National Energy Board

Office national de l'énergie

Short-term Outlook for **Natural Gas** and **Natural Gas Liquids**

to 2006

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An **ENERGY MARKET ASSESSMENT** • October 2005

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Cat. No. NE23-131/2005E
ISBN 0-662-41205-2

This report is published separately in both official languages.

Copies are available on request from:
The Publications Office
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Internet: www.neb-one.gc.ca

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

Printed in Canada

Nº de cat. NE23-131/2005F
ISBN 0-662-74783-6

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

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Acronyms

AECO-C or AECO	Alberta Energy Company storage facility
AEGS	Alberta Ethane Gathering System
BP	British Petroleum
C_1	methane
C_2	ethane
C_{2+}	ethane plus
C_3	propane
C_{3+}	propane plus
C_4	butane
C_{5+}	pentanes plus; also known as natural gasoline and condensate
CAPP	Canadian Association of Petroleum Producers
CBM	coal bed methane
CCPA	Canadian Chemical Producers' Association
CIF	cost, insurance, and freight
CO_2	carbon dioxide
CSUG	Canadian Society of Unconventional Gas
EEEP	Edmonton Ethane Extraction Plant
EGLJV	Empress Gas Liquids Joint Venture
EIA	Energy Information Administration
EMA	Energy Market Assessment
EOR	enhanced oil recovery
EPG	electric power generation
EUB	Alberta Energy and Utilities Board
GDP	Gross Domestic Product
IEA	International Energy Agency
JEEP	Joffre Ethane Extraction Plant
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M&NP	Maritimes and Northeast Pipeline
MAPCO	Mid-America Pipeline Company
MTBE	methyl tertiary-butyl ether
N_2	nitrogen
NEB or Board	National Energy Board
NGC	natural gas from coal
NGLs	natural gas liquids
NGTL	TransCanada Alberta System
NRCan	Natural Resources Canada
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of Petroleum Exporting Countries

PNGTS	Portland Natural Gas Transmission System
RFO	residual fuel oil
RFP	Request for Proposals
TCPL-AB	TransCanada - Alberta pipeline system
TQM	Trans Québec and Maritimes Pipeline
U.S.	United States
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

Units

b/d	=	barrels per day
bbl	=	barrels
Bcf	=	billion cubic feet
Bcf/d	=	billion cubic feet per day
Btu	=	British thermal units
Btu/cf	=	British thermal units per cubic feet
cf	=	cubic feet
GW	=	gigawatt
GW.h	=	gigawatt hour
kg/m^3	=	kilogram per cubic metre
kt/a	=	thousand tonnes per annum
lb	=	pound
m^3	=	cubic metres
m^3/d	=	cubic metres per day
Mcf	=	thousand cubic feet
Mb/d	=	thousand barrels per day
MMb	=	million barrels
MMb/d	=	million barrels per day
MMBtu	=	million British thermal units
MMcf	=	million cubic feet
MMcf/d	=	million cubic feet per day
MW	=	megawatt
Tcf	=	trillion cubic feet

Conversion Factors

1 cubic metre	=	35.3 cubic feet of natural gas
1 cubic metre	=	6.29 barrels
1 gigajoule	=	0.95 thousand cubic feet of natural gas at 1 000 Btu per cubic foot
1 cf	=	1 MBtu
1 Mcf	=	1 MMBtu
1 Mcf	=	1.054615 GJ
1 Bcf	=	1.054615 PJ
1 Tcf	=	1.054615 EJ

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal agency that regulates several aspects of Canada's energy industry. Its purpose is to promote safety and security, environmental protection and economic efficiency in the Canadian public interest within the mandate set by Parliament in the regulation of pipelines, energy development and trade. The main functions of the NEB include regulating the construction and operation of pipelines that cross international or provincial borders, as well as tolls and tariffs. Another key role is to regulate international power lines and designated interprovincial power lines. The NEB also regulates natural gas imports and exports, oil, natural gas liquids (NGLs) and electricity exports, and some oil and gas exploration on frontier lands, particularly in Canada's North and certain offshore areas.

The NEB collects and analyses information about Canadian energy markets through regulatory processes and market monitoring. From these efforts, the Board produces publications, statistical reports and speeches that address various market aspects of Canada's energy commodities. The Energy Market Assessment (EMA) reports published by the Board provide analyses of the major energy commodities. Through these EMAs, Canadians are informed about the outlook for energy supplies in order to develop an understanding of the issues underlying energy-related decisions. In addition, policy makers are informed of the regulatory and related energy issues that need to be addressed. On this note, the Board has received feedback from a wide range of market participants across the country that the NEB has an important role and is in a unique position to provide objective, unbiased information to federal and provincial policy makers.

This EMA, entitled *Short-term Outlook for Natural Gas and Natural Gas Liquids to 2006*, is the first EMA report that presents a combined short-term analysis and outlook for natural gas and NGLs. The report provides comprehensive information on the complex natural gas and NGL industries and highlights recent developments and emerging issues. A key objective of this EMA is to expand the effectiveness of the Board's monitoring.

During the preparation of this report, the NEB conducted a series of informal meetings and discussions with petrochemical officials, pipeline companies, natural gas producers and marketers, government departments and agencies, consultants and industry associations. The NEB appreciates the information and comments provided and would like to thank all participants for their time and expertise.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

Executive Summary

North American natural gas markets have experienced an extremely close balance between supply and demand in recent years. Since 2001, supply growth has not kept pace with growth in demand. These tight market conditions have contributed to high and volatile natural gas prices. Many analysts believe that there has been a step-change in natural gas prices. In addition, over the past year, oil prices have had a major impact on natural gas prices. Products derived from crude oil compete with natural gas and NGLs in their major North American markets. Dramatic increases in oil prices and limited fuel-switching opportunities have exacerbated the upward movement in natural gas prices. These high prices have led to decreased demand in some sectors as industries have improved their energy efficiency through investments to decrease the energy intensity of their processes and there have also been some industrial closures.

As western Canada grew to become a major producer of natural gas, a correspondingly large natural gas processing capability was also developed to extract NGLs. In Canada, essentially all of the ethane, 87 percent of propane and 67 percent of butane production is sourced from natural gas. Pentanes plus from gas plants comprise most of the condensate production in Canada. To create additional benefits, a world-scale petrochemical industry was developed in Alberta that converted NGLs into higher valued products such as ethylene.

Considering that NGLs in Canada are primarily extracted from natural gas, changes to the supply and demand for natural gas would impact NGL supply. Periods of high and volatile natural gas prices affect the economics of extracting NGLs from the gas stream. Conversely, NGLs left in the gas stream increase the supply of natural gas.

Natural Gas Supply and Demand

Observations: Natural gas prices are determined within an integrated North American market and are affected by regional considerations such as transportation costs, infrastructure constraints and weather. However, natural gas prices can also be strongly influenced by global oil prices since oil-based products like fuel oils compete with natural gas, especially in the U.S. Northeast.

Natural gas prices are expected to continue to be strongly influenced by the price of crude oil and should generally fall in the price range set by residual fuel oil (RFO) and No. 2 heating oil. Based on expectations that West Texas Intermediate (WTI) crude oil could average about US$50 per barrel throughout the outlook period, average natural gas prices would be expected to range from US$6.90/MMBtu to US$10.34/MMBtu. To account for the crude oil market's current influence on natural gas prices and to reflect the risk and volatility in that market, a US$10 per barrel change in oil prices was also analyzed. This expands the natural gas price projection range to US$5.51/MMBtu to US$12.41/MMBtu. Given tight supplies and limited ability to increase supplies quickly, which could be further exacerbated by severe weather, gas prices are expected to remain high and volatile. As a result, gas prices may exceed the forecast range during the outlook period.

The profile for Canadian natural gas production appears to have flattened and is expected to remain around 476.0 million m^3/d (16.80 Bcf/d) through 2006. As Canadian conventional gas production declines, this may be offset by increases in natural gas from coal (NGC) production. Natural gas from coal, which is also known as coal bed methane, may become a significant contributor to Canadian gas supply in the longer term.

By 2006, natural gas demand is expected to grow in Canada and the U.S. to approximately 1 980.7 million m^3/d (69.92 Bcf/d) from approximately 1 950.7 million m^3/d (68.86 Bcf/d) in 2004, an increase of 1.5 percent.

In Canada the most significant growth in demand for natural gas is from oil sands operations, which could reach 28.6 million m^3/d (1.01 Bcf/d) by the fourth quarter of 2006, an increase of 8.3 million m^3/d (0.29 Bcf/d) over 2004.

Issue 1: Canadians are facing high and volatile natural gas prices over the outlook period. Although high gas prices have benefited Canadian economic growth, higher energy costs present a challenge for consumers and the industrial sector.

Issue 2: For oil sands producers, high and volatile natural gas prices have added uncertainty to the cost of their operations. Consequently, suitable alternatives for natural gas are being investigated by oil sands producers and they will make investment decisions based on the overall economics of their operations.

Conclusion: Canadian energy producers are price takers in an integrated North American market that is also influenced by international oil prices. Over the outlook period there are limited options to manage price risk. However, over the longer term, the challenge of high natural gas prices can be broached in a number of ways including, improved energy efficiency, demand-side management, enhanced energy technologies and alternative energy options.

Governments and industry should continue to support research into developing and implementing new technologies to reduce natural gas demand in oil sands operations.

Natural Gas Infrastructure

Observations: The existing utilization of natural gas infrastructure in Canada and the U.S. will shift as the nature and location of North American gas supply changes. Deliverability of conventional gas from Canada's largest producing province, Alberta, is expected to decline over the projection period, while gains are expected from British Columbia and Saskatchewan. Growth in U.S. gas production is expected to come mainly from the Rockies. Combined with the expected increase in liquefied natural gas (LNG) imports into North America, it is expected that the volume and patterns of gas flows through existing pipeline infrastructure will undergo change. In addition, new transportation infrastructure has also been proposed by industry participants.

The requirement for pipelines and other energy facilities is also influenced by changes in gas demand. For example, as we move further into the future (beyond the outlook period), increasing consumption of natural gas by oil sands operations in western Canada could reduce the amount of gas available for other downstream markets and would thereby impact gas flow on existing transmission pipelines. Similarily, an increasing demand for natural gas-fired power generation will also contribute to natural gas demand growth over the outlook period. Natural gas for power generation in

Canada and the U.S. could increase from about 528.9 million m^3/d (18.67 Bcf/d) in 2004 to about 564.0 million m^3/d (19.9 Bcf/d) in 2006. In Canada, although beyond the outlook period, natural gas for power generation could increase by 5.7 to 17.0 million m^3/d (0.20 to 0.60 Bcf/d) if coal-fired generation in Ontario is replaced with natural gas-fired generation by 2009. The growing use of natural gas for power generation and heating may also result in greater swings in pipeline flows and greater reliance on the use of natural gas storage, closer to the end use market, to meet peak demands.

Issue: The changing nature and location of natural gas supplies and changes in natural gas use patterns may result in changes to the existing infrastructure and to existing rate design, tolls and tariffs. In addition, over the longer term (beyond this outlook period), increased LNG imports into the U.S. and potentially into Canada, and future natural gas development in the North, will require new transportation and storage infrastructure. Typically, infrastructure projects are high capital cost and are subject to lengthy development cycles due in large part to fragmented regulatory approval processes which are costly and often have long lead-times.

Conclusion: In order to efficiently develop new infrastructure or vary existing infrastructure, there needs to be a shared understanding of how regulatory bodies will efficiently collaborate with one another and engage in innovative and smart regulatory solutions.

NGL Supply, Demand and Infrastructure

The Canadian NGL industry will be facing challenges in the future. Demand for NGLs is expected to increase, reflecting growth in demand for heating, petrochemicals, gasoline and diluent for bitumen and heavy oil. Ethane is currently considered to be supply-constrained as a petrochemical feedstock and for use in enhanced oil recovery. Similarly, pentanes plus, which are used as a heavy oil and bitumen diluent are also in tight supply.

There is limited growth expected in NGL supply over the outlook period. First, the economics of NGL extraction is based upon the price of gas relative to the NGL component prices. High natural gas prices relative to the price of oil discourage the extraction of NGLs. Second, the increase in oil sands demand for natural gas reduces the amount of liquids-rich gas available at the straddle plants. Third, NGC is almost pure methane and generally does not contain NGLs. This means the increased production of NGC could result in a leaner gas stream entering some of the gas processing plants.

Issue: A significant investment has been made in developing the NGL transportation and extraction facilities and in providing feedstock to the petrochemical sector. These industries are evaluating their options to secure additional NGL sources and find alternatives.

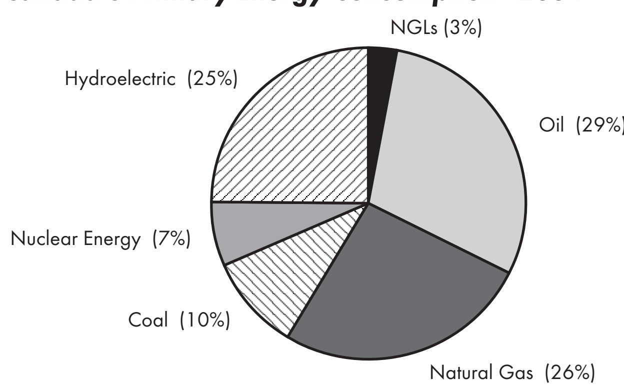
Conclusion: Both the NGL extraction and petrochemical sectors are being challenged by tight supply and high commodity prices. Governments and the impacted sectors need to address options for diversification of feedstock supply and improvements in the efficiency of current NGL extraction processes.

INTRODUCTION

In 2004, natural gas comprised over 25 percent of the total North American primary energy consumption, the second largest share after oil. In Canada, the share was slightly higher at 26 percent. To further illustrate the importance of natural gas to the economy in 2004, natural gas exports from Canada totalled more than C$27 billion. Natural gas liquids (NGLs) constitute about three percent of Canada's primary energy demand. Export revenue for Canadian propane was C$2.2 billion and C$543 million for butane. Figure 1.1 shows Canada's primary energy consumption in 2004 by energy commodity.

FIGURE 1.1

Canada's Primary Energy Consumption - 2004



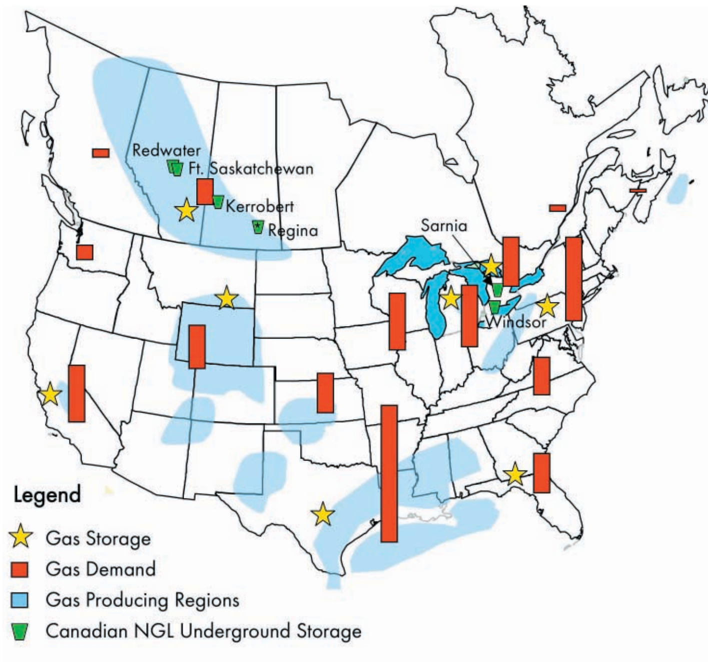
Source: BP Statistical Review of World Energy – June 2005

As western Canada grew to become a major producer of natural gas, a correspondingly large natural gas processing capability was also developed. Considering that NGLs in Canada are primarily extracted from natural gas, changes to the supply and demand for natural gas impacts NGL supply. In Canada, essentially all of the ethane, 87 percent of propane and 67 percent of butane production is sourced from natural gas. Pentanes plus from gas plants comprise most of the condensate production. To provide additional benefits from the extracted NGLs, a world-scale petrochemical industry was developed in Alberta. Export revenue from chemicals, plastics and fertilizers, many of which are outputs from our ethane-based petrochemical sector, was almost C$27 billion in 2004.

Figure 1.2 provides a snapshot of the Canadian and U.S. natural gas and NGL industries, showing relative demand, supply regions, natural gas storage, and Canadian NGL storage locations. The shaded areas show the gas producing region and in Canada and the U.S. lower 48 states. Approximately 95 percent of Canadian and U.S. lower 48 states natural gas production currently comes from an area roughly following the continental divide. Natural gas demand, however, is widespread with some major market centres located a significant distance from the major sources of supply. In fact, much of the demand is in the U.S. Northeast, the U.S. Midwest, California and the U.S. Gulf Coast. The U.S. also imports a modest amount of liquefied natural gas (LNG). Canadian gas is exported to the U.S. and transported to markets in central Canada through a vast network of pipelines. Natural gas storage helps bridge the gap between supply and demand, especially in the winter, when consumption for space heating is high. The major NGL supply source is the same as for natural gas; therefore NGL storage in Alberta is also close to the supply source. Canadian NGL storage is centred primarily in Alberta and Ontario, the petrochemical hubs in Canada.

F I G U R E 1 . 2

Natural Gas Supply and Demand - Canada and U.S.



Source: NEB, Statistics Canada

2004 Natural Gas Production		
	Million m^3/d	Bcf/d
Canada	473.4	16.7
U.S.	1 436.2	50.7
Total	**1 909.6**	**67.4**

2004 Natural Gas Demand		
	Million m^3/d	Bcf/d
Canada	218.7	7.7
U.S.	1 726.6	61.0
Total	**1 945.3**	**68.7**

2004 Canadian NGL Production from Gas Plants		
	Thousand m^3/d	Mb/d
Ethane	40.2	252.8
Propane	28.0	176.0
Butane	16.1	101.4
Pentanes Plus	25.5	160.8
Total	**109.8**	**691.0**

North American natural gas markets have experienced an extremely close balance between supply and demand in recent years. Since 2001, supply growth has not kept pace with demand. These tight market conditions have contributed to high and volatile natural gas prices. Many analysts believe that there has been a step-change in natural gas prices. In addition, over the past year, dramatic increases in oil prices and reduced fuel-switching opportunities have exacerbated the upward movement in gas prices. High prices have led to decreased demand in some sectors through improved energy efficiency and some industrial closures. Moreover, periods of high and volatile natural gas prices affect the economics of extracting NGLs from the gas stream.

1.1 The Basics of Natural Gas and NGLs

Natural gas is a significant contributor to North American energy supply. It is valued as one of the cleanest burning energy sources and has a variety of residential, commercial and industrial uses. Most of the natural gas produced in North America comes from conventional sources; however, unconventional natural gas production is becoming increasingly important. In Canada, the development of unconventional natural gas has not progressed as fast as in the U.S. However, one unconventional source, specifically natural gas from coal (NGC), is growing rapidly and could potentially make up a larger percentage of the supply picture.

Depending on the source, the composition of natural gas varies. In its raw form, natural gas consists primarily of methane, but also contains varying quantities of heavier hydrocarbons, and perhaps some other constituents that add little or no heating value such as water, carbon dioxide, nitrogen, sulphur or hydrogen sulphide. Natural gas is often processed to remove and recover most of the heavier hydrocarbons, which are referred to as NGLs. Natural gas liquids have value as separate products, but the removal of the heaviest hydrocarbons such as pentanes plus, butanes and propane from the gas stream is also required for the efficient operation of natural gas pipelines. Consequently, most of these liquids are extracted in facilities located relatively close to the producing fields in what are referred to as field plants.

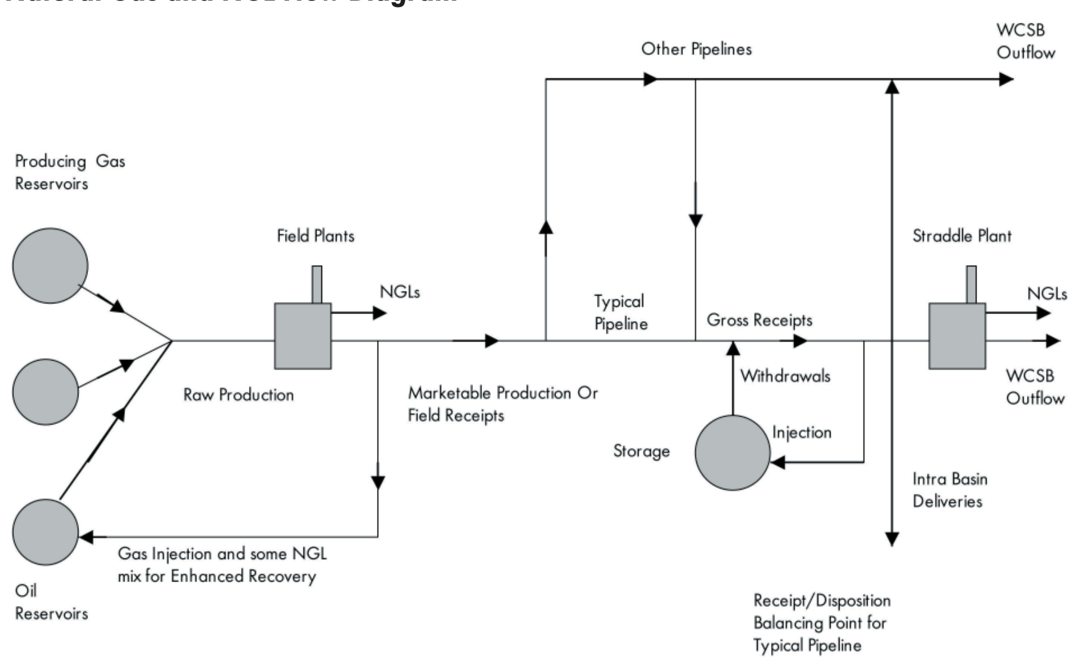
Of all the NGLs, ethane is most similar to methane, which is the predominant component of natural gas. Due to this similarity in chemical structure, the removal of ethane and further trace amounts of propane and butane is more difficult. This process can be referred to as taking a 'deeper cut' of the NGLs in the gas stream. Since the process is more sophisticated and costly, these deep cut facilities tend to be concentrated in fewer locations and are larger in scale. The most important facilities in western Canada are situated across the route of the major pipelines leaving Alberta where they figuratively 'straddle' the pipeline and are referred to as straddle plants. After processing, the clean or 'marketable' natural gas is transported through a network of pipelines and delivered to storage or the point of use. Figure 1.3 is a simplified diagram that shows the possible flows of natural gas and NGLs.

