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
Office national de l'énergie

The British Columbia **Natural Gas** Market

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

gas
gas
gas
gas

An **ENERGY MARKET ASSESSMENT** • April 2004

Cat. No. NE23-117/2004E
ISBN 0-662-36978-5

This report is published separately in both official languages.

Copies are available on request from:
The Publications Office
National Energy Board
444 Seventh Avenue S.W.
Calgary, Alberta, T2P 0X8
E-Mail: publications@neb-one.gc.ca
Fax: (403) 292-5576
Phone: (403) 299-3562
1-800-899-1265
Internet: www.neb-one.gc.ca

For pick-up at the NEB office:
Library
Ground Floor

Printed in Canada

Nº de cat. NE23-117/2004F
ISBN 0-662-76737-3

Ce rapport est publié séparément dans les deux langues officielles.

Demandes d'exemplaires :
Bureau des publications
Office national de l'énergie
444, Septième Avenue S.-O.
Calgary (Alberta) T2P 0X8
Courrier électronique : publications@neb-one.gc.ca
Télécopieur : (403) 292-5576
Téléphone : (403) 299-3562
1-800-899-1265
Internet : www.neb-one.gc.ca

Des exemplaires sont également disponibles à la bibliothèque de l'Office :
Rez-de-chaussée

Imprimé au Canada

FIGURES

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.

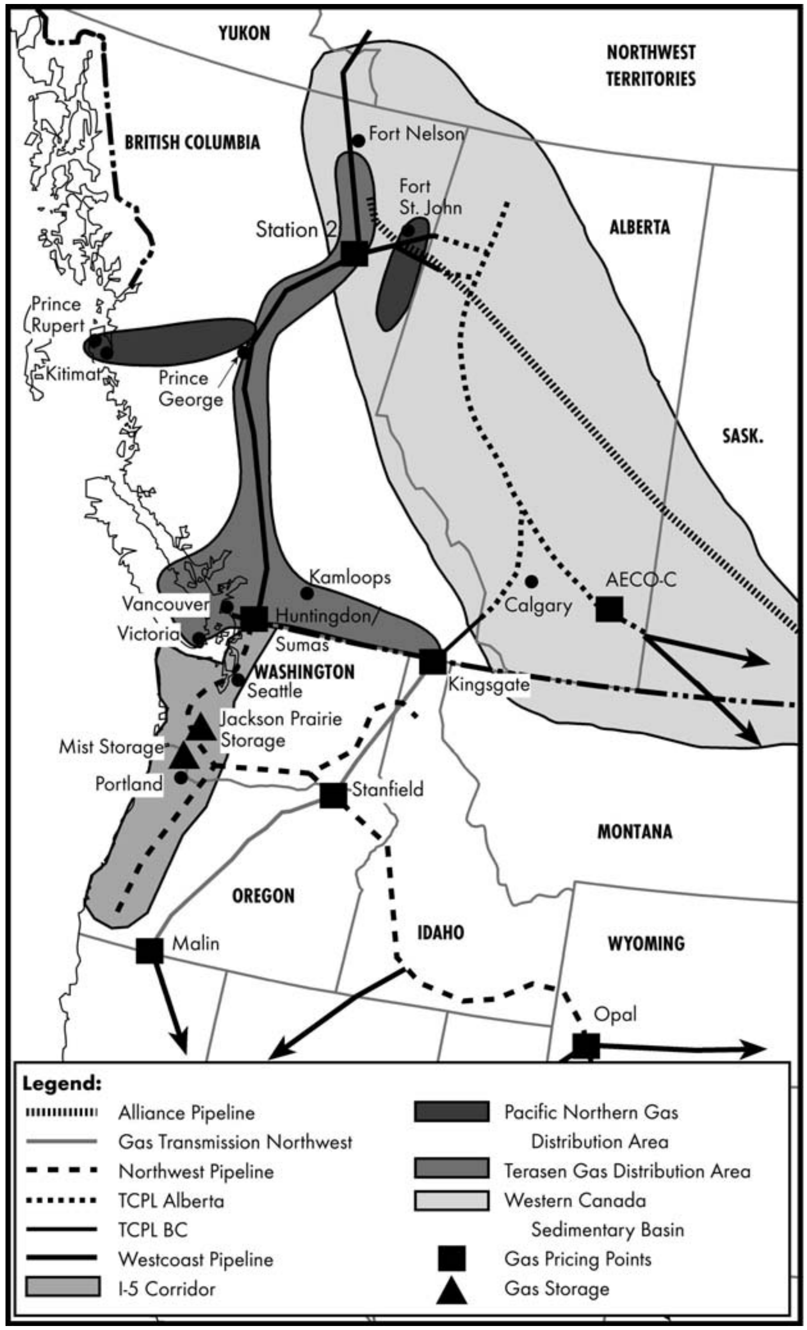
2.2 British Columbia Domestic Natural Gas Markets

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.

FIGURE 2.1

B.C. and Pacific Northwest Regional Natural Gas Markets



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.

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.

