feet
MMcf/d	=	million cubic feet per day
MW	=	megawatt
Tcf	=	trillion cubic feet

CONVERSION FACTORS

cubic metre	=	35.3 cubic feet
gigajoule	=	0.95 thousand cubic feet of natural gas at 1 000 Btu per cubic foot
hectare	=	2.47 acres
kilometre	=	0.62 mile

Foreword

As part of its mandate, under the *National Energy Board Act*, the National Energy Board (NEB or the Board) continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and natural gas liquids) and the demand for Canadian energy commodities in both domestic and export markets. The Board publishes reports on energy, known as Energy Market Assessments (EMA), which examine various facets of the Canadian energy market. These reports include both long-term assessments of Canada's supply and demand and specific reports on current and near-term energy market issues.

In addition to its mandate to monitor energy markets in Canada, the Board has a specific monitoring role pursuant to its regulatory responsibilities. The Board is required to monitor Canadian energy markets to ensure that markets are operating such that Canadian energy requirements are being met at fair market prices.

This EMA, *The British Columbia Natural Gas Market: An Overview and Assessment*, examines the current functioning of the British Columbia (B.C.) natural gas market and provides an overview of the issues in this market. The objective of this report is to advance the understanding of the B.C. natural gas market and to heighten awareness of regional natural gas markets in Canada.

During the preparation of this report, a series of meetings and discussions was held with a cross-section of the natural gas industry, including producers, gas marketers, pipeline transmission companies, local distribution companies, end-users, industry associations and government agencies. The Board appreciates the information and comments it received.

EXECUTIVE SUMMARY

The B.C. natural gas market has faced a number of challenges in the last few years, including rising prices, price spikes and increased price volatility. New exploration and development projects have been announced for northeast B.C. New pipeline projects have been developed that move gas from northeast B.C. to eastern markets, away from the traditional B.C. domestic and U.S. Pacific Northwest (PNW) export markets along the West Coast. Consumers, especially industrial consumers, are taking measures to reduce natural gas consumption and are exploring fuel alternatives. Is the market functioning as it should? This is the question that some market participants and consumers are asking.

Findings

The Board is of the view that, although there are some challenges, the B.C. natural gas market is working well. The Board finds that:

- natural gas prices in B.C. are now integrated with the North American gas market;
- there has been a significant upward step in natural gas prices throughout North America, including B.C.;
- B.C. consumers have responded to higher prices by reducing demand;
- producers in B.C. have responded to higher prices by increasing exploration and production;
- transportation developments have facilitated the movement of B.C. produced gas to markets east of B.C.;
- price discovery is being improved due to better price reporting standards and access to electronic gas trading at pricing points for B.C. gas;
- price volatility is being managed by market participants;
- B.C.'s small market size and lack of storage in the Lower Mainland limit market liquidity in comparison with other major market centres such as AECO-C in Alberta; and
- overall the market is working well and consumers and producers are making the appropriate changes to the higher natural gas price environment.

Discussion

Prior to 1998, the B.C. natural gas market was not fully connected with the North American gas market. After 1998 a series of pipeline expansions, including the construction of the Alliance pipeline from northeast B.C. to Chicago, increased the potential for B.C. and Alberta gas from the Western Canada Sedimentary Basin (WCSB) to reach North American gas markets. Gas prices in Alberta and B.C. rose and prices at AECO-C, Station 2 and Sumas/Huntingdon became more closely aligned with other North American markets.

Since 2000, natural gas price dynamics in North America have changed fundamentally. The growth in natural gas production that occurred throughout the 1990s slowed and in the face of increasing demand, prices rose throughout North America. As the balance between supply and demand became tighter, gas prices became more volatile than in the 1990s.

B.C. and PNW consumers have reacted to higher prices by reducing demand. After the California gas price spike in the winter of 2000/2001, consumers became concerned about natural gas price levels and price volatility. Industries changed their gas purchasing practices, switched fuels and improved energy efficiency. Residential consumers reduced their household consumption by improving energy conservation and turning down thermostats.

The gas exploration and development industry responded to higher prices and to regulatory incentives from the Province of British Columbia (the Province) with increased bidding at provincial land sales and with increased drilling activity. By 2003, production had risen from 54 $10^6m^3/d$ (1.9 Bcf/d) in 1998 to 71 $10^6m^3/d$ (2.5 Bcf/d), while oil and gas revenues to the Province rose from $0.4 billion in 1998 to in excess of $2 billion.

Transportation developments in B.C. have improved market access for B.C. gas production. New pipeline developments such as construction of the Alliance pipeline and numerous cross-border pipelines connecting with the TransCanada PipeLines Alberta system (TCPL Alberta) have facilitated the movement of gas to eastern markets. These transportation developments have provided B.C. gas producers with more market options and have provided additional impetus to increased exploration efforts in northeast B.C.

U.S. regulatory initiatives with respect to price discovery have improved price transparency at U.S. pricing points like Sumas/Huntingdon. The commencement of electronic gas trading at Station 2 on the Natural Gas Exchange (NGX) is improving price discovery there. However, prices at Sumas/Huntingdon remain susceptible to short-term price spikes, especially during peak winter demand. Without a major gas storage facility near the Lower Mainland, the Sumas/Huntingdon market does not have the same flexibility to respond to rapidly changing demand conditions as some other gas markets in North America. Market participants have become accustomed to managing gas price volatility through improved market monitoring and revised gas purchasing strategies, short-term fuel switching and demand management techniques. Nonetheless, liquidity and, hence, flexibility in B.C. is limited by the small size of the regional gas market.

Two features of the B.C. gas market stand out from other regional markets. The first is the lack of market-based storage for the Lower Mainland. With the expected growth in gas-fired power generation demand and a decrease in industrial demand, the overall demand profile has become more weather sensitive. Additional storage facilities in the Lower Mainland would assist in managing peak demand loads and would also improve the functioning of the gas market at Sumas/Huntingdon.

The second feature, in contrast with many other parts of North America, is that opportunities exist to increase gas supply from B.C. Current NEB resource estimates indicate that potential exists to increase production from northeast B.C. and that there is potential to find natural gas in other B.C. supply basins. The pace of any gas resource development will depend on many factors, including the management of various environmental, land-use, socio-economic and First Nations issues.

Introduction

The last ten years have witnessed many profound changes in the B.C. natural gas market. Numerous exploration developments have been announced for northeast B.C. Discussion of offshore oil and gas development has been initiated by the Province. New pipelines, including the Alliance pipeline and cross-border pipelines that connect with the TCPL Alberta system, have been built to take gas production from northeast B.C. to market. The Southern Crossing Pipeline (SCP) was completed and enables Alberta gas to access the Lower Mainland market.

Led by the industrial and power generation sectors, demand for natural gas in B.C. rose by one-third during the 1990s. Natural gas exports to the U.S. Pacific Northwest (PNW) more than doubled during this period. Producers responded to the increased demand by tripling the annual number of gas wells drilled, thereby increasing production by 67 percent over the last ten years. In recent years, however, B.C. consumers have cut back on their use of natural gas and exports to the PNW through Huntingdon have waned. B.C. gas producers have looked at other markets in which to sell growing production.

For many British Columbians, however, the most significant change has been in the price of natural gas. In the last five years, natural gas prices have risen about three times above the historic levels experienced in the 1990s. In addition, gas prices have become more volatile and sharp price spikes have occurred at the Sumas/Huntingdon market.

What has brought about these changes in the marketplace? Are markets working well? B.C. consumers have become concerned about the impact higher and unpredictable natural gas prices are having on heating and energy costs for their homes and businesses and on the provincial economy. Concerns have also been raised by some market participants about price transparency and liquidity in the B.C. market, especially at Sumas/Huntingdon.

This report presents an overview and assessment of the gas market in B.C. Examinations of natural gas demand in B.C. and the PNW markets are provided in Chapter 2. Recent transportation developments and issues are reviewed in Chapter 3. Chapter 4 presents an overview of regional gas pricing and looks at the evolution of natural gas prices in B.C. Chapter 5 concludes with a discussion of recent developments in supply with a focus on northeast B.C. By comprehensively reviewing various aspects of the B.C. gas market, this EMA intends to familiarize readers with the current state and functioning of this regional Canadian market.

MARKETS FOR BRITISH COLUMBIA NATURAL GAS

Highlights

- Higher natural gas prices have impacted demand
- B.C. natural gas demand has been flat since 2000 and declined in 2003
- Lower Mainland consumers have reduced household natural gas consumption
- B.C. industrial natural gas use has declined in the last two years
- Natural gas exports to the PNW through Huntingdon peaked in 1998
- Power generation is a growing market for natural gas in the PNW

This chapter focuses on trends and developments in B.C. and the PNW markets for northeast B.C. gas. Gas from northeast B.C. can also reach markets accessible through Alberta including Alberta, Eastern Canada and the continental U.S. as well as California. The B.C. domestic gas market and the PNW market, concentrated along the U.S. Interstate Highway 5 corridor (I-5 Corridor), are the major traditional markets for B.C. gas transported by Westcoast Energy Inc., which carries on business as Duke Energy Gas Transmission Canada (Westcoast). In order to provide a context for the discussion of gas use trends in these traditional markets, especially consumer reaction to higher gas prices, an overview of the B.C. gas distribution system is provided.

2.1 British Columbia Natural Gas Distribution System

A single major transmission pipeline connects northeast B.C., the only producing area in the province, with the Lower Mainland market around Vancouver (Figure 2.1). Owned by Westcoast, this long distance pipeline transports gas to the B.C. Interior and Lower Mainland markets and to Huntingdon, B.C. for export to U.S. markets in the PNW. Gas exports through Huntingdon physically serve coastal markets along the I-5 Corridor.

Gas is delivered to B.C. consumers, mainly by the two major local distribution companies (LDCs) that operate in B.C.: Terasen Gas Inc. (Terasen) and Pacific Northern Gas Ltd. (PNG). Terasen provides gas distribution services to customers in the most highly populated regions of B.C., including the Lower Mainland, the B.C. Interior (Prince George, Kamloops and the Okanagan Valley) and eastern Vancouver Island, Campbell River to Victoria. West central B.C., around Prince Rupert and Kitimat, is served by PNG. Northeast B.C., which includes Fort St. John and Dawson Creek, is served by PNG's subsidiary, Pacific Northern Gas (N.E.) Ltd.

2.2 British Columbia Domestic Natural Gas Markets

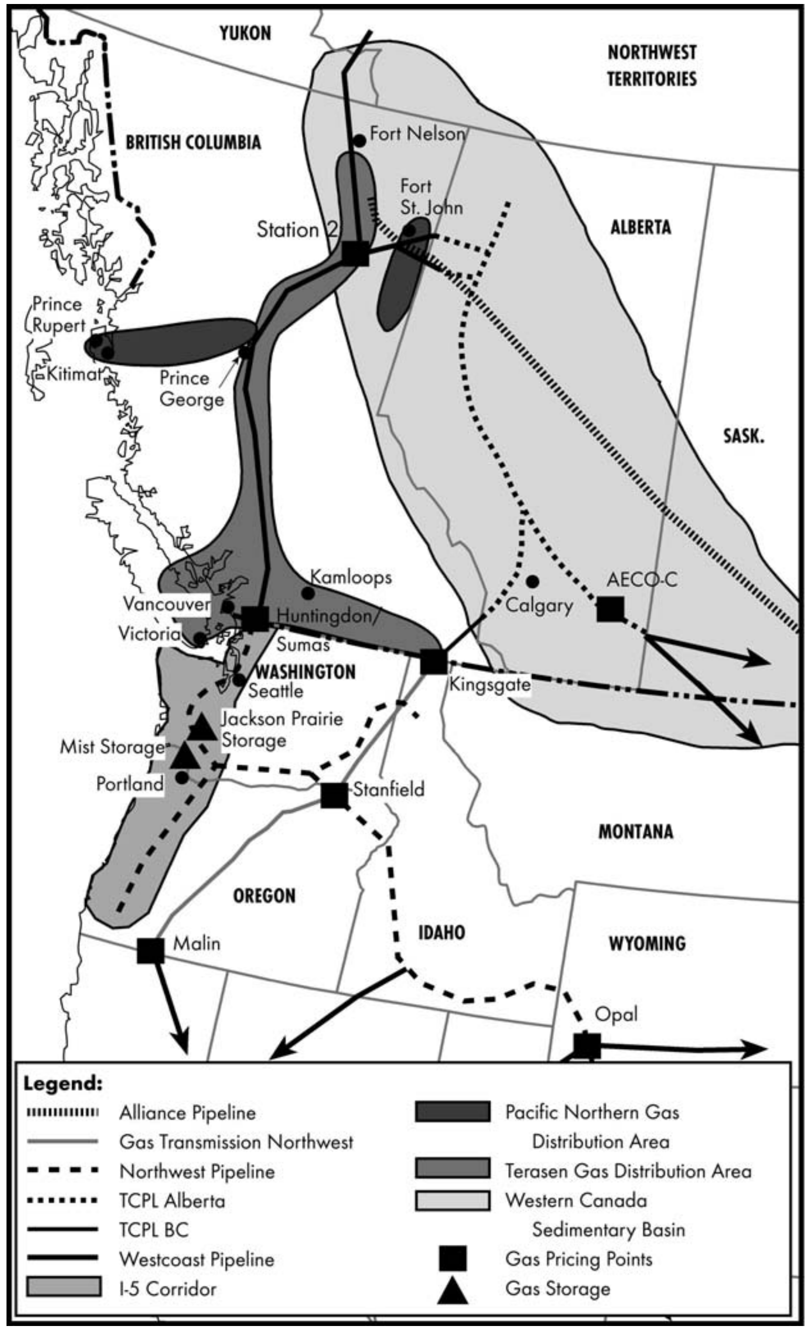
B.C. is the third largest natural gas consuming province in Canada. Provincial consumption grew steadily throughout the 1990s to 23 10^6m^3/d (820 MMcf/d) in 2000. Since 2000, when natural gas prices began to increase sharply, B.C. demand has generally been flat, followed by a decline in 2003 (Figure 2.2).

Gas consumption in B.C. is dominated by industrial demand. In 1990, one half of the natural gas consumed in the province was used by core (residential and commercial) customers and the other half by industrials and power generators. By 2003, industry and power generation use had grown to 58 percent of total gas consumption and core customer use was at 42 percent.

Industry uses natural gas for heat and power in manufacturing processes and also as a raw material for manufacturing industrial products. Fertilizer (e.g. ammonia) and chemical manufacturers (e.g. methanol) are examples of industries that use natural gas as a raw material feedstock. Residential and commercial consumers predominantly use natural gas for space heating and appliances.

FIGURE 2.1

B.C. and Pacific Northwest Regional Natural Gas Markets



Peaks in demand can occur either with the arrival of an Arctic cold front, or when the west coast experiences low water level conditions, with the accompanying reduced ability to generate hydro electricity. When electricity from hydro generation is limited, gas-fired electrical generation is a common back-up.

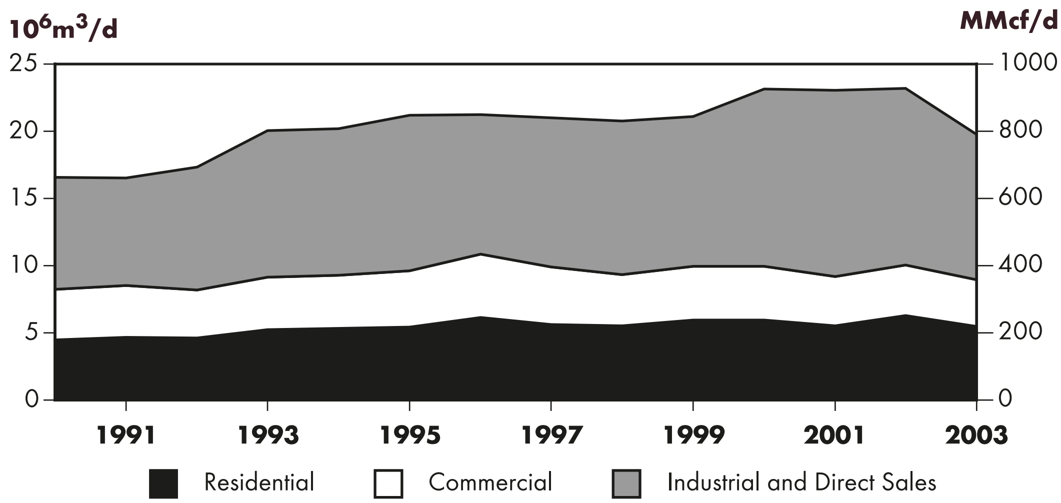
Residential and Commercial Markets

From 1990 to 2003, residential consumption retained its share of B.C.'s gas market, but commercial consumption lost market share.