Commercially significant amounts of propane and butane are also produced from crude oil refining processes. In the international market, where crude oil refining accounts for most of the light hydrocarbon liquids produced, propane and butane are also known as liquefied petroleum gas (LPG). Pentanes plus are also known as plant condensate or natural gasoline and differ from field condensate produced from oil, which contains some middle distillates and heavier components such as naphtha and gasoil. Pentanes plus from natural gas make up almost all of the condensate supply in Canada, and therefore, the terms are often used interchangeably.

Ethane, propane, butane and pentanes plus all have important roles in the energy economy. Although some ethane in Canada is used as a solvent to enhance oil recovery, ethane's only major market is as a raw material for the ethylene industry to produce derivative products such as polyethylene (plastic), ethylene glycol and ethylbenzene. Propane is commonly known as a fuel for barbeques but, it has a much wider range of commercial uses, such as space heating, feedstock for the petrochemical industry,

FIGURE 1.3

Natural Gas and NGL Flow Diagram



crop drying, transportation and other agricultural and industrial uses. Butane is mainly used by refiners to manufacture gasoline, but it is also a petrochemical feedstock. In recent years, butane use as a diluent for heavy crude oil has grown. Most of the pentanes plus produced in Canada are used as diluent for heavy crude oil to facilitate its shipment through pipelines.

1.2 Scope of this Report

The Board decided to publish this EMA, *Short-term Outlook for Canadian Natural Gas and Natural Gas Liquids to 2006*, to expand its short-term analysis of energy markets and to examine issues jointly facing the natural gas and NGL industries through to 2006. Supply and demand dynamics for both natural gas and NGLs are discussed in this report as NGLs are a component of natural gas and any analysis of NGLs requires a corresponding analysis of natural gas developments.

The objective of this report is to present a historical review, from 2000 to 2004, and an outlook for natural gas and NGL supply, demand, infrastructure and pricing through to the end of 2006. While the supply, demand and infrastructure discussions will emphasize the Canadian situation and issues, prices are often reflective of market developments outside of Canada and, therefore, an examination of these issues requires a broader perspective. Chapter 2 examines natural gas and oil prices and includes a discussion on the price relationship between these commodities and NGLs. Chapter 3 discusses the short-term expectations for North American natural gas supply and demand including the contribution of NGC and LNG to the supply picture. Chapter 4 presents the Canadian NGL supply and demand by product. Chapter 5 examines the different parts of the North American infrastructure including gas plants, gathering systems and pipelines. Chapter 6 concludes with a synthesis of the key observations and related issues.

COMMODITY PRICES

Unprecedented high and volatile energy prices are being felt throughout North America. As all energy markets are linked together, events in one market, such as the crude oil market, can become an important factor affecting the natural gas market. The crude oil market has become the main driving force underpinning the energy market in the past few years. A relationship between crude oil and natural gas prices exists since natural gas competes with refined oil products. This is particularly true in the major markets for residential heating, industrial fuel and electrical generation. NGLs also compete with products derived from crude oil and are sourced primarily from natural gas in Canada.

2.1 Crude Oil Prices

2.1.1 2000 to 2004 Background

At the beginning of 2000, West Texas Intermediate (WTI) prices were US$27 per barrel. Commercial oil stocks in the major Organization for Economic Cooperation and Development (OECD) markets were the lowest in ten years but by year-end, demand growth turned out to be weak and commercial oil inventories began to build. In 2001, the September 11 terrorist attack further negatively impacted the U.S. economy and accompanying oil demand. World onshore commercial inventories were high, and the Organization of Petroleum Exporting Countries (OPEC) had to cut production to support oil prices. In 2002, however, the environment changed quickly with the U.S. economic recovery, combined with concerns over the availability of supplies from Iraq and Venezuela, and hurricane damage to production facilities in the Gulf of Mexico. By year-end 2002, WTI crude traded at US$31 per barrel. In 2003, crude oil prices were again impacted by global demand growth returning to over 2 percent after five years of weakness, mainly from strong demand in China. At this time, there were also low crude and product stocks and problems continued in Venezuela. Finally, there was the war with Iraq. These factors all contributed to supply concerns and consequently higher oil prices.

Prices surged in 2004 as global oil consumption increased at its fastest pace in almost three decades. According to the International Energy Agency (IEA), oil demand in China, the world's second largest oil consumer after the U.S., grew more than 15 percent in 2004. The strong demand growth absorbed much of the world's spare production and refining capacity. At year-end, the price of WTI exceeded US$43 per barrel – almost 40 percent higher than the 2003 average.

2.1.2 2005 to 2006 Crude Oil Price Outlook

The Board's outlook for crude oil prices is underpinned by several considerations, including demand for transportation fuels, supply growth from non-OPEC countries, the ability of OPEC countries to meet growing demand worldwide, and the capacity to transport and refine crude oil. Led by growth in China and the U.S., global oil demand is expected to rise 2.2 percent in 2005, or by 216 200 m^3/d

(1.4 MMb/d), to a record 13.3 million m³/d (83.5 MMb/d), according to the IEA in September 2005. This follows oil demand growth of 3.4 percent in 2004, the largest increase since 1976. At the same time, the IEA lowered its 2005 supply forecast, mainly due to lower supply growth from Russia.

Against this backdrop, the Board assumes that the reference crude oil price, WTI, will trade around US$50 per barrel through 2006. The oil market seems to perceive the downside to be limited to around US$40 per barrel, while there is no upper limit. Product shortages or a crude supply interruption could quickly propel oil prices higher, while slower economic growth would be required to undermine OPEC's ability to manage the global oil market and drive prices below US$40 per barrel. Geopolitical risks continue to be a concern, especially in Iraq, Iran and Nigeria. Petroleum product tightness is likely, since refineries are running near capacity and oil demand growth is expected to be greater than refinery capacity additions over the next two years.

Refer to the Board's September 2005 EMA, *Short-term Outlook for Canadian Crude Oil to 2006*, for a detailed analysis of crude oil and product supply, prices and markets.

2.2 Natural Gas Prices

In recent years, the growth in natural gas supply from the Western Canada Sedimentary Basin (WCSB) has slowed and has not kept pace with the increase experienced in North American demand, resulting in higher and more volatile natural gas prices. The key factors that influence natural gas markets and prices are:

- demand, which is primarily affected by weather, competing fuel prices and storage levels;
- supply; and
- market psychology.

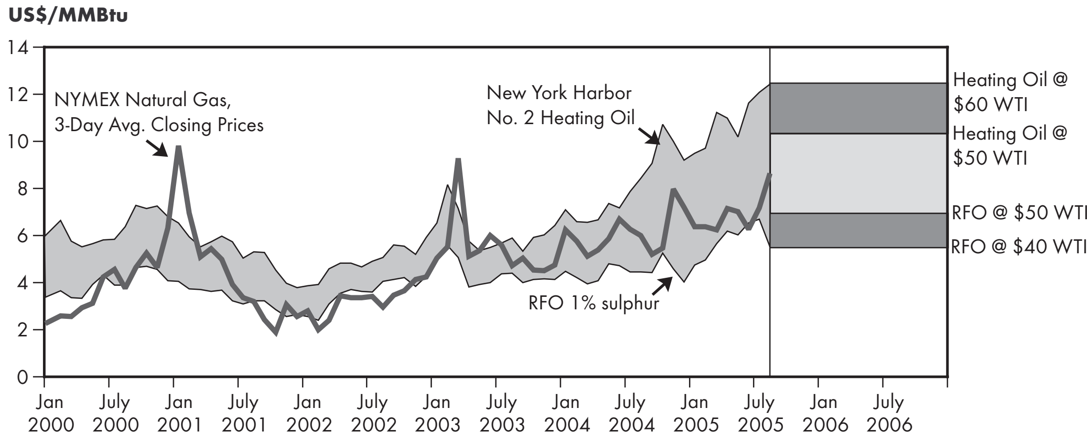
Natural gas competes with fuel oil as the energy supply for multi-fuel capable facilities, particularly in the U.S. Northeast. This connects the price of gas to that of fuel oil products. No. 2 heating oil generally provides an upper bound, while 1 percent sulphur residual fuel oil (RFO) generally provides a lower bound. No. 2 heating oil historically commanded a 30 percent premium, on an energy equivalent basis, to crude oil. This premium began to erode in late 2001 and currently sits at about 20 percent. On the other hand, RFO has generally been priced at a discount to crude oil, on an energy equivalent basis. Historically, RFO has been priced at about 80 percent of the value of crude. Figure 2.1 shows the historical relationship between natural gas and key petroleum New York Mercantile Exchange (NYMEX) product prices since 2000 and the expected price range to 2006.

Canadian and U.S. natural gas markets have increasingly evolved into an integrated North American market over the past decade. Significant credit can be attributed to the pipeline transmission system that connects Canadian and American supply basins and storage facilities with consumers. Since deregulation of the North American natural gas market in the mid-1980s, existing reserves in the WCSB were easily developed and the infrastructure was built to connect these supplies to growing natural gas markets across North America. This significant growth in natural gas production from the WCSB provided the supply needed to meet the majority of incremental North American demand, and helped to keep North American natural gas prices low at around US$2/MMBtu.

There has also been growth in the non-physical trade of gas. It may be bought and sold several times before reaching the end-user and the location where it is physically consumed, which may differ from the transaction point. Gas may also be traded into the future, to help manage risks associated with uncertainty in changing prices. This has enabled the market to evolve such that natural gas is now

F I G U R E 2 . 1

Petroleum Products and NYMEX Natural Gas Prices



freely traded across an integrated North American market and the price and flow of natural gas may be influenced by factors and events in other regions. Gas sales and purchases have also become more short-term oriented while gas flows have become more flexible to respond to dynamic regional prices across North America.

2.2.1 2000 to 2001 – The California Energy Crisis

Significant price increases occurred during the winter of 2000–2001. This was driven by an energy shortfall in California and surrounding regions that was caused by low hydro-electric availability, low gas storage inventory, and a sudden loss of pipeline capacity supplying natural gas to the region. High prices were further exacerbated by cold weather and high demand, which culminated in peak North American natural gas prices in January 2001 as illustrated by the three-day average natural gas closing price on the NYMEX, which peaked at US$9.79/MMBtu (Figure 2.1).

In response to these unprecedented high gas prices, consumers responded by reducing natural gas use through conservation, switching to cheaper fuels, and in the case of many industrials, through shutdowns or reductions in plant operations. Producers also responded by drilling wells at an unprecedented rate to provide a small increase to gas production.

2.2.2 2001 to 2004 – Response to Changing Conditions and Prices

As producer activity increased to raise North American gas production, the U.S. economy entered a recession in 2001. Meanwhile, other measures by consumers to switch fuels or reduce natural gas consumption were aided by the effects of mild weather and the terrorist events on 11 September 2001, which combined to abate the growth in natural gas demand. As a result, natural gas prices fell once again to levels set by competing RFO and No. 2 heating oil. In October 2001, the NYMEX natural gas price fell below US$2/MMBtu.

In 2002, a gradual economic recovery in the U.S. and decreased drilling activity in response to the lower prices in late 2001 began to tighten the balance between North American supply and demand, making prices more sensitive to changes in weather and the prices of alternative fuels. The price averaged US$3.25/MMBtu in 2002. Since early 2002, growing tension in Iraq and other oil producing regions have led to disruptions and uncertainty in crude oil supply. This factor, combined with strong demand, led to steady increases in the price of crude oil. Natural gas prices also increased along with crude oil prices. In addition, during times of peak weather demand or constrained infrastructure, there have been extreme short-term escalations in regional natural gas prices. For example, in January 2004, cold weather and infrastructure constraints led to intense competition for gas in the U.S. Northeast and surrounding markets. This resulted in daily cash prices reaching up to US$70/MMBtu in the New York and Toronto areas.

Higher natural gas prices since 2003 have helped to support active drilling programs by producers. However, despite record levels of activity, gas production levels have not been able to keep pace with the growing rate of demand in North America. Since 2002, LNG imports to North America have more than doubled to meet the growing demand for natural gas and in response to higher North American prices.

2.2.3 2005 to 2006 Natural Gas Price Outlook

Sustained high prices of alternative fuel oils (because of higher crude oil prices) and a limited availability of clean fuel options are likely to mean increased gas demand, and continued upward pressure and volatility in future natural gas prices. Looking forward to 2006, natural gas prices are expected to continue to be strongly influenced by the price of crude oil and should fall generally in the price range set by 1 percent sulphur RFO and No. 2 heating oil, which are the primary oil-based fuels that compete in the same major markets as natural gas.

Based on expectations that WTI crude oil could average about US$50 per barrel throughout the outlook period, the historical ratios for No. 2 heating oil and RFO would yield a range of about US$6.90/MMBtu to US$10.34/MMBtu for natural gas depending on natural gas fundamentals. In a tight gas market, small changes in supply or demand can translate into large changes in the price of natural gas; therefore, high volatility of prices should be expected. Since the crude oil market is currently at the forefront of natural gas price influences, a US$10 per barrel change in oil prices was analyzed to reflect the risk and volatility in the crude oil market. Using WTI crude oil prices of US$40 and US$60 per barrel expands the natural gas price projection range to between US$5.51/MMBtu and US$12.41/MMBtu. The North American natural gas market is expected to remain supply constrained throughout the projection period, and demand is expected to show some continued resilience to higher gas prices in light of its attribute as a cleaner burning fuel.

High natural gas prices encourage continued high drilling activity and investments necessary to develop gas supply from new regions in North America. High prices also help support the expected growth of LNG imports required to meet North American demand. Nonetheless, there is a cost consequence of high natural gas prices to consumers and energy-intensive industries in North America.

2.3 NGL Prices

Canada exported about 8.8 million m^3 (55.2 million bbl) of propane and 1.9 million m^3 (11.6 million bbl) of butane to the U.S. in 2004. This was equal to about 75 percent of its propane and about 22 percent of its butane production. Since these exports represent about 12 percent of U.S. demand, prices in Canada are influenced by the U.S. market. NGL pricing is complex, and in addition to major factors such as weather and petrochemical demand, NGL prices are also affected by the price relationships between NGLs, crude oil and natural gas. These relationships can cause the NGL market to occasionally behave atypically over the short term. In addition, with tight global

LPG supplies, the international LPG market has become increasingly important in the last few years and has a greater influence on North American prices.

2.3.1 North American Commodity Price Relationships – NGL, Oil and Natural Gas Comparison

NGL prices are mainly influenced by the price of crude oil as NGLs compete primarily with oil-based products (in particular, naphtha, heating oil and gasoil) in their primary markets. Generally, crude oil prices determine the basis for the NGL price ceiling, while natural gas prices form the floor price. Natural gas prices form the floor price because if the price for NGLs approaches the price of natural gas, the financial incentive to incur the additional costs associated with extracting the liquids from the gas stream decreases. Hence, the minimum value of NGLs left in the natural gas stream is the natural gas price.

Natural gas prices typically trade at a value below crude oil on an energy equivalent basis, and NGL prices track that of the higher-valued oil products. Given the higher energy content of crude oil, propane and butane at the major pricing point in the U.S., Mont Belvieu, Texas, have generally traded at about 65 to 80 percent and 85 percent, respectively, of the price of crude oil on a volumetric basis.

In late 2000 through to 2004, there were several periods when natural gas prices were valued at parity with crude oil or above. Natural gas liquid prices, as represented by propane in Figure 2.2, switched from tracking crude oil to tracking the higher priced natural gas. Under these circumstances, extraction margins decline. Section 4.1.1.1, *Extraction Economics* provides further details on this concept.

For the 2005 to 2006 outlook period, the crude oil market is expected to be the major driver for all energy prices. This added support to both natural gas and NGL prices will exacerbate the impact of seasonal and other factors on their respective prices. Crude oil prices, for the most part, will likely remain higher than natural gas in the outlook period; however, as the premium of crude oil prices over natural gas falls, extraction margins for Canadian producers will be reduced. It is anticipated that there could be short periods in the winter with natural gas prices higher than crude. In these instances, NGL prices will be determined by natural gas prices.

FIGURE 2.2

Propane, Natural Gas and Crude Oil Price Comparison (Heat Content Basis)

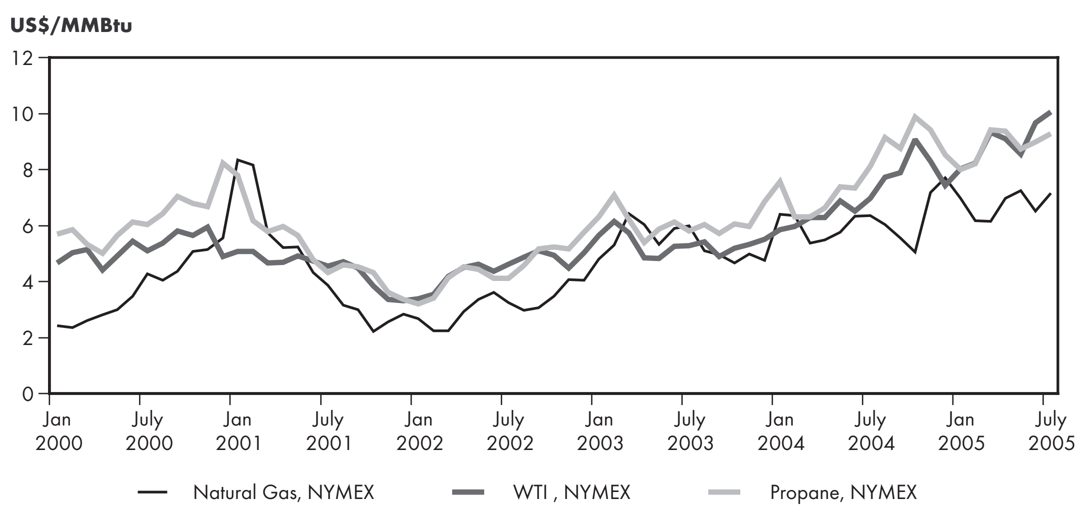
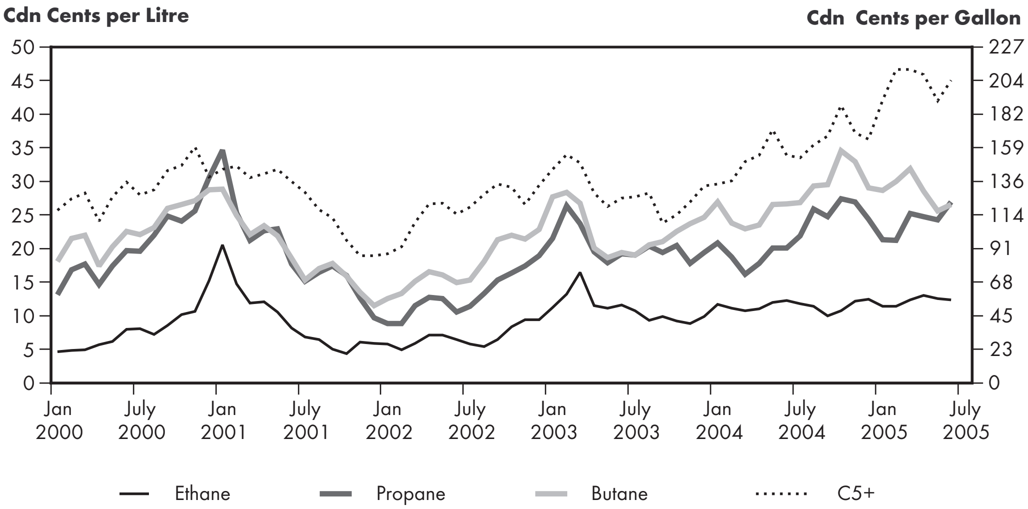


FIGURE 2.3

Canadian Reference Prices for Ethane, Propane, Butane and Pentanes Plus



Source: Alberta Department of Energy

Pentanes plus prices in Canada are not driven by natural gas because it is equivalent in quality to a light crude oil. It will be valued at a premium to WTI, particularly in western Canada, because condensate availability will likely remain tight and pentanes plus make up the bulk of the Canadian condensate supply. Propane and butane prices are expected to trade at lower than historical values relative to crude oil. The ethane price should continue to be tied closely to natural gas. In Canada, the ethane market is not as liquid or transparent as in the U.S. because there are only a few buyers and sellers. Figure 2.3 shows the reference prices for Canadian NGLs.

2.3.2 *Global LPG Prices*

Prior to 2000, North America was the world's largest LPG supply source and the largest consuming market, enabling it to be the LPG price setter. The large petrochemical sector located at Mont Belvieu on the U.S. Gulf Coast is strategically located to receive LPG from Europe, Africa and the Middle East (the world's second largest LPG supply region) at a relatively low cost. Offshore supply is traditionally attracted to the U.S. Gulf Coast during the summer months when product values are normally weaker and storage for surplus product is needed. The storage capability at Mont Belvieu is unparalleled and can accommodate the summer production both in North America and offshore.

Since 2000, global LPG supply and demand balances have changed to the point where they exert some influence on North American LPG prices. As illustrated in Figure 2.4, Asia has replaced North America as the largest market for LPG. Strong growth in demand is expected in Asia versus a slow gradual growth in North America. Overall, the current tight global LPG market situation is expected to continue beyond 2006.