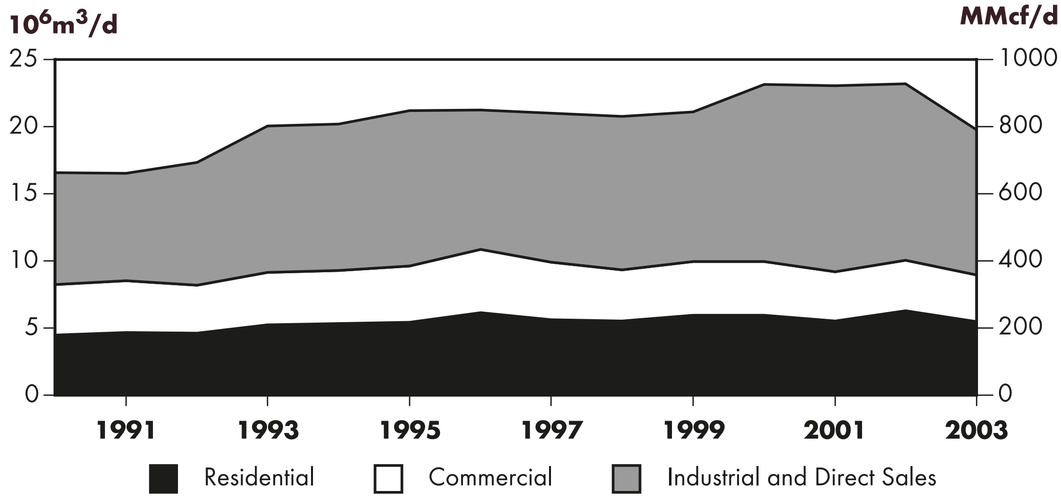
Residential and Commercial Markets

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.

FIGURE 2.2

B.C. Annual Natural Gas End-Use

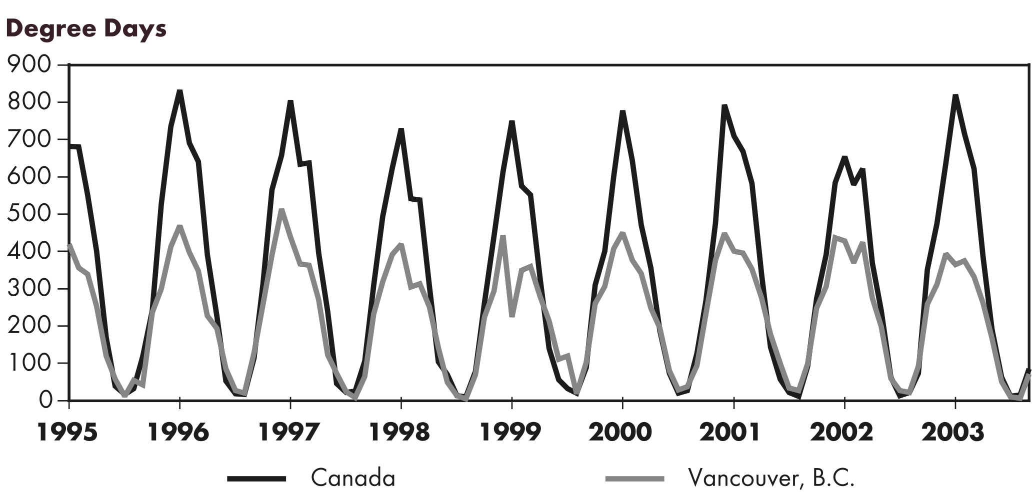


Source: Statistics Canada

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).

FIGURE 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.

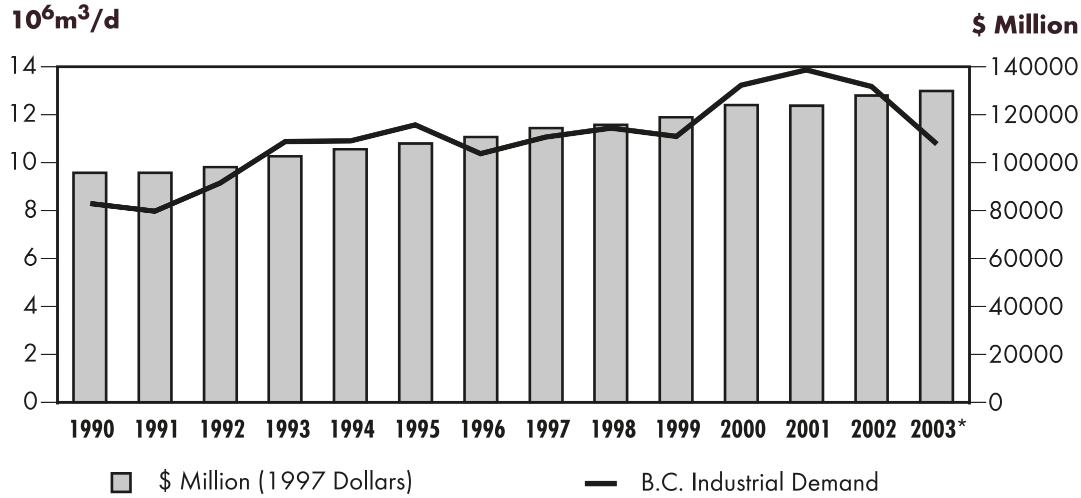
Natural gas demand in the industrial sector, including gas-fired generation, grew at about six percent per year between 1990 and 2001 (Figure 2.4). Combined industrial and gas-fired generation demand grew faster than the 2.7 percent average annual provincial rate of economic growth for the same period. 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

F I G U R E 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.