The largest core market in B.C. for natural gas is the Lower Mainland, where weather is a major determinant of demand. The heating season in the Vancouver area lasts from November to February. By Canadian standards, B.C.'s Lower Mainland heating season is comparatively short and mild, but it can experience fairly severe winter peaks. Figure 2.3 compares weather severity between Vancouver, B.C. and the average for Canada.

F I G U R E 2 . 2

B.C. Annual Natural Gas End-Use

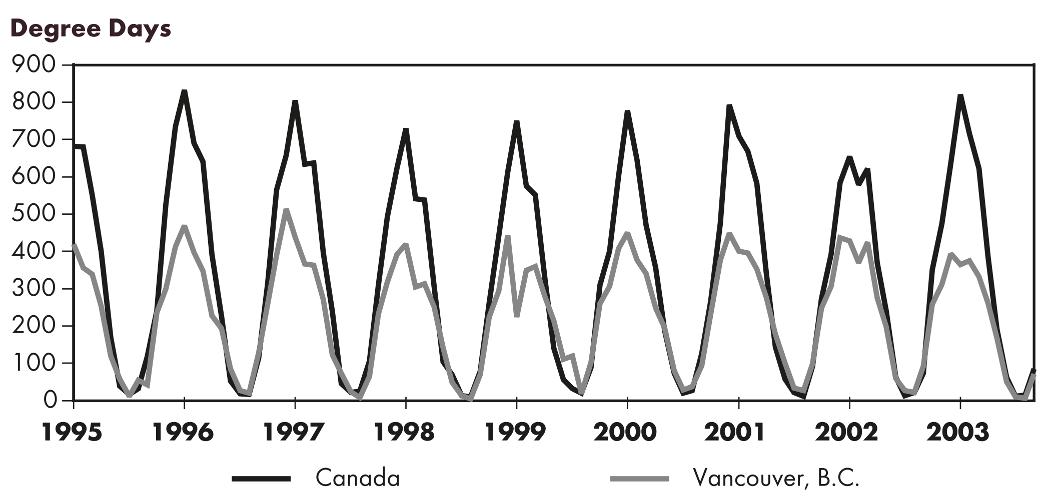


Source: Statistics Canada

Note: Direct sales are combined with the industrial category, because most direct sales are made to industrial and power generation users. Direct sales may also include some large commercial users (e.g. hospitals, schools and post-secondary institutions).

F I G U R E 2 . 3

Degree Days Comparison between Canada and Vancouver, B.C.



Source: Statistics Canada

In response to higher prices, residential and commercial consumers have taken measures to reduce gas consumption. During periods of high natural gas prices many consumers have turned down thermostats or used portable baseboard electrical heaters instead of natural gas. Some consumers have also installed more efficient furnaces and water heaters and improved home insulation. These measures are reducing demand per household. According to Terasen, average gas use per Lower Mainland customer has fallen from over 120 GJs in the late 1990s to about 104 GJs in 2003, after adjusting for weather variablility.

Growth in natural gas consumption also faces competition from electricity for space heating. In contrast to rising natural gas prices, BC Hydro electricity rates have been frozen since 1993. Electricity rates may be set to rise in 2004 as BC Hydro has applied to the British Columbia Utilities Commission (BCUC) for a rate increase. In order to reduce land development costs, some real estate developers are installing only electricity services to new homes, thereby limiting gas penetration into the new home market. At the same time, many consumers perceive gas prices as high and volatile in comparison with electricity prices, thereby influencing home buyers' decisions on space heating installations. Despite these competitive factors, population growth is a major driver for residential gas demand. B.C.'s population continues to grow, which is expanding the overall housing market and should help maintain residential gas demand.

Industrial Market

The industrial sector is the largest user of natural gas in the province. Nevertheless, natural gas meets only about one-quarter of the province's total industrial energy demand. Hog fuel and pulping liquor, used by B.C.'s forestry industries, are the largest industrial energy sources in the province, followed by natural gas and electricity. Fuel oil is an important industrial back-up fuel.

Large natural gas users in B.C. are the pulp and paper, wood product, petroleum refinery and petrochemical industries. These commodity-based industries use large amounts of energy to convert raw materials into semi-finished and finished products. For forest products industries, natural gas costs can represent between 5 to15 percent of overall production costs. Another industry that uses natural gas is the Lower Mainland greenhouse industry. Natural gas can account for up to 25 percent of a greenhouse operator's overall costs.

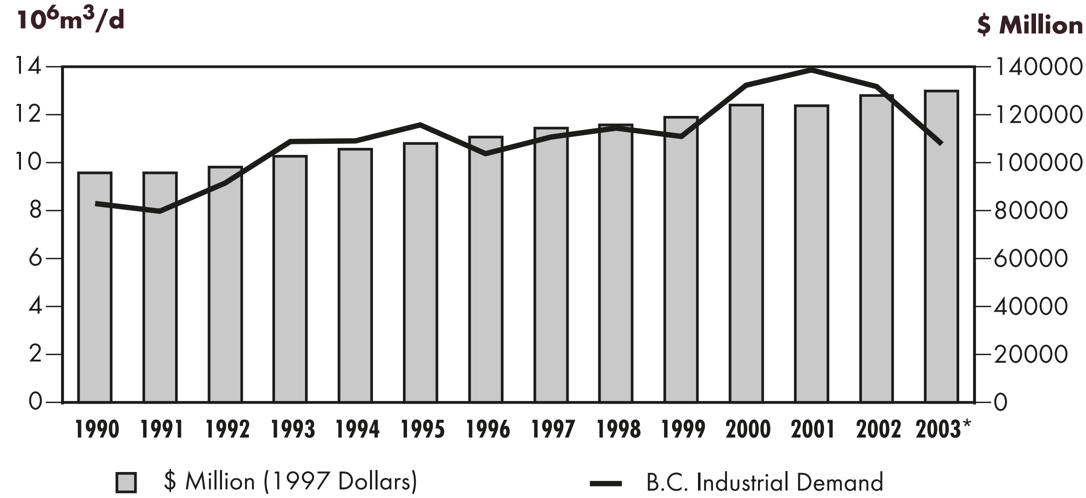
Natural gas demand in the industrial sector, including gas-fired generation, grew at about six percent per year between 1990 and 2001 (Figure 2.4). Combined industrial and gas-fired generation demand grew faster than the 2.7 percent average annual provincial rate of economic growth for the same period. Despite a growing B.C. economy over the last two years industrial demand has declined, partially in response to higher gas prices.

During the 1990s, stable prices, convenience and environmental concerns promoted natural gas use in the industrial sector at a rate faster than the province's rate of economic growth. However, convenience of use and environmental concerns about using alternative fuels may not overcome the cost pressures that many gas-intensive B.C. industries presently face. The softwood lumber dispute with the U.S., appreciation of the Canadian dollar and international competition are competitive business factors that are having an impact on B.C. industries. A higher natural gas price is only one of many cost pressures facing B.C.'s large industrial gas users.

Industries in B.C. have taken a number of steps to manage costs. These include greater use of financial risk management tools, improved energy efficiency measures, alternative fuel use and temporary plant closures. Gas price volatility has created a business environment in which industries continually monitor natural gas costs and plan their gas purchasing strategies. When compared with

FIGURE 2.4

A Comparison of B.C. Gross Domestic Product and B.C. Industrial Natural Gas Demand



Source: Statistics Canada, B.C. Government

* Preliminary estimate for B.C. Gross Domestic Product

the stable price environment of the 1990s, gas has become a larger and more unpredictable component of total production costs.

Every large industrial user of natural gas is evaluating its natural gas usage with an eye to reducing consumption. Industrial users are making incremental energy efficiency improvements to their manufacturing plants based on rising gas price thresholds. Gas price volatility hampers making efficiency investments, because of the risk that gas prices may fall below the breakeven point for the efficiency investment. Steady prices, even if higher, make it easier for companies to plan their efficiency investments. Another uncertainty surrounding making an investment in energy efficiency revolves around the issue of individual plant viability. In a competitive business climate, it is difficult to justify energy efficiency investments in plants that may be closed.

Industries are also looking at increasing their use of fuel alternatives such as wood waste, hog fuel, coal and petroleum products. For example, NorskeCanada has applied to the B.C. government for an environmental permit to use tire-derived fuel, coal and old railway ties as supplemental fuels at its Crofton B.C. pulp and paper mill on Vancouver Island. Currently, the plant uses natural gas and fuel oil as supplemental fuels in conjunction with hog fuel. Uncertainties related to fuel switching include air quality and CO_2 emissions standards relating to the use of wood waste, fuel oil and coal. Many large industries have also expressed concern with respect to the availability of long-term wood waste supplies and the cost of fuel oil.

One area where the forest industry is making major investments is in electricity generation from biomass. Major projects by Canadian Forest Products Ltd., Weyerhaeuser Company, Riverside Forest Products Limited and West Fraser Mills Ltd. will make manufacturing facilities owned by these companies more electricity self-sufficient or will deliver excess power into the BC Hydro grid. Some of these investments will have the additional benefit of reducing natural gas consumption.

In recent years, announcements of new major industrial plants in B.C. have been rare, limiting prospects for growth in industrial gas usage. Industry consultations also indicate that adjustments to higher prices will be an ongoing effort for the near term. Natural gas represents the highest

CanAgro Produce Ltd. – The Energy Challenges Faced by a Greenhouse Grower

South coastal British Columbia is among the best sites in Canada for greenhouse growers because the temperate climate and favourable solar and wind conditions of the region minimize the amount of energy required to operate greenhouse facilities. This region is home to CanAgro Produce Ltd. (CanAgro), a major greenhouse grower whose operation has expanded since 1996 to cover 33 hectares. CanAgro primarily grows tomatoes and peppers with about 70 percent of production destined for the U.S. export market.

Energy accounts for 20 to 25 percent of CanAgro's total costs and is third after marketing and distribution costs and the cost of labour. With an average annual energy requirement of 680 000 GJ, the combination of price increases in the order of $2.00 to $3.00/GJ over the past year, compounded by price spikes of even higher magnitude, can translate into millions of dollars of additional cost to CanAgro. However, these costs cannot easily be passed on when competing in a global market. Further, once a crop is planted in December, the grower is committed for eleven months with harvesting occurring from February to November. In other words, unlike some other commercial businesses, greenhouse growers like CanAgro cannot simply reduce or cease operations for a short period during energy price spikes because it would lose millions of dollars of crop inventory.

Many greenhouse growers such as CanAgro rely primarily on natural gas for their energy needs. Gas service is provided through a contract for interruptible service from the local distributor. When service interruptions occur, perhaps to meet residential demand during extremely cold weather, CanAgro must rely on # 2 fuel oil stored on site.

CanAgro has seen higher and increasingly volatile natural gas costs since the winter of 2000/2001. Moreover, within the context of an increasingly connected North American market, increases in local gas costs for CanAgro often seem to be triggered by weather patterns experienced in other parts of the continent. The ability to estimate future energy costs within an overwhelming North American gas market is a serious challenge faced by many end-users. Some end-users manage price volatility through hedging practices. However, such practices require a letter of credit that is often unobtainable for smaller businesses. Credit requirements for an operation the size of CanAgro can be as high as 30 percent of the total gas cost committed in advance.

CanAgro has taken a number of steps to manage energy costs. For example, it has imported state-of-the-art boilers from Europe that are rated 93 to 95 percent energy efficient. Flue gas economizers are also employed. At this level, there is little room left to improve energy efficiency and any such improvements would be very costly to achieve.

Alternatives to natural gas are widely sought by the greenhouse industry. However, restrictions on combustion emissions limit the ability to switch from gas to alternative fuels in some areas. For example, while some operations in the Fraser Valley air-shed have installed wood waste boilers, others have been unable to obtain emission permits. CanAgro will be offsetting a portion of its energy requirements by securing waste heat from a nearby landfill cogeneration facility. The future, though, may rest with the use of coal in a cleaner way. In addition to perhaps more stable costs than natural gas, the combustion of coal instead of gas would provide almost twice as much carbon dioxide, a necessary component for plant growth, and would alleviate the cost of buying carbon dioxide to pipe into greenhouses.

The greenhouse industry in B.C. accounts for about half a billion dollars to the provincial economy. Many greenhouse operations are challenged to operate in an environment of gas prices at $6.00/GJ. CanAgro is of the view that the natural gas industry must recognize that gas prices have been too high. Without relief from high gas prices, the industry fears that a number of greenhouses may be forced to move south to a warmer climate.

In December 2003, CanAgro Produce Ltd. merged with Century Pacific Greenhouses to form Hot House Growers Incorporated (HHGI). This merger created a larger scale greenhouse operation with greenhouses located in the Lower Mainland at Delta, Pitt Meadows and Abbotsford. The Lagoons Division in Delta uses waste heat from the co-generation facility.

HHGI's total annual energy requirement is presently over one million gigajoules. With the merger, HHGI has since been able to establish a five year natural gas hedge that included delivery charges. The co-generation facility and the purchase of a long-term gas hedge have reduced energy costs to 13 to 15 percent of total costs from 20 to 25 percent.

proportion of overall operating costs in industries that use gas as a feedstock. Methanex, a methanol manufacturer, closed its Kitimat methanol plant in 2000 because of high feedstock prices and reopened the plant in 2001. The plant continues to operate, but Methanex is building or acquiring new plants in Chile and Trinidad where gas costs are lower.

The industrial sector is the most price sensitive market for gas. Many industries relied on low energy cost inputs as one of the competitive factors for locating in B.C. With higher natural gas prices and greater competition for natural gas supplies from gas-fired power generators, especially in the PNW, large industrial users have had to take remedial actions to manage gas costs. The industrial sector has also had to compete with the core market, especially during price peaks, which is not as sensitive to price changes as the industrial sector.

Power Generation Market

Most of the electricity in B.C. is generated from hydro sources. Annual natural gas demand for power generation fluctuates, but can account for up to 15 percent of provincial natural gas demand in any year depending on water levels and weather conditions. Vancouver Island is the only area presently under consideration by BC Hydro for new gas-fired power generation. However, BC Hydro is considering alternative power generation proposals for Vancouver Island from independent power producers, not all of which would be gas-fired.

On the Lower Mainland, the future of BC Hydro's large Burrard Power Plant is under review by Members of the Legislative Assembly. This is an older, less efficient, gas-fired power generation facility. Replacing Burrard with a new generating facility may not necessarily increase gas usage because of the increased efficiency of new equipment. During an early 2004 cold spell, BC Hydro used Burrard to meet high provincial electricity demand. Gas-fired generation will continue to fulfill a back-up generation role in B.C. as well as competing for additional electricity loads.

2.3 Pacific Northwest Natural Gas Market

The PNW market covers the states of Washington, Oregon and Idaho. The PNW market is divided by the Cascade Mountain range. Coastal areas along the I-5 Corridor, largely within 160 kilometres (100 miles), receive gas exports from Sumas/Huntingdon (Figure 2.1). Gas exports from Huntingdon peaked in 1998 at 32.8 $10^6m^3/d$ (1 167 MMcf/d) and declined to 2003 (Figure 2.5). Exports from Huntingdon satisfied about 55 percent of the total PNW demand for gas in 2001.

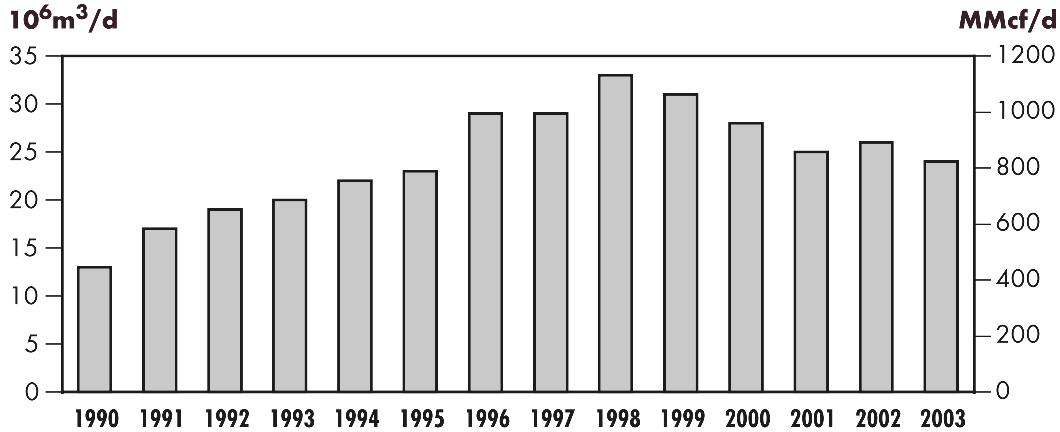
Eastern Washington, eastern Oregon and Idaho receive Canadian gas, mostly from Alberta, via the Gas Transmission Northwest Corporation (GTN) pipeline that crosses the international border at Kingsgate, B.C. Only a small amount of B.C. gas enters this market via GTN. Gas from the U.S. Rockies Basin also reaches the PNW through Opal, Wyoming. In Feburary 2004, TransCanada Corporation announced it was purchasing GTN from National Energy & Gas Transmission, Inc.