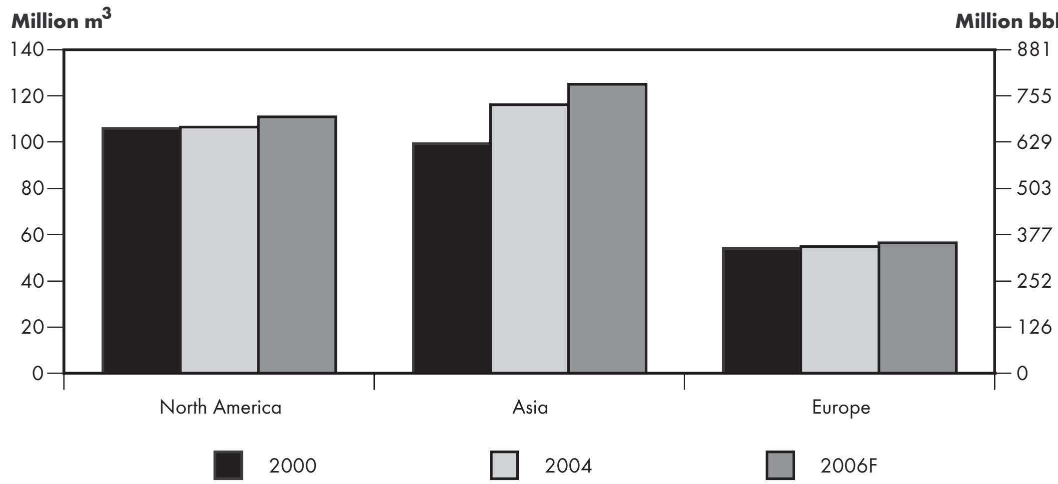
As shown in Figure 2.5, propane prices in different markets across the globe generally move together. On occasions when a North American shortfall of supply coincides with that of another region, the North American price will be driven higher to attract supplies.

Asia's residential and commercial heating demand for LPG in 2004 exceeded that of North America's chemical, residential and commercial sectors combined. This indicates that competition for supplies can be expected to be particularly strong in the coming winter months, which will be reflected in higher prices. If crude oil and natural gas in North America were trading near parity in the same period, extraction margins would normally be negative. However, the additional impact of strong global LPG prices on the North American price could push up LPG prices above both natural gas and crude oil, and maintain positive extraction margins.

Going forward, the long-term trend is for a relatively tight global LPG market. Increased global competition for LPG supplies is expected to lead to higher prices. Alternatively, if the world economies react to high energy prices, demand growth could slow somewhat, reducing competition.

FIGURE 2.4

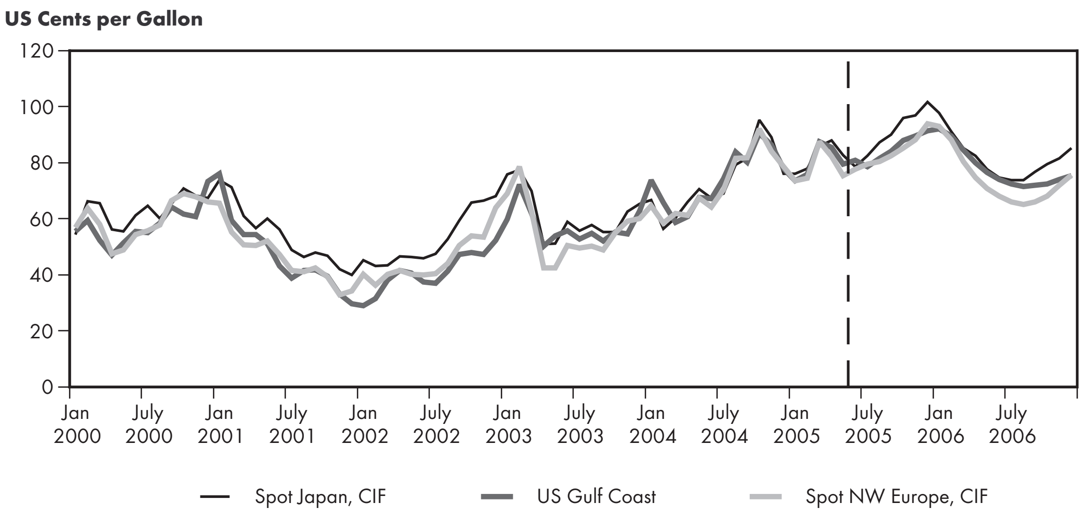
Regional LPG Demand



Note: f: forecast
Source: Purvin & Gertz

FIGURE 2.5

Global Propane Prices



Source: Purvin & Gertz

Natural Gas Supply and Demand

3.1 Natural Gas Supply

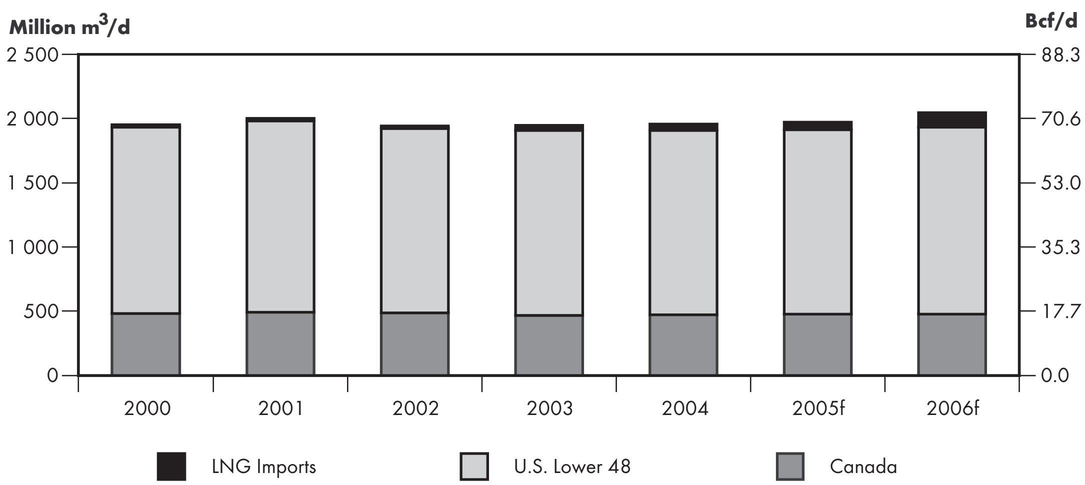
3.1.1 North American Production

Canadian gas produced from the WCSB contributes almost 98 percent of the total gas produced in Canada and will remain the mainstay for the outlook period. Alberta, British Columbia and Saskatchewan contribute roughly 80, 16 and 4 percent, respectively, to the production from the WCSB, while natural gas from offshore Nova Scotia provides most of the remaining production.

The Board expects minimal change in average annual Canadian gas deliverability[1] over the projection period from 473.4 million m^3/d (16.71 Bcf/d) in 2004 to 477.9 million m^3/d (16.87 Bcf/d) by 2006. Refer to the NEB's previously published EMA, *Short-term Canadian Natural Gas Deliverability, 2004 – 2006*, for additional details.[2] Conventional WCSB gas and offshore Nova Scotia gas will likely maintain deliverability levels around 456.0 million m^3/d (16.10 Bcf/d) and 11.0 million m^3/d (0.39 Bcf/d), respectively, over the outlook period. Although deliverability of conventional gas from the largest producing province, Alberta, is expected to decline over the projection period from

F I G U R E 3 . 1

Average Annual Natural Gas Supply for Canada and the U.S.



Note: f: Forecast

1 With sufficient pipeline capacity and markets (including storage) to accommodate deliverability, deliverability and production can be considered to be the same for this analysis.

2 The Board's updated *Short-term Canadian Natural Gas Deliverability, 2005-2007* will be published in October 2005.

approximately 365.5 million m³/d (12.90 Bcf/d) to 352.5 million m³/d (12.44 Bcf/d), the Board expects that gains from British Columbia and Saskatchewan will offset declines from Alberta.

High natural gas prices will be a key factor in encouraging more gas drilling; however, the projected supply increases are not expected to keep pace with demand. The high levels of drilling activity have only managed to offset the higher decline rates and lower productivity of new wells.

Overall, the outlook for natural gas supply in Canada and the U.S. is for production to grow about 2 percent by 2006 to approximately 1 936.5 million m³/d (68.36 Bcf/d) (Figure 3.1). The Board expects that average annual U.S. gas production will rise slightly over the outlook period from 1 424.6 million m³/d (50.29 Bcf/d) in 2004 to approximately 1 458.9 million m³/d (51.50 Bcf/d) in 2006, with growth coming mainly from the Rockies.

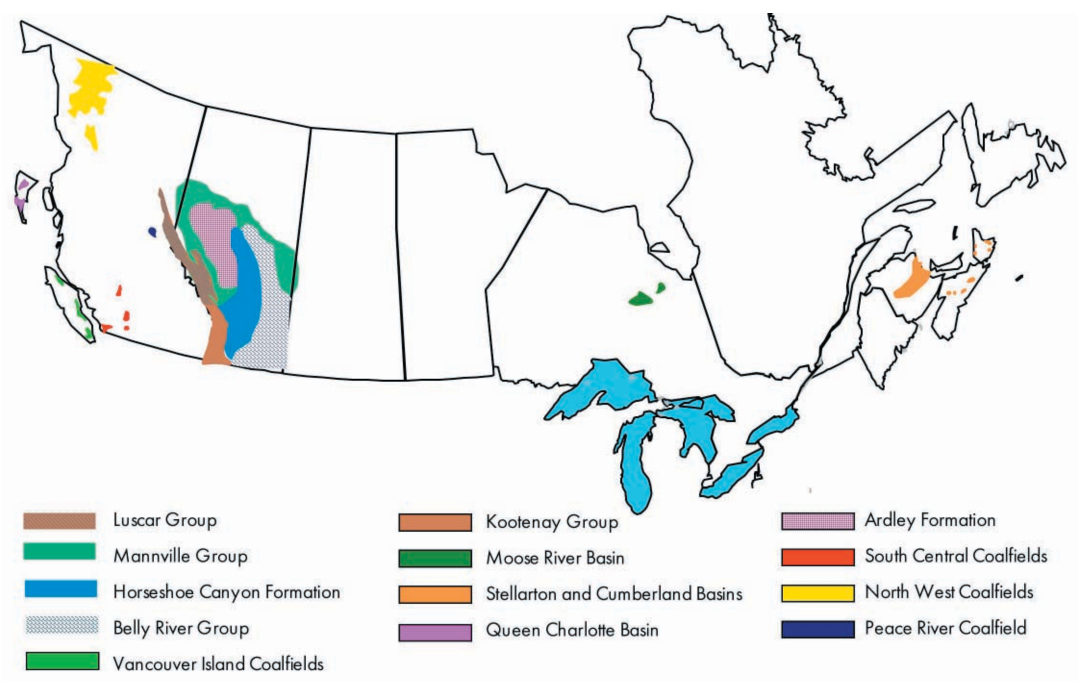
3.1.1.1 Natural Gas from Coal

Natural gas from coal (NGC), also known as coal bed methane (CBM), has the potential to become a significant source of natural gas in Canada. Interest in this resource has increased since 2001 in light of relatively flat North American gas production and increasing demand. Natural gas from coal occurs in coal seams in several areas in Canada but exists predominately in the western provinces as shown in Figure 3.2. Development of the resource is at an early stage with the production in 2004 at 4.3 million m³/d (0.15 Bcf/d) or less than 1 percent of Canadian gas output. Commercial NGC production is currently from the Horseshoe Canyon coals in south-central Alberta.

The Board estimates that NGC could account for 12.8 million m³/d (0.45 Bcf/d) of production by the end of 2006, which would be less than 3 percent of Canadian gas production. Since NGC is almost entirely methane and contains no NGLs, the growing deliverability of NGC will not contribute to the availability of NGLs in Canada. If anything, NGC development could potentially impact NGL

FIGURE 3.2

Canadian Coal Zones with NGC Potential



Source: Canadian Society of Unconventional Gas (CSUG) recovery further in the future as NGC volumes increase and the concentrations of NGLs in the gas stream entering the processing plants become diluted. Natural gas liquids recovery is greater with higher concentrations of NGLs in the gas stream and recovery can become uneconomic when NGL concentration is too low. Segregating NGC to its own distribution line is one possible method to address this issue.

3.1.2 Liquefied Natural Gas

With the marginal growth in production from the U.S. lower 48 and Canada, new sources of supply will be required to meet the projected growth in natural gas consumption. These potential new sources extend beyond traditional indigenous supply and include access to the rapidly developing global LNG market. Natural gas becomes LNG when it is condensed into a liquid and stored at temperatures below -160°C (-256°F). This liquid state occupies only 1/600th of the volume of natural gas in its gaseous state, which facilitates and reduces the cost of transportation to the market.

Proven reserves of natural gas worldwide are about 20 times greater than the volume of proven natural gas reserves of North America. Furthermore, advances in liquefaction and transportation technologies have lowered the unit cost of LNG by 30 percent over the past decade, and LNG is now viewed as cost competitive with domestic supplies.

LNG is presently exported from about 12 countries (Indonesia, Algeria, Malaysia, Australia, Brunei, United Arab Emirates, United States, Libya, Nigeria, Qatar, Oman and Trinidad and Tobago). As shown in Table 3.1, the NGL content and related heat content in LNG varies by country of origin. The heat content can vary from a high of about 1 162 Btu/cf for LNG sourced from Libya to around 1 000 Btu/cf for LNG sourced from Alaska, Egypt and Norway. LNG sourced from the Middle East has a heat content around 1 125 Btu/cf and LNG sourced from Pacific Rim countries like Indonesia, Malaysia and Australia has a heat content of around 1 110 Btu/cf. For safe and efficient operations, pipelines in Canada and the U.S. specify an acceptable range for heat content that typically extends from just under 1 000 Btu/cf to 1 085 Btu/cf.

Existing LNG imports into the U.S. east coast terminals have mostly been from Trinidad. Cove Point, Maryland LNG is reported to have accepted 14 percent of its imports from Algeria in 2004. Possible LNG sources for the proposed Canadian west coast facilities include: Russia, Indonesia, Australia, Malaysia and the Middle East. Potential sources for LNG imports to Quebec may include: the Middle East, Norway and North and West Africa. Atlantic Canada may source LNG imports from Trinidad and Tobago, Qatar, Russia and Algeria.

For the countries that do not have a ready market for liquids, the NGLs are normally not extracted at the source; rather, this may occur at the point of destination. The proposed project located at Kitimat, B.C. includes infrastructure plans for NGL recovery. Considerations prior to building

TABLE 3.1

LNG Composition by Source

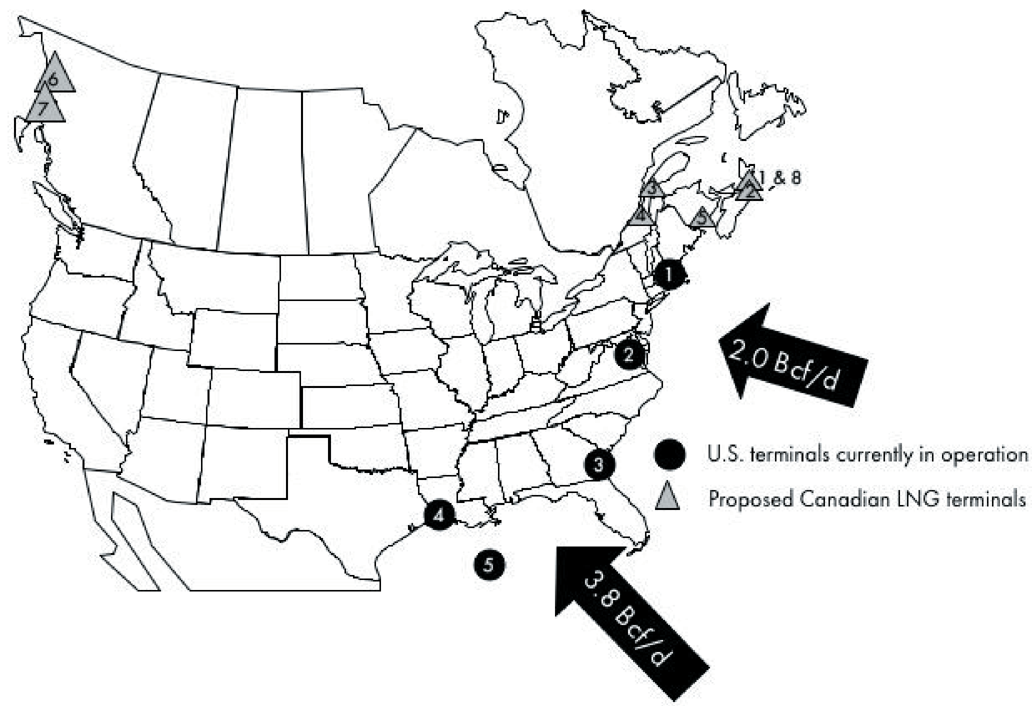
LNG Source	Methane (C_1) (Mole %)	Ethane (C_2) (Mole %)	Propane (C_3) (Mole %)	Butane (C_4) (Mole %)	Nitrogen (N_2) (Mole %)	Heat Content (Btu/cf)
Trinidad	99.72	0.06	0.0005	0.0005	0.20	1 040
Algeria	86.98	9.35	2.33	0.63	0.71	1 098
Other LNG	80 to 99	1 to 17	0.1 to 5	0.1 to 2	0 to 1	1 000 to 1 160

facilities for NGL recovery includes an evaluation of the amount of liquids in the gas, the appropriate technology for NGL recovery, market values of the natural gas and NGLs, the costs to move the NGLs to market, capital costs, fuel and other operating costs.

While new LNG sources, especially the Pacific Rim and Middle East, produce gas that significantly exceeds the specification of Canadian and U.S. pipelines, other LNG sources such as Egypt and Norway, produce gas within the existing Canadian and U.S. specification.

FIGURE 3.3

Current U.S. LNG Terminals and Proposed Canadian LNG Projects

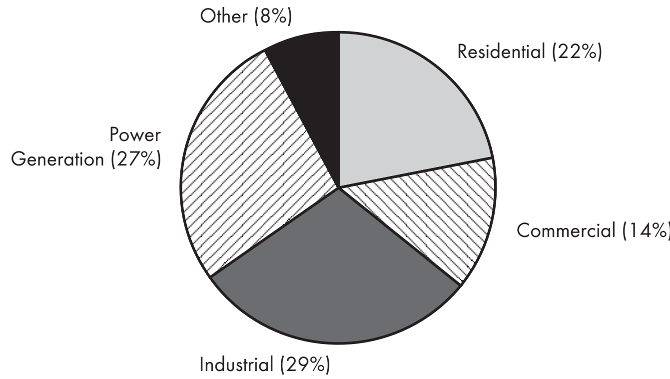


Location	Terminal	Company	Capacity (Bcf/d)	On Stream Date
Currently operating U.S. LNG Terminals ●				
1 Everett, Massachusetts	Tractebel	DOMAC	1.035	present
2 Cove Point, Maryland	Dominion	Cove Point LNG	1.0	present
3 Elba Island, Georgia	El Paso	Southern LNG	1.22	present
4 Lake Charles, Louisiana	Southern Union	Trunkline LNG	2.1	present
5 Gulf of Mexico	Energy Bridge	Excelerate Energy	0.5	present
Total			**5.8**	
Proposed Canadian LNG Terminals ▲				
1 Point Tupper, Nova Scotia	Bear Head	Anadarko Petroleum Corporation	0.75 to 1.0	late 2008
2 Goldboro, Nova Scotia	Keltic Goldboro	Keltic Petrochemicals Inc.	1.0	late 2009
3 Gros Cacouna, Quebec	Cacouna Energy	TransCanada PipeLines Limited and Petro-Canada	0.5	late 2009
4 Quebec City, Quebec	Rabaska	Gaz Metro Limited Partnership, Gaz de France, and Enbridge Inc	0.5	late 2009
5 Saint John, New Brunswick	Canaport	Irving Oil Limited and Repsol YPF	1.0	late 2008
6 Ridley Island, British Columbia	WestPac Prince Rupert	WestPac Terminals Inc.	0.3	2009
7 Emsley Cove, British Columbia	Kitimat	Galveston Energy	0.610	2009
8 Point Tupper, Nova Scotia	Statia	Statia Terminals Canada Partnership	0.5	n/a

In response to continued high gas prices in North America in 2004, LNG imports to North America increased by about 30 percent over 2003 levels to an average of about 51 million m^3/d (1.8 Bcf/d), supplying almost 2 percent of North American demand. In the past few years, the existing receiving terminals have undergone expansions and are operating with a current capacity of about 80 million m^3/d (2.8 Bcf/d). As well, numerous new facilities and further expansion of some existing terminals have been proposed. North American LNG import capacity in 2006 is expected to grow to 164.3 million m^3/d (5.8 Bcf/d), with actual imports at about 113 million m^3/d (4.0 Bcf/d). A number of the proposed new LNG projects being considered are for sites in Canada; however, none of the new facilities will be built within the timeframe of this outlook. Figure 3.3 shows the LNG terminals that are currently operating in the U.S. and the proposed Canadian LNG projects.

FIGURE 3.4

Canada and U.S. Natural Gas Demand - 2004



Total Consumption: 1 945 million m^3/d (68.7 Bcf/d)

Source: NEB, Statistics Canada, EIA

Increased capacity to import LNG, however, is not guaranteed supply. It represents a potential for supply, if market conditions are right. North America will face competition for LNG supply from other regions, such as Asia and Europe. Suppliers of LNG will ship to North America when the market is most attractive. Arbitrage opportunities are worldwide and on occasion, tankers bound for one terminal are redirected elsewhere in the world. The global nature of LNG trade will begin to link North American gas prices to prices in those competing markets.