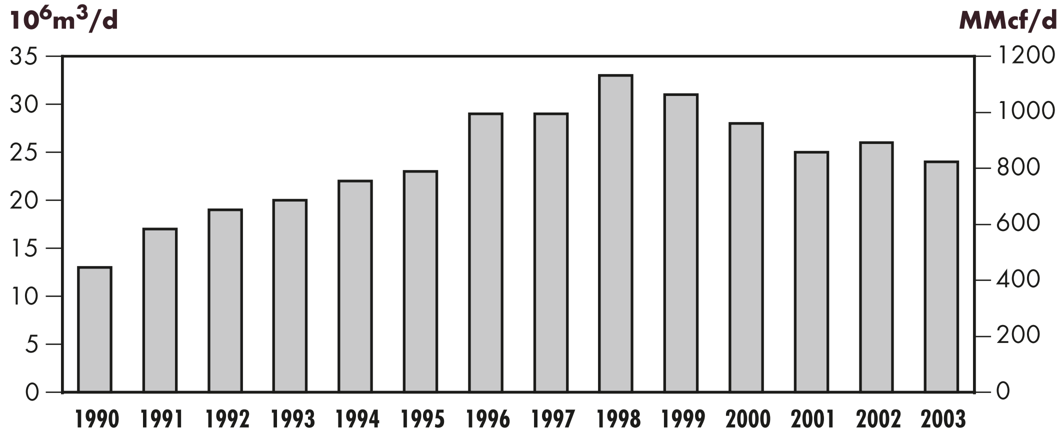
Eastern Washington, eastern Oregon and Idaho receive Canadian gas, mostly from Alberta, via the Gas Transmission Northwest Corporation (GTN) pipeline that crosses the international border at Kingsgate, B.C. Only a small amount of B.C. gas enters this market via GTN. Gas from the U.S. Rockies Basin also 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

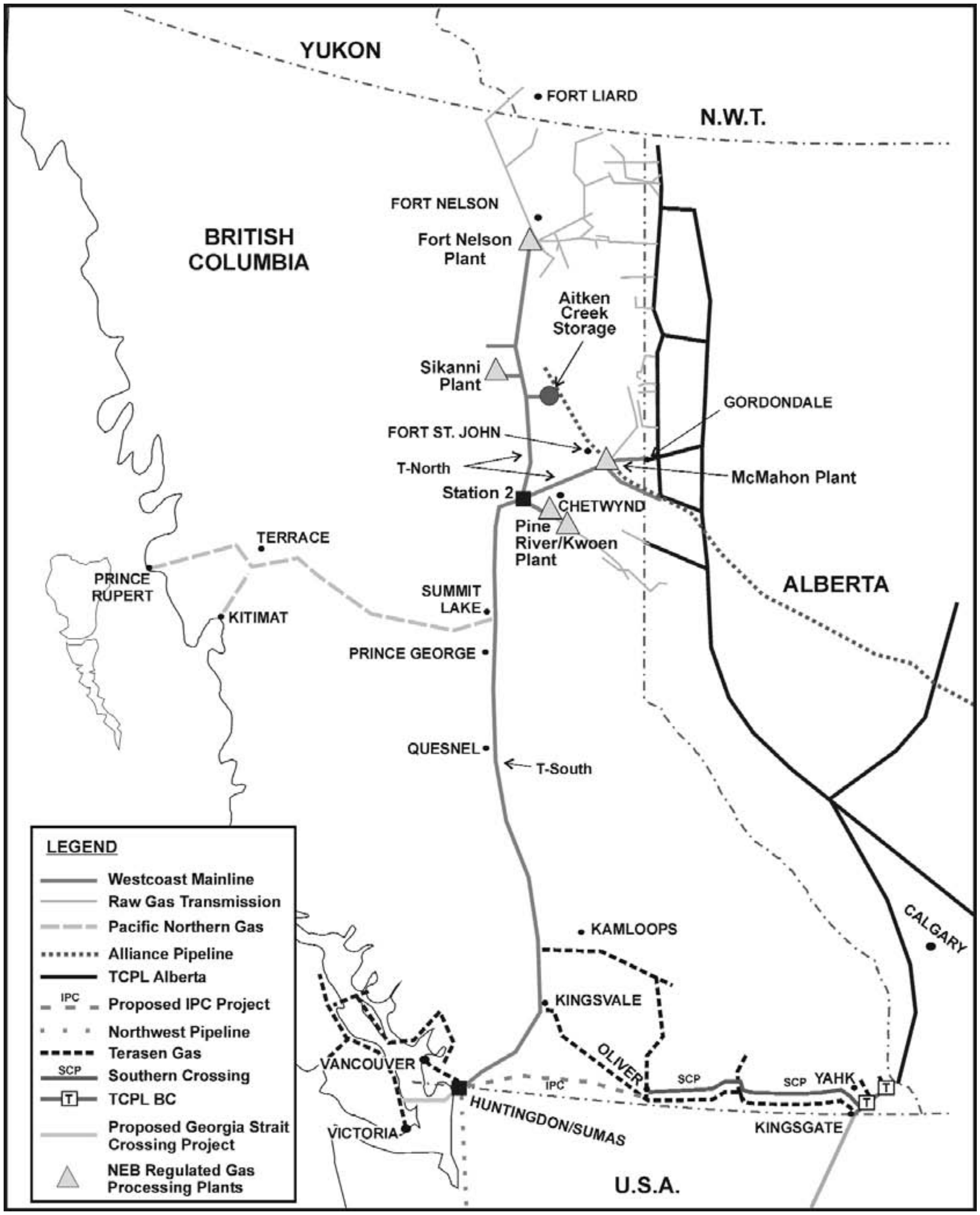
The Westcoast system has been delivering natural gas, primarily from northeast B.C., since 1957 when it was the first major gas export pipeline built in Canada (Figure 3.1). Unlike other major natural gas transporters in Canada, its system includes gathering and processing facilities in addition to transmission. 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 $10^6m^3/d$ (1.2 Bcf/d) from Fort Nelson and 21.5 $10^6m^3/d$ (760 MMcf/d) from Fort St. John.