The PNW is typically a winter peaking market that responds to core and power market peaks simultaneously. The core load represented about 41 percent of the PNW market in 2001. Industrial use and power generation made up the balance of 59 percent. At about 30 percent of total demand, the gas market for power generation is larger in the PNW than in B.C.

In the past few years, weak economic conditions and higher gas prices have eroded industrial demand; its proportion of the total market shrank from 51 percent in 1990 to 29 percent in 2001. Further, it is widely expected that coastal manufacturing and other facilities, which were once attracted to the

FIGURE 2.5

Natural Gas Export Volumes at Huntingdon, B.C.



Source: NEB

region by cheap and abundant hydro power, such as those that produce aluminum or steel, will not return. Forest products companies, like Weyerhauser Company, are using as much wood waste as possible. Other consumers have turned to small hydro facilities or #2 fuel oil. Reduced industrial demand has implications for the market. Industrial load is normally not peaking in nature and greater industrial demand would lower transportation costs for residential and commercial consumers.

Growth in gas demand for power generation has been rapid over the past decade, reaching over 13.7 $10^6m^3/d$ (482 MMcf/d) in 2001 from 0.6 $10^6m^3/d$ (21 MMcf/d) in 1990. As with industrial demand, the power generation load has been reduced as of late due to weak economic conditions, higher gas prices and improved water levels for hydro power. Several gas-fired generation projects have been delayed and not all of the plants that have been built in the PNW are fully utilized. In 2003, the Northwest Gas Association reduced its estimate of growth in the power generation sector from 4.5 to 2.3 percent per year to 2025. However, while power generation growth may have slowed, development continues. Calpine Corporation expects to place a 248 MW plant at Goldendale, Washington into service in July 2004.

Despite eroding demand in the industrial sector and slowdown in the growth of the power generation sector, the outlook for the residential and commercial sectors remains constant. Core demand grew from 10.8 $10^6m^3/d$ (383 MMcf/d) in 1990 to 18.7 $10^6m^3/d$ (659 MMcf/d) in 2001. Puget Sound Energy, a major LDC in the I-5 corridor, expects its total load to grow 2.5 percent per year, but its peaking requirement to grow by 3.8 percent. Within the next four years, Puget Sound Energy anticipates that a second, summer demand peak will be experienced with growth in power generation to meet air-conditioning requirements.

Natural Gas Transportation and Storage

Highlights

- Pipeline developments to markets east of B.C. have provided northeast B.C. gas production with greater access to eastern markets
- Planned Westcoast pipeline expansion to B.C. and PNW markets scaled back
- Some PNW LDCs are holding more capacity on Westcoast to Station 2
- B.C. Lower Mainland market lacks gas storage, but storage capacity expanded in PNW

The transportation infrastructure to move natural gas out of northeast B.C. has undergone considerable development in the past five years. The most notable development has been the growth in pipeline capacity from northeast B.C. to connections in Alberta which allow producers to access a large number of markets. Northeast B.C. gas can now be transported to markets via the Westcoast system, the Alliance pipeline and through various producer pipelines which interconnect with the TCPL Alberta system. Before discussing transportation trends, a brief discussion of each of these transportation systems is provided.

3.1 Westcoast System

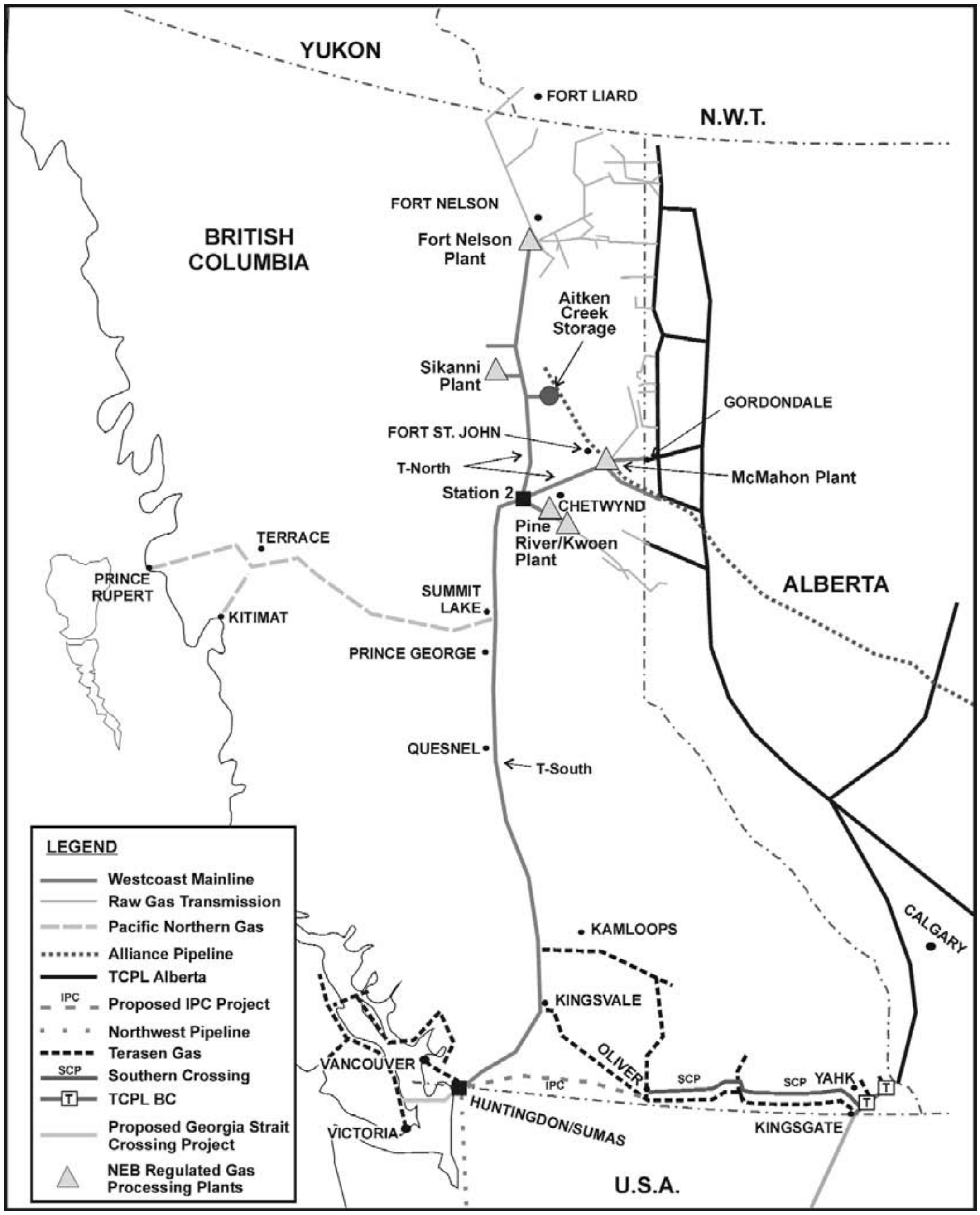
The Westcoast system has been delivering natural gas, primarily from northeast B.C., since 1957 when it was the first major gas export pipeline built in Canada (Figure 3.1). Unlike other major natural gas transporters in Canada, its system includes gathering and processing facilities in addition to transmission. The gathering system brings raw gas from fields in B.C., the Yukon, the Northwest Territories and, to a limited extent Alberta to Westcoast's processing plants. In B.C., there are significant quantities of gas, called acid gas, that have a high sulphur and carbon dioxide content. Acid gas requires more processing to make it suitable for pipeline transportation than natural gas with fewer impurities.

Westcoast owns and operates four gas plants (Fort Nelson, McMahon, Sikanni, PineRiver/Kwoen) in northeast B.C. which are under the NEB's jurisdiction (Figure 3.1). By international standards, three of the four are considered to be very large facilities and their existence has allowed fewer plants to be built in the province. As a result, there are 35 gas plants in B.C. compared with over 700 plants in Alberta. B.C. has less than five percent of the processing plants in the WCSB despite having 15 percent of production. This large plant model is changing as producers are building more gas plants in the province in competition with Westcoast's gas gathering and processing services.

Westcoast's transmission system includes the Fort Nelson and Fort St. John Mainlines (also known as T-North or Zone 3) and the Southern Mainline (T-South or Zone 4). T-North connects to the Southern Mainline at Station 2, an important gas trading point. T-North's capacity is approximately 34.0 $10^6 m^3/d$ (1.2 Bcf/d) from Fort Nelson and 21.5 $10^6 m^3/d$ (760 MMcf/d) from Fort St. John.

F I G U R E 3 . 1

Natural Gas Transportation Systems in British Columbia



The Southern Mainline, with a capacity of approximately 56.7 $10^6m^3/d$ (2.0 Bcf/d), extends from Station 2 southward to a point on the international boundary near Huntingdon, B.C. and Sumas, Washington. There it connects to multiple pipelines including: (1) Terasen, which takes gas from the interconnect to serve the Lower Mainland and Vancouver Island markets; (2) Northwest Pipeline, which serves the PNW; and (3) a number of smaller pipelines that cross the border and supply gas to various industrial facilities in Washington State.

In January 2003, Westcoast received the Board's approval to expand its Southern Mainline system by 5.7 $10^6m^3/d$ (200 MMcf/d), effective November 1, 2003. However, Westcoast has only proceeded with a reduced expansion of 2.4 $10^6m^3/d$ (85 MMcf/d), as some shippers chose not to renew expiring transportation contracts. Subsequently, additional pipeline transportation capacity of 5.6 $10^6m^3/d$ (198 MMcf/d) was not renewed by shippers effective November 2004. The capacity coming available in November will have to be absorbed before Westcoast can proceed with the remaining facilities for which it has received regulatory approval. As a result, the Westcoast system is not currently capacity constrained.

Shippers do not fully utilize their annual contracted capacity on Westcoast given the seasonal nature of the markets served. However, the system is full during peak winter periods. The average utilization rate on T-South was 78 percent in 2003, which is little changed from the previous year.

Contracting Trends on Westcoast

There has been a shift in the type of organizations holding long-haul capacity on T-South. A trend across North America in recent years has seen producers and consumers gradually allowing their long-haul capacity to expire and contracting for transportation capacity only as far as the nearest market hub at which point they can buy or sell gas from the many market players there. B.C. producers have also indicated that they would prefer to contract mainline capacity on Westcoast only as far as Station 2, rather than all the way to Sumas/Huntingdon. By doing so, their capital is freed up for other uses and they do not have to assume the risk of holding long-term pipeline capacity.

Marketers held a significant amount of capacity on T-South between Station 2 and Sumas, but since the collapse of Enron Corporation (Enron) in late 2001, fewer companies are actively engaged in the gas marketing business. However, the contracts held by these marketers continue to be in effect until their termination dates, so the freeing up of capacity on Westcoast by marketing companies has been a gradual process.

With marketers retrenching, and some producers preferring to go only to Station 2, some PNW LDCs have stepped in to take the capacity on T-South and purchase gas at Station 2 rather than at Sumas/Huntingdon. Their stated reasons for taking T-South capacity include the desire to purchase gas closer to the producing area, to better partner with financially sound B.C. gas producers, to better ensure security of supply and to obtain access to the best possible gas prices.

An additional reason that PNW LDCs gave for going to Station 2 was a desire to reduce the risk of price volatility by bypassing the Sumas/Huntingdon market. PNW LDCs calculated that in just two months, December 2000 and January 2001, when prices spiked at Sumas/Huntingdon well above Station 2 prices, they could have paid for four or five years of pipeline capacity on T-South if they could have bought gas at Station 2 instead.

LDCs are taking additional T-South capacity despite the issue noted by a number of parties consulted for this EMA, that prices at Station 2 are not sufficiently below Sumas prices to fully cover the cost of transportation on that segment. The fact that producers' netbacks are higher if they sell at Station 2 rather than Sumas provides additional motivation for them to give up T-South capacity and sell at Station 2. For LDCs, the security and access to supply benefits appear to outweigh the risk that the differential will not fully cover the transportation costs.

Westcoast Transportation Rate Regulation

Since June 1998, Westcoast's tolls for gathering and processing services (not transmission) have been freely negotiated in the marketplace. Westcoast, which is regulated by the NEB, and its stakeholders agreed to a framework for light handed regulation that defined the principles under which Westcoast would negotiate contracts with individual shippers, including appropriate tolls. This method was established to accommodate producers' desire for faster response to service requests and more flexible tolling arrangements.

Since 1997, Westcoast's transmission tolls have been determined through settlements negotiated between all the major stakeholders. Over that period, the T-North toll has increased by 25 percent and the T-South toll to Huntingdon has increased by 16 percent. The current long-haul T-North toll is \$110.50/10^3m^3/month (\$.103/mcf), while the T-South toll is \$294.37/10^3m^3/month (\$.274/mcf). In December 2003, Westcoast applied to the Board for 2004 tolls seeking a 7.9 percent increase in the T-South toll.

3.2 Alliance Pipeline

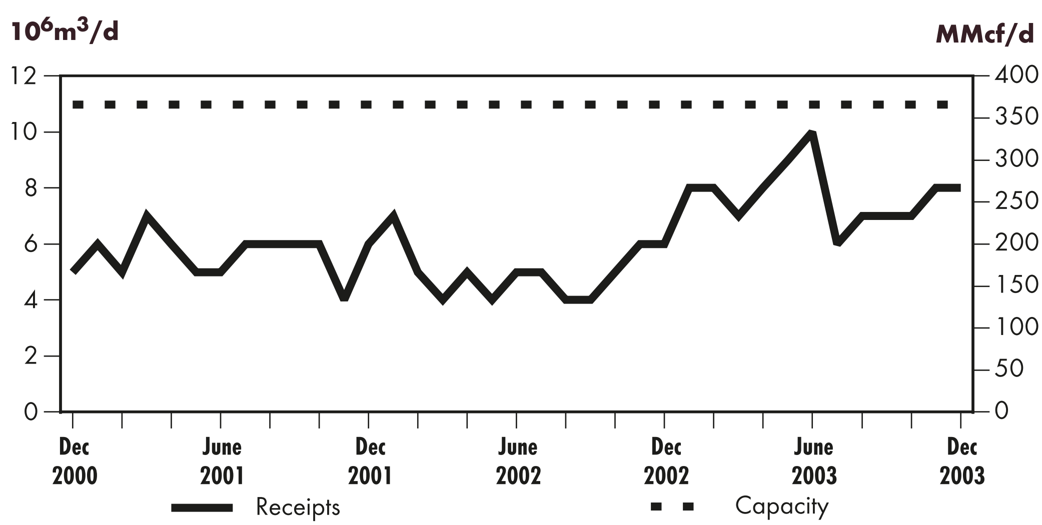
The Alliance pipeline transports approximately 44 10^6m^3/d (1.55 Bcf/d) of liquids-rich Canadian gas mainly from Alberta and, to a lesser extent from B.C., to Chicago and the U.S. Midwest market. It began shipping gas to markets in December of 2000. Although the Alliance mainline starts in Alberta at Gordondale, a lateral extends into B.C. as far west as the Aitken Creek storage facility (Figure 3.1). Alliance's total capacity to take gas out of B.C. is 10.4 10^6m^3/d (366 MMcf/d).

Alliance's B.C. flows to date have been less than capacity would allow. However, shipments showed an increase in 2003, with flows averaging 7.6 10^6m^3/d (270 MMcf/d), up from 5.0 10^6m^3/d (178 MMcf/d) the previous year (Figure 3.2).

In response to enquiries by producers seeking additional capacity out of B.C., either because of increasing production or due to a desire to find alternative transportation arrangements, Alliance sought non-binding, confidential expressions of interest for incremental capacity in June 2003 and received some expressions of interest from producers. Alliance has said that an expansion, if it proceeds, would not involve any expansion of mainline capacity. Therefore, given that the mainline is essentially full in Canada, any additional flows from B.C. would have to be accommodated by reduced Alberta gas volumes.

FIGURE 3.2

Alliance Pipeline B.C. Receipts



Source: Alliance Pipeline Ltd.