3.2 Natural Gas Demand

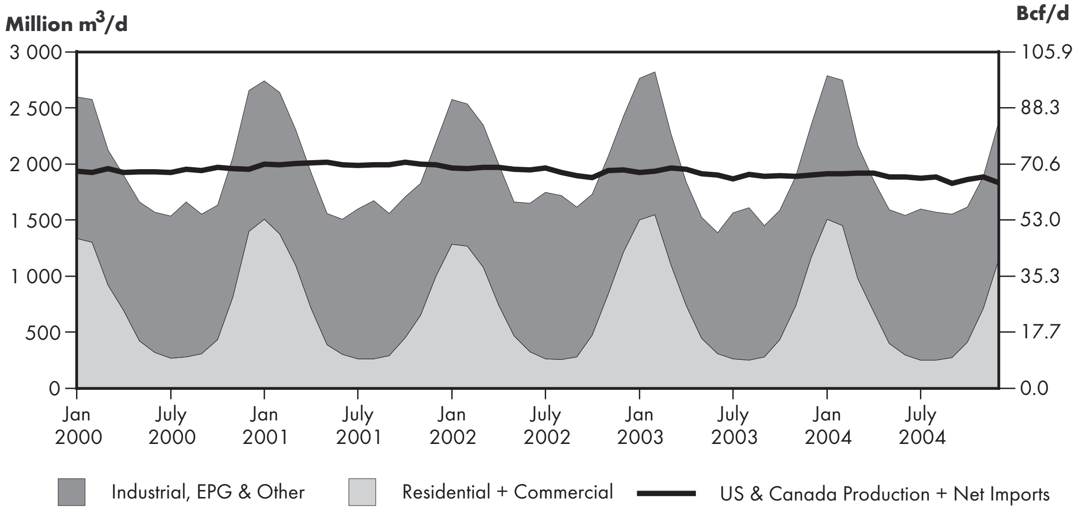
Natural gas accounts for approximately one quarter of all energy consumed in Canada and the U.S. It is primarily used by the residential and commercial sectors as a source of space heating, by the industrial sector as a source of process heat and as a building block in chemical production, and by the electric power generation (EPG) sector to produce electricity (Figure 3.4).

3.2.1 Heating Demand: Residential and Commercial

With use in the residential and commercial sectors heavily directed at space heating, particularly in the winter months, natural gas demand is very seasonal and weather-sensitive, as shown in Figure 3.5. Canadian and U.S. natural gas demand peaks in winter months when demand can exceed production by over 850 million m^3/d (30.0 Bcf/d). The seasonal imbalance between supply and demand highlights the important role that natural gas storage plays in balancing the market. The increasing use of natural gas for power generation has also begun to create smaller peaks in the summer, as residential and commercial cooling requirements are increasingly being met by natural gas-fired electricity generation. This has narrowed the opportunities during the year to replenish storage levels.

FIGURE 3.5

Canada and U.S. Natural Gas Demand and Supply



Sources: EIA, NEB and Statistics Canada

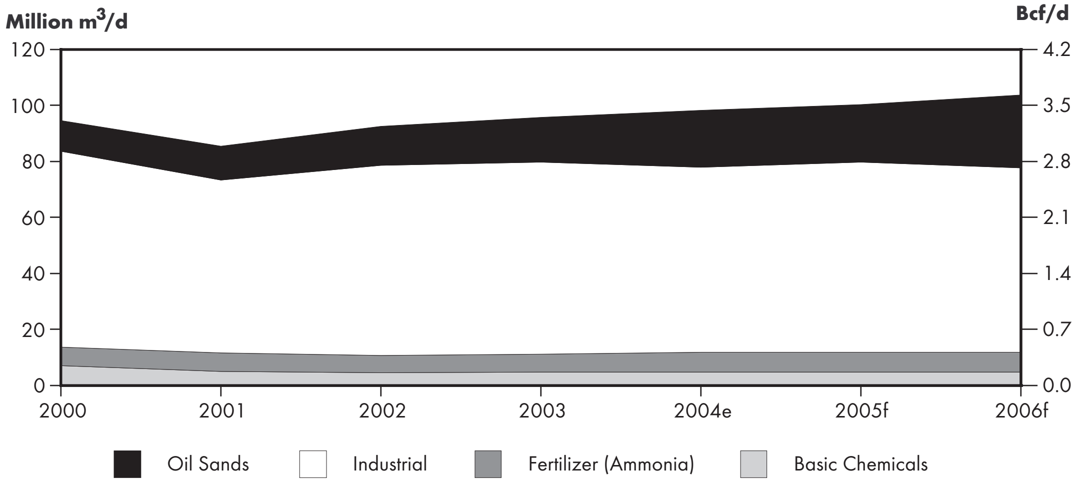
The future of natural gas use in the residential and commercial sectors is dependent on factors such as weather and the number, size and efficiency of new buildings. Although newer homes are more energy-efficient, the trend in North America is to build larger homes with higher ceilings, which require more heat per unit of floor space. New homes in both Canada and the U.S. are, on average, 13 to 16 percent larger than the average existing housing stock, with correspondingly greater needs for heating and cooling. In the commercial sector, floor space has grown at an average annual rate of about 1.6 percent since 2000.

The residential and commercial sectors have little ability to switch to other fuels when gas prices rise and therefore, the response to higher prices is limited to conservation and energy efficiency improvements. Although significant energy efficiency improvements are possible through appliance, furnace and building upgrades, these are limited by economics and the rate of new housing and equipment stock turnover. The turnover time for appliances and furnaces can be lengthy. Therefore, it is not surprising that, even in light of the increasing natural gas prices, the intensity with which natural gas is used in these sectors has remained relatively steady since 2000. In addition, the U.S. Energy Information Administration reported that even during the gas price spike of 2001, the average winter daytime household thermostat setting had not changed from 70.2°F (21.2°C), the average for 1997.

Taking into account improvements for energy efficiency, the outlook to 2006 for natural gas demand for the residential and commercial sectors is essentially flat. However, actual consumption will be highly dependent on weather. In Canada, natural gas use in these sectors could grow by 2.8 million m^3/d (0.1 Bcf/d) over the outlook period to 90.6 million m^3/d (3.20 Bcf/d). This is under the assumption that energy efficiency improvement trends continue, the number of households continue to grow at an average annual rate of 1.4 percent, and commercial floor space grows at an average annual rate of 1.8 percent. However, there may be variations across regions such as in Quebec, where the province would like to diversify its energy consumption. The provincial government has outlined an energy strategy that would see diversification of heating equipment to include using sources of energy other than electricity. This could potentially increase natural gas demand and reduce electricity demand in winter.

FIGURE 3.6

Canadian Industrial Uses of Natural Gas



Notes: e: estimate
f: forecast

Source: NEB, Statistics Canada

3.2.2 *Industrial and Non-Energy Demand*

The industrial sector accounts for almost one-third of the total North American natural gas demand and almost 40 percent of Canadian demand. Industrial demand is largely independent of seasonal weather patterns and is very stable throughout the year. Since natural gas prices rose in 2001, considerable demand adjustments have occurred in the industrial sector, as illustrated in Figure 3.6. North American non-oil sands industrial demand for natural gas declined at an estimated average annual rate of 1.8 percent between 2000 and 2004, and consumption for this sector in 2004 is estimated to be about 7 percent less than in 2000. The decrease in consumption is largely due to energy intensity improvements, fuel switching, the economic slowdown in 2001, and some industrial closures.

While some industries have been able to mitigate the impact of higher gas prices by temporarily switching to other fuels such as RFO or coal, other industries have engaged in a more permanent substitution of fuels. An example is the pulp and paper sector, which is moving away from natural gas and relying more on wood waste. Although the circumstances for switching to fuel oil for industrial purposes do not usually last long, they help reduce demand for natural gas during periods of peak demand and price. Of the estimated 572.2 million m^3/d (20.20 Bcf/d) of North American industrial natural gas demand, it is estimated that about 6 percent or 35.4 million m^3/d (1.25 Bcf/d) can be switched, usually to RFO, within 30 days. Even plants that have a fuel-switching capability generally cannot switch all of their fuel requirements from natural gas. Furthermore, emissions restrictions and environmental considerations also limit the ability to burn high sulphur RFO in some areas.

Most industrials are engaged in activities to improve energy efficiency and intensity, but have little or no capability to use alternative fuels, especially in direct-flame manufacturing processes. Some industries have found it necessary to reduce operations or shut down temporarily in the face of high gas prices. However, shutdowns may not be a desired option and may result in permanent loss of market for some industries. On the positive side, co-generation has captured synergies and economies of scale for some to enable infrastructure that provides process heat and electricity at little incremental gas demand.

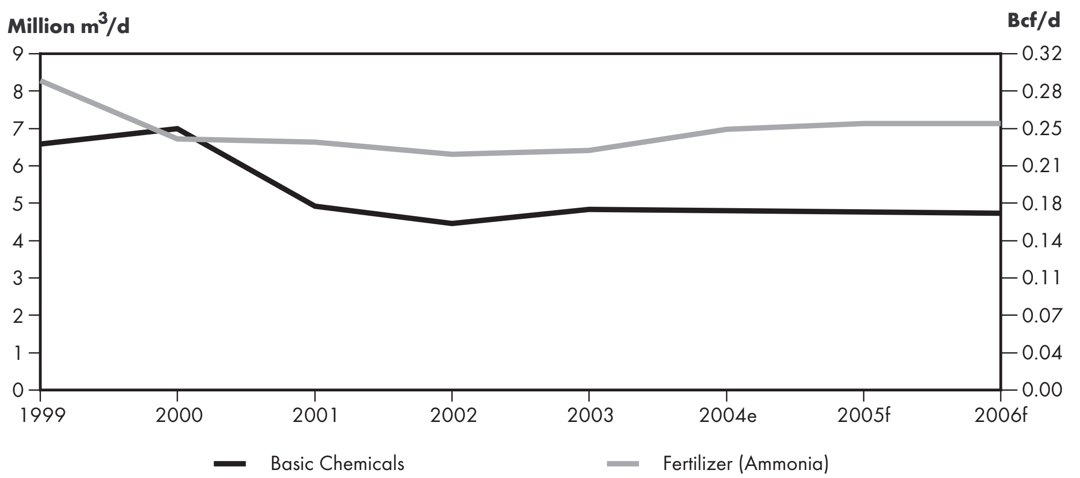
Sixty percent of North American industrial natural gas demand comes from gas-intensive industries such as chemicals, mining (including oil and gas), cement, primary metals, food, agriculture, and pulp and paper. Natural gas costs are typically greater than five percent of production costs, making these producers quite sensitive to natural gas prices. For these industries, the combination of strong global economic growth, rising shipping costs (due to high oil prices to import competing products) and a falling U.S. dollar (which helps U.S. producers by discouraging import substitution) helped keep North American industrial output strong in 2004, despite high gas costs. However, the rising Canadian-U.S. exchange rate put some pressure on Canadian exporters. Some of these industries, such as agriculture, petrochemicals and steel, experienced high product prices in 2004, which enabled them to withstand high natural gas costs for production of their products.

Natural gas is also used as a feedstock in the production of fertilizer (ammonia) and methanol. The fertilizer industry in North America is greatly affected by higher natural gas prices because the cost of ammonia (derived from natural gas) is the largest component of its operating costs. Given the lower cost of natural gas in many places around the world, fertilizer companies may relocate production to locations where natural gas is plentiful and inexpensive, and then transport their final product to North America. Fertilizer plants and other industrial plants that are located close to tidewater in North America are most vulnerable to overseas competition. Inland facilities that are located close to the markets they serve are likely more competitive as transportation costs for their products are much lower. In particular, Canadian producers (especially in Alberta) enjoy some advantage over many U.S. competitors because of their proximity to feedstock and, therefore, lower pipeline tolls for transporting the raw material to the plant.

While strong agricultural prices in the U.S. are helping buoy demand and prices for ammonia fertilizers that are derived from natural gas, high gas prices have resulted in the shutdown of 16 plants in the U.S. since 1998 and a 35 percent drop in production. On the other hand, Canadian ammonia production increased by five percent over the same period. A weak U.S. dollar may discourage import substitution in the U.S. and leave new ammonia fertilizer facilities in southeast Asia and Europe to satisfy global demand outside of North America.

F I G U R E 3 . 7

Canadian Natural Gas Feedstock Use



Notes: e: estimate
f: forecast

Source: NEB, Statistics Canada

A global methanol overcapacity has developed over the past few years. Therefore, due to an increase in competition and the removal of methyl tertiary-butyl ether (MTBE) from gasoline in the U.S., about 40 percent of Canadian and U.S. methanol production capacity has been shut down since 1999. Annual Canadian methanol nameplate capacity has gone from 2 450 kt/a in 1997 to 1 350 kt/a by 2005[3], which accounts for the drop in natural gas use in basic chemicals as shown in Figure 3.7. This figure also shows that about one-quarter of the natural gas feedstock demand appears to have been permanently lost since 1999 and even with the positive growth in 2004 and outlook for 2005, it is not expected that natural gas use in these industries will return to 1999 levels within the timeframe of this outlook.

The last five years have placed numerous challenges on the Canadian and U.S. industrial sector, but relatively speaking, industrial gas demand has remained resilient. It appears that the most price sensitive players have been permanently lost and fortunate economic circumstances of 2004 mitigated the effects of high gas prices. For the outlook period, Canadian and U.S. non-oil sands industrial demand is expected to decline further at an average annual rate of 2.5 percent, and it appears that further fuel switching opportunities are limited. It is expected that while global economic expansion appears to be slowing, the pace of real Gross Domestic Product (GDP) growth will remain robust.

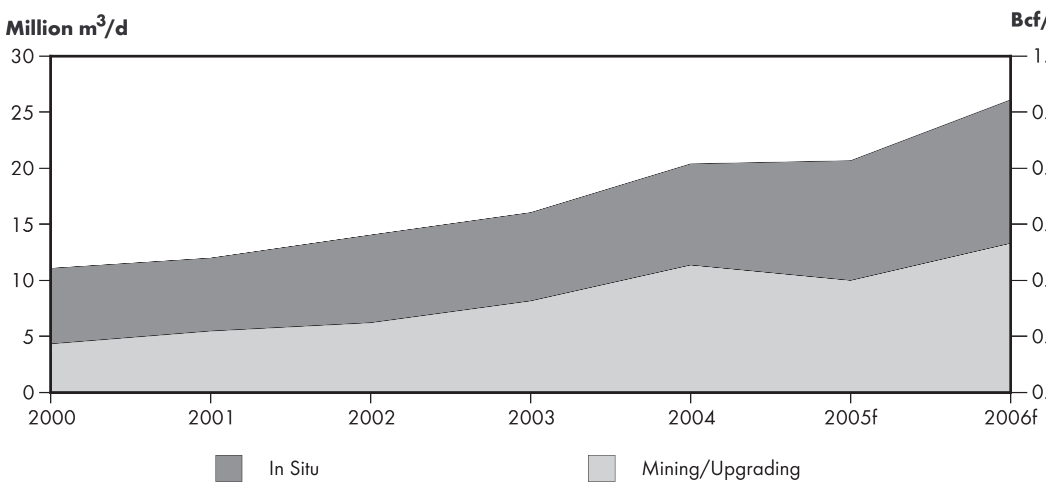
3.2.3 Natural Gas for Oil Sands

In 2004, about 20.4 million m^3/d (0.72 Bcf/d) of natural gas was used by oil sands projects to produce electricity onsite, provide process heat in bitumen recovery, and produce steam that is used for in situ recovery through steam injection processes. Natural gas is also an important source of hydrogen needed for hydro-cracking and hydro-treating in the upgrading of bitumen to higher quality synthetic crude oil.

Scenarios for oil sands development show that the natural gas requirement (Figure 3.8) for mining and upgrading will decline from 11.3 million m^3/d (0.40 Bcf/d) in 2004 to an average of 9.9 million m^3/d (0.35 Bcf/d) in 2005 due to operational problems and reduced throughputs at three

FIGURE 3.8

Average Annual Natural Gas Requirements for Oil Sands Operations



Note: f: forecast

Source: EUB, NEB

3 Canadian Chemical Producers' Association, *Overview of the Canadian Chemical Manufacturing Industry* 2005.

of Alberta's major integrated mining/upgrading plants. Operations are expected to return to normal by the end of 2005. With the scheduled start-up of Syncrude Canada Ltd.'s Stage 3 expansion and the addition of Suncor Energy Inc.'s Millennium Vacuum Unit, natural gas demand for mining and upgrading should grow to 13.6 million m^3/d (0.48 Bcf/d) by the end of 2006. The natural gas requirement for in situ projects is expected to increase during the outlook period to 15.2 million m^3/d (0.54 Bcf/d) as nine new projects or project expansions begin production (Figure 3.8). Hence, about 28.7 million m^3/d (1.01 Bcf/d) could be consumed at oil sands operations by the fourth quarter of 2006, averaging about 26.0 million m^3/d (0.92 Bcf/d) for the year. By 2006, total bitumen production will have almost doubled from 2000 levels, growing from 104.9 thousand m^3/day (660 Mb/d) in 2000 to 205.0 thousand m^3/d (1.29 MMb/d) in 2006.

Oil sands operators are currently developing and implementing new technologies, such as bitumen gasification, to reduce natural gas use in their processes. Low-value asphaltenes extracted from bitumen could be gasified and thus converted into a synthesis gas composed of hydrogen and compounds of carbon. Two bitumen upgrader projects (Suncor and Nexen/Opti Joint Venture) are currently contemplating using asphaltene gasification, but the technology has yet to be proven.

Growing Alberta natural gas demand for oil sands operations can impact NGL production because gas that is consumed in the province does not reach the straddle plants for extraction. Ethane is the most impacted by this, although volumes consumed as intra-Alberta gas supply are relatively small (about 1 100 m^3/d to 1 580 m^3/d or 7 to 10 Mb/d). Going forward, a new straddle plant may be required to strip liquids from the natural gas going to the oil sands. Additionally, if the synthesis gas produced from petroleum coke gasification was used as fuel to run growing mining or in situ production, the rapidly increasing requirement for natural gas could be offset, leaving more gas to reach Alberta's straddle plants.

3.2.4 Natural Gas for Power Generation

From 1998 to 2004, natural gas was the fuel of choice for new power generation. Many regions opted for natural gas-fired generation over conventional generation sources that included coal, nuclear and large hydro. The significant growth in natural gas-fired power generation capacity in North America can be largely attributed to low capital cost, a relatively short construction lead time for gas-fired plants, low natural gas prices throughout the 1990s, and a preference for natural gas over other fossil fuels because of its clean burning properties. Moreover, there has been generally less public opposition to natural gas-fired plants than to coal-fired or nuclear facilities.

In Canada, approximately 2 000 MW of natural gas-fired power generation was added to the Canadian supply mix from 2000 to 2003 for a total installed capacity of 8 700 MW[4]. This represents just over 7 percent of Canada's total installed capacity of 117 000 MW. In terms of energy production, natural gas-fired generation provided just under 6 percent of the 568 505 GW.h total in 2003. The associated fuel required for generation is expected to continue to increase as generation from this asset type is expected to grow at an average annual rate of 1.75 percent for the outlook period.

Although outside the time horizon of this report, significant potential gas requirements for power generation will be driven by Ontario's policy to remove 7 500 MW of coal-fired capacity from its system. To replace this capacity, the government has initiated a series of Request for Proposals (RFPs) for thermal power generation (not including coal), renewables, and conservation and demand response. Although the refurbishment of existing nuclear generation might meet part of the requirement for the displaced coal, there will likely be a significant volume of new natural

4 From 1998 to 2003, natural gas-fired generation increased by approximately 4 300 MW.

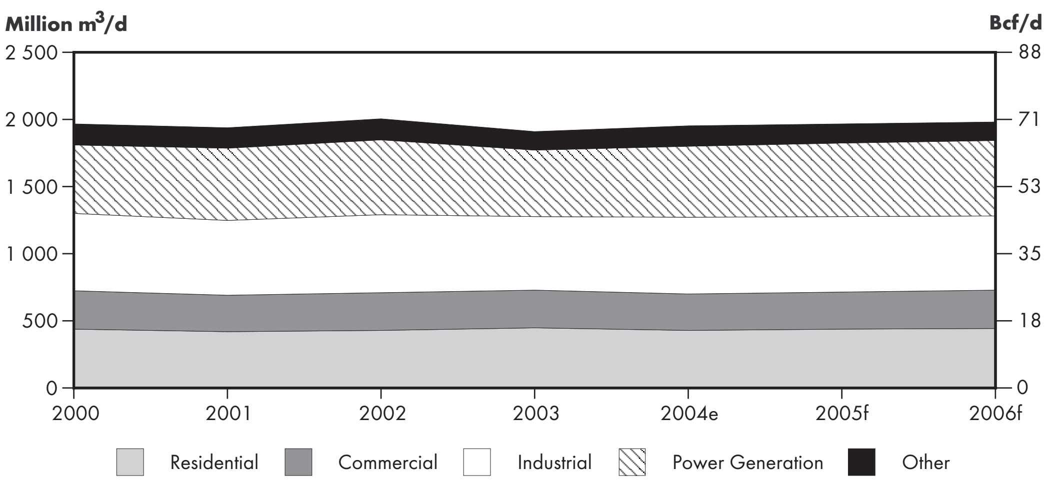
gas-fired power generation entering the system. For example, in its recent 2 500 MW RFP, the Ontario government awarded contracts for the development of 2 225 MW of natural gas-fired generation (including co-generation). Consequently, natural gas for power consumption could greatly increase in the order of 5.7 to 17.0 million m^3/d (0.20 to 0.60 Bcf/d) if all coal-fired generation is replaced by 2009. Aside from a step increase in natural gas consumption in Ontario, potential issues may arise regarding adequate infrastructure required to meet the new generation and additional competition with industrial consumers of natural gas.

Within many U.S. regions, generation oversupply developed because over 200 000 MW of new natural gas-fired generation was added to the supply mix from 1998 to 2003. This situation has led to an underutilization of the natural gas-fired fleet. However, as demand continues to grow, energy produced from natural gas-fired generation will continue to increase as incremental demand is met mostly by gas-fired generation. In addition, in regions such as the U.S. Pacific Northwest, a combination of below-normal hydroelectric generation conditions and increased opportunities for export of electricity to California will lead to increased usage of the natural gas-fired fleet. The EIA expects associated fuel required for generation to continue to increase, as generation from this asset type is expected to grow at an average annual rate of 4.6 percent throughout the outlook period to 538.5 million m^3/d (19.01 Bcf/d).