FIGURE 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

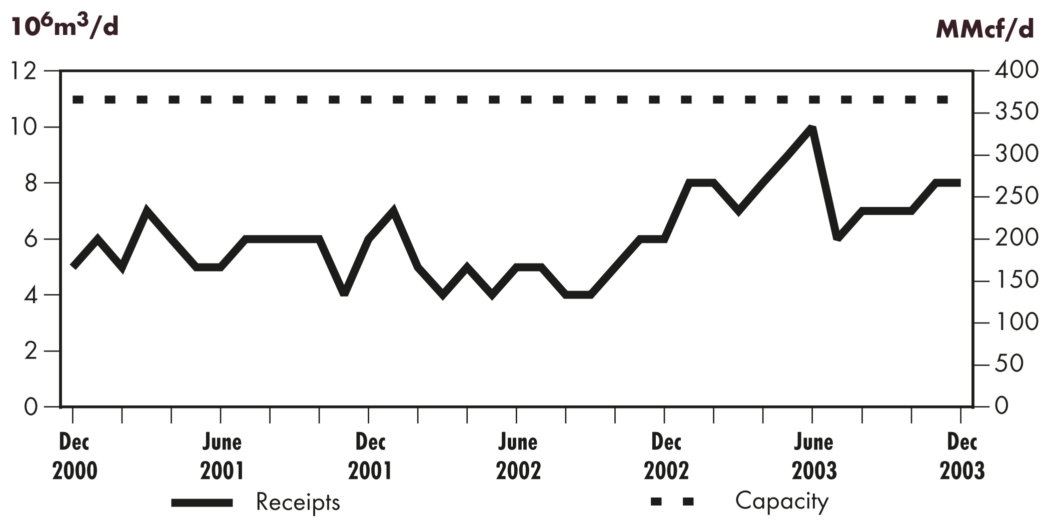
The Alliance pipeline transports approximately 44 10^6m^3/d (1.55 Bcf/d) of liquids-rich Canadian gas mainly from Alberta and, to a lesser extent from B.C., to Chicago and the U.S. Midwest market. It began shipping gas to markets in December of 2000. Although the Alliance mainline starts in Alberta at 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

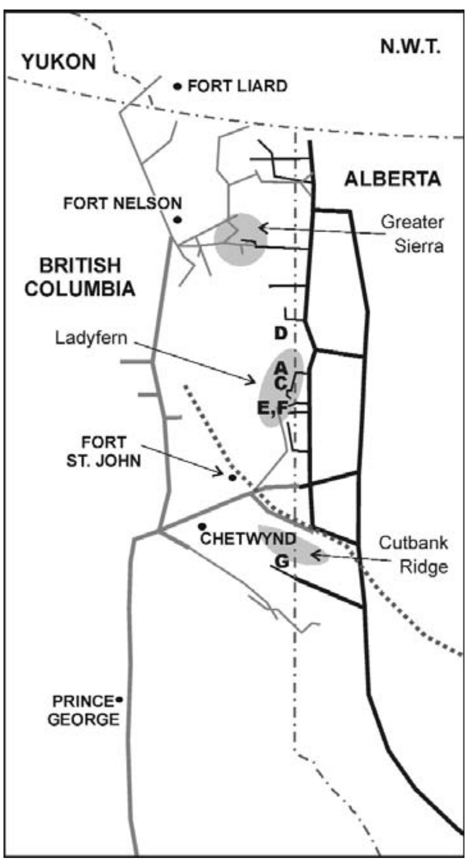
The Westcoast system also interconnects with the TCPL Alberta system at Gordondale, Alberta enabling the eastward flow of gas to Alberta and downstream domestic and export markets. (Figure 3.1) The interconnection with TCPL Alberta is bidirectional and permits Westcoast to either deliver or receive gas there. While the net flows of B.C. gas at Gordondale are quite small (averaging less than 0.9 $10^6 m^3/d$ (30 MMcf/d) in the 2002/2003 contract year), the capacity of the line is approximately 5.7 $10^6 m^3/d$ (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 $10^6 m^3/d$ (550 MMcf/d) of marketable gas flowed into Alberta on these producer-owned lines, down from 24 $10^6 m^3/d$ (845 MMcf/d) in 2002, largely reflecting the decline in production from the Ladyfern field.