3.3 Cross-border Pipelines into Alberta

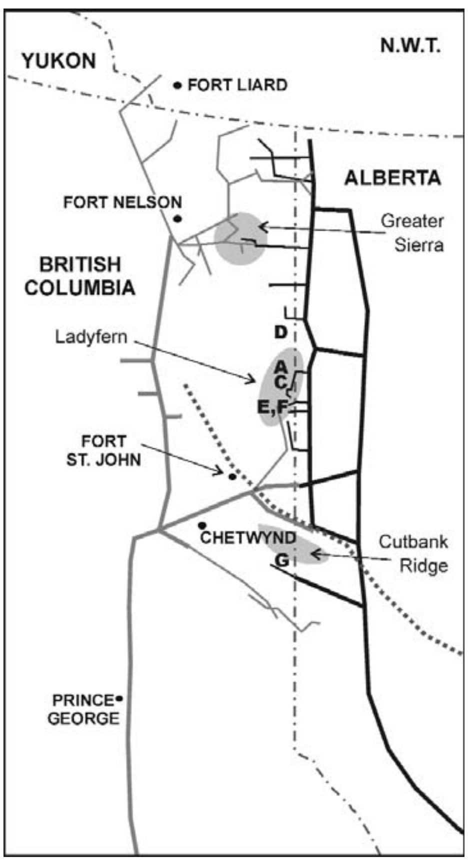
The Westcoast system also interconnects with the TCPL Alberta system at Gordondale, Alberta enabling the eastward flow of gas to Alberta and downstream domestic and export markets. (Figure 3.1) The interconnection with TCPL Alberta is bidirectional and permits Westcoast to either deliver or receive gas there. While the net flows of B.C. gas at Gordondale are quite small (averaging less than 0.9 $10^6m^3/d$ (30 MMcf/d) in the 2002/2003 contract year), the capacity of the line is approximately 5.7 $10^6m^3/d$ (200 MMcf/d) and there is firm capacity available to move gas eastward.

Since the mid-1980s, at least 20 pipelines have been built to move gas from northeast B.C. into Alberta. These have ranged in size from gathering systems with a capacity of a few million cubic feet per day to large diameter pipelines capable of flowing several hundred million cubic feet daily. Most extend for a very short distance to a pipeline built by TCPL Alberta in 1995 along the B.C./Alberta border. Many of these pipelines are no longer flowing at full capacity.

Most of these pipelines have been segments of less than 35 kilometres, designed to bring gas from B.C. production areas located near the inter-provincial border, such as Ladyfern, to the nearby TCPL Alberta system (Figure 3.3). In fact, approximately 90 percent of the capacity built in this time frame was built to access the Ladyfern play. In 2003, an average of 15.6 $10^6m^3/d$ (550 MMcf/d) of marketable gas flowed into Alberta on these producer-owned lines, down from 24 $10^6m^3/d$ (845 MMcf/d) in 2002, largely reflecting the decline in production from the Ladyfern field.

F I G U R E 3 . 3

Northeast B.C. Cross-border Pipelines Built 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

In April 2004, EnCana will bring the 83 kilometre Ekwan pipeline into service. Ekwan will transport gas from the Greater Sierra region, an area currently served by the Westcoast system. Although EnCana was already moving significant volumes from the region into Westcoast, additional capacity was required to accommodate future production growth from the area and to diversify its market and transportation options.

3.4 Transportation Trends for Northeast British Columbia Production

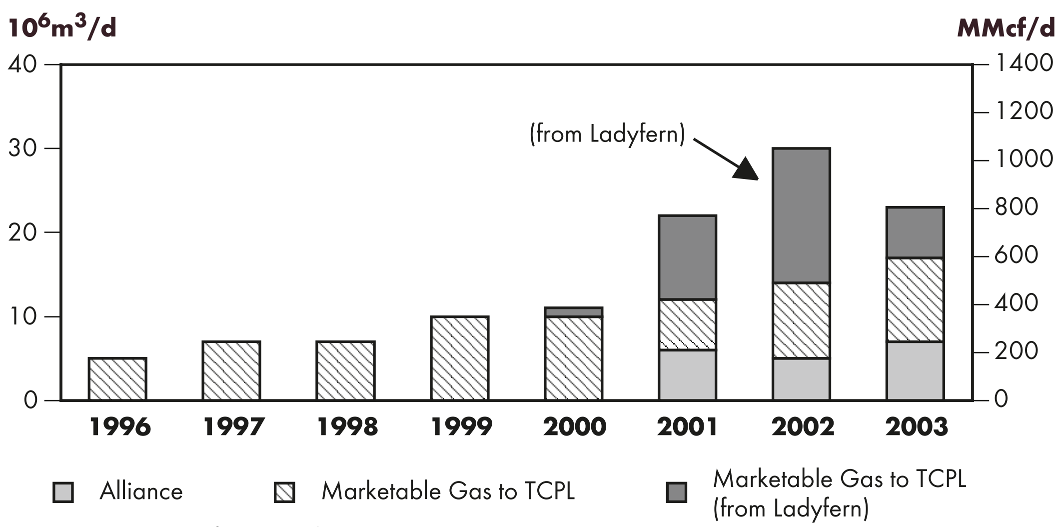
Gas flows into Alberta started to increase substantially in 2000 and 2001, with the start of production from the Ladyfern field and the beginning of flows on the Alliance system (Figure 3.4). LadyFern had a particularly significant impact since deliverability from the Ladyfern field rose to over 19.8 $10^6 m^3/d$ (700 MMcf/d) by mid-2002. However, production has since fallen rapidly to 4.4 $10^6 m^3/d$ (155 MMcf/d) in November 2003, accounting for the lower gas flows into Alberta in 2003.

Approximately one third of marketable B.C. production is now moved into Alberta. While traditional export and provincial markets have been declining since 2000, according to pipeline disposition data, gas production has grown (Figure 3.5). These incremental supplies have been absorbed by Alberta and markets further east, as the B.C. and PNW markets could not absorb the increased production. In addition, access to Alberta provides producers with a greater choice of options for markets, transportation systems and storage facilities than flowing gas west to B.C. or the PNW.

B.C. market participants expressed two views concerning the impact that increasing transportation capacity into Alberta is having on the market. Consuming groups were concerned that B.C. gas moving east into non-traditional markets would no longer be available to B.C. or PNW buyers. On the other hand, producers stated that having the ability to flow into Alberta, as well as B.C., increased security of supply for B.C. by encouraging increased exploration and development of supply. Further, weak markets, particularly in the summer months, limited producer ability to sell incremental supplies in B.C. and the PNW. Access to multiple markets has provided producers with an additional impetus to increase natural gas supply because gas would not be trapped in the Province.

FIGURE 3.4

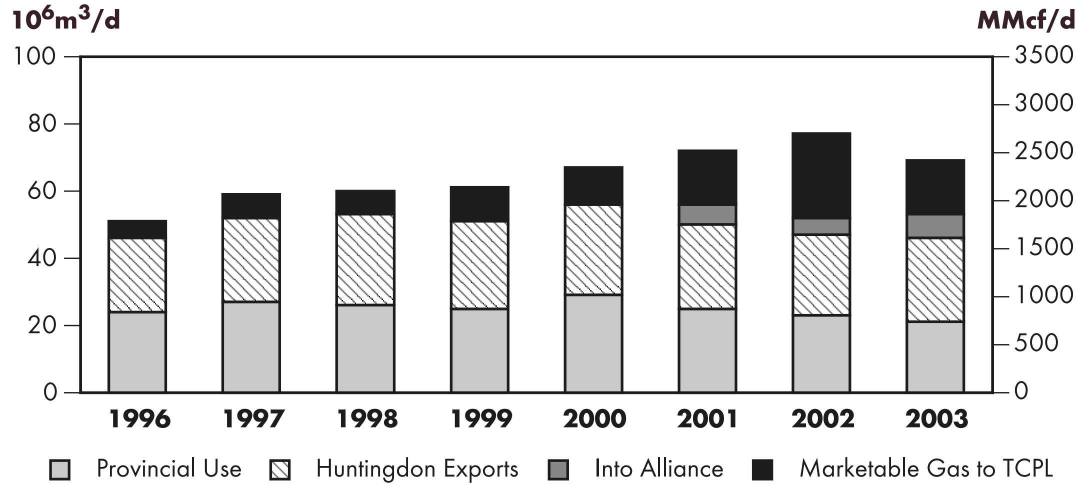
Marketable Natural Gas Flows from Northeast B.C. to Alberta



Source: B.C. Ministry of Energy and Mines

FIGURE 3.5

Disposition of Marketable Northeast B.C. Natural Gas Supplies[1]



1. Includes Yukon and NWT production

Source: B.C. Ministry of Energy and Mines

Future cross-border pipeline developments will continue to be influenced by the location of discoveries, producer desire to diversify markets and market conditions in B.C. and the PNW. In April 2004, the Ekwan pipeline will commence deliveries into the TCPL Alberta system and later gas from EnCana's Cutbank Ridge play is expected to flow east as well.

3.5 Storage and Peaking Capacity in British Columbia

Natural gas storage is extremely limited in B.C. and consists of one underground storage production area facility, Aitken Creek Storage (Aitken Creek), in northeast B.C. and a small liquefied natural gas (LNG) facility on Tilbury Island in the Lower Mainland used by Terasen to meet the peaking needs of its own system.

There is no large underground market area gas storage facility in the Lower Mainland. Upstream storage facilities, while beneficial for producers and shippers, have limited usefulness for downstream consumers during times of pipeline constraint which typically occur during peak demand periods when storage is most critical. Two important facilities for the Lower Mainland and PNW end-use markets are Jackson Prairie in Washington and Northwest Natural's Mist facility in Oregon. Both facilities have undergone expansions in recent years. During winter demand peaks, Terasen can exchange gas it has stored in U.S. storage facilities, like Jackson Prairie, for access to gas that may be flowing at Sumas/Huntingdon.

While most parties consulted for this EMA in B.C. do not expect additional storage will be built in the Lower Mainland in the near future, it continues to be an issue because more storage capability could improve utilization of the pipeline system and help mitigate seasonal price spikes. Some producers have pointed out that expanded upstream storage would also be desirable. Without expanded upstream storage, producers must flow gas to markets even if market conditions are unfavourable. Further, producers indicated that they would be more willing to lock in prices if there were additional storage available in either the production or market areas.

Southern Crossing Pipeline

Southern Crossing Pipeline (SCP) was built by Terasen primarily to meet its peak and seasonal load. In addition, it provides transportation service to third party shippers. It is a 312 kilometre bidirectional line extending from the TCPL B.C. system at Yahk, just north of Kingsgate, B.C. on the U.S. border to Terasen's smaller Interior Transmission System near Oliver, B.C. (Figure 3.1). With this facility, Terasen can receive 7.8 $10^6m^3/d$ (275 MMcf/d) at Yahk and deliver up to 3.0 $10^6m^3/d$ (105 MMcf/d) to the Westcoast system at Kingsvale for ultimate delivery to the Lower Mainland. This provides an alternative supply source for both the B.C. Inland and Lower Mainland markets.

Approximately two thirds of the capacity is dedicated to manage peaks in demand in Terasen's service territory, the other third to third party shippers. Pipeline utilization has been low, as would be expected from a facility built to manage peaks in demand. If Alberta gas prices were sufficiently lower than Station 2 prices, it would be economic to use SCP to bring Alberta gas to the Lower Mainland and utilization of the system would increase. Terasen is still contemplating construction of the Inland Pacific Connector pipeline, which would extend SCP from Oliver, B.C. directly to Sumas/Huntingdon.

3.6 Georgia Strait Crossing Pipeline Project

The proposed Georgia Strait Crossing Pipeline Project (GSX) would carry gas from Sumas/Huntingdon across western Washington State and the Strait of Georgia to Vancouver Island. The pipeline would be capable of supplying 2.71 $10^6m^3/d$ (96 MMcf/d) to two power generation facilities on the island, one of which is already operating, and other users. The pipeline has received regulatory approval from the Federal Energy Regulatory Commission (FERC) in the U.S.

In Canada, a Joint Review Panel established under the *Canadian Environmental Assessment Act* and the *National Energy Board Act* approved the pipeline subject to a number of conditions, one of which is that GSX must provide evidence that the proposed Vancouver Island Generation Project (VIGP) has received the required regulatory approvals before construction commences on the pipeline. BC Hydro has undertaken a call for a tender process inviting private sector developers to either submit proposals for new generating capacity to be located on Vancouver Island or to tender bids to acquire VIGP assets. If VIGP is found to be part of a cost-effective solution to provide power to Vancouver Island, then BC Hydro would submit the proposal for BCUC review.

NATURAL GAS PRICING

4.1 Natural Gas Market Price Formation

Station 2 and Sumas/Huntingdon are the two main pricing points for B.C. gas (Figure 2.1). Station 2 is a pricing point for gas on the Westcoast system that originates primarily from northeast B.C., but can also include gas from the Yukon, the Northwest Territories and Alberta. Sumas/Huntingdon is a U.S. border pricing point for Canadian natural gas on the Westcoast system. The Sumas/Huntingdon price point largely reflects market conditions for natural gas from the B.C. Lower Mainland to Portland, Oregon.

Highlights

- Average natural gas prices in B.C. have tripled since the 1990s
- Gas prices in B.C. are integrated with North American prices
- Sumas/Huntingdon and Station 2 are not as liquid as some other markets
- The B.C. natural gas market remains susceptible to short-term price spikes
- Price discovery has improved at Sumas/Huntingdon and Station 2
- Market participants have become accustomed to managing price volatility

Sumas/Huntingdon and Station 2 are small regional pricing points. In contrast, Henry Hub, in Louisiana, the pricing point for gas traded on the New York Merchantile Exchange (NYMEX), and AECO-C, the pricing point for gas traded in Alberta on the Natural Gas Exchange (NGX), are considered by the natural gas industry to be highly liquid trading points. Smaller regional pricing points have neither the liquidity nor all of the gas transportation services offered by the larger pricing points, such as storage. Small regional pricing points have lower traded volumes, fewer transactions and fewer buyers and sellers. Access to pipeline systems, creditworthy counterparties and financial credit may also be diminished because of small market size. The lack of Lower Mainland storage hampers market development at Sumas/Huntingdon because market participants cannot store gas for sale at a later date at Sumas/Huntingdon.

Parties consulted for this EMA were of the view that the markets at both Sumas/Huntingdon and Station 2 were not functioning under ideal conditions, although some parties consulted for this EMA reported that liquidity at Sumas/Huntingdon was improving. These parties also indicated that new market participants had entered the Sumas/Huntingdon market since the decline in liquidity following the departure of Enron and other marketers in 2001. Most parties consulted for this EMA held the view that Station 2 was less liquid than Sumas/Huntingdon, because fewer market participants trade gas at Station 2.

The California price spike of 2000/2001 shook market confidence in the validity of gas price indices. In the U.S., FERC and the Commodity Futures Trading Commission began to investigate these allegations. In the course of these investigations, specific instances of gas and electricity market manipulation came to light, such as the reporting of false gas trades to industry trade publications. To improve price transparency and confidence in U.S. price reporting, FERC, gas price publishers, and companies reporting gas transactions to publishers have worked toward establishing gas price reporting standards. As a consequence, price reporting at Sumas/Huntingdon has improved. After the departure of the Enron gas trading system in 2001, Intercontinental Exchange (ICE), an electronic energy trading system, started providing gas trading services at Sumas/Huntingdon and Station 2.

In December 2003, NGX, an electronic energy trading system with operations in Canada's major gas markets including Alberta and Dawn, Ontario began offering service at Station 2. Market information for Station 2 (gas volumes traded, number of transactions, bid price range and daily weighted average price) is now available on-line for gas traded on NGX. Information on the NGX system is based on all trades conducted through NGX, in contrast with U.S. pricing points that rely on market price surveys which sample a limited number of buyers and sellers. NGX was purchased in January 2004 by the TSX Group Inc. whose core operations include the Toronto Stock Exchange.

Better price reporting standards and the emergence of new electronic trading platforms are helping to improve price discovery at Sumas/Huntingdon and Station 2. Small market size, however, continues to limit liquidity in the B.C. market.

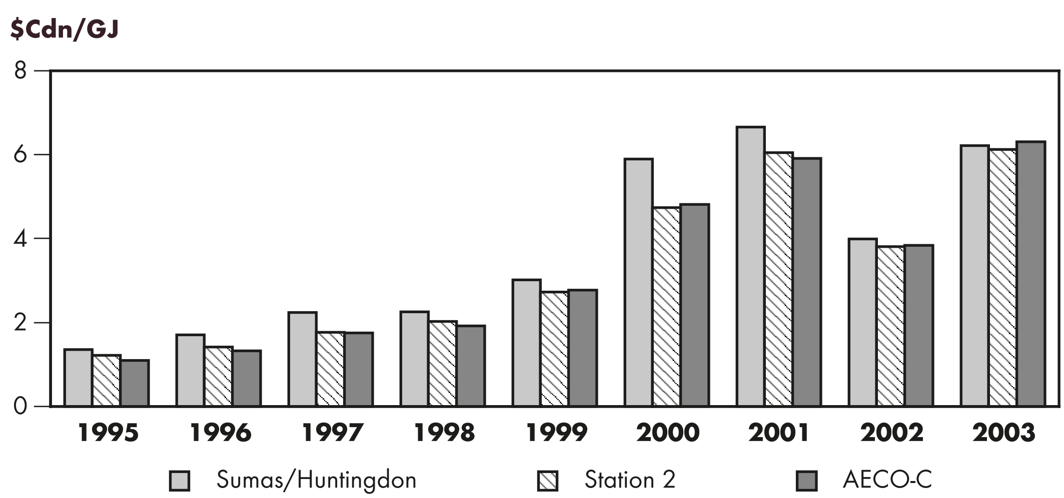
4.2 A History of Natural Gas Prices in British Columbia

In 1995, the average annual price of natural gas at Sumas/Huntingdon and Station 2 was under \$2.00/GJ; by 2003 the price was over \$6.00/GJ, a threefold increase. During this period, gas prices rose across North America including AECO-C in Alberta (Figure 4.1).