Factors that will influence natural gas-fired power generation include hydroelectric generating conditions, availability of baseload coal-fired and nuclear generation, and demand sensitivity to weather. Due to natural gas prices reaching unprecedented levels and experiencing greater price volatility, along with the concerns regarding fuel supply and associated infrastructure issues, the incentive to build new natural gas-fired power generation has decreased. As a result, many regions are considering other options for incremental generation capacity, and are reassessing the economic feasibility and extent of the natural gas-fired generation option in an effort to develop diversified generation portfolios.

FIGURE 3.9

Canada and U.S. Natural Gas Consumption

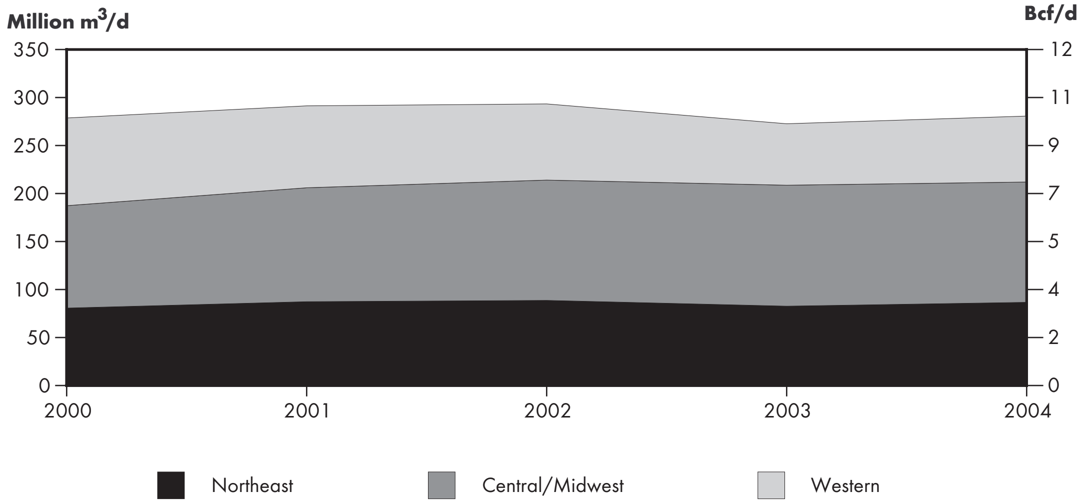


Notes: e: estimate
f: forecast

Source: NEB, EIA

F I G U R E 3 . 1 0

Natural Gas Exports by U.S. Region



3.2.5 Exports

Revenue from natural gas exports exceeded C$27 billion in 2004, accounting for more revenue to Canada than any other energy export. Natural gas exports totalled 102.0 billion m^3 (3.60 Tcf) in 2004. The U.S. Central/Midwest and Northeast regions historically receive the greatest portion (Figure 3.10) of Canadian exports. (Refer to Appendix 4 for the states included in the U.S. geographic regions.) Canadian natural gas accounts for 15 percent of U.S. natural gas consumption. There is little anticipated change in this makeup since the traditional U.S. supply regions for these markets are not expected to be able to increase production. As well, no significant infrastructure is planned over this time horizon to deliver gas from other regions.

Production within Canada is levelling off, whereas domestic demand continues to grow. This developing trend will undoubtedly be reflected in future export levels, but for the period of this short-term assessment it is unlikely that there will be a drastic change. The steady trend in export levels since 2000 can be expected to persist to 2006. As a means of diversifying the source of imports and responding to growing demand, U.S. imports of LNG have also been rising and are expected to continue to do so in the future.

NGL Supply and Demand

4.1 NGL Supply

Production of natural gas liquids from gas plants depends on raw natural gas production, the composition of the natural gas, and the extraction efficiencies of field and straddle plants. Production of propane and butane from refineries contributes a smaller portion of the total Canadian NGL supply.

4.1.1 NGL Production from Gas Plants

This NGL supply outlook is based on the WCSB raw gas supply outlook (reflecting the Board's short-term natural gas supply outlook outlined in Chapter 3) and the estimated NGL content by producing region. Natural gas produced from the Central and Foothills Front regions of Alberta have the highest NGL concentrations in the WCSB, followed next by the Alberta-Northwest and Fort St. John, B.C. regions. Appendix 1 shows the geographic regions of the WCSB. Over the outlook period, the regional NGL content is not expected to change significantly from 2004 concentrations.

As future Canadian natural gas production gradually moves westward and higher carbon dioxide content pools begin production, straddle plant efficiency and ethane quality could be affected. In 2003, this issue was addressed with the introduction of a TCPL-AB carbon dioxide recovery service and a related tariff. The TCPL-AB tariff includes a financial incentive for shippers to use the carbon dioxide recovery service to transport low carbon dioxide concentration gas (i.e., less that two percent) on the pipeline. Consequently, several members of the industry consider an increase in carbon dioxide concentration from the Foothills Front region a manageable issue, suggesting that the mechanism to accommodate future increasing carbon dioxide levels is in place. However, additional costs will have to be incurred to remove carbon dioxide to maintain ethane recovery at the straddle plants.

A significant part of NGL production, ethane in particular, is a function of gas flows past straddle plants. For this EMA, a slight decrease has been factored into the individual liquids supply outlooks to account for increased volumes of natural gas that may be directed to growing oil sands production and therefore, bypass the existing NGL extraction infrastructure.

Taking into account that the average NGL concentration in the WCSB is expected to remain unchanged and carbon dioxide levels are expected to be managed, it is anticipated that the supply of NGLs from gas processing plants should essentially track the flat natural gas supply outlook.

4.1.1.1 *Extraction Economics*

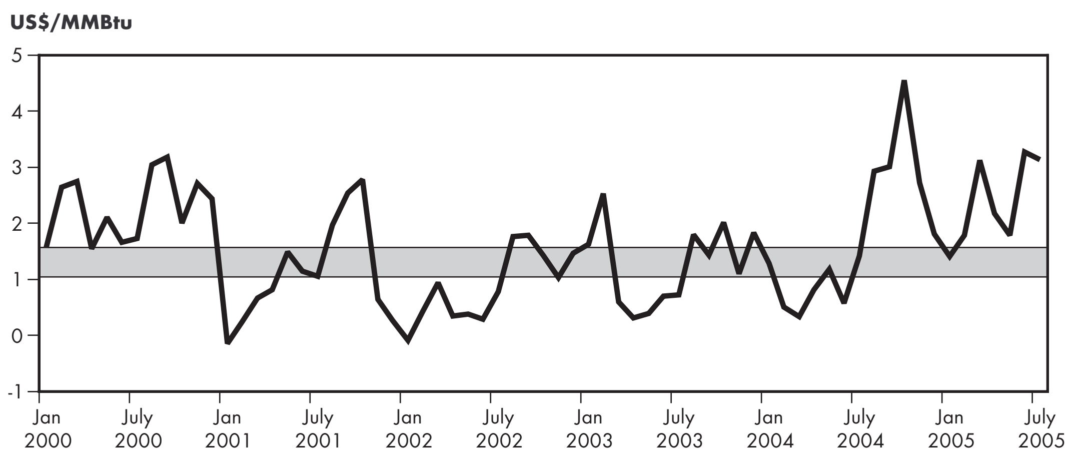
The extraction margin is the difference between the NGL price and the cost of natural gas, the associated transportation costs and processing costs[5]. Since 1998, the margins for liquids have been increasingly volatile, and in certain months, extraction economics have not favoured the recovery of NGLs in Alberta.

During periods of relatively high gas prices, extraction margins tend to decline, which means that the incentive to extract and separate the NGLs to specification products may disappear. If the profitability disappears, North American gas plant operators begin to adjust operations to minimum liquids recovery levels. This is referred to as 'NGL rejection'. As a result, producers receive the higher gas price for liquids left in the gas stream and avoid paying gas-processing fees. Therefore, if plant profitability remains poor, liquids production could remain below full recovery levels leading to lower NGL supply. Data from the U.S. indicates that during periods of high natural gas prices, variation in NGL extraction can supplement U.S. natural gas supply by up to 0.7 percent (up to 10.5 million m^3/d or 0.37 Bcf/d)[6].

Figure 4.1 illustrates the differential between propane and natural gas prices. The value of propane over natural gas represents the extraction margin and determines whether extraction is economically feasible. The band represents low-cost and high-cost producer break-even levels (US$1/MMBtu and US$1.55/MMBtu)[7] to cover processing, extraction, fractionation and transportation costs. Periods when the differential fell below this band occurred when North American gas prices were high, reaching or exceeding parity with crude oil on an energy equivalent basis. At the same time, the price for propane was valued near or equivalent to natural gas, but not above.

F I G U R E 4 . 1

Edmonton Propane – AECO-C Gas Price Differential



Note: Edmonton price is the Alberta propane reference price. The band represents the low-cost and high cost producer break-even levels at US$1/MMBtu and US$1.55/MMBtu.

5 Processing costs include extraction and fractionation costs.

6 Data supplied by PIRA Energy Group.

7 In general, propane break-even margins for extraction and transportation vary between US$0.09/gal for low-cost producers and US$0.14/gal for high-cost producers (equivalent to US$4 per barrel versus US$6 per barrel, respectively).

For the outlook period, crude oil is expected to trade around US$50 per barrel (US$8.58/MMBtu) and the natural gas price is expected to range between US$6.90/MMBtu and US$10.34/MMBtu. NGL extraction margins could occasionally collapse when the gas price is at the higher end of the range.

In Canada, propane is essentially the only NGL subject to rejection because the supply of ethane, butane and condensate are effectively tight. Additionally, butane and condensate are primarily recovered to meet gas pipeline and dew point specifications. In some cases, extraction plants have the capability to extract an ethane plus mix and then re-inject propane back into the gas stream; however, this approach is often uneconomic.

The petrochemical sector consumes most of the available ethane supply. In order to secure its feedstock requirements, Canadian petrochemical companies have contractual arrangements with the Alberta straddle plants. These contracts, in conjunction with the configuration of various field extraction plants, currently limit the amount of ethane that can be rejected. As more long-term contracts come up for renewal, it is expected that future contracts will likely provide straddle plants with more flexibility to extract or reject ethane. To maintain ethane recovery, the petrochemical companies will be required to assume increased processing costs related to higher fuel costs.

4.1.2 Refinery Production

In 2004, Canadian refineries produced about 4 300 m^3/d (27 Mb/d) of propane and 7 760 m^3/d (49 Mb/d) of butane. These volumes accounted for 13 percent of the total propane production and 33 percent of the total butane production. The combined production of propane and butane from refineries equals about 12 percent of total NGL production, excluding pentanes plus. A negligible amount of ethane is produced from refining processes.

Refineries are currently facing two major issues: the recent regulations in North America on reducing sulphur in gasoline and diesel; and, insufficient capacity to accommodate the increasing volumes of heavy crude oil. The majority of refineries will be addressing these issues simultaneously through capital investments in equipment. Distillation unit improvements and upgrader additions are the two main components contributing to refinery capacity increases. Historically, distillation unit adjustments increased refinery capacity by about 0.5 percent per year. The addition of upgrading unit capacity is assumed to increase refinery capacity by an average of about 1.5 to 2 percent per year. Consequently, for this outlook, refinery production of propane and butane is assumed to grow by an average of 1.25 percent per year. Overall, refining production will account for an increasing portion of total supply going forward, supplementing the flat gas plant production of these liquids.

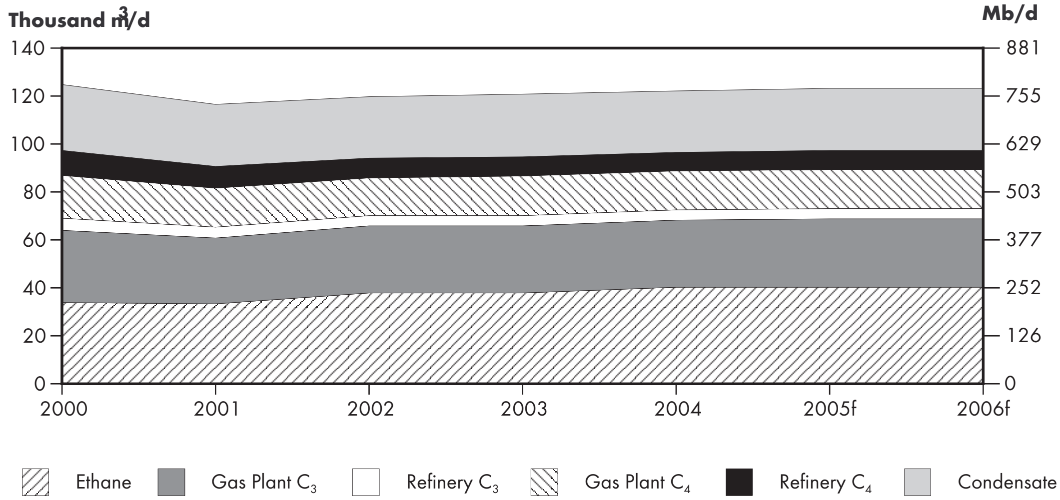
4.1.3 Ethane Supply

Ethane production is expected to average about 40 220 m^3/d (253 Mb/d) through 2006 (Figure 4.2), approximately the same as in 2004. This excludes about 8 740 m^3/d (55 Mb/d) of theoretically available ethane entrained in the Alliance gas stream. Appendix 2 provides an approximation of the Alliance gas composition.

Future ethane supply is a concern for the Alberta petrochemical industry given that WCSB natural gas supply is not expected to grow. In 2003, a new straddle plant was brought online at Joffre, Alberta and the deep-cut capability of an Empress, Alberta straddle plant was also expanded to add incremental ethane supply. However, despite this additional ethane supply and a further small deep-cut expansion at another Empress straddle plant to be completed in September 2005, an ethane

FIGURE 4.2

Canadian NGL Production



Note: f: forecast

supply shortfall could materialize if WCSB conventional natural gas production declines. In fact, with the increase in ethylene demand in 2004, Alberta ethane supply is currently considered constrained.

Approximately 55 to 60 percent of theoretically available ethane is extracted from the gas stream. One option, if economically feasible, is to take a deeper cut at some of the straddle plants at Empress, but this would require an increase in the price of ethane to pay for capital investments. Additionally, a deeper cut would result in increased volumes of CO_2 being extracted with the ethane, requiring further investment in carbon dioxide removal capability.

There is ethane entrained in gas streams that currently do not flow past existing straddle plants and facility investments could be made to capture these volumes. Industry discussions are underway to attract NGL supply from this region. For example, to optimize capacity utilization, Pembina Pipeline Corporation is constructing a link between its Peace and Federated pipeline systems to reconfigure deliveries to the Edmonton area. It is expected that the optimization will provide processing plants in the west central Alberta with 3 970 m^3/d to 4 760 m^3/d (25 to 30 Mb/d) of incremental ethane plus capacity on the Peace pipeline, commencing about November 2005. Ethane purchasers would have to pay a premium to attract ethane from the Alliance system and to pay for any required capital investment. According to some parties, access to regional fractionation capacity to accommodate any increased ethane plus is also an issue.

Beyond the timeframe of this report, there are other potential projects to supplement ethane supply. Ethane may be extracted from off-gas produced from Alberta's oil sands upgrader projects. Currently, liquids are being shipped from the Fort McMurray area to Redwater, Alberta. This future potential feedstock supply could be used to support the petrochemical industry. Up to 7 950 m^3/d (50 Mb/d) of ethane/ethylene mix could be accessed by 2015. As well, volumes of propane/propylene mix are currently being extracted from off-gas and significant incremental volumes could also be accessed. For more details, see the Board's EMA, *Canada's Oil Sands Opportunities and Challenges to 2015*, dated May 2004.

Northern gas delivered by the proposed Mackenzie Valley Pipeline could help maintain utilization of the straddle plants if the projects are approved. However, given the composition of the gas, this would only add a relatively small volume of ethane. In the longer run, ethane from Alaskan natural gas could provide a significant amount of incremental ethane supply, estimated between 23 850 m^3/d to 47 690 m^3/d (150 Mb/d to 300 Mb/d), if the project is approved and the ethane is extracted in Alberta.

To gain access to incremental ethane and to maintain competitiveness with the U.S. Gulf Coast, the petrochemical sector suggests that government policy should recognize the massive investments needed to convert ethane to ethylene and other high-value products. Alberta's royalty regime encourages other forms of energy production. In light of this, the petrochemical sector suggests that a royalty mechanism be developed to encourage incremental ethane production from Alberta gas gathering systems.

Ethane extraction from Alaskan gas will be driven by natural gas economics, not NGL economics. According to various market participants, the petrochemical industry could make contractual arrangements with the Alaskan gas producers if it wants to ensure that liquids will be extracted in Alberta.

4.1.4 Propane and Butane Supply

For 2005 and 2006, total propane production is expected to remain flat at about 32 590 m^3/d (205 Mb/d), with gas plant production making up approximately 87 percent of total production (Figure 4.2). Butane production is also expected to remain flat at about 24 320 m^3/d (153 Mb/d), with gas plant production consisting of approximately 67 percent of this total. Western Canada accounts for the majority of supply; however, there is some production associated with Sable Island gas, which is extracted at the Point Tupper, Nova Scotia facility.

4.1.5 Pentanes Plus Supply

During this outlook, pentanes plus production is expected to be flat at about 25 900 m^3/d (163 Mb/d) (Figure 4.2). This outlook includes slightly less than 320 m^3/d (2 Mb/d) of pentanes plus that is entrained in the Alliance system gas. This volume is recovered near Chicago and is returned to the Alberta market by rail for use as diluent. In 2005, a de-butanizer was added at an Empress straddle plant, resulting in about 790 m^3/d (5 Mb/d) of incremental condensate recovery. Prior to this addition, the same volume of pentanes plus was extracted from the propane plus mix shipped to Sarnia, Ontario on Enbridge Pipelines.

4.2 NGL Demand

4.2.1 Ethane

Total Canadian ethane demand in 2004 was about 39 700 m^3/d (250 Mb/d). Petrochemical feedstock demand represents almost all of the Canadian ethane requirements. In 2004, ethane demand in western Canada equalled 36 880 m^3/d (232 Mb/d), representing about 86 percent of ethylene plant capacity. In eastern Canada, ethane feedstock demand was about 1 600 m^3/d (10 Mb/d). This volume is incremental to ethane produced in the eastern region by internal refinery processes and represents only a small portion of the eastern Canadian feedstock slate.

The capacity of Alberta ethylene plants to process ethane is between 42 800 m^3/d and 44 400 m^3/d (270 Mb/d and 280 Mb/d). However, the capacity of derivative plants at Joffre would have to be increased by 2 380 m^3/d to 3 970 m^3/d (15 Mb/d to 25 Mb/d) to match this ethane feed rate.

Originally, the Joffre cracker and derivative plants were constructed with matched capacities of 40 480 m^3/d (255 Mb/d), but due to optimization/de-bottlenecking, the cracker capacity has increased. Expansion of derivative capacity to take advantage of growing ethylene demand is unlikely until there is an increase in ethane supply.

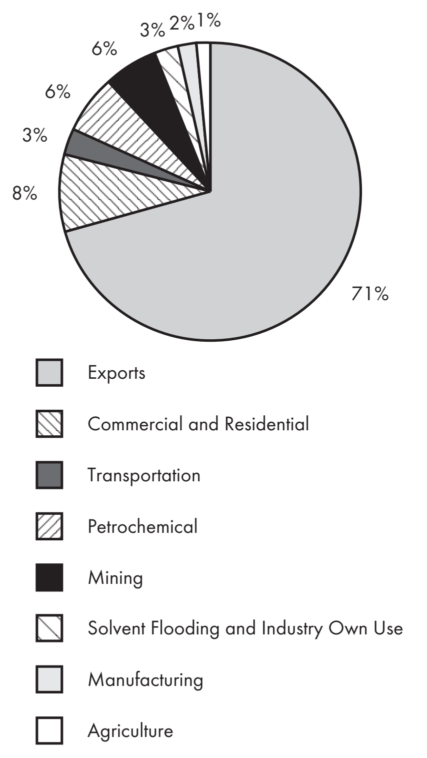
The ethane requirement for enhanced oil recovery (EOR) in 2004 totalled about 1 270 m^3/d (8 Mb/d). For 2005, miscible solvent flood demand is expected to be about 1 170 m^3/d (7 Mb/d) and for 2006, it is estimated to be about 1 290 m^3/d (8 Mb/d). Solvent flood demand currently exceeds available ethane supply. Some companies are evaluating the effectiveness of carbon dioxide as a solvent in enhancing oil recovery. If the carbon dioxide pilot floods are successful, use of carbon dioxide as a miscible solvent could limit ethane use for EOR.

4.2.2 Propane

Propane demand in Canada can vary between 6 350 m^3/d and 10 320 m^3/d (40 Mb/d and 65 Mb/d). As illustrated in Figure 4.3, the major demand sectors for propane include residential and commercial heating, petrochemicals, mining, transportation, solvent flooding, manufacturing and agriculture. Propane fuel demand is dependent on weather.

FIGURE 4.3

Canadian Propane Demand - 2004



Total Demand = 33 860 m^3/d (213 Mb/d)

In North America, overall fuel demand is expected to grow, particularly in the residential and commercial sectors, based on the U.S. growth in population and the increasing demographic shift to rural locations.

The petrochemical industry consumes on average 1 750 m^3/d (11 Mb/d) of propane in eastern Canada and between 793 m^3/d to 3 970 m^3/d (5 Mb/d to 25 Mb/d) in Alberta. Petrochemical demand varies with the price of propane relative to other feedstocks. To illustrate, the swing volume for total petrochemical demand in Canada is estimated to vary between 2 380 m^3/d (15 Mb/d) and 7 940 m^3/d (50 Mb/d). In light of the outlook for polyethylene and polypropylene petrochemical demand, demand for propane should be strong through 2005 and 2006 in both the domestic and export markets.

Propane currently accounts for about one percent of transportation fuel use in Canada. Propane's use as a transportation fuel is in steady decline mainly due to marginal support for alternative fuels and the high cost of automobile conversions.