FIGURE 3.3

Northeast B.C. Cross-border Pipelines Built to Alberta since 1999



Legend			
		Capacity	
Location on Map	Pipeline	$10^6 m^3/d$	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

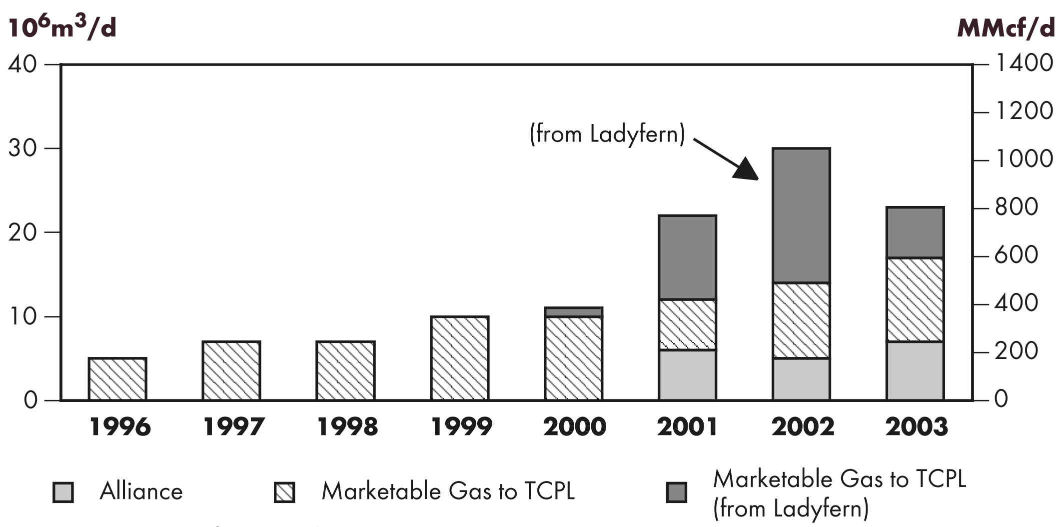
Gas flows into Alberta started to increase substantially in 2000 and 2001, with the start of production from the Ladyfern field and the beginning of flows on the Alliance system (Figure 3.4). LadyFern had a particularly significant impact since deliverability from the Ladyfern field rose to over 19.8 $10^6 m^3/d$ (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

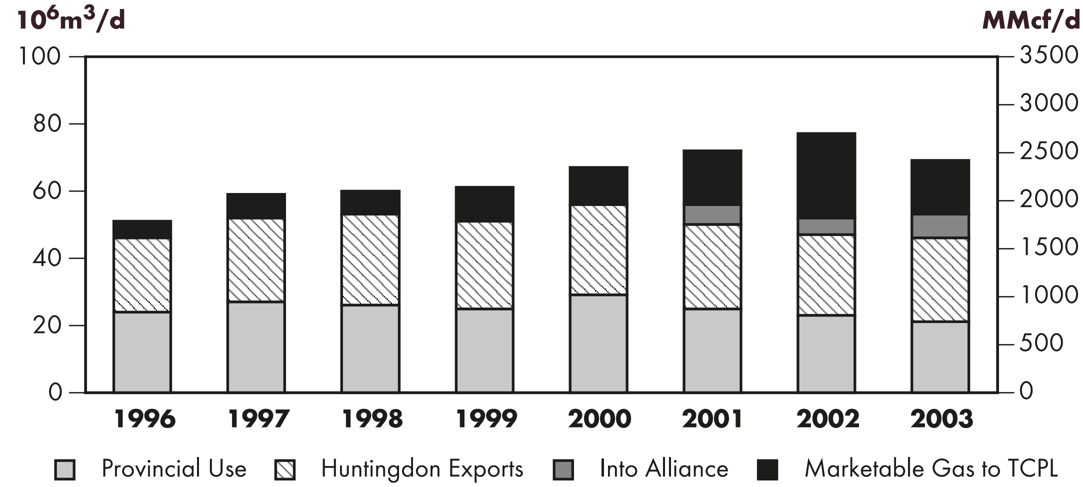
Marketable Natural Gas Flows from Northeast B.C. to Alberta



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.

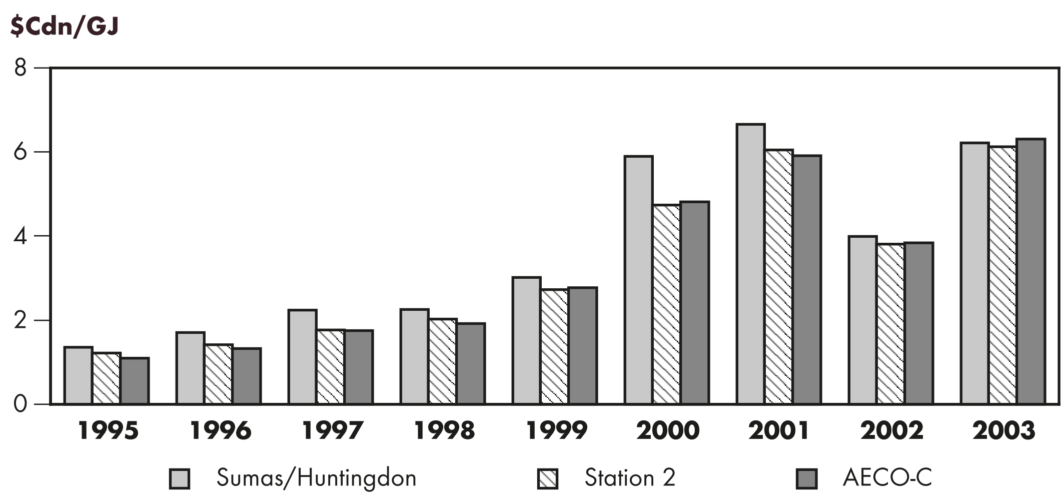
4.2 A History of Natural Gas Prices in British Columbia

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.