Prior to 1998, gas prices at Station 2 and AECO-C were lower than in other parts of the continent and not fully connected with the North American gas market. Pipeline expansions on Foothills Pipe Lines/Northern Border Pipeline and TransCanada PipeLines alleviated the pipeline transportation capacity constraint that had existed out of the WCSB. As a consequence, gas prices rose in the fall of 1998 at AECO-C and Station 2 in relation to the Henry Hub price for natural gas as traded on

FIGURE 4.1

Annual Average Natural Gas Price Comparison: Sumas/Huntingdon, Station 2 and AECO-C



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

NYMEX (Figure 4.2). The price of gas at Huntingdon/Sumas also rose in conjunction with prices at Station 2 and AECO-C. By 1999, prices for gas in the WCSB and at Sumas/Huntingdon were more closely aligned with other North American pricing points.

Like most markets, there is a history of seasonal natural gas price spikes in B.C. These occurrences can be seen in the history of natural gas prices at Sumas/Huntingdon prior to 2000, especially in the winters of 1997 to 1999 (Figure 4.2). Markets in the Lower Mainland and the PNW typically experience peak demand during the winter heating season, from November to February. Consequently, prices tend to be highest during January, usually the coldest month.

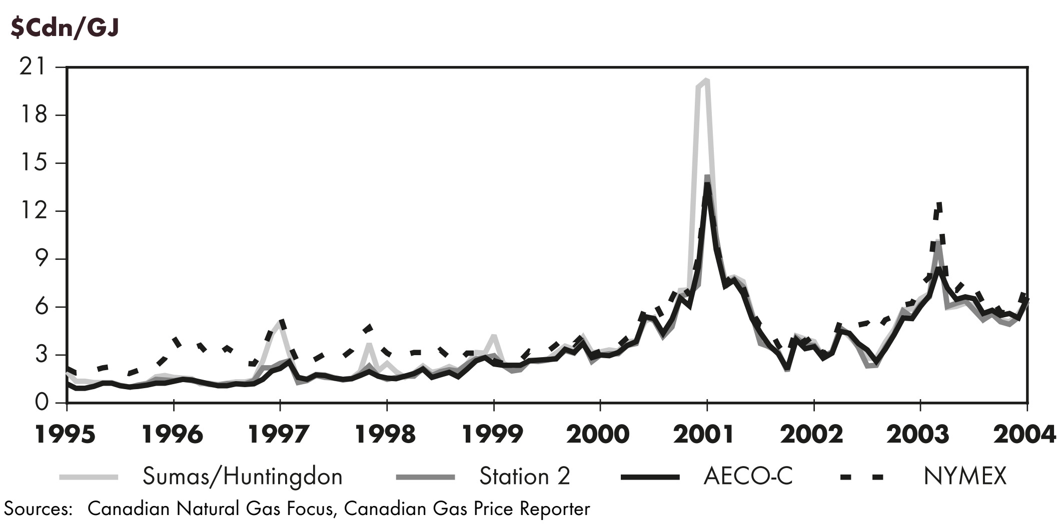
The impact of this cold weather can be exacerbated by the limited amount of storage facilities within the Lower Mainland market area. Unlike some regions where many buyers can draw on gas storage to meet peaking demand, buyers at Sumas/Huntingdon, who do not have storage elsewhere, must compete for gas volumes available off the Westcoast system. While transportation capacity on Westcoast is available through most of the year, system utilization can be very high during the winter peaks. The lack of market storage leaves Sumas/Huntingdon more susceptible to winter price spikes.

Prices at Sumas/Huntingdon can also be influenced by developments in California. Similar weather conditions along the west coast can influence demand in B.C., the PNW and California at the same time. Another major influence on Sumas/Huntingdon gas prices is California electricity demand, especially in low hydro years such as 2000/2001. Electricity generators located in B.C. and the PNW can increase electricity exports to California by bringing spare gas-fired generation on-line. The additional electric power load can increase the demand for natural gas at Sumas/Huntingdon in a very short period of time which can cause price volatility. For example, in the winter of 2000/2001, spot prices at Sumas/Huntingdon peaked at $20.23/GJ and followed the price spike at Malin, a pricing point on the California/Oregon border (Figure 4.3). Prices at AECO-C were lower than at Sumas/Huntingdon during the 2000/2001 price spike showing that the Sumas/Huntingdon market followed developments in California.

Prices at Station 2 in B.C. are related to AECO-C prices in Alberta (Figure 4.4). Both of these pricing points reflect market conditions for WCSB sourced gas. In 2003, the average annual price of

FIGURE 4.2

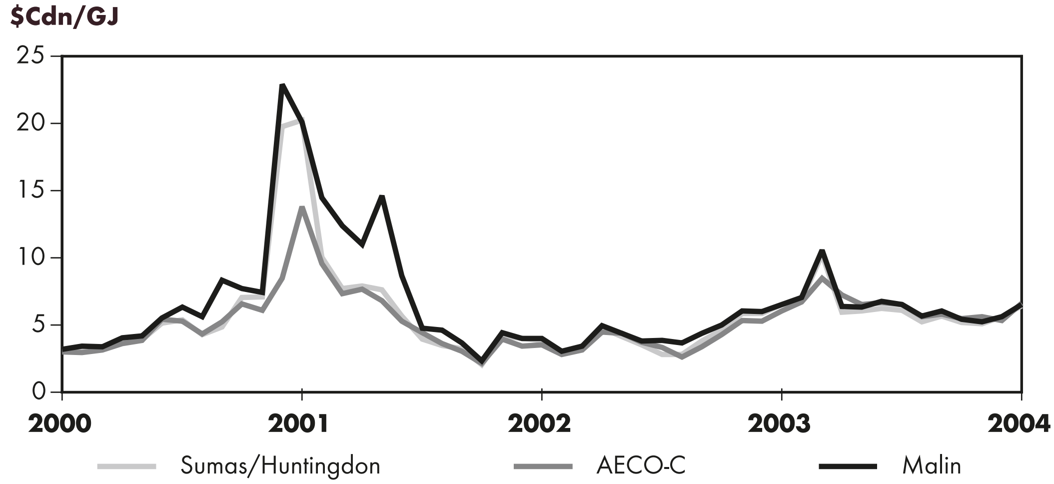
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Station 2, AECO-C and NYMEX



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

FIGURE 4.3

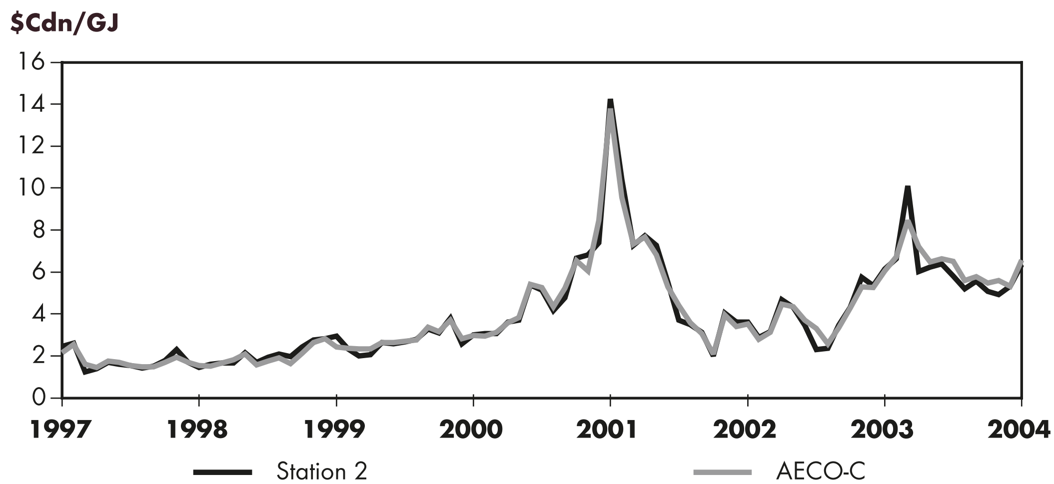
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Malin and AECO-C



Source: Canadian Natural Gas Focus

FIGURE 4.4

Spot Natural Gas Price Comparison: Sumas/Huntingdon, Station 2 and AECO-C



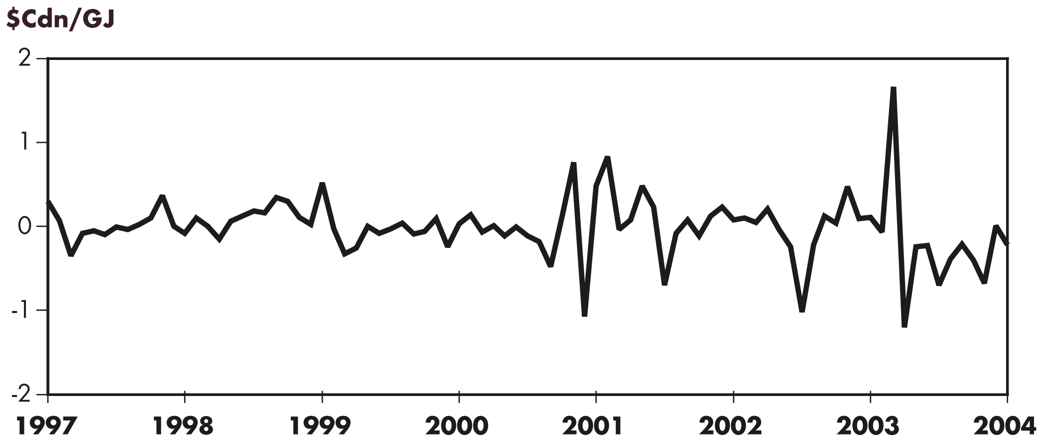
Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

gas at AECO-C slightly exceeded the average annual price at Huntingdon/Sumas as well as Station 2 (Figure 4.1). This reflected the relative change in the market price for gas from eastern markets served by AECO-C and western markets served by Station 2. Price signals indicated a somewhat stronger demand for gas in eastern markets.

Since the 1990s, the overall impact on B.C. consumers of changing market dynamics has been exposure to higher and more volatile North American gas prices and increased competition for gas supply in northeast B.C. from eastern markets. Price variability between Station 2 and AECO-C rose in late 2000. At this time, the Alliance pipeline began operations in northeast B.C. providing an additional market outlet for northeast B.C. gas supply and North American demand for gas increased prices in all supply regions including the WCSB (Figure 4.5).

F I G U R E 4 . 5

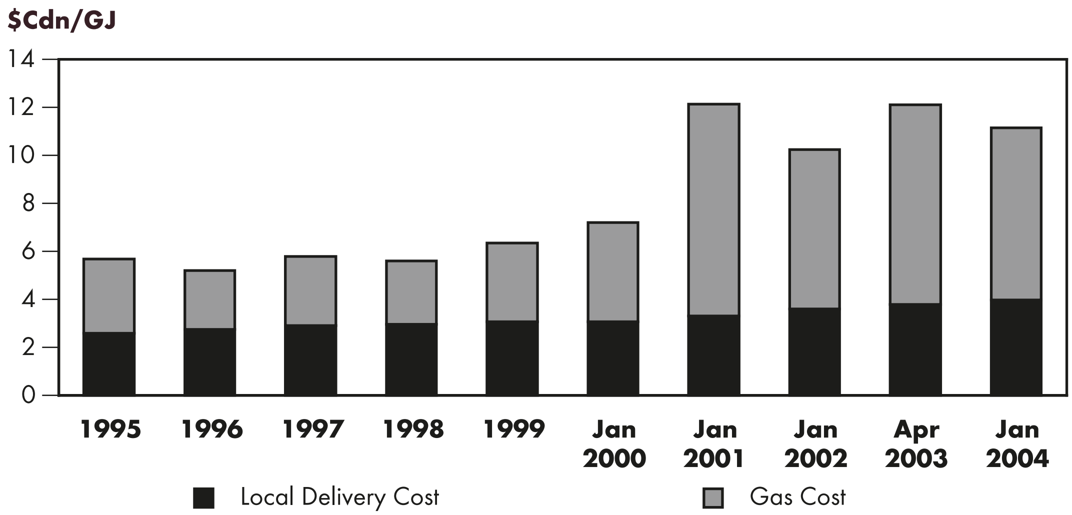
Price Differential: Station 2 less AECO-C



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

F I G U R E 4 . 6

Residential Natural Gas Price Components (Lower Mainland) - Terasen Gas Inc.



Source: Terasen Gas Inc.

Note: Average customer use has been kept constant at 120 GJ per year in order to demonstrate gas cost at the same level of use over time, however, as noted earlier Lower Mainland customers have reduced average use over this period.

4.3 Retail Natural Gas Prices

Retail gas prices paid by B.C. consumers include gas costs and local delivery costs. During the 1990s, there was an almost even split between the cost of gas and local delivery costs for a typical Lower Mainland residential consumer (Figure 4.6). Since 2000, when continental gas prices moved into a new trading range, the cost of gas has assumed a much larger proportion of a Lower Mainland residential customer's natural gas utility bill.

The British Columbia Utilities Commission (BCUC) sets the local delivery rates for Terasen and PNG and reviews gas costs. Terasen uses financial risk management tools, including a portfolio of fixed price contracts from various supply sources, contract hedges and spot purchases to manage gas price risk, but the cost of gas largely flows through to consumers based on market prices.

4.4 Managing Natural Gas Price Volatility

Market participants in B.C. have developed various strategies for dealing with price volatility. These include both physical and financial solutions.

The main physical tool for dealing with gas price volatility, which reflects short-term changes in gas demand, is storage. Injecting gas into a physical underground storage facility during low price periods and then drawing down storage during high price periods is the usual manner in which markets deal with peaks in gas demand, especially winter gas demand. The B.C. Lower Mainland is one of the few large urban centres in North America without access to a nearby storage facility. Without adequate market-based storage, it is more difficult for large Lower Mainland gas users to manage short-term gas price spikes.

Short-term demand can also be managed with simple strategies such as altering industrial production schedules or lowering residential room temperatures during a price spike. Burning alternative fuels, such as wood in home fireplaces or fuel oil in greenhouses, are other options that B.C. consumers have used to manage short-term price volatility. Air emissions standards, regulated by the Greater Vancouver Regional District in the Lower Mainland, can limit the use of alternative fuels for some large users. Alternative fuel use may also be restricted by limited supply, and may not necessarily be cheaper than gas because of increased short-term demand for alternatives such as fuel oil.

Market participants consulted for this EMA revealed a variety of gas buying strategies to help manage price volatility. Each strategy was tailored to meet a particular market outlook and specific business need. Some participants were not prepared to lock-in their gas purchases and bought gas on a daily basis at Sumas/Huntingdon on the spot market. Other market participants purchased yearly gas contracts for future delivery at Sumas/Huntingdon on a quarterly basis, thereby averaging their annual acquisition costs for the year. Some purchasers, with access to pipeline transportation on Westcoast, locked in fixed price deals directly with producers at Station 2. Other market participants, such as Terasen, had a mixed portfolio of fixed price contracts from various supply sources, contract hedges and spot purchases.

Hedging, purchasing a long term contract and protecting the value of that contract with an offsetting short position, is a sophisticated and costly endeavour. Many market participants pointed out that they do not have the expertise, independent financial resources or access to credit to enter into a long-term gas market hedge. After the departure of Enron and other marketers from Sumas/Huntingdon, it has become difficult to find counterparties with whom to conduct a hedge. Financial institutions such as banks and insurance companies, who might play an intermediary financing role, are exploring entering these markets.

Unstable and unpredictable prices reduce end-users' perception of natural gas as a reliable low-cost energy source. Natural gas price volatility and the cost of managing that volatility have become factors when considering future long-term investments, especially by industrial consumers.

NATURAL GAS SUPPLY

5.1 British Columbia Natural Gas Resources

B.C. is the second largest provincial producer of natural gas in Canada. All of the gas is produced in northeast B.C., which is part of the WCSB. In addition, geological and geophysical exploration, and some exploratory drilling have identified nine other basins within the province and the west coast offshore area that are believed to have hydrocarbon potential (Figure 5.1).

Highlights

- A large resource potential exists for future development
- Natural gas production has increased by 62 percent in the past ten years.
- Higher natural gas prices have been a key factor encouraging rising drilling activity
- Technological advancements have opened areas for drilling
- Provincial oil and gas strategy has encouraged exploration and development
- Provincial oil and gas revenues from royalties and land sales have risen

The total marketable gas resource potential for conventional gas in B.C., including the west coast offshore, is estimated at 1 921 $10^9 m^3$ (68 Tcf), of which 1 243 $10^9 m^3$ (44 Tcf) remains undiscovered. Prospects appear numerous in northeast B.C.; the NEB currently estimates the ultimate potential for conventional marketable natural gas in northeast B.C. at 1 436 $10^9 m^3$ (51 Tcf). Of this, about 773 $10^9 m^3$ (27 Tcf) of conventional marketable gas remains undiscovered.