4.2.3 Butane

Domestic butane demand in 2004 totalled about 21 110 m^3/d (133 Mb/d). The Canadian butane supply and demand balance is tightening due to growth in gasoline blending, alkylation and heavy oil diluent demand. Data on butane demand as a diluent is not readily available to the public so it is roughly estimated to range from 3 170 m^3/d to 3 970 m^3/d (20 Mb/d to 25 Mb/d). The ultimate limit of butane diluent demand will be defined by oil pipeline vapour pressure capability and acceptance by crude buyers of the amount blended with oil. About 2 380 m^3/d (15 Mb/d) of butane is used in eastern Canada for petrochemicals. Butane is normally the costliest NGL feedstock.

4.2.4 Pentanes Plus

Condensate, which is used as a heavy oil and bitumen diluent, is in a supply shortfall situation in western Canada due to increasing bitumen production. In 2004, total condensate supply consisted of 1 380 m^3/d (9 Mb/d) of field condensate and 24 180 m^3/d (152 Mb/d) of pentanes plus produced from gas plants. All of the condensate produced in western Canada is consumed in Alberta. Production is expected to remain flat through 2006 at 25 560 m^3/d (161 Mb/d).

4.2.5 Exports

In 2004, the ethane balance was very tight with no volumes available for export. About 71 percent of the propane supply is exported from Canada and of this volume, about 60 percent is directed to the U.S. Midwest. In light of the flat supply projection, the expected growth in North American propane heating demand and the expected increase in U.S. petrochemical demand for propylene production, Canadian exports of propane to the U.S. should remain at about 24 070 m^3/d (151 Mb/d). About 5 040 m^3/d (32 Mb/d) or about 21 percent of the total butane supply was exported to the U.S. This volume is expected to decline as Canadian gasoline blending, alkylation and bitumen diluent demand rises. No significant volumes of pentanes plus are available for export. In fact, condensate is imported into Alberta to supplement growing diluent demand.

4.2.6 Petrochemicals

The U.S. Gulf Coast petrochemical industry has a significant influence on NGL prices. This sector is the price sensitive swing consumer that drives NGL values between natural gas and oil prices.

Petrochemicals are the building blocks for the production of many plastics and chemicals in daily use. The core of Canada's petrochemical industry is located in Alberta where capital investments in ethane-based cracker and petrochemical derivative facilities total about C$11 billion.

Ethylene and propylene are two of the main chemical commodities from which many significant derivatives are produced. Ethane is the most efficient feedstock for the production of ethylene, as it yields the fewest number of co-products. Cracking ethane feedstock yields 81 percent ethylene and 19 percent other co-products. Propane, butane and heavier hydrocarbons are also used as feedstock in eastern Canada but, by comparison, propane yields only 43 percent ethylene and 57 percent co-products. Ethylene yields from butane and condensate are much lower. Given that co-products have value and that feedstock costs account for 65 to 70 percent of the total cost of ethylene production, feedstock choice has a strong influence on operating profitability.

Since future ethane supply and feedstock flexibility is a concern in Alberta, the ethylene plants located near Joffre expanded their cracking capability to use small volumes of propane as feedstock in 2002. Alberta ethylene plants can accommodate up to 7 to 10 percent propane in the feedstock slate. Cracking greater volumes of propane would require additional facility investment, which is unlikely at this time given that cracking propane involves the production of co-products that require a market. As well, transportation costs to reach markets for co-products are a consideration. Furthermore, propane commands a significant price premium, particularly during the heating season.

In eastern Canada, the petrochemical centres are located in the Sarnia, Ontario area and in Varennes, Quebec. Approximately 19 percent of Canada's total ethylene production comes from Ontario and 6 percent from Quebec. An advantage held by Sarnia and Varennes is that they are located within 500 miles (805 km) of 50 percent of the Canadian population and close to the U.S., a huge market where most of the end-use petrochemical products are produced and consumed.

While the crackers in eastern Canada are older, generally smaller facilities, these steam crackers are more flexible with respect to feedstock use to produce both ethylene and propylene. Over 714 000 m^3/d (4.5 MMb/d) of crude oil is refined within the 500 mile (805 km) radius, supplying a large portion of the ethane, propane, butane, naphtha and gas oil feedstock for the eastern Canadian crackers. In addition to local refined petroleum products, crude oil and condensates can be imported from almost anywhere in the world (e.g., West Africa, North Sea or South America). The ability to switch feedstocks and products quickly enables the eastern Canadian producer to benefit from the highest valued products and co-products, using the most competitive feedstock. The eastern Canadian sector is expected to undergo a slight expansion in capacity. For example, NOVA Chemicals is currently revitalizing some of its Sarnia assets to increase efficiency and to meet emission targets. These investments could ultimately increase capacity to consume propane and butane by 800 to 950 m^3/d (5 to 6 Mb/d).

4.2.7 Olefins and Petrochemical Derivatives

Upgrading NGL feedstocks to olefins, such as ethylene and propylene, and to end products adds incremental value to the Canadian economy. For example, upgrading ethane to ethylene increases the product value by approximately two times. Appendix 3 shows the various end products produced from ethane. Incremental value is added along the product path.

The petrochemical derivative markets, such as polyethylene and polypropylene, drive the olefin markets and hence, petrochemical demand for NGLs. Ethylene and propylene are the feedstocks used to produce polyethylene, polypropylene, and other plastics and fibres.

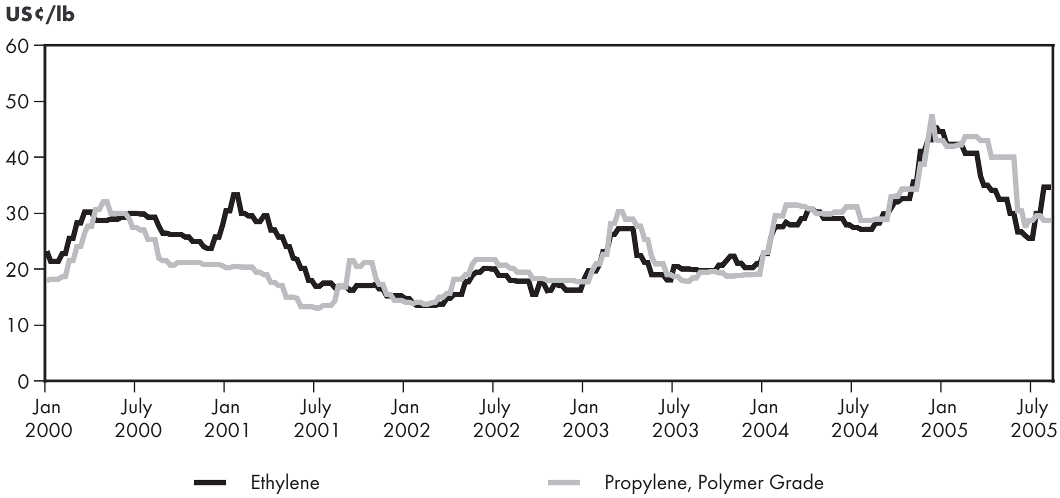
Canadian production is focused on ethylene although some propylene is also produced at Redwater, Alberta and in eastern Canada. Growth in petrochemical demand has historically been correlated to growth in GDP. Currently, growth in ethylene demand is estimated to be about 0.8 times the GDP rate in mature economies and up to 1.5 times or more in the high-growth, emerging economies, such as China. In 2004, global ethylene demand strengthened significantly by about 6 percent.

To 2006 and beyond, global demand for ethylene and its co-product propylene is expected to remain robust. In contrast, global ethylene supply capacity grew by less than one percent in 2004, causing global operating rates at plants to reach about 90 percent. Over the next few years, new global capacity will be added, led by expansions in the Middle East, which will cause an increase in ethylene supply.

Ethylene demand growth in the mature North American market has been slower due, in part, to plastic recycling and competition from propylene. Profit margins for North American producers have not been adequate to encourage investment in ethylene capacity expansions. In Canada, particularly in Alberta, as ethane supply is now constrained relative to demand, petrochemical buyers may have to pay higher prices to encourage additional ethane extraction. A global supply shortfall is expected in the near term for propylene with the annual demand growth rate projected at four to five percent.

FIGURE 4.4

Mont Belvieu Ethylene and Propylene Prices



Source: Purvin & Gertz

Although feedstock and energy costs have increased in recent years, ethylene and propylene prices also increased (Figure 4.4), outpacing costs and yielding improved bottom lines. After a period of de-stocking in mid-2005, olefin orders and prices are once again improving. With the world economy expected to sustain growth of over three percent in 2005 and world industrial production somewhat higher, the prospects for chemical demand remain favourable.

4.2.7.1 Competitiveness of the Canadian Petrochemical Sector in the North American Market

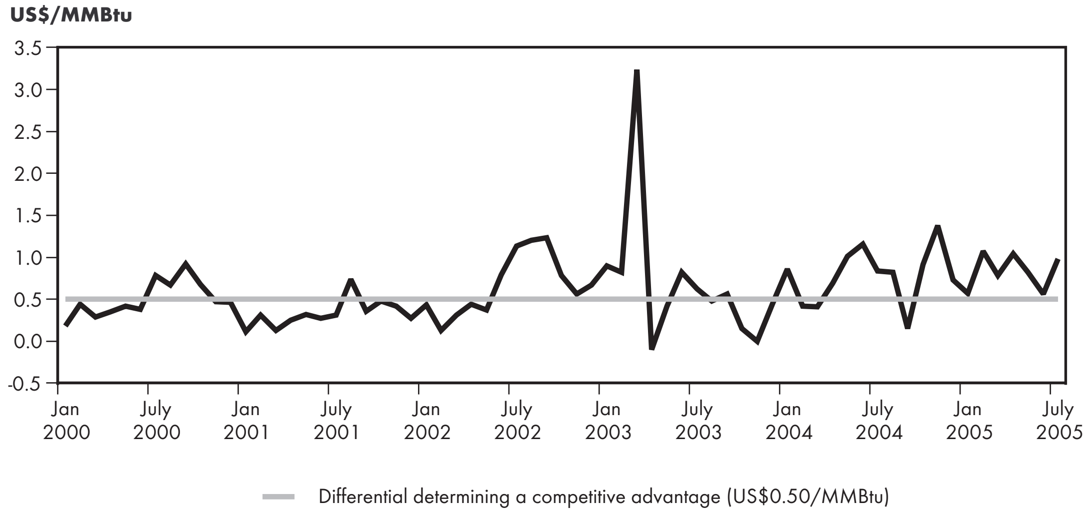
With its high concentration of petrochemical cracking and derivative infrastructure, the U.S. Gulf Coast is the primary competitor to Alberta's petrochemical sector. One of the main issues facing the Alberta petrochemical industry is whether its ethane crackers can continue to experience a cost advantage relative to the U.S. Gulf Coast.

For illustrative purposes, the NYMEX natural gas price at Henry Hub represents U.S. Gulf Coast natural gas prices. The positive U.S. Gulf Coast - AECO natural gas price differential (Figure 4.5) indicates that Alberta, for the most part, has maintained a cost advantage relative to the U.S. Gulf Coast. Since ethane prices in Canada are directly tied to natural gas prices, the Alberta ethylene producers continue to have an advantage over U.S. Gulf Coast gas-based plants. A differential in the order of about US$0.50/MMBtu is generally considered to be a competitive advantage. The divergence in U.S. and Canadian natural gas prices recently gave Canadian gas-based crackers an increased advantage over their Gulf Coast counterparts. It is expected that this advantage will remain into 2006; however, increases in gas demand in western Canada and changes to natural gas supply in the U.S., related to LNG, make the future advantage less certain.

In the U.S., ethylene plants that are strictly limited to the use of gas-based feeds account for 35 percent of capacity. Naphtha crackers and flex-feed crackers account for the remaining 65 percent. However, many flex-feed crackers routinely use significant volumes of ethane and propane. Therefore, the price relationship between natural gas and crude oil is an important aspect to consider when assessing the relative competitiveness of Alberta ethylene versus Gulf Coast production. During periods of relatively high gas prices, Gulf Coast oil-based ethylene plants (which use naphtha or gas oil as feedstock) have a cost advantage over gas-based facilities.

FIGURE 4.5

Three-day NYMEX Natural Gas – AECO-C Basis



While Alberta ethylene production costs are on average still lower than on the Gulf Coast, the cost advantage is becoming less. Periods where high natural gas prices make gas-based ethylene production less competitive are becoming more frequent. Based on the parity to oil assumptions for this outlook, with oil expected to be valued around US$50 per barrel (US$8.58/MMBtu) and gas between US$6.90/MMBtu to US$10.34/MMBtu, a naphtha-based price advantage could be the case during various periods in 2005 and 2006. The gain from the high value of co-products contributes to the naphtha advantage.

In summary, the current high price for natural gas in North America has eroded the international competitiveness of gas-based crackers, moving North America from one of the world's lowest-cost ethylene producing regions in the late 1990s to a relatively high-cost region. However, Alberta ethane-based ethylene continues to be at an advantage in the North American market compared to the U.S. Gulf Coast gas-based product. Additionally, the Alberta sector has an economy of scale advantage.

With growth in North American ethylene demand expected to remain significant, ethylene produced in Canada is expected to continue to be competitive in North America. Although ethane feedstock supply is considered to be constrained in Alberta, the 2004 ethane supply was sufficient to effectively meet demand. However, the Alberta petrochemical industry will not likely expand until it has access to incremental ethane supply.

INFRASTRUCTURE

5.1 Natural Gas Gathering and Processing – 'The Midstream'

There are approximately 692 gas plants in Canada involved in the processing of raw natural gas into marketable gas and NGLs. The majority of these plants are small field plants that process raw natural gas production to remove any impurities such as sulphur, water and other contaminants. Raw natural gas reaches the plants through a network of gathering pipelines. The larger straddle plants focus on incremental extraction and production of NGLs.

5.1.1 Field Plants

Field plants are required to process the gas stream to make it suitable for marketing and transportation. In many cases, the majority of heavier NGLs such as pentanes plus, butane and propane are removed at these facilities to ensure the remaining gas meets the dew point or quality specifications on pipelines. At larger facilities, these liquids may be further separated to the individual product streams, while at smaller facilities the liquids are handled and transported as a mixture. About one-quarter of the ethane produced in Alberta comes from field plants.

T A B L E 5 . 1

Canadian Gas Processing Plants

	# Gas Plants with Activity	Raw Gas Processing Capacity (MMcf/d)
Alberta	619 (of 872)	31 320.5
British Columbia	52	5 753.1
Saskatchewan	20	600.0
Nova Scotia	1	154.2
Total	**692**	**37 827.8**

Source: EUB, Oil & Gas Journal, June 2005

5.1.2 Straddle Plants

Alberta's nine straddle plants account for about 75 percent of the ethane, 40 percent of the propane, 20 percent of the butane and 5 percent of the pentanes plus recovered in Canada. The straddle plants are of particular importance as a source of ethane. The production of ethane and other NGLs from straddle plants is dependent on the flow of gas in the pipeline through the extraction facility and on the NGL content of the gas stream. The extraction efficiency of straddle plants ranges from 40 percent for older technology units to 85 percent for newer turbo-expansion units. Greater deep-cut efficiencies would require additional investment. Appendix 5 shows the straddle plant locations on the Alberta Ethane Gathering System (AEGS) and the current operators.

5.2 Natural Gas Pipelines

Canadian gas production is connected to the North American gas market through a network of thousands of kilometres of pipelines (Figure 5.1) that enables buyers to purchase and transport natural gas from a number of supply sources across the continent.

The Canadian pipeline grid consists of gas gathering, transmission and distribution systems that transport processed natural gas. Once natural gas is produced, it is processed at field gas plants to remove any impurities such as sulphur, water and other contaminants. The processed gas is then collected by gathering systems, which feed into the main transmission pipelines. These transmission pipelines typically transport large volumes of gas at high pressure over long distances from supply sources to more distant market centres. The Canadian gas market is served by several major transmission pipelines, which also interconnect with the U.S. pipeline grid at about a dozen export points. The major straddle plant facilities are located on the major Alberta transmission pipelines.

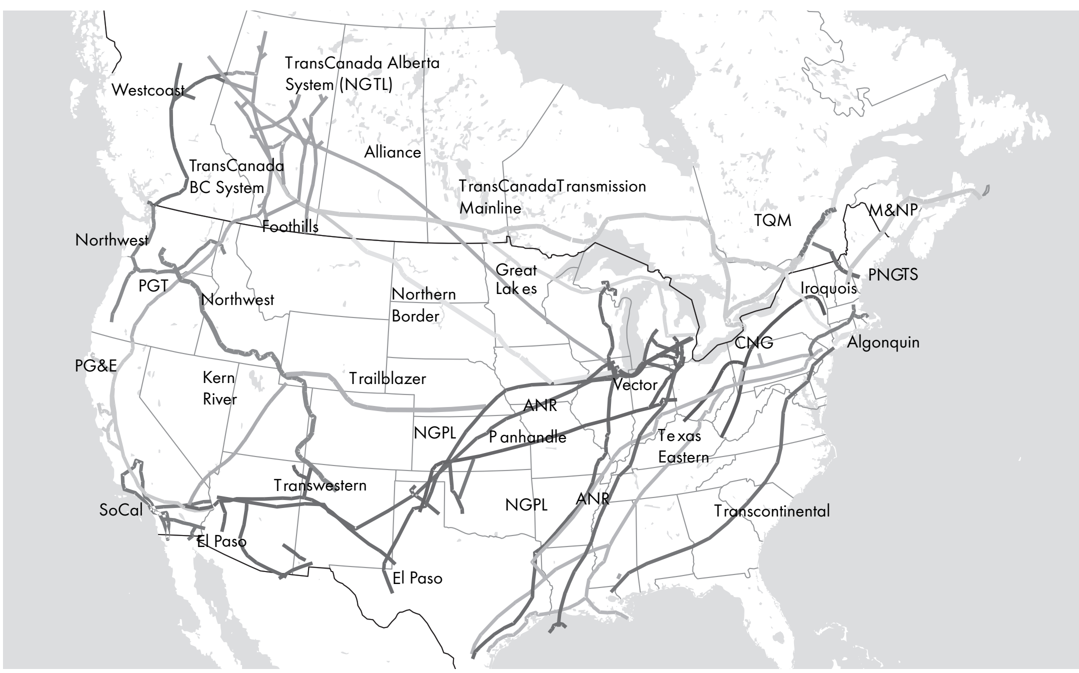
5.3 Distribution and Storage

Distribution systems are the retail component of the pipeline industry. Local distribution companies receive gas from transmission pipelines and deliver it to end-users, such as homes and businesses, within a franchise area.

Partly because of its significant use for heating in residential and commercial settings, the demand for natural gas is very seasonal and can be significantly higher during the winter. As a result, natural gas storage is used to optimize the amount and use of transmission pipelines connecting supply and market regions. Storage capacity located at the market region enables excess supply delivered during the summer to be made available to meet the higher demands during winter. Natural gas storage in the supply regions can also be used to supplement production and manage pipeline flows to meet

FIGURE 5.1

North American Gas Pipeline Grid



unexpected and sudden changes in demand. It can also be used as insurance against unforeseen disruptions or fluctuations that may occur in the production or delivery of natural gas. In these ways, storage acts as a buffer between production and consumption, and helps to reduce the amount of infrastructure and associated costs to transport and distribute gas from the wellhead to the consumer.

In 2004, the working gas capacity of all storage facilities in North America was estimated at over 127.5 billion m^3 (4.5 Tcf) of which about 17.0 billion m^3 (600.1 Bcf), or 13 percent, is located in Canada. Together, North American storage facilities are capable of delivering over 1.1 billion m^3/d (38.83 Bcf/d) of gas during peak periods of demand. Deliverability from Canadian storage during these peak periods can be over 198.3 million m^3 (7.00 Bcf/d) or about 18 percent of the peak North American storage deliverability. Figure 5.2 illustrates the distribution of storage in North America, showing the estimated capacity and the deliverability capability over an entire month.

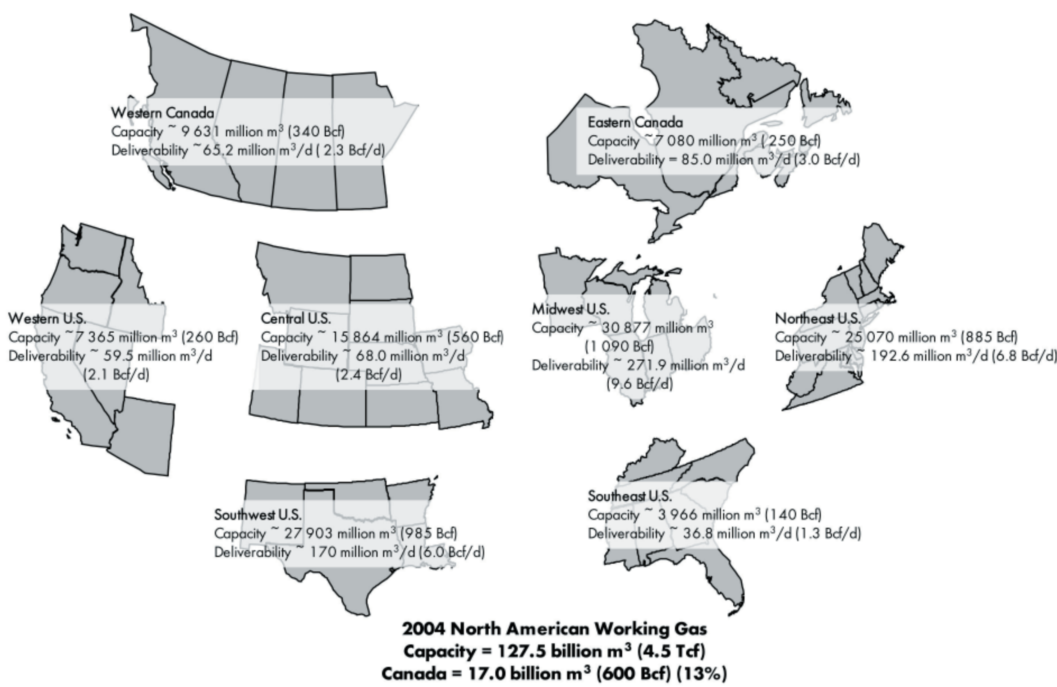
In Canada, the majority of gas storage is split between Ontario, in the east and Alberta, in the west. In Alberta, storage facilities are owned by utilities, midstream companies, pipelines and producers, whereas in Ontario, storage facilities were developed and are owned primarily by utilities. It is proposed that in 2005, 1.7 billion m^3 (60.01 Bcf) of additional storage will be developed in Alberta.