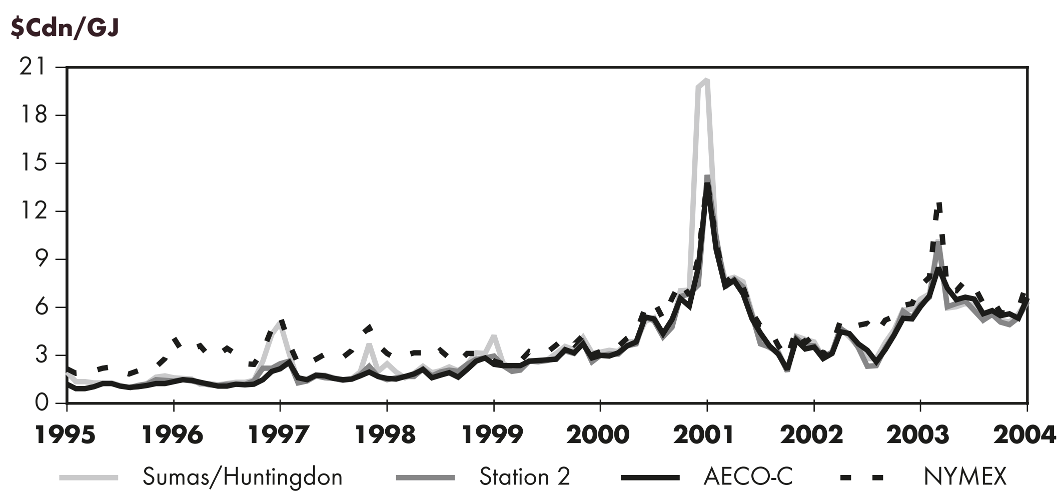
The impact of this cold weather can be exacerbated by the limited amount of storage facilities within the Lower Mainland market area. Unlike some regions where many buyers can draw on gas storage to meet peaking demand, buyers at Sumas/Huntingdon, who do not have storage elsewhere, must compete for gas 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

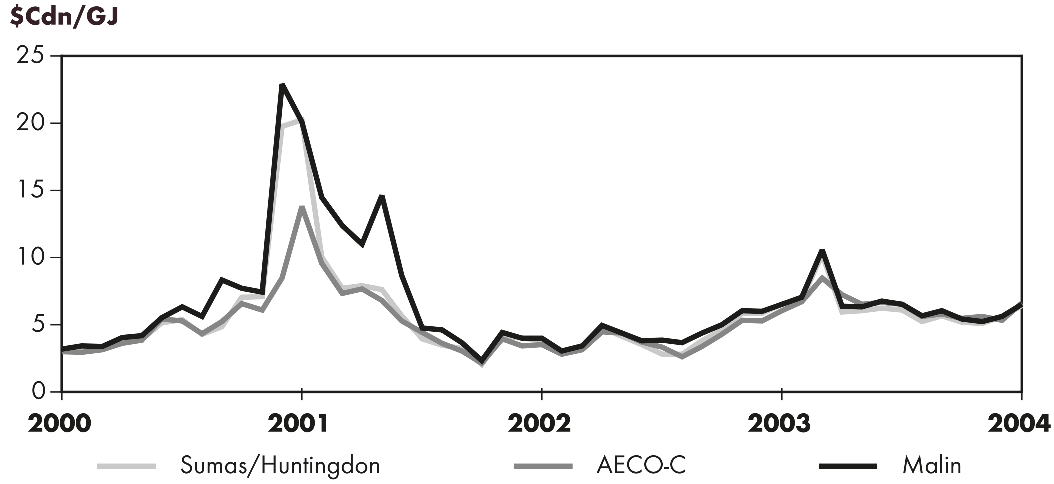
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Station 2, AECO-C and NYMEX



Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

FIGURE 4.3

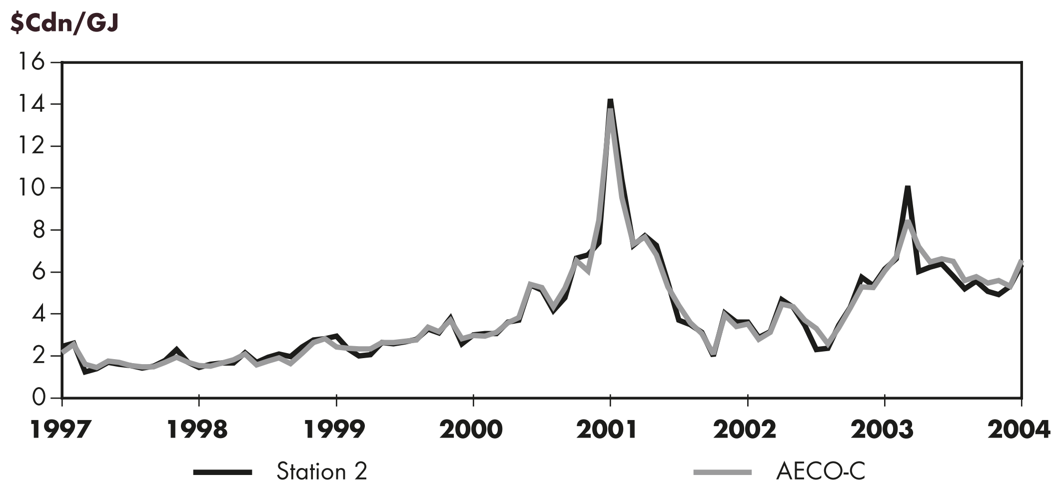
Spot Natural Gas Price Comparison: Sumas/Huntingdon, Malin and AECO-C