The Plains area of northeast B.C., while one of the most developed areas in B.C., is not as mature in development as Alberta. The recent discovery in the Slave Point formation at Ladyfern indicates that additional resources may be found in the deeper horizons. The Foothills region, forming the western edge of the WCSB, is also estimated to have good potential for additional resources. Overall, the potential volume of undiscovered gas resources has spurred higher drilling activity, especially exploratory wildcat wells, which have increased by 30 percent over the past decade.

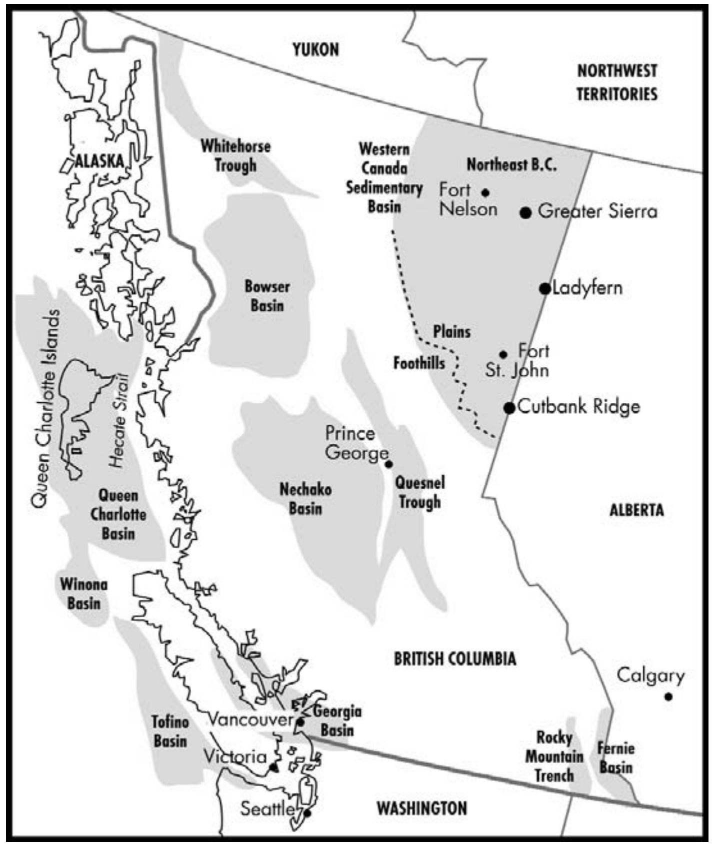
Throughout the central part of the province, several sedimentary basins, such as the Bowser, Whitehorse and Nechako Basins, have been identified as having significant petroleum and natural gas resource potential. However, it has been difficult to estimate the ultimate potential of natural gas resources due to the limited geological and geophysical information that is available. The Province, though, is commencing a program to evaluate the resource potential of the basins in conjunction with industry partners.

There are also basins located offshore from the west coast that are expected to contain natural resources, based on limited exploration drilling that occurred in the 1960s. The NEB estimates the ultimate potential of the west coast offshore at 255 $10^9 m^3$ (9 Tcf). The majority of the offshore natural gas resources are expected to be found in the Queen Charlotte Basin, which is the largest offshore basin and is situated around the Queen Charlotte Islands. In 1972, the Canadian government declared an indefinite moratorium on offshore oil and gas activities due to environmental concerns. This was extended after the Exxon Valdez oil spill in 1989. In 2003 the Minister of Natural Resources Canada announced that Canada will proceed with a review of the federal moratorium for the Queen Charlotte Area.

In addition to the sizeable potential for conventional gas resources, the province is known to have unconventional natural gas resources such as coalbed methane (CBM). Estimates of the volume of this resource range as high as 2 510 10^9m^3 (89 Tcf) but, it is unclear as to how much CBM may eventually be produced. Nine experimental projects are currently underway in the province but, at this point, there has not been any commercial production.

FIGURE 5.1

B.C. Natural Gas Supply Basins



Sources: B.C. Ministry of Energy and Mines; Geological Survey of Canada

5.2 Exploration and Development Activity in Northeast British Columbia

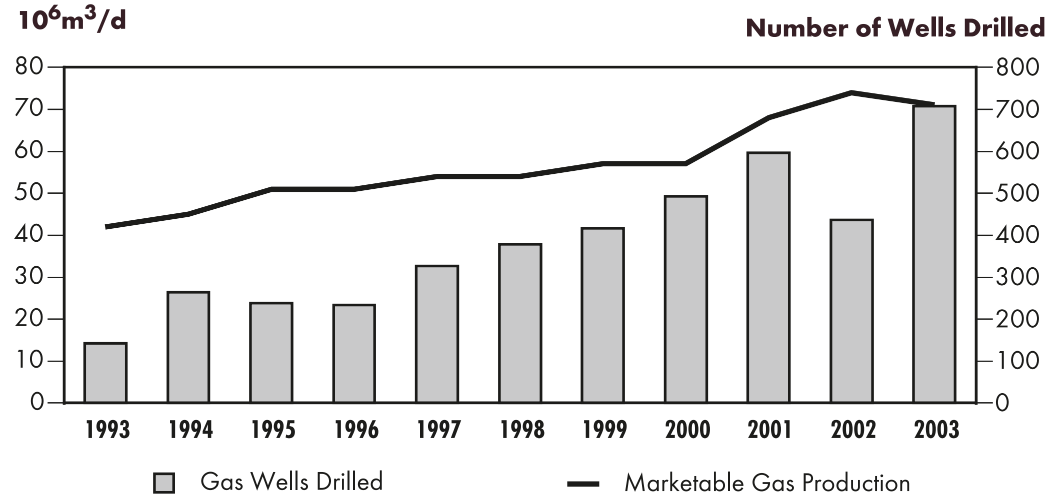
Considering the relative volume of the conventional natural gas resources that remain undiscovered, many producers are focusing on northeast B.C. as an area with excellent prospects for exploration and development. Encouraged by higher natural gas prices, producers have been pursuing these opportunities. In fact, over the past 10 years, drilling activity has increased over 300 percent, with 708 gas wells drilled in 2003 (Figure 5.2).

Almost all drilling in 2003 occurred in the Plains area with some 698 wells located there and only 10 wells were drilled in the Foothills. Wells drilled in the Foothills tend to be deeper and more expensive than those drilled on the Plains. Much of the natural gas activity was development drilling focused on the Fort St. John and Fort Nelson areas. These areas have experienced more development over the years than other regions and therefore, the average recoverable reserves per new well has been decreasing.

In terms of drilling, northeast B.C. is less developed than Alberta. Consequently, individual gas wells are generally more productive than those in most areas of Alberta. The average well in B.C. has an initial productivity of about 25 $10^3m^3/d$ (0.9 MMcf/d), whereas the average well in Alberta has an initial productivity of one-third that volume. In some regions of B.C., such as the Foothills, wells can exhibit initial productivity of 226 $10^3m^3/d$ (8 MMcf/d) or more. Based on average well production,

FIGURE 5.2

B.C. Marketable Natural Gas Production and Wells Drilled



Source: B.C. Ministry of Energy and Mines

production from wells in B.C. tends not to decline as quickly as production from wells in Alberta, although there can be variability between different producing areas in each province.

Gas Production

Marketable gas production in B.C. has increased by 62 percent in the past ten years, from about 42 $10^6m^3/d$ (1.5 Bcf/d) to 71 $10^6m^3/d$ (2.5 Bcf/d) in 2003 (Figure 5.2). The Plains region, which includes the highly productive Ladyfern field, accounted for about 88 percent of production with the remainder from the Foothills. Exploration and development drilling by producers replaced 115 percent of production in 2002. This level of reserves replacement further reinforces the optimistic outlook for gas supply in B.C. The Energy Market Assessment published by the NEB in December 2003 titled *Short-term Natural Gas Deliverability from the Western Canada Sedimentary Basin 2003-2005* projects an increase in B.C. gas production of 11 percent from year-end 2002 to 2005.

Exploration Plays

An exploration and development play that has received much attention is the 1999 Ladyfern gas field near the Alberta border. This is the first deep Devonian gas play in B.C. Production commenced in early 2000 and grew quickly to 20.5 $10^6m^3/d$ (725 MMcf/d) by March 2002; at this date Ladyfern accounted for more than one-quarter of provincial production. However, the wells have experienced high decline rates and production has since fallen off sharply. Drilling in the Devonian continues, but producers are now also drilling shallower wells at Ladyfern. These less prolific, shallow targets are now considered to be economic by producers because of access to existing pipeline facilities that were installed to produce the Devonian zone.

The Greater Sierra area, east of Fort Nelson, is another play under development. The field is currently producing about 6.2 $10^6m^3/d$ (220 MMcf/d) and the planned drilling of 150 horizontal wells per year is expected to increase production to 11.3 $10^6m^3/d$ (400 MMcf/d) by 2005. It is anticipated that an extensive drilling program will reduce drilling costs from \$4 million to about \$1.5 million per well.

The Cutbank Ridge area, south of Dawson Creek on the Alberta border, has been the focus of large investments in land sales over the past year. EnCana Corporation (EnCana) purchased $369 million of lease rights totaling 142 000 hectares at a single land sale in the fall of 2003. As well, EnCana had purchased additional rights in the area prior to that sale. This new play is estimated to contain more than 113 $10^9 m^3$ (4 Tcf) of recoverable gas based on seismic surveys, geological analysis and exploratory drilling. EnCana estimates about 100 to 200 horizontal wells will be drilled each year. Drilling costs, initially about $4 million per well, are expected to decline over time. EnCana forecasts significant production by 2005.

B.C. can be a costly region for gas exploration and development. Drilling gas wells in northeast B.C. can be very challenging, since it is a remote, rugged and geologically complex region with limited road and pipeline infrastructure. Often producers need to construct roads across muskeg in order to access drilling sites, which limits drilling to the winter season when the surface is frozen. Some producers have acted to extend the drilling season by using wooden and plastic drilling mats to transport rigs and drilling equipment into muskeg areas (Figure 5.3).

The application of technology such as drilling mats, horizontal drilling, under-balanced drilling and 3-D seismic has improved drilling economics in the region. Northeast B.C. has also seen the implementation of some large scale drilling programs that improve economies of scale by lowering costs per well.

The remoteness of northeast B.C. and the limited development to date can present environmental, socio-economic and land management issues many of which involve First Nations communities. Pristine environments can have many potential uses including wildlife areas, forestry and tourism. First Nations issues largely arise over the potential impacts of oil and gas development on traditional land-use such as trapping, fishing and hunting. Also of importance is the impact any development can have on archeological, cultural and heritage sites. With respect to oil and gas activity, First Nations have raised concerns over both the effects and the cumulative effects of these activities. In

FIGURE 5.3

Wooden Mats for Drilling Site and Road Access in Northeast B.C.

Photo courtesy of EnCana Corporation

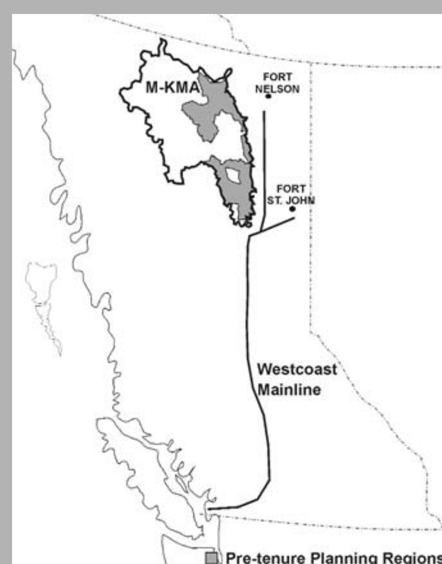
most cases, producers have been able to resolve land access issues with First Nations successfully, although delays may occur that can increase project costs.

5.3 British Columbia Oil and Gas Strategy

The Province has launched initiatives to improve the industry's competitiveness in B.C. compared with Alberta and other producing regions. The Province began by creating the Oil and Gas Commission in 1998 to provide a single window for regulatory approvals for oil and gas activities. Other initiatives included increased spending on road infrastructure and working with First Nations to develop consultation protocols for dealing with oil and gas exploration and development applications. The Province also established a planning framework to facilitate the development of natural resources, for example, in the Muskwa-Kechika Management Area (M-KMA).

Other initiatives introduced over the past few years include the elimination of the provincial sales tax on production machinery and equipment, a reduction in the corporate income tax rate to match Alberta, elimination of the corporate capital tax and various fees, and modification to the royalty regime for natural gas production. Of note, production grew substantially over this period, increasing 32 percent between 1998 and 2003.

Pre-tenure Planning: the Muskwa-Kechika Management Area



The Muskwa-Kechika Management Area (M-KMA) is a 63 000 square kilometre area in northeast B.C. that straddles the western edge of the WCSB. It was created by the Province in 1997 to protect a unique and relatively undeveloped ecological region. It encompasses one of the continent's largest wilderness expanses south of the 60th parallel and supports extensive wildlife populations in terms of both numbers and species diversity. An innovative approach to managing development given its ecological, cultural, archaeological and economic importance has been taken. The M-KMA is divided into (1) Parks and Protected Areas (16 400 square kilometres), (2) Special Management Areas (36 300 square kilometres) where environmentally sensitive industrial activities including oil and gas operations are allowed and (3) Special Wildland Zones (9 200 square kilometres), which allow some mining and oil and gas development, but no timber harvesting.

The Province has a legal requirement for an oil and gas pre-tenure development plan to be in place in an area before petroleum and natural gas rights can be sold there. However, it is not required before geophysical activities can take place. The intent of the pre-tenure planning is to encourage and guide responsible socio-economic and environmental planning ahead of most development activities.

One area in the M-KMA, the Sikanni, has experienced oil and gas activity for many years. Some of the other areas within the M-KMA now have pre-tenure plans in place and plan development is actively underway in the other pre-tenure plan areas. Plans completed to date have focused on the eastern edge of the M-KMA, where resource potential is thought to be the highest. The Province estimates that there is gas resource potential of 90 to 181 $10^9 m^3$ (3.2 to 6.4 Tcf) in the pre-tenure plan areas of the M-KMA. Oil and gas land sales commenced in some parts of the M-KMA in early 2004. The Province estimates the value of the natural gas in the area at about $16 billion.

In recent years, energy policy in the province has been under review. The provincial government commissioned a task force that released a report, titled *Strategic Considerations for a New British Columbia Energy Policy*, in March 2002. Using the task force's recommendations as a foundation, the provincial government formulated an energy plan released in November 2002, *Energy for Our Future: A Plan for B.C.* The plan recognizes that B.C. is increasingly integrated into the North American energy market and that the energy sector is well positioned to generate economic growth for the province. Several provincial government initiatives emerged from the energy plan, which are relevant to the development of B.C.'s natural gas industry.

In May 2003, the Province announced further measures to attract energy investment. The Province identified four pillars for its Oil and Gas Development Strategy: (1) a road infrastructure program; (2) targeted royalty reductions for marginal, deep wells and summer drilling; (3) further regulatory streamlining; and (4) oil and gas service sector development.

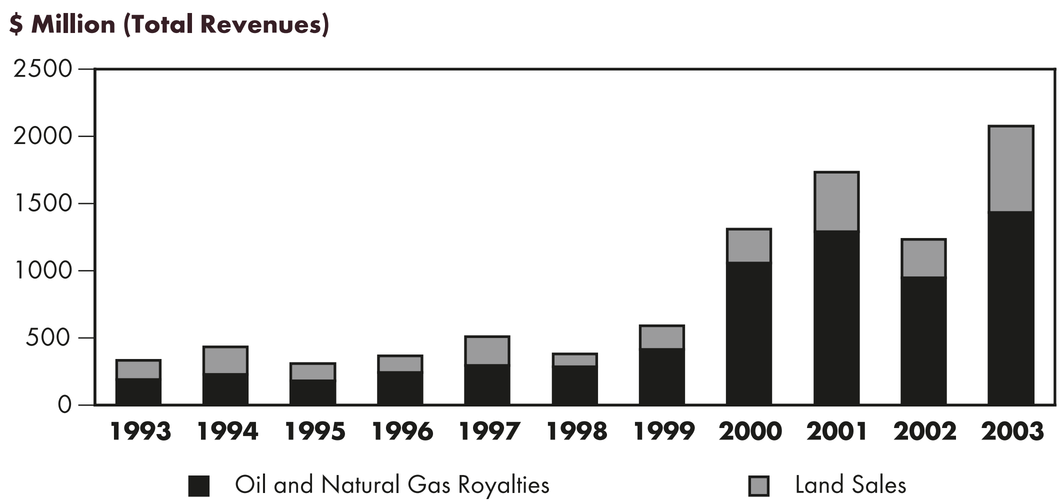
Six months later, in November 2003, additional steps were announced toward the stated goal of making B.C. the most competitive oil and gas jurisdiction in North America. These initiatives included: (1) further changes to deep drilling royalty credits; (2) royalty credits to encourage environmentally friendly horizontal and directional drilling technologies; (3) additional funding for road infrastructure; (4) creation of a single piece of legislation to govern the Oil and Gas Commission; and (5) a training fund to equip workers with the skills for employment in the oil and gas sector.