Storage is also widely used for commercial reasons, enabling participants to buy and store natural gas when prices are low and withdraw and sell it when prices are high. In today's environment, with a tight balance between the supply and demand of natural gas in North America, storage plays an increasingly important role in meeting peak North American gas demand. The amount of available, marketable gas in storage has also become a key indicator and influence on seasonal and short-term natural gas prices.

While there has been some new storage capacity and deliverability added over the past decade, storage development has not kept pace with the growth in peak winter gas demand. As illustrated

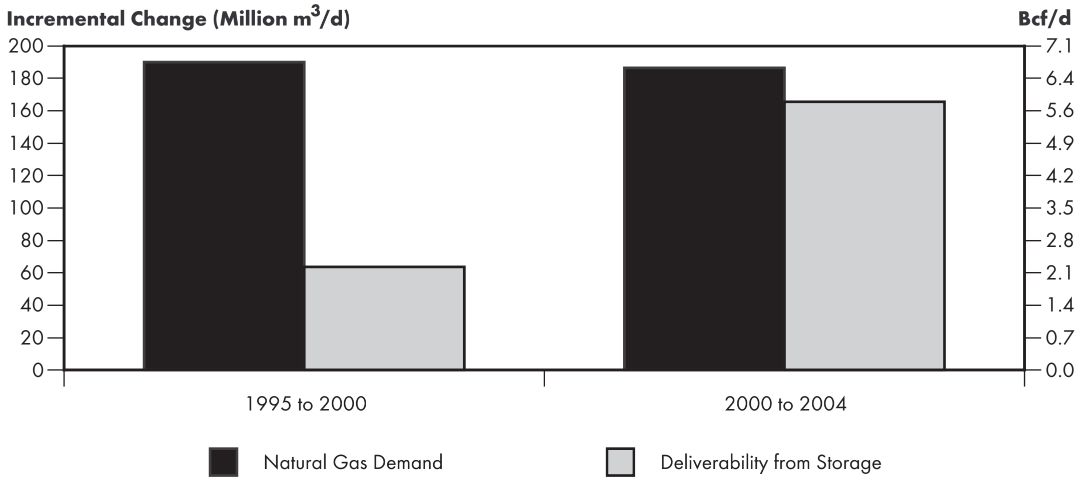
FIGURE 5.2

Distribution of North American Gas Storage - 2004



F I G U R E 5 . 3

Growth in Winter (Jan-Feb) Natural Gas Demand and Storage Deliverability



in Figure 5.3, the average natural gas demand during the months of January and February for North America has increased by about 376.3 million m^3/d (13.28 Bcf/d) over the past decade. Meanwhile, storage deliverability has only increased by about 229.3 million m^3/d (8.09 Bcf/d). Not only is the overall balance between the supply and demand of natural gas in North America now tighter than ever, but also, the ability of using storage to meet regional and seasonal changes in demand is also more limited as peak winter demand has grown at a greater rate.

5.4 Utilization of Natural Gas Infrastructure

In the past, rapid development and significant growth in gas supply from the WCSB supported the growth in infrastructure required to deliver the gas to markets and the expansion of associated facilities to produce natural gas liquids in western Canada.

In recent years, the pace of supply growth from the WCSB has become much slower and traditional markets served by Canadian gas now have the flexibility to access many other sources of gas supply. These potential sources extend beyond traditional indigenous supply and may include access to global LNG, development of new areas (such as gas from the North) and NGC. As the nature and location of gas supply changes so, too, does the need and utilization of specific natural gas infrastructure in Canada.

The requirement for pipelines and infrastructure is also influenced by changes in gas demand. Consumer demand for gas may require increased flows on Canadian pipelines, while increased consumption of natural gas by oil sands operations in western Canada may reduce the amount of gas available for other markets and the flow on transmission pipelines. The growing use of natural gas for electricity generation and heating may also mean greater swings in pipeline flows and greater reliance on natural gas storage to meet peak demands.

Looking ahead to 2006, there are a number of potential changes to North American gas supply and demand that may result in significant changes to the utilization and requirement for Canadian natural gas infrastructure. These possible changes include:

- Declining gas production and growing gas demand in Alberta. Despite the expectation of supportive prices, high drilling and increased production from British Columbia, growing gas demand for oil sands development and declining Alberta production may result in lower flows on western Canadian transmission pipelines.

- Increasing gas supply from the U.S. Rockies region and LNG imports (particularly in the U.S. Gulf Coast) are likely to be key sources of incremental supply to meet growing gas demand in North America. This incremental supply also provides competition to Canadian gas for markets and transportation and may impact Canadian gas flows to particular markets in the west and mid-west.
- Increased gas demand in eastern Canada and the U.S., associated with the growing gas-fired power generation and replacement of coal-fired generation, may require additional infrastructure to access growing supply from the U.S. Rockies and LNG imports along the U.S. Gulf Coast.
- The growing gas demand during summer and winter peak periods will also make greater demands on gas storage. Not only will additional storage be beneficial to optimize pipeline flows and to provide supply during these peaks, but seasonal pipeline flows may also change in response to fluctuating demand and in response to a narrowing window of opportunity to refill storage inventory due to greater summer and winter demands.

5.5 Beyond 2006

There are also significant changes beyond 2006 that may impact Canadian infrastructure in addition to those described previously.

Northern Pipeline Proposals

Several proposals for pipelines to deliver gas from either Alaska or the Mackenzie Delta have been discussed in recent years. The Mackenzie Gas Project application was filed with the Board on 7 October 2004. The project proponents (Imperial Oil Resources Ventures Limited, ConocoPhillips Canada [North] Limited, Shell Canada Limited, ExxonMobil Canada Properties, and the Aboriginal Pipeline Group) plan to deliver 33.8 million m^3/d (1.19 Bcf/d) of gas from the Mackenzie Delta by way of a 1 220 km pipeline along the Mackenzie Valley into northern Alberta. These proposals, if approved, would provide access to additional gas supply and would utilize the existing pipelines throughout western Canada.

LNG Imports

The potential for importing of LNG (refer to Section 3.1.2) into eastern or western Canada or the northeast United States would provide additional gas supply and storage for those growing markets. However, the impact on gas infrastructure will be very dependent on where the LNG is landed in North America. Lateral pipelines may be required to connect the LNG receiving terminals to the main transmission pipelines, and backhaul arrangements or flow reversal of existing pipelines may be necessary to deliver the new gas supply to its market.

5.6 NGL Transportation

Pipelines are usually the most cost efficient mode of transport to move NGLs, followed by railcars and then tank trucks for short distances. Pipelines transport approximately 49 percent of propane and 28 percent of butane exports. Interconnects with the pipeline infrastructure in the U.S. contribute to the higher netback prices realized by western Canadian producers when moving NGLs into the U.S.

In comparison, volumes moving into Quebec and the Atlantic provinces rely on railcars and trucks to reach the end market. The Cochin, Enbridge and Alliance pipelines are the main transmission systems for transporting NGLs from western Canada to markets in the U.S. and Ontario. Figure 5.4 shows the NGL gathering and transmission systems in western Canada.

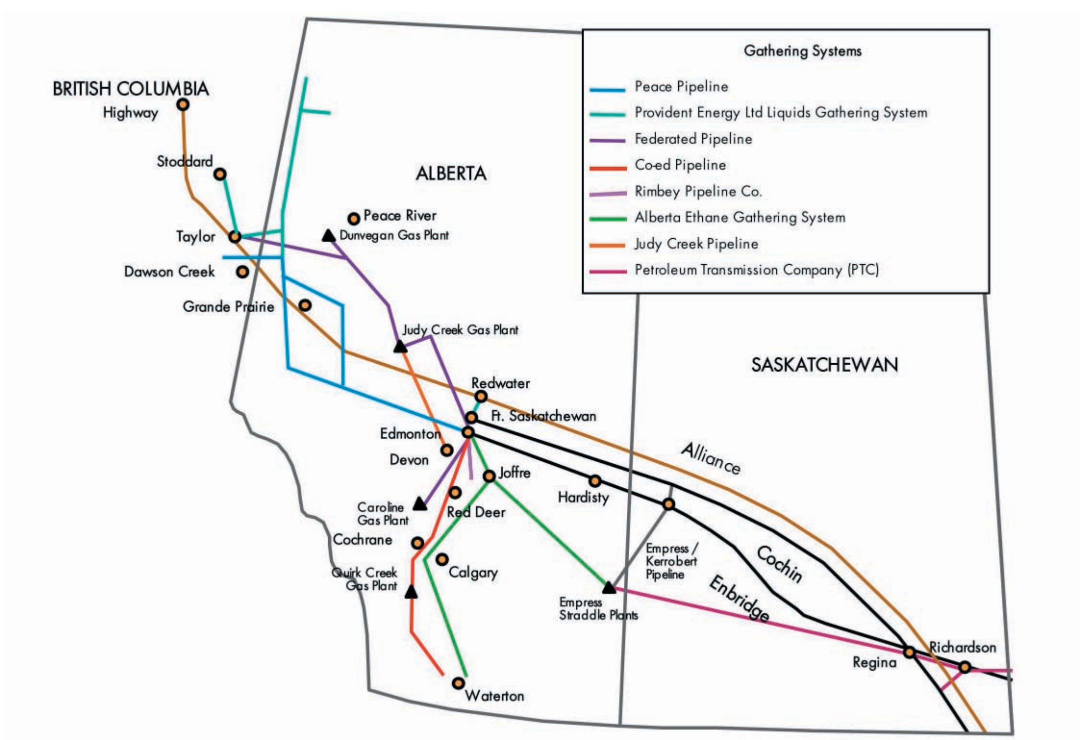
5.6.1 Cochin Pipeline

The Cochin Pipeline system can ship ethane, ethylene, propane and butane from Fort Saskatchewan, Alberta to Sarnia, Ontario. In 2004, the pipeline's total throughput of about 10 320 m^3/d (65 Mb/d) consisted of 65 percent propane, 14 percent ethane and 21 percent ethylene. Prior to September 2002, there were occasional butane shipments. However, since then, there have been no shipments due to its use as a diluent in western Canada and in the production of iso-octane. The Cochin system is connected to a series of truck terminals, connecting pipelines, underground storage facilities and, indirectly, to petrochemical plants. The U.S. portion of the pipeline interconnects with the Mid-America Pipeline Company (MAPCO) system, which ships product to the U.S. Gulf Coast through Conway, Kansas and to the U.S. Midwest and Northeast, and to Ontario.

In January 2003, the design capacity of the pipeline was decreased to about 17 690 m^3/d (105 Mb/d) from the original capacity of about 17 800 m^3/d (112 Mb/d) due to lower utilization. However, a rupture and fire on the U.S. portion of the pipeline in July 2003 has resulted in pressure restrictions. Capacity has varied considerably since then and apportionment will intermittently remain an issue for the outlook period since the pipeline is not expected to return to full operating capacity until the first quarter of 2006. This could affect stock building in the U.S. Midwest for the 2005–2006 winter, possibly resulting in short-term lower Edmonton prices for propane in the summer of 2005.

FIGURE 5.4

NGL Gathering and Transmission Systems in Western Canada



An inability to rebuild inventory at Conway could result in prices at Conway, for the 2005–2006 winter, that are significantly higher than the U.S. Gulf Coast price and this could impact prices in the Edmonton area.

5.6.2 Enbridge Pipelines

The Enbridge Pipeline system extends from Edmonton to the international border near Gretna, Manitoba. The Lakehead system (the U.S. portion of Enbridge) stretches from the international border at Neche, North Dakota to the international boundary near Marysville, Michigan. Enbridge continues on to Sarnia, Ontario.

BP Canada Energy Company (BP) is the only company that ships NGL mix from Edmonton. EnCana Corporation and BP, who together jointly own the Kerrobert Pipeline which connects Empress to Kerrobert, Saskatchewan, ship NGLs to Enbridge. In 2004, throughput, which consisted of a propane plus mix, was about 17 000 m^3/d (107 Mb/d). The approximate composition of the mix in 2004 was a 60:30:10 ratio of propane, butane and condensate, respectively. Beginning in late 2005, the mix will contain propane and butane only, due to the addition of the de-butanizer at an Empress straddle plant.

Enbridge Inc. announced on 16 August 2005 that it received sufficient expressions of interest from potential shippers for the Gateway Condensate Import Pipeline. This pipeline, with an intial planned capacity of 23 850 m^3/d (150 Mb/d), would transport offshore condensate from Kitimat or Prince Rupert, B.C. to Edmonton, Alberta for blending with bitumen. The condensate pipeline is one component of the Gateway Project, which also involves a crude oil export pipeline that would transport crude oil from Edmonton to Kitimat or Prince Rupert to service both the U.S. West Coast and Asia-Pacific markets.

5.6.3 Alliance Pipeline

The Alliance Pipeline system, which transports liquids-rich natural gas from northeast British Columbia and northwest Alberta to a delivery point near Chicago, Illinois, began operation in December 2000. Producers and processors in the WCSB with access to Alliance have an alternative option for the disposition of liquids by leaving them in the gas stream. Liquids are then extracted and fractionated at the Aux Sable Liquids Plant located near Chicago. Shippers on Alliance relinquish the rights to NGLs entrained in the natural gas stream and receive the Chicago gas price, less the tariff for the equivalent heat content.

Note that the market served by the Aux Sable facility is not a new market for Canadian NGL producers. Changing the location for extraction to Aux Sable, simply changes the supply source from Canada to the U.S. Aux Sable produces about 8 700 m^3/d (55 Mb/d) of ethane, 2 800 m^3/d (18 Mb/d) of propane and 1 100 m^3/d (7 Mb/d) of butane.

For producers with access to Alliance, the economics can occasionally favour the additional injection of propane and butane above the indigenous levels of these components. By delivering a richer gas to the U.S. Midwest, producers can often receive a better netback for the propane and butane components. Alliance charges a volumetric toll; therefore, the implicit transportation costs per unit of energy for propane and butane as constituents of a gas stream are much less than for methane. For example, the Alliance toll for methane delivered to Chicago is approximately US$1/MMBtu[8] versus US$0.40/MMBtu for propane (equivalent to US¢3.7/gal on a liquid basis). Delivery of propane to the Midwest via Cochin and MAPCO pipelines as specification product is relatively more expensive.

8 Alliance: Demand Chart 100 percent Load Factor Rate, 19 percent Authorized Overrun Service.

The Alberta NGL market requires producers to compete with the U.S. market to recover more liquids in Alberta. Since there are a number of producers without NGL recovery facilities, Alberta market values would have to provide sufficient compensation to these producers to justify investment in such facilities.

5.6.4 Railcars

The railway sector provides an integral link in the NGL transportation network. Currently, there are 17,000 pressure-rated tank cars in service for all of North America, with approximate capacities of about 125 m^3 to 130 m^3 (33 000 to 34 500 gallons). Propane moves via rail to a variety of markets including the U.S. Midwest, Northeast, and Northwest, and to eastern Canada. Butane movement by rail has declined in recent years, due to its increased use as a diluent within Alberta. Condensate movement into Alberta by rail could become more significant as diluent demand for heavy crude oil remains high. Some condensate has been railed to Alberta from the Aux Sable plant and other points in the U.S. Midwest.

Recently, marketers have raised several issues regarding railcars. First, the average tank car age is increasing. This increases the number of days per year the cars are out of service for maintenance from 60 to 90 days, up from 30 to 45 days. As more tank cars require servicing simultaneously, this creates a bottleneck at the service stations. Secondly, due to high prices in the scrap metal market, resulting from high Chinese demand for steel, many tank cars were taken out of service earlier than in the past. Thirdly, there have been labour problems with the rail companies, which have slowed propane movement in the last two out of three winters. Lastly, tank car leasing companies are trending more towards long-term lease contracts, knowing that the market will be tight in the near term. Therefore, marketers who in the past could possibly get leasing companies to lease cars for only six months of the year have encountered difficulty. The tank car situation is expected to remain tight for at least two years, since there is a 12 to 18 month delay to build new cars.

Another significant but consistent factor exacerbating problems surrounding rail car availability is winter weather. Cold and snow can cause technical difficulties, while propane heating demand is the strongest during these months. Competition for rail capacity from other commodities with high winter demand can also compound the situation, especially during severe winters.

5.7 Underground NGL Storage

The majority of Canadian NGLs are stored in large, underground salt caverns that are located close to major market centres. Aboveground storage spheres store the remainder. Table 5.2 presents Canada's underground NGL storage capacity. Ethane, ethane plus and propane plus storage is located

TABLE 5.2

Canada's NGL Underground Storage Capacity
As of 1 January 2005 (thousand m^3)

	Ethane	Propane	Butane	Mix	Total
Alberta	316	976	502	917	2 710
Saskatchewan	0	405	190	150	745
Ontario	153	1 414	538	409	2 515
Total	**469**	**2 795**	**1 230**	**1 476**	**5 970**

primarily in western Canada close to the fractionators, whereas, specification propane and butane storage capacity is divided almost equally between Ontario and western Canada.

Inventory levels depend on a number of variables including price, production, demand and the season. The level of inventory draw during the winter months is normally dependent on the severity of the weather. Extremely cold weather can draw inventories down at an accelerated rate.

Propane inventories typically follow a cyclical pattern during the year. Inventories decrease from late fall to early spring, to reflect an increase in consumption during the crop drying and heating seasons. On the other hand, inventories increase from late spring into early fall.

Butane inventories are also drawn down in the winter months and built up during the summer, but butane demand is less weather dependent than propane demand. The inventory levels for both regions track each other, but in some instances the drawdown is greater in one area based on demand, particularly by refineries. Butane is used for gasoline blending and alkylation. During the winter, there is increased demand for butane as a blending agent in gasoline because a higher vapour pressure is required during this period to compensate for colder temperatures. Like propane, prices of natural gas and crude oil affect the amount of butane available in inventory. When the price of natural gas is high, less butane could be available because some refiners may burn butane as fuel in place of natural gas.

Since 2000, specification propane storage utilization has ranged from a maximum of 68 percent to as low as 4 percent at the end of the heating season. Similarly, specification butane storage has ranged from 66 percent to 9 percent.

Conclusions

Natural gas prices are set within an integrated North American market and are affected by regional considerations such as transportation costs, infrastructure constraints and by weather fluctuations. However, the crude oil market has become a main driving force underpinning the energy market in the past few years. The competition between natural gas and refined oil products, particularly in the U.S. Northeast, provides the relationship between crude oil and natural gas prices. Natural gas prices are expected to continue to be strongly influenced by the price of crude oil and should generally fall in the price range set by RFO and No. 2 heating oil. Based on expectations that WTI crude oil could average about US$50 per barrel throughout the outlook period, average natural gas prices would be expected to range from US$6.90/MMBtu to US$10.34/MMBtu. Since the crude oil market is currently at the forefront of natural gas price influences, a US$10 per barrel change in oil prices was analyzed to reflect the risk and volatility in the crude oil market. This expands the natural gas price projection range from US$5.51/MMBtu to US$12.41/MMBtu. Nonetheless, it is expected that gas prices will be high and volatile because of the tight balance between supply and demand.

Looking out to 2006, the Board expects natural gas production from Canada and the U.S. to remain fairly flat at approximately 1 930 million m^3/d (68.1 Bcf/d). Canadian deliverability of conventional gas from the largest producing province, Alberta, is expected to decline over the projection period but this decline may be offset by gains from British Columbia and Saskatchewan. The Board expects that U.S. gas production growth will mainly come from the Rockies region. Natural gas from coal, which contains no NGLs, will play a small role in the outlook for Canadian production. Consequently, a significant challenge for the Canadian NGL producers beyond the outlook period will be both the lack of incremental conventional gas available for processing and the lower liquids concentration in gas from other sources. Therefore, limited growth in overall NGL supply is expected.

Supplementing Canadian and U.S. natural gas production will be the growing capacity to import LNG into the U.S., particularly in the U.S. Gulf Coast. While a number of proposed LNG projects are being considered for sites in Canada, none will be in operation by 2006. Therefore, LNG imports will not be a source of NGLs in Canada in the near term, but depending on the origin of the LNG, could be a consideration in the future. Nonetheless, LNG will become an important source of natural gas to meet the gradual growth in North American natural gas demand. Natural gas demand is highly dependent on weather, but there are a few notable segments of demand that are expected to grow more rapidly. By the end of 2006, oil sands operations in Alberta could consume about 28.7 million m^3/d (1.01 Bcf/d), an increase of 8.3 million m^3/d (0.29 Bcf/d) from 2004. In addition, natural gas for power generation in Ontario could increase by up to 5.7 million m^3/d (0.20 Bcf/d) as coal-fired generation is replaced. Natural gas for power generation in the U.S. is also expected to grow to approximately 538.5 million m^3/d (19.01 Bcf/d).

These demand trends have important implications for the availability of natural gas and hence, may impact the recovery of NGLs. In Canada, growing natural gas demand for oil sands operations in Alberta could impact NGL supplies as gas that is directed to the oil sands will not reach the straddle plants for extraction of liquids. Overall, the tight natural gas supply and demand balance has contributed to much higher natural gas prices. For the outlook period, if the premium of crude prices over natural gas narrows, extraction margins for Canadian NGL producers will be reduced. It is anticipated that there could be short periods in the winter when natural gas prices could be higher than crude oil prices. During these periods, producers may opt to leave NGLs, mainly ethane and propane, in the gas stream.

Declining ethane supply and volatile oil and gas prices are the main issues facing the petrochemical sector. Canadian ethane-based ethylene continues to be at an advantage compared to the U.S. Gulf Coast product, and growth in North American ethylene demand remains significant. However, the Alberta petrochemical sector will likely not be able to grow until it has access to incremental feedstock supply.

Petrochemical Pentanes plus, which are used as heavy oil and bitumen diluent are also in short supply. Consequently with bitumen production expected to increase, pentanes plus in Canada will continue to be valued at a premium to WTI.