Source: Canadian Natural Gas Focus

FIGURE 4.4

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



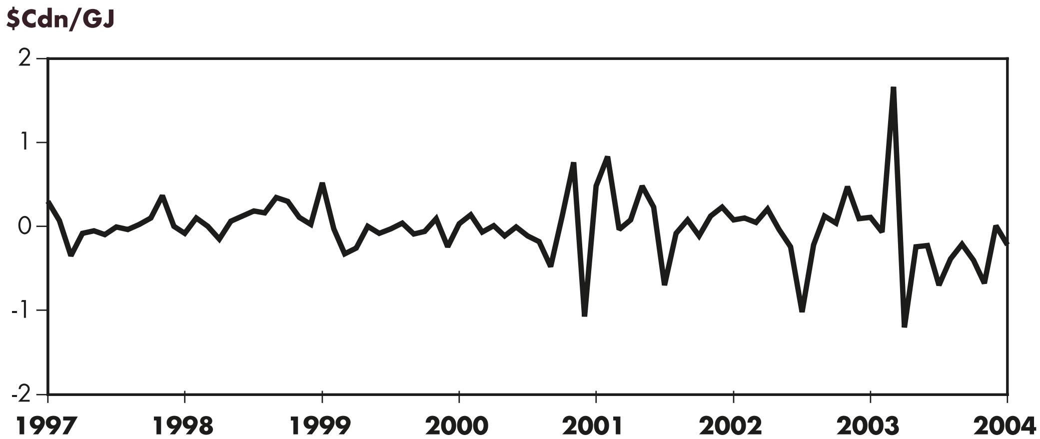
Sources: Canadian Natural Gas Focus, Canadian Gas Price Reporter

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

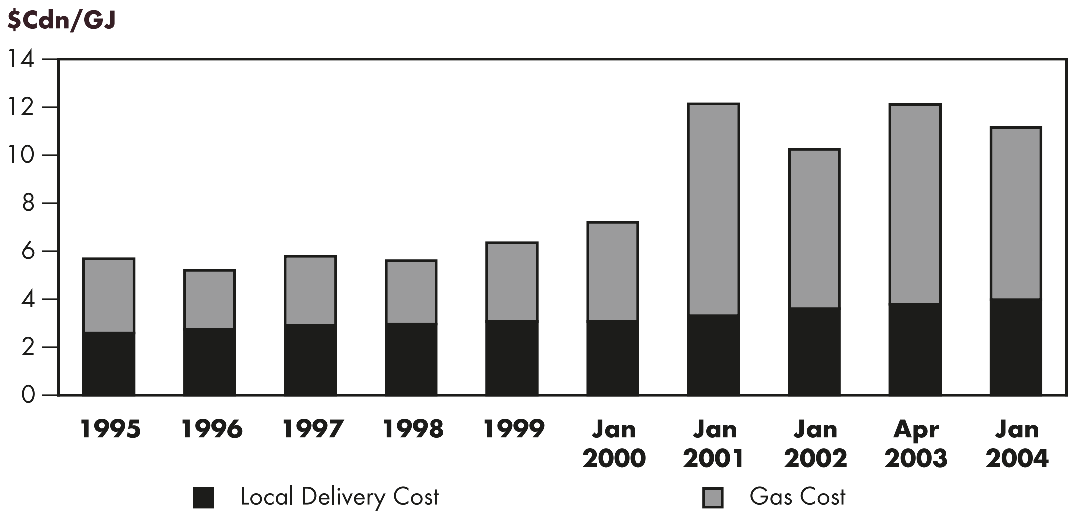
Price Differential: Station 2 less AECO-C



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 10^9m^3 (68 Tcf), of which 1 243 10^9m^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 10^9m^3 (51 Tcf). Of this, about 773 10^9m^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.

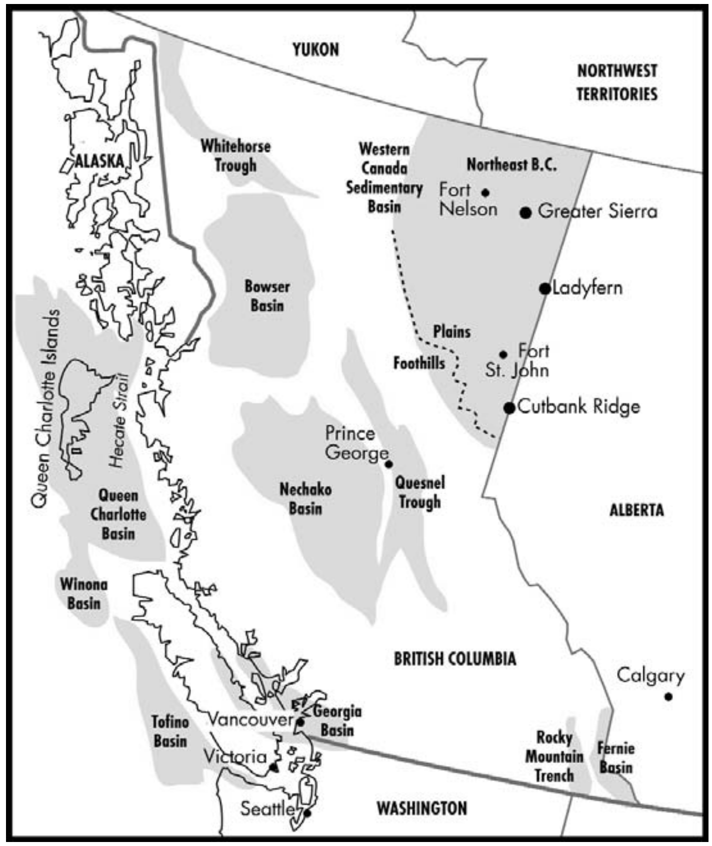
Throughout the central part of the province, several sedimentary basins, such as the Bowser, Whitehorse and Nechako Basins, have been identified as having significant petroleum and natural gas resource potential. However, it has been difficult to estimate the ultimate potential of natural gas resources 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 10^9m^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