Land sales have also risen in recent years as industry interest in B.C. has grown. Over the past ten years, the Province has received $2.58 billion from land sales for oil and gas activity. Last year, alone, an unprecedented $647 million was raised from land sales, further demonstrating producer interest in B.C.

The Province estimates that in 2003, oil and gas revenue from royalties and land sales will exceed $2 billion (Figure 5.4). The oil and gas industry now provides more direct revenue to the Province than any other natural resource sector. In contrast, the revenue generated by the oil and gas industry in 1998, prior to the rise in continental natural gas prices, was only about $0.4 billion.

F I G U R E 5 . 4

B.C. Provincial Oil and Natural Gas Revenues



Source: B.C. Ministry of Energy and Mines

List of Parties Consulted

Alliance Pipeline Ltd.
Apache Canada Ltd.
Avista Energy Canada, Ltd.
BC Greenhouse Growers' Association
British Columbia Utilities Commission
Calpine Energy Services, LP.
Canadian Association of Petroleum Producers
Canadian Forest Products Ltd.
Canadian Natural Resources Limited
CanAgro Produce Ltd. (merged with Century Pacific Greenhouses to form Hot House Growers Incorporated, December 2003)
Cascade Natural Gas Corporation
Central Heat Distribution Ltd.
Chevron Canada Resources
EnCana Corporation
Export Users Group
IGI Resources, Inc.
Ministry of Energy and Mines, Province of British Columbia
Murphy Oil Company Ltd.
National Energy & Gas Transmission, Inc.
Natural Gas Steering Committee
Norske Skog Canada Limited
Oil and Gas Commission (British Columbia)
Puget Sound Energy, Inc.
Samson Canada, Ltd.
Talisman Energy Inc.
Terasen Gas Inc.
Unocal Canada Limited
West Fraser Mills Ltd.
Westcoast Energy Inc. (carrying on business as Duke Energy Gas Transmission Canada)
Western Pulp Inc.
Weyerhaeuser Company
Willis Energy Services Ltd.

GLOSSARY

3-D Seismic	A geophysical survey using equipment which sends a seismic signal into the earth which can be recorded and analyzed to obtain information on subsurface formations and features. A three dimensional survey provides a more dense cluster of data than conventional two dimensional seismic.
Acid Gas	Natural gas containing some percentage of hydrogen sulphide or carbon dioxide.
Capacity	The amount of natural gas that can be produced, transported, stored, distributed or utilized in a given period of time.
Coal Bed Methane	Natural gas, primarily methane, found in coal deposits.
Cogeneration	A facility which produces process heat as well as electricity.
Conventional Gas	Natural gas occurring in a normal porous and permeable reservoir which, at a particular point in time, can be technically and economically produced using normal production practices.
Core Market	Consists of the residential and commercial customers of a local natural gas distribution company.
Decline Rate	A term used to describe the decrease in production rate over time as a resource is depleted.
Degree Day	Data are calculated by Environment Canada and measure the extent to which the outdoor mean temperature (the average of the maximum and the minimum) falls below 18 degrees for each calendar day. One-degree day is counted for each degree of deficiency below 18° Celsius for each calendar day.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Direct Sales	Gas purchase arrangements transacted directly between producers, brokers or marketers and end-users
Directional Drilling	Drilling whereby the drill bit can be turned in any direction to reach the desired location.

Drilling mats	Wooden or plastic mats or pallets which are placed on a soft ground surface to stabilize it and allow placement and movement of heavy drilling equipment.
Electronic Trading	Refers to gas purchases and sales which take place via an electronic trading system. These systems allow gas to be bought and sold on an anonymous basis and provide for price discovery.
Exchange	Natural gas that is received from, or delivered to, another party in exchange for natural gas delivered to, or received from that other party.
End-Use Markets	Refers to the total consumer market for natural gas which includes the industrial, gas-fired power generation, commercial and residential markets.
Feedstock	Natural gas used as an essential component of a process for the production of a product (e.g. fertilizer).
Flue Gas Economizer	Captures waste heat from the flue gas of a boiler and transfers it to the boiler feedwater, thereby reusing energy and improving energy efficiency.
Formation	A geological zone or sedimentary layer which may be of interest in exploration for hydrocarbons.
Fuel-switching	The ability to substitute one fuel for another. It is generally based on price and availability.
Gas Well	A well bore with one or more geological horizons capable of producing natural gas
Geophysical	The analysis of sedimentary zone formations by the use of seismic equipment which records subsurface data.
Hedging	A financial risk management tool used for protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one market transaction with another. A long position in an underlying market instrument can be hedged or protected with an offsetting short position in a related underlying market instrument.
Hog Fuel	Wood waste fuel consisting of pulverized bark, wood shavings, sawdust, low grade lumber and lumber rejects from sawmills, plywood mills and pulp mills.
Horizon	A term often used to describe a subsurface formation or zone.
Horizontal Drilling	A well which deviates from the vertical and is drilled horizontally along the pay zone.

Hub	A geographical location where large numbers of buyers and sellers trade natural gas and where gas can be physically delivered.
Land Sales	The sale of leases and licenses by the Crown of subsurface formations for hydrocarbon exploration.
Liquidity	A measure of the ease with which potential buyers and sellers may transact business.
Liquids Rich	Gas that contains significant quantities of natural gas liquids.
Liquefied Natural Gas	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260° F at atmospheric pressure.
Local Distribution Company	An entity that owns a distribution system for the delivery of natural gas to end-use customers.
Marketable Gas	Natural gas that has been processed to remove impurities and natural gas liquids and is ready for consumer use. Its heating value may vary depending upon its chemical composition.
Natural Gas Liquids	Hydrocarbon components recovered from raw natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes, and pentanes plus.
NYMEX	The largest physical commodity futures exchange traded on the New York Mercantile Exchange for delivery of natural gas at the Sabine Pipe Line Co.'s Henry Hub in Louisiana.
Pre-tenure Planning	In some regions, prior to the British Columbia government making oil and gas tenures available in the region, pre-tenure plans must first be developed which identify sensitive resource values and develop appropriate objectives and strategies to support environmentally responsible development.
Price Differential	The difference in gas prices between two pricing points.
Price Transparency	The degree to which prices and other aspects of trades (volumes, duration, etc.) can be determined or verified at pricing points.
Price Volatility	The range of movement in commodity market prices.
Pulping Liquor	A by-product of the manufacture of chemical pulp which can be used as a fuel.
Reservoir	A porous and permeable underground rock formation containing a natural accumulation of crude oil or raw natural gas that is confined by impermeable rock or water barriers.
Royalty Credits	The British Columbia government is paid a royalty on natural gas produced from crown leases. Royalty credits are an elimination of certain royalties based on types of development work performed.

Spot Market	Transactions for gas that are generally for 30 days or less.
Storage	A facility or reservoir used to accumulate natural gas during periods of low demand and used to deliver natural gas during periods of high demand.
T-North	The Westcoast Fort Nelson and Fort St. John Mainlines which both terminate at Station 2, also known as Zone 3.
T-South	The Westcoast Mainline between Station 2 and Huntingdon, B.C., also known as Zone 4.
Undiscovered Resources	Resources that are estimated to be recoverable from accumulations that are believed to exist on the basis of available geological and geophysical evidence but which have not yet been shown to exist by drilling, testing or production.
Ultimate Gas Potential	An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology. It consists of cumulative production, remaining established reserves, discovered resources and undiscovered resources.
Under-balanced Drilling	Drilling when using a light drilling fluid which lowers bottomhole pressure to avoid damaging the formation with drilling fluid.
Wildcat Wells	A well drilled in an unproven area. Also known as an "exploration well".

APPENDIX D

Natural Gas Price Forecast Discussion

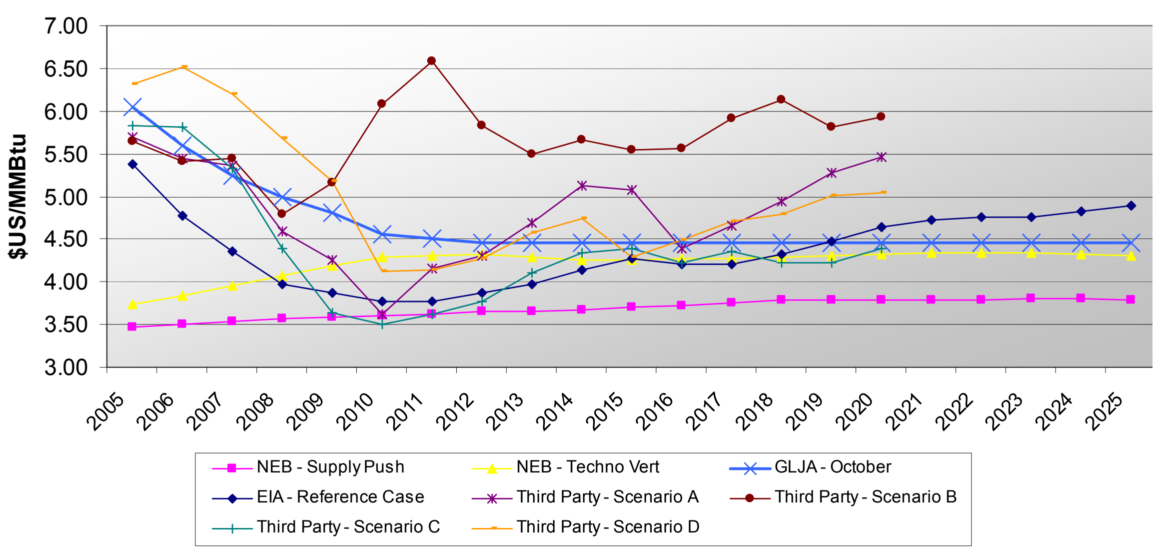
Appendix D

Supplementary Natural Gas Price Forecast Information

In forecasting future demand for natural gas, Terasen Gas Inc. (TGI) takes into account expected future trends in gas prices. In preparing this resource plan, TGI obtained gas price forecasts from an independent source, Gilbert Laustsen Jung Associates Ltd. (GLJA)[1]. TGI also cross referenced the GLJA price forecast with forecasts from other organizations such as the NEB, EIA and an independent Third Party. All organizations are highly respected within the energy industry. While the other forecasts were not used directly in evaluating future demand for natural gas at TGI, they were compared to the GLJA forecast as a further check on the reasonableness of the GLJA data. The forecasts are graphed in Figure D-1, and the assumptions for each scenario are discussed below.

TGI purchases gas at several different gas market centres including Alberta (AECO) and Sumas in British Columbia near the Washington – B.C. Border. The Henry Hub is the principal pricing point for natural gas spot and futures trading in the United States and Canada. Many natural gas marketers use the Henry Hub as their price benchmark for spot and future trades of natural gas. Given the volatility of natural gas prices, the market has developed a pricing relationship between the Henry Hub and various other important market centres in the United States and Canada including AECO and Sumas. In other words, prices at the AECO and Sumas exchange spots are derived from the Henry Hub less a basis differential. Prices vary somewhat between market centres due to several factors such as location relative to production and supply areas.

Figure D-1 - Natural Gas Price Forecasts Comparison at the Henry Hub (2004 Real Constant Dollars)



The National Energy Board has developed two price scenarios: Supply Push and Techno-Vert. The Supply Push represents a world in which technology advances gradually and Canadians

1 http://www.glja.com – Additional detail on the GLJA price forecast can be obtained from their website or by contacting them at 4100, 400-3rd Avenue S.W., Calgary, Alberta T2P 4H2 (403) 266-9500.

take limited action with respect to the environment. There is a security of continental supply and the 'push' to develop known conventional sources of energy. Techno-Vert represents a world in which technology advances rapidly and Canadians take broad action with respect to the environment. There is an accompanying preference for environmentally friendly products and cleaner-burning fuels.

As part of the Annual Energy Outlook 2005, the EIA has developed seven price forecasts: a Reference Case, High Economic Case, Low Economic Case, High A Oil Price Case, Low Oil Price Case, October Oil Futures Case and a High B Oil Price Case. Each forecast has embedded assumptions pertaining to gross domestic product (GDP), technology development and advancement and the impact of oil prices. While all forecasts were used for comparison to the GLJA, only the Reference Case is depicted here.

The Third Party has generated four distinct forecasts from years 2005 to 2020 based on a wide range of energy and natural gas issues. These issues include available reserves, source and regions of supply, expected transmission infrastructure improvements, social, political and environmental influences, and end user demand and competing forms of energy.

Scenario A expects trends of the recent past to continue into the future. The development of liquefied natural gas facilities throughout North America will help to mitigate gas prices through the mid-term of the forecast period by giving off-shore producer’s access to North American markets. Electricity production remains a key use for natural gas through the mid-term but falls near the end of the study period resulting in a drop in natural gas demand and a corresponding increase in prices.

Scenario B predicts the highest natural gas prices among any of their most recent gas price forecasts. This scenario is set in a socio-political environment that places a high degree of importance on the development of renewable, 'green' energy technologies and added costs for energy systems that produce greenhouse gases and other emissions. In this case, the Third Party expects demand for natural gas to decrease and as a result there would be few incentives for development of less accessible gas reserves and related technologies. A tight demand-supply relationship ensues with prices rising through the middle of the study period and remaining high into the future.

Scenario C is set in an environment of less geo-political stability that results in higher oil prices and again, more incentive for exploration of and access to North American reserves and an increase in North American production. This scenario assumes world turmoil and slower economic growth will occur, which combined with greater supply as domestic energy security becomes a key focus, keeps longer term gas prices low.

Assumptions behind Scenario D include continuous technology improvements that allow natural gas production in North America to offset growth in gas demand. Economic growth remains relatively high, and high prices for natural gas early in the study period provide the incentive for technology investment. In the longer run these technology improvements and access to gas supplies keep prices low over the longer term.

The GLJA price forecast sits within the middle to low range of all forecasts. With the exception of the Third Party Scenario B forecast, all other forecasts anticipate a downward trend or softening of prices from 2005 through to 2010. Although the GLJA does not seek to predict gas price fluctuations in the same way that the other organizations do, the foregoing discussion confirms that the GLJA forecast is a reasonable prediction of future natural gas prices.

APPENDIX E

Terasen Gas Inc. 2004 Resource Plan Stakeholder Consultation Materials

Appendix E I

Union of British Columbia Municipalities Brochure

Appendix E I

Resource Planning Brochure

Resource planning at Terasen Gas

At Terasen Gas, we're developing long-range plans to ensure we have the supply and infrastructure available to accommodate our province's growing demand for natural gas.

To achieve these objectives, we evaluate demand and supply options over a long-term planning horizon and consider their economic, environmental and social implications. We use this balanced approach to enable us to develop plans that deliver affordable, secure, reliable and safe natural gas service, meeting the future needs of our customers. The result is Terasen Gas' Resource Plan.

Community input

Our sustainable future envisions natural gas as a competitive fuel choice and a valued component of community energy planning.

By working in partnership with municipalities and maintaining natural gas as a competitive energy choice, residents and businesses in your community will continue to have alternatives for their energy needs.

Community and stakeholder involvement is integral to ensuring that our Resource Plan delivers sound and workable solutions for customers. The Terasen Gas Resource Plan for the Mainland will be published by the end of 2004. As we work on the plan, we'd like to hear from communities in the province and welcome your participation.

Contact us

For more information on our Resource Plan, or to schedule a time for us to meet with your community and discuss energy options, please contact James Wong, Manager, Forecasting at (604) 592-7871, or send an email to James.Wong@terasengas.com

Terasen Gas delivers natural gas and piped propane to homes and businesses. The Terasen Gas group of companies includes Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Squamish) Inc. and Terasen Gas (Whistler) Inc. For information about natural gas service, safety and energy efficiency visit www.terasengas.com.

Appendix E II

Municipal Presentation Package Sample

Natural Gas and Energy Planning

City of Surrey
February 18, 2005

Today's Discussion Topics:

- A Competitive Energy Choice
- Natural Gas in a Sustainable Energy Future
- Efficient Use of Energy Resources
- Natural Gas Compared to Other Energy Systems
- Provincial / Regional Growth and Energy Use Trends
- Terasen Programs for Efficient Energy Use
- Resource Planning at Terasen and What it Means for You
- Can We Work Better, Together?

What is a Resource Plan?

- A long-term plan to meet forecasted customer needs.
- A planning document that outlines stakeholder input and analyzes financial, environmental, and socio-economic impacts.

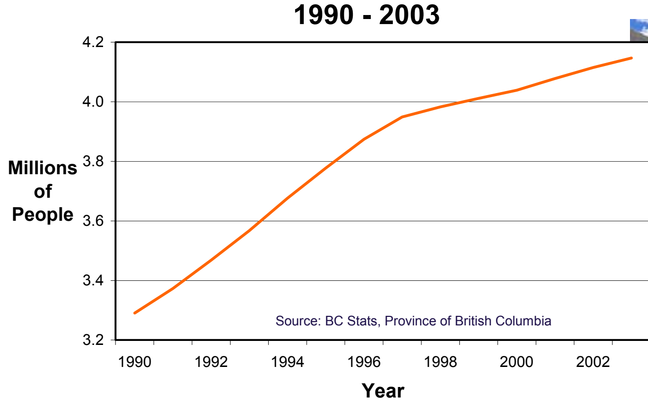
"Resource Planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run." –

BCUC Resource Planning Guidelines, 2003

Making wise energy decisions for our future

As British Columbia grows, communities and individuals across the province are displaying a growing interest in sustainable energy options.

Population Growth in B.C.
1990 - 2003



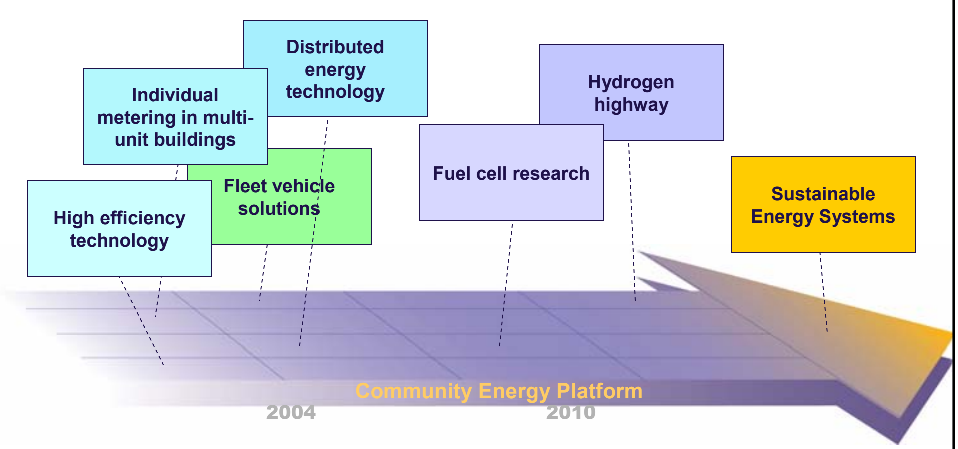
Natural gas is a natural choice

Natural gas remains the fuel choice on the road to our sustainable future.

- Clean and energy efficient
  - Air quality and greenhouse gas reduction
  - New technology
- Safe & Reliable
- Available
  - Terasen pipeline distribution system
  - Proven North American and world wide reserves
- Competitively priced
  - Natural gas versus electricity, propane, renewables and other fuels

A Flexible Energy Platform…

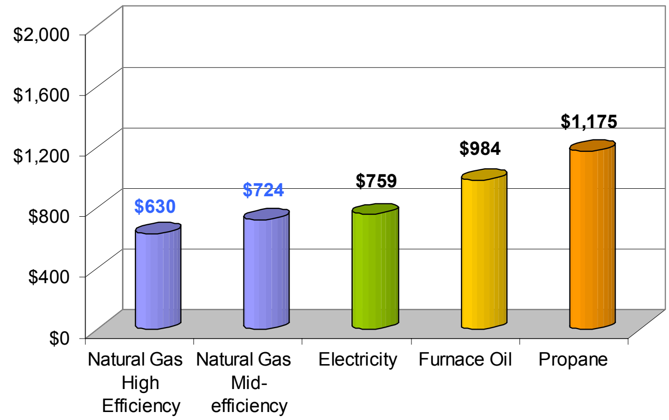
Natural Gas is an important part of an efficient, environmentally sensitive, economic and cost effective energy platform today, and an important bridging fuel for advancements in energy system technology for tomorrow…



A Competitive Energy Choice

Terasen Gas

2004 Annual Fuel Cost Comparison
Space Heating - Lower Mainland



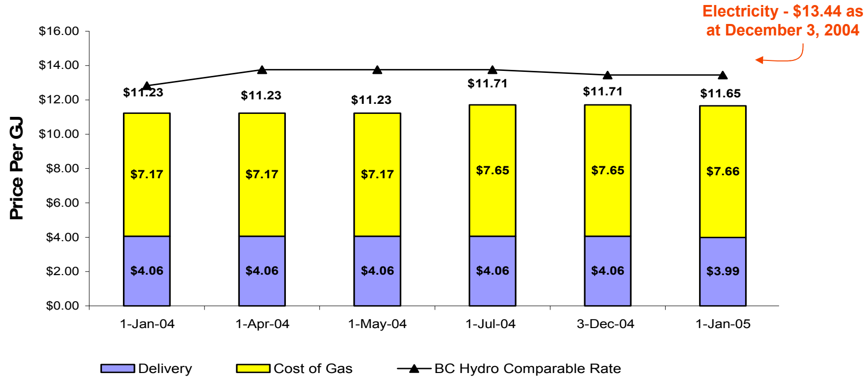
Gas rates effective December 1, 2004
All fuel costs as of December 1, 2004

A Competitive Energy Choice

Terasen Gas

Lower Mainland Residential Bill History per GJ
Gas vs. Electric Comparison
Terasen Gas Delivery and Commodity Charges

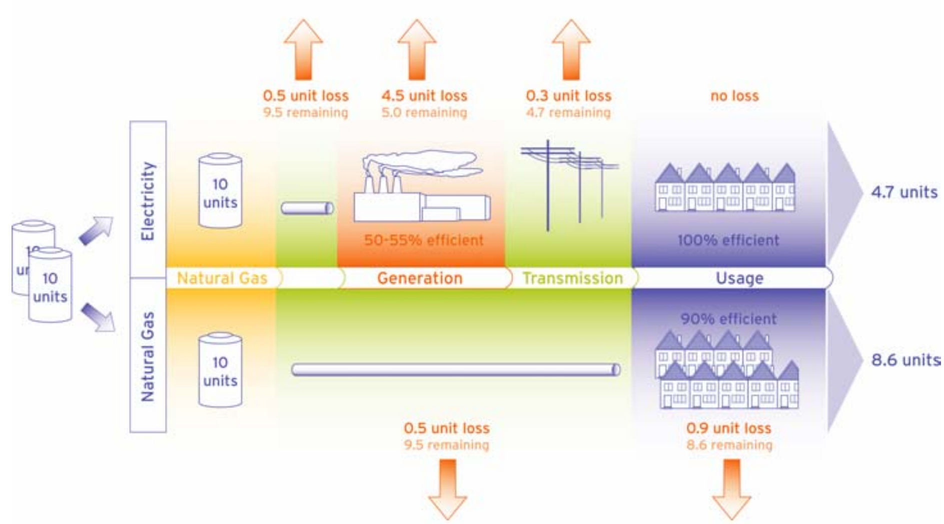
Electricity - $13.44 as at December 3, 2004



*Natural gas use of 110 GJ *Efficiency of gas equipment is 80% relative to 100% for electricity *Terasen Gas amount includes basic charge
*BC Hydro amount does not include basic charge since a household already pays the basic electric charge for non-heating use

Home Heating Efficiency
Natural Gas vs. Electricity (new demand)

Terasen Gas



Energy Choice Considerations
Space Heating

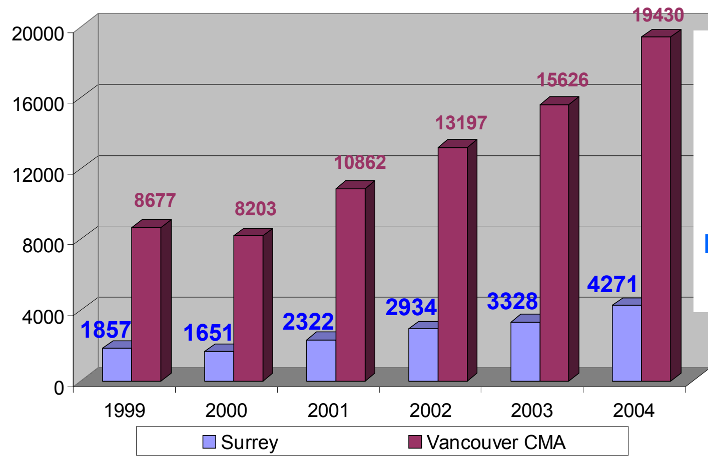
Terasen Gas

	Natural Gas	Electric baseboard	Ground Source Heat Pump
Supply Capacity	Lots of Supply (market sets price)	Lots of Supply (price set below market)	Can require additional infrastructure to meet full demand requirements
Attributes	Safe and Dependable	Safe and Dependable	Complex
Life Cycle Costs Modeling Study Example Done for BC Ministry of Energy and Mines	High Efficiency Gas Furnace & Conventional Gas Hot Water; Base; **14 - 29% Savings**	*Note: Lower Mainland Case; **Baseline**; Electric Baseboard Heating & Electric Hot Water	**34 - 74% Higher Cost**; Ground Source Heat Pump & Electric Hot Water

Regional Growth

Housing Starts in Surrey

(Source: CMHC)



2004

Single – 2143

Semi – 230

Row – 1240

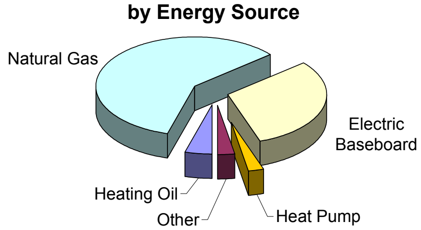
Low Rise – 403

High Rise – 34

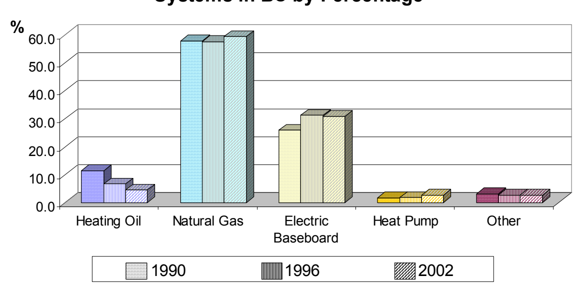
Provincial Energy Use
Overall Residential Heating

2002 BC Heating Systems by Energy Source

Source: Natural Resources Canada



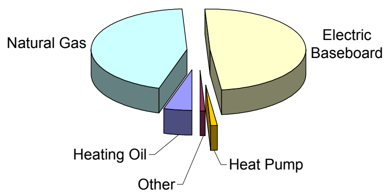
History of Residential Heating Systems in BC by Percentage



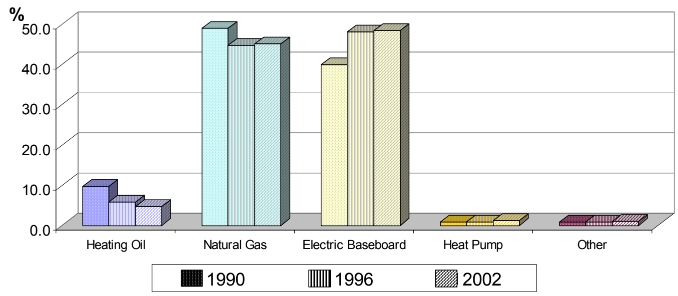
Provincial Energy Use
Multi-family Residential Heating

2002 Distribution of Heating Systems by Energy Source in BC Apartments

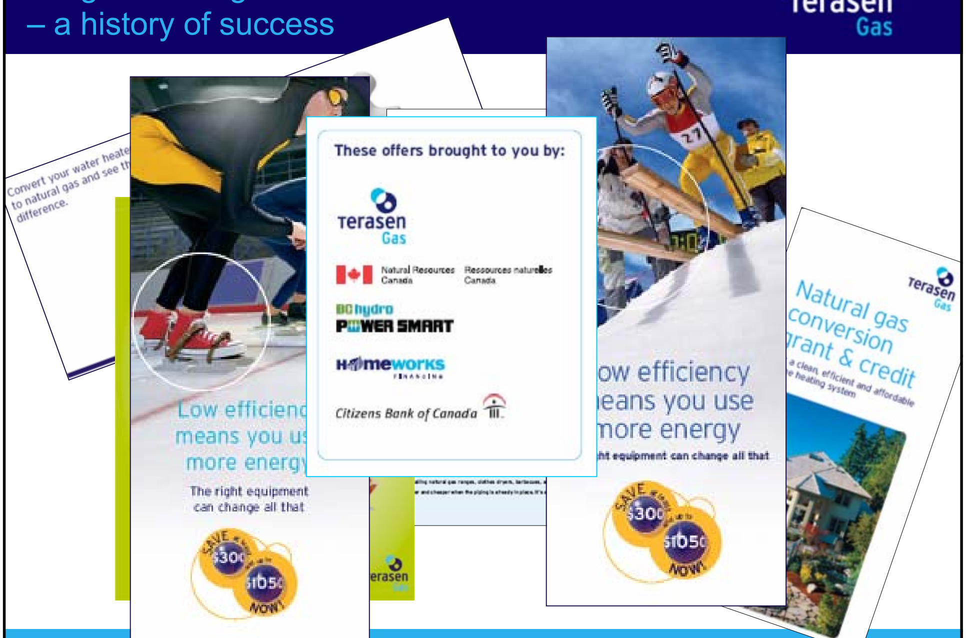
Source: Natural Resources Canada



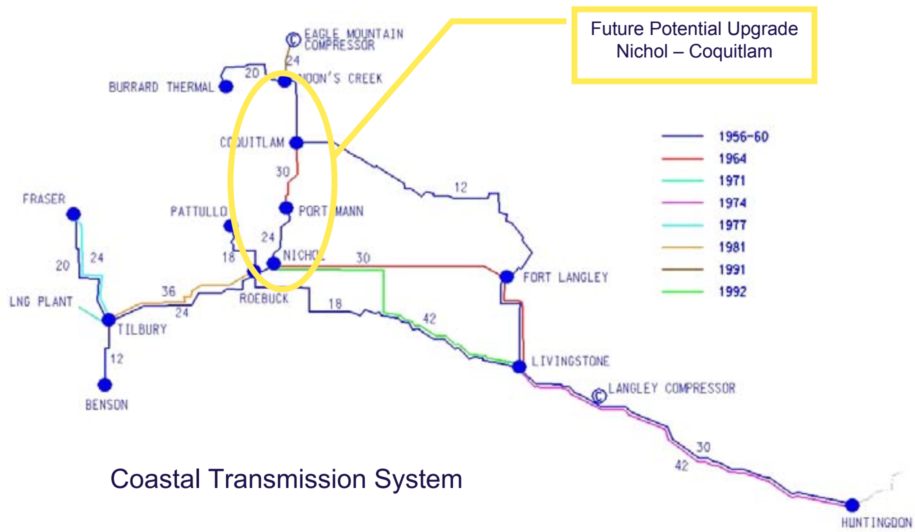
History of Apartment Heating System Stock in BC by Percentage



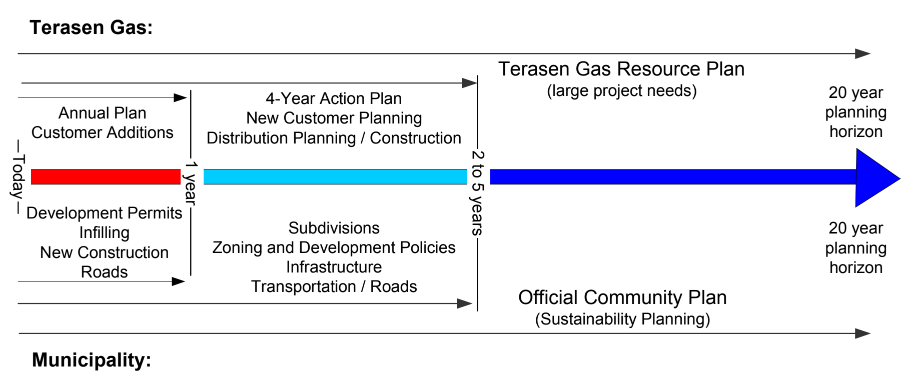
Integrated Programs
– a history of success



Terasen Gas Resource Plan



Working Together for Effective and Timely Planning



Next Steps

Resource Plan:

We want your feedback on the Resource Plan!

- Provide Terasen with your comments, questions and concerns
- Survey will be circulated later this week asking for your input
- Feedback will be incorporated into the finalized Resource Planning submission to the British Columbia Utilities Commission (BCUC)

- Finalized Resource Plan will be available by the end of March
  - If you would like a copy – please contact Amy Hennessy