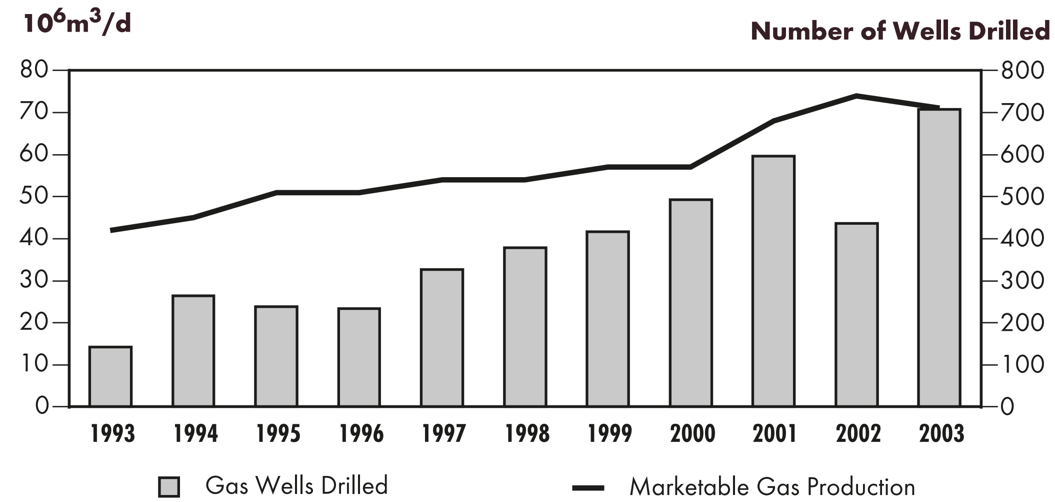
Considering the relative volume of the conventional natural gas resources that remain undiscovered, many producers are focusing on northeast B.C. as an area with excellent prospects for exploration and development. Encouraged by higher natural gas prices, producers have been pursuing these opportunities. 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 10^9m^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

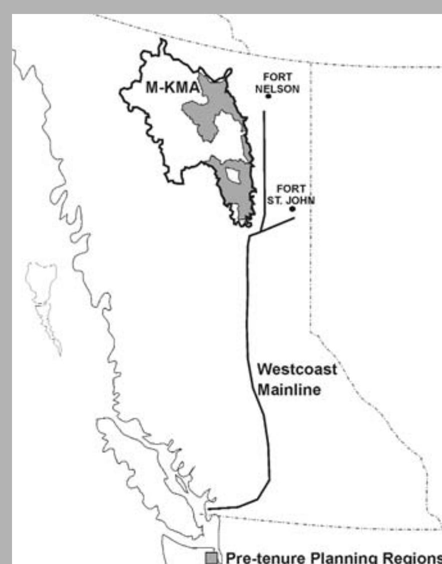
most cases, producers have been able to resolve land access issues with First Nations successfully, although delays may occur that can increase project costs.

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.

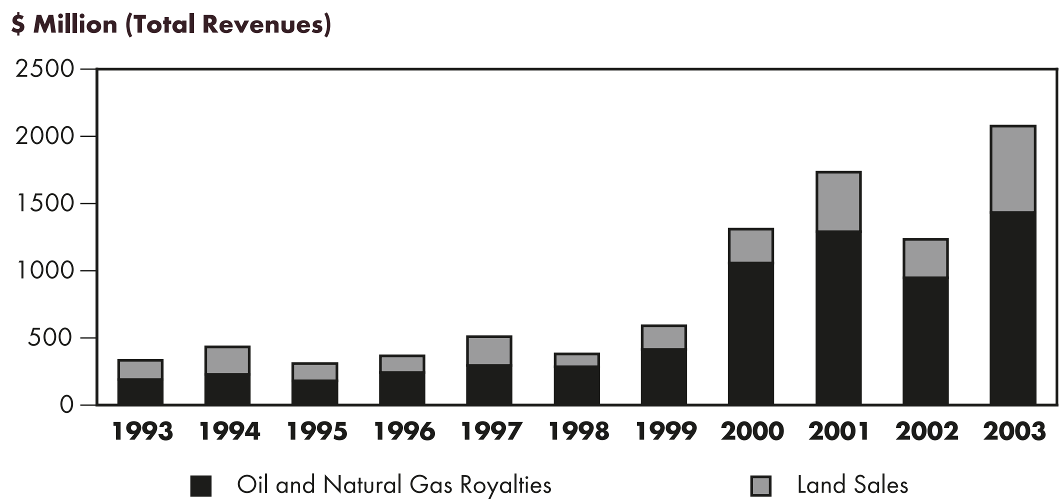
Six months later, in November 2003, additional steps were announced toward the stated goal of making B.C. the most competitive oil and gas jurisdiction in North America. These initiatives included: (1) further changes to deep drilling royalty credits; (2) royalty credits to encourage environmentally 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.

FIGURE 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".

Canada