Under the NEB's 2005–2008 Strategic Plan, it was recognized that policy makers, in particular, would benefit from being advised of the regulatory and related energy issues that need to be addressed. In this context, through information extracted from the research, analysis and comments obtained in the preparation of this report, the following main issues were identified:

1. **High and volatile natural gas prices.** During the outlook period it is expected that natural gas prices will be high and volatile because of tight supplies and the inability to increase supplies quickly. The unpredictability of natural gas prices creates challenges for consumers. Although high gas prices benefit producing provinces, they represent a higher cost for consumers and pose a significant business challenge for many Canadian industries. Canadians are price takers in an integrated North American market that is influenced by international oil prices. Over the outlook period there are few options to address this. However, over the longer term, consumers may need to consider other mechanisms to mitigate the effects of high natural gas prices such as conservation, energy efficiency improvements and research into alternative technologies.
2. **Use of natural gas in oil sands operations.** For oil sands producers, high and volatile natural gas prices mean added uncertainty to the cost of operations. Consequently, suitable replacements for natural gas use are being investigated. This is a market decision; therefore, oil sands producers will make investment decisions that reflect the ongoing economics of their operations. Oil sands operators are currently developing and implementing new technologies, such as bitumen gasification, to reduce natural gas use in their processes. Two bitumen upgrader projects (Suncor and Nexen/Opti Joint Venture) are currently contemplating using asphaltene gasification, but the technology has yet to be proven. For others, increasing consumption of natural gas at oil sands operations further tightens the gas market and contributes to higher prices. Regarding these issues, governments and industry should continue to support research into developing and implementing new technologies, such as bitumen gasification, to reduce natural gas use at oil sands operations.
3. **Gas supply and demand effects on natural gas infrastructure.** As the nature and location of gas supply changes, so too, does the need and utilization of specific natural gas infrastructure in Canada. In particular, changes with respect to increased NGC production and LNG imports to North America may affect the traditional flow of Canadian gas. Changes in consumer demand for gas may change the requirement for pipelines and infrastructure and alter flows on Canadian pipelines. For example, increased consumption

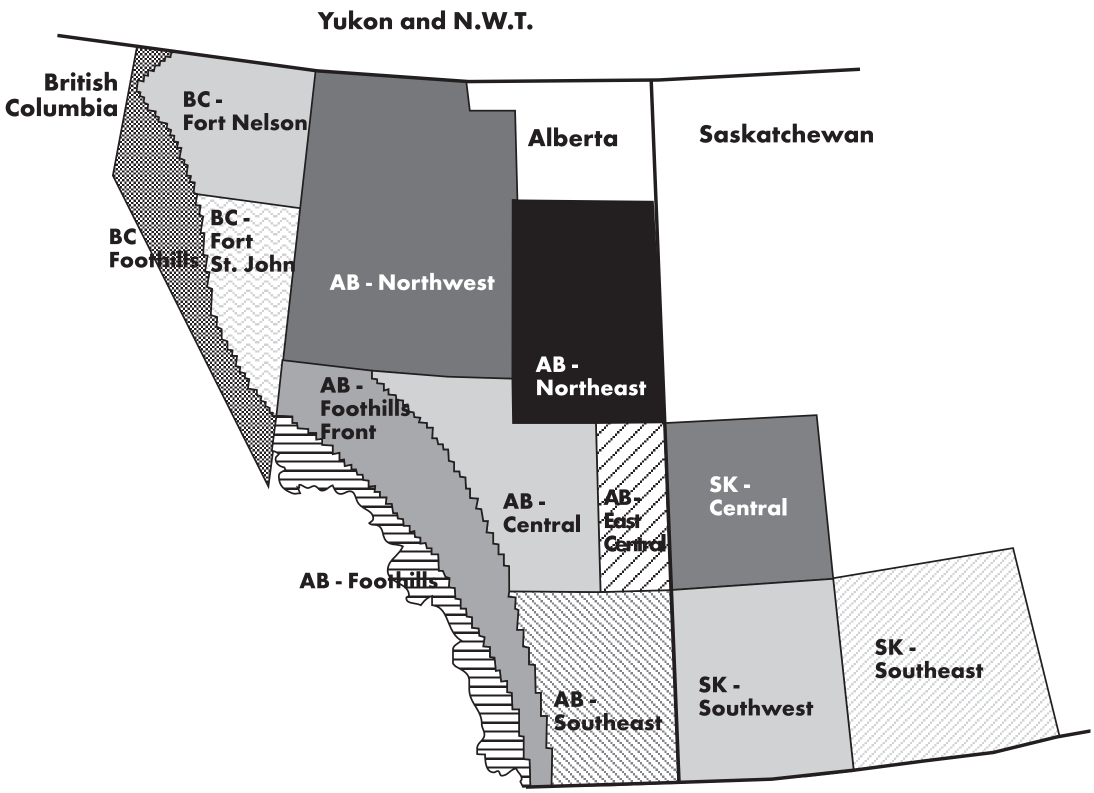
of natural gas by oil sands operations in western Canada may reduce the amount of gas available for other markets and the flow on transmission pipelines. Also, the growing use of natural gas for electricity generation and heating may also mean greater swings in pipeline flows and greater reliance on the use of natural gas storage to meet peak demands. Hence, changes in the existing infrastructure may require new approaches to existing rate design, tolls and tariffs. Beyond this outlook period, possible increases in LNG imports in Canada and accessing natural gas from the North, may require new delivery and storage infrastructure, which are costly, often have long lead-times and involve multiple jurisdictions. New approaches to regulatory integration and clear, efficient and timely regulatory approvals will be required in order to bring new projects to fruition.

4. **NGL supply and demand effects on NGL infrastructure.** NGL mixes can be further separated into ethane, propane, butane and pentanes plus, which all have specific end-use markets. In Canada, the majority of the propane is exported. Domestic use for butane has been increasing due to its use as a heavy crude oil diluent although some volumes continue to be exported. Pentanes plus supply is tight, and the outlook is for significantly increasing demand for use as diluent for heavy oil and bitumen, but it can be imported in small volumes. Of all the NGLs, a major issue lies with a tight ethane supply, since the Canadian petrochemical industry is primarily ethane-based. There are a few possible options to gain access to incremental ethane supply. These include upgrading existing straddle plants to take a deeper cut of ethane. New infrastructure could also be added to extract more liquids from gas streams that currently do not flow past existing straddle plants and from gas streams going to the oil sands. Alternatively, there could also be benefits in modifying and diversifying the petrochemical industry focus away from ethane to other feedstocks such as propane or synthetic gas liquids from upgrader and refinery processes. The optimal choice will depend on the economics and views on the potential for incremental gas supply and changing gas flows in North America.

WCSB Geographic Regions

FIGURE A1.1

WCSB Geographic Regions



Alliance Gas Composition

TABLE A2.1

Alliance Gas Composition

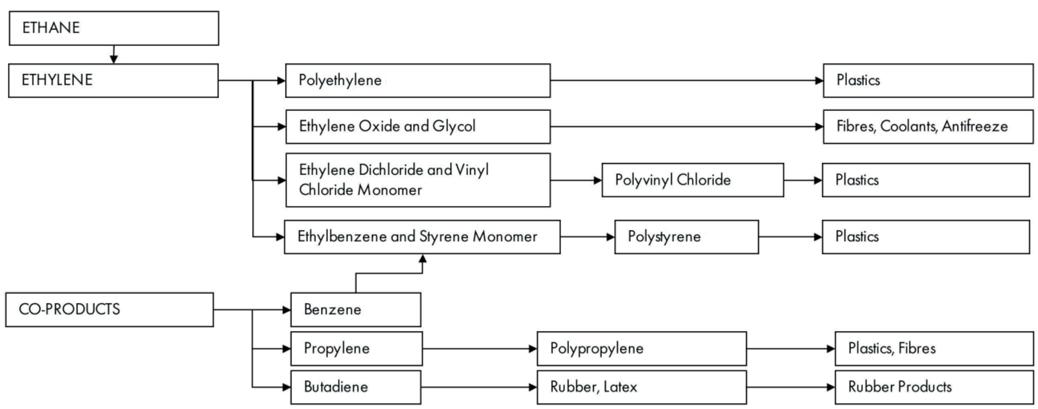
Component	Mole % (Assuming a heat content of 1 082 Btu/cf)
N_2/CO_2	1.00
C_1	90.97
C_2	5.50
C_3	1.80
C_4	0.60
C_{5+}	0.13
Total	**100.00**

Source: Alliance Pipeline Company

ETHANE, ETHYLENE AND DERIVATIVE APPLICATIONS

FIGURE A3.1

Ethane, Ethylene and Derivative Applications

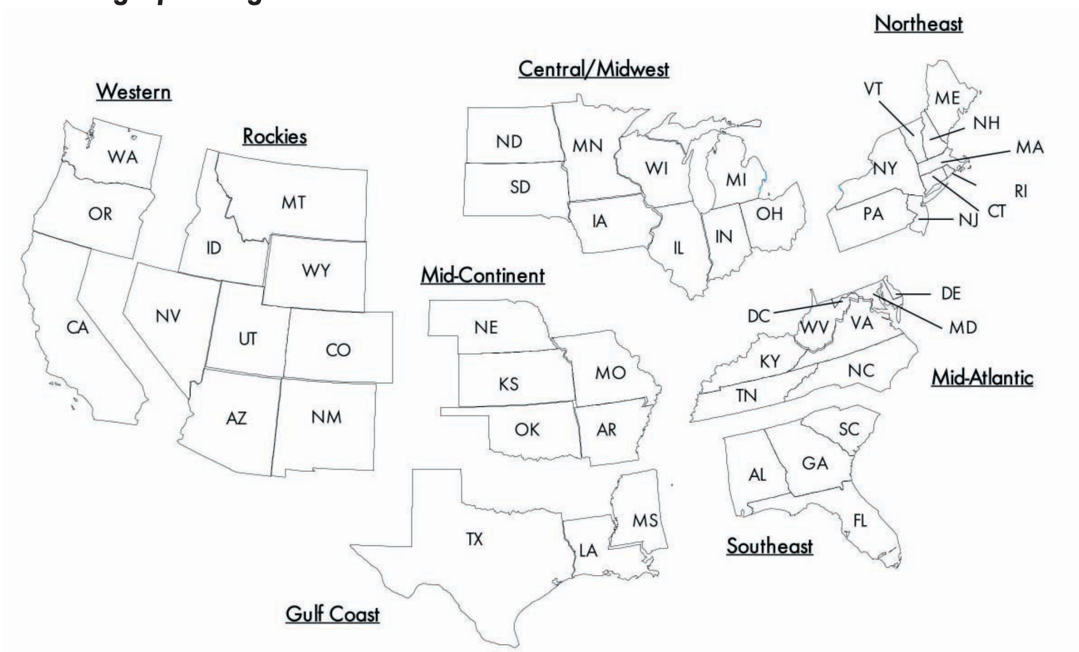


Source: Canadian Chemical Producers' Association (CCPA)

U.S. GEOGRAPHIC REGIONS FOR NATURAL GAS

F I G U R E   A 4 . 1

U.S. Geographic Regions for Natural Gas

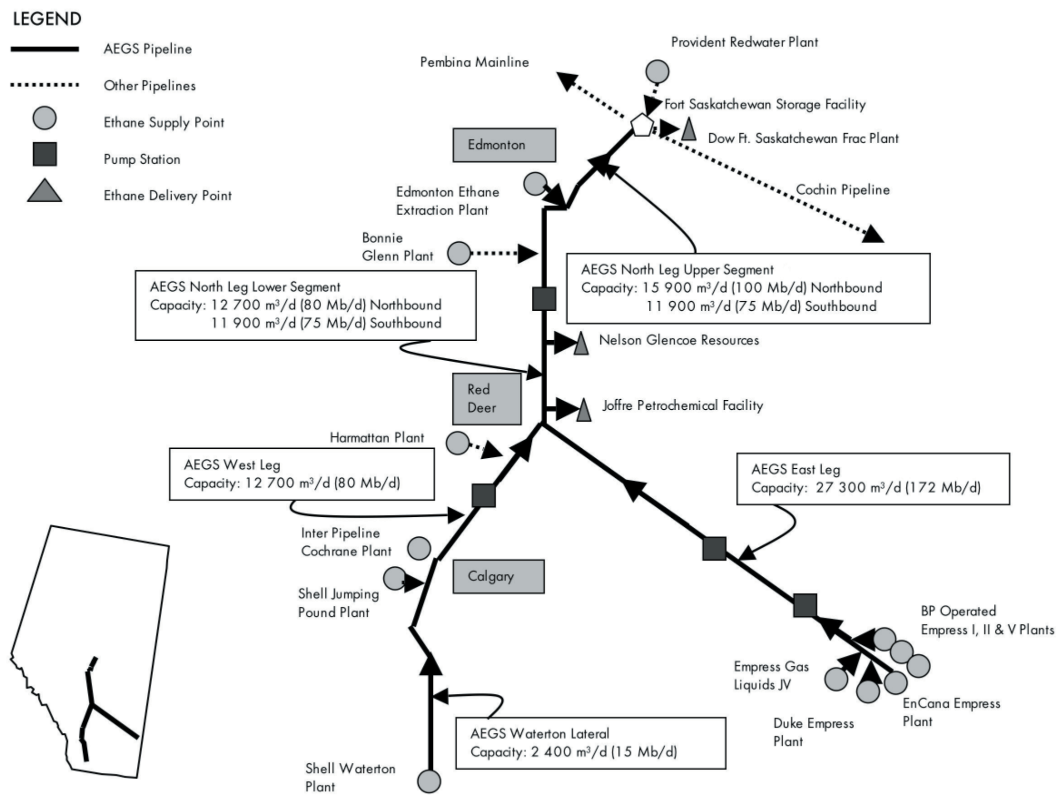


Western		Gulf Coast		Mid-Continent		Southeast	
CA	California	LA	Louisiana	AR	Arkansas	AL	Alabama
OR	Oregon	MS	Mississippi	KS	Kansas	FL	Florida
WA	Washington	TX	Texas	MO	Missouri	GA	Georgia
				NE	Nebraska	SC	South Carolina
				OK	Oklahoma		
Rockies		**Central/Midwest**		**Northeast**		**Mid-Atlantic**	
AZ	Arizona	IA	Iowa	CT	Connecticut	DC	District of Columbia
CO	Colorado	IL	Illinois	MA	Massachusetts	DE	Delaware
ID	Idaho	IN	Indiana	ME	Maine	KY	Kentucky
MT	Montana	MI	Michigan	NH	New Hampshire	MD	Maryland
NV	Nevada	MN	Minnesota	NJ	New Jersey	NC	North Carolina
NM	New Mexico	ND	North Dakota	NY	New York	TN	Tennessee
UT	Utah	OH	Ohio	PA	Pennsylvania	VA	Virginia
WY	Wyoming	SD	South Dakota	RI	Rhode Island	WV	West Virginia
		WI	Wisconsin	VT	Vermont		

AEGS SYSTEM

FIGURE A5.1

AEGS System



Straddle Plant	**Operator**	**Raw Gas Processing Capacity**	
		million m³/d	**Bcf/d**
Empress I	BP Canada Energy Company	n/a	n/a
Empress II	BP Canada Energy Company and Inter Pipeline Fund	73.6	2.6
Empress V	BP Canada Energy Company and Inter Pipeline Fund	31.2	1.1
Empress Gas Liquids JV (EGLJV)	ATCO Midstream	31.2	1.1
Duke Empress	Duke Energy Empress LP*	68.0	2.4
EnCana Empress	EnCana Corporation	33.8	1.2
Cochrane	Inter Pipeline Fund	70.8	2.5
Edmonton Ethane Extraction Plant (EEEP)	ATCO Midstream and ATCO Gas	10.2	0.4
Joffre Ethane Extraction Plant (JEEP)	Taylor Management	n/a	n/a

*Duke Energy Gas Transmission purchased ConocoPhillips Company's interest in the Empress system effective 1 August 2005.

n/a not available

Source: EUB; company sources

Web Sites of Interest

Alberta Department of Energy www.energy.gov.ab.ca

Alberta Energy and Utilities Board www.eub.gov.ab.ca

British Columbia Ministry of Energy, Mines and Petroleum Resources www.em.gov.bc.ca

British Petroleum (BP). *Statistical Review of World Energy 2005*. 54th Edition
www.bp.com/genericsection.do?categoryId=92&contentId=7005893

Canada - Nova Scotia Offshore Petroleum Board www.cnsopb.ns.ca

Canadian Association of Petroleum Producers (CAPP) www.capp.ca

Canadian Chemical Producers' Association www.ccpa.ca

Canadian Gas Association www.cga.ca

Canadian Industrial Energy End-Use Data and Analysis Centre
www.cieedac.sfu.ca/CIEEDACweb/mod.php?mod=pub&op=user&menu=1601

Canadian Society of Unconventional Gas (CSUG) www.csug.ca

Energy Information Administration (EIA) www.eia.doe.gov

Industrial Gas Users Association www.igua.ca

International Energy Agency (IEA) www.iea.org

National Energy Board (NEB) www.neb-one.gc.ca

Natural Resources Canada www.oee.nrcan.gc.ca

Statistics Canada www.statcan.ca

Glossary

Alkylate	A high-octane product from alkylation units. An alkylation unit is a refining process for chemically combining isobutane with olefin hydrocarbons (e.g., propylene, butylene) through the control of temperature and pressure in the presence of an acid catalyst, usually sulphuric acid or hydrofluoric acid. The product, alkylate, an isoparaffin, is blended with motor and aviation gasoline to improve the antiknock value.
Bitumen	A highly viscous mixture, mainly of hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Condensate	The light liquid hydrocarbons separated from crude oil after production, and the mixture of pentanes and heavier hydrocarbons separated from natural gas production. Also, see *pentanes plus*.
Crude oil	A mixture of mainly pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable except raw gas, condensate or bitumen.
Crude oil (heavy)	Generally, a crude oil having a density greater than 900 kg/m^3.
Deep-cut facilities	A gas plant next to or within gas field plants that can extract ethane and other natural gas liquids using a turbo expander.
Deliverability	The amount of natural gas a well, reservoir, storage reservoir or producing system can supply at a given time.
Derivative	A compound chemically derived or obtained from another and containing essential elements of the parent substance.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport on crude oil pipelines.

Distillation	Process of purifying a liquid mix into separate fractions by successive reboiling steps to obtain separation.
Enhanced oil recovery	Any method for enhancing oil recovery from a pool or what would be obtained through natural depletion.
Ethane plus	Mixture of natural gas liquids consisting of ethane and heavier hydrocarbons.
Ethylene	A chemical building block made up of two carbon atoms and four hydrogen atoms used to manufacture plastics, solvents, pharmaceuticals, detergents and additives.
Extraction	The process of separating hydrocarbons (ethane, propane, butane, pentanes plus) from raw gas.
Feedstock	In this report, feedstock refers to raw material supplied to a refinery, oil sands upgrader or petrochemical plant.
Field plant	A plant near the source of gas, which processes raw gas and is located upstream of pipelines which move the gas to markets. These plants remove impurities, such as water and hydrogen sulphide, and may also extract natural gas liquids from the raw gas stream.
Fraction	All the compounds that boil at a specified boiling point range.
Fractionator	A facility where mixed liquid streams, such as ethane plus, are separated into component parts. Includes de-ethanizers, depropanizers, debutanizers, condensate strippers, ethylene and propylene splitters.
Fuel value	Value of a product based on its use as a fuel.
Gasoil	Categorized under the middle distillate cut of crude oil.
Gulf Coast	Includes the U.S. states of Texas, Louisiana and Mississippi.
Heating oil	Also known as No. 2 fuel oil. A distillate fuel oil commonly used for household space heating.
Hub	A geographic location where large numbers of buyers and sellers trade a commodity and where physical receipts and deliveries occur.
Hydrocarbons	Organic compounds of hydrogen and carbon atoms that form the basis of all petroleum products. Hydrocarbons may be liquid, gaseous or solid.
In Situ Recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Liquefied petroleum gas	A mixture of mostly propane and some butane. This term is used globally because most propane and butane supplies in the world, with the exception of Canada and the U.S., come from refinery processes.
Marketable natural gas	Natural gas that has been processed to remove impurities and natural gas liquids. It is ready for market use.

Middle distillates	The portion of refined petroleum products that includes jet fuel, diesel, naphtha and heating oil.
Miscible	Phases that can mix and form a homogeneous mixture. Hydrocarbon gases and liquids are commonly miscible.
Naphtha	Categorized under the middle distillate cut of crude oil. Includes end products such as benzene, toluene and xylene.
Natural gas from coal	The naturally occurring dry, predominantly methane gas produced during the transformation of organic matter into coal.
Natural gas liquids	The hydrocarbon components recovered from processing natural gas. This generally includes ethane, propane, butane, pentanes and heavier hydrocarbons.
Natural gasoline	See *pentanes plus*.
NGL rejection	North American gas plant operators bypass the plant facilities to adjust operations to minimum liquids recovery levels.
Off-gas	Natural gas produced from the bitumen production in the oil sands. This gas is typically rich in natural gas liquids and olefins.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Pentanes plus	A mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil.
Price differential	The difference in prices between two trading points or two commodities.
Propylene	A chemical building block made up of three carbon atoms and six hydrogen atoms used to manufacture plastics, solvents, pharmaceuticals, detergents and additives.
Residual fuel oil	The remaining refinery product after the removal of more valuable fuels such as gasoline and middle distillates. It is used primarily for power generation and fuel for various industrial processes.
Rockies	Includes the U.S. states of Montana, Wyoming, Colorado, Utah, Nevada, Arizona and New Mexico.
Solvent flood	An enhanced recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.
Specification product	A crude oil or refined petroleum product with defined properties .
Spot sale	Transactions which are generally for 30 days or less.

Straddle plant	A reprocessing plant located on a pipeline that extracts natural gas liquids from previously processed gas before such gas leaves or is consumed within the province.
West Texas Intermediate	A commonly used benchmark price for light sweet crude oil produced in the U.S. and refined in North America. WTI refers to the price of a particular grade of crude oil for delivery at Cushing, Oklahoma.
Working gas	The amount of gas in a storage facility above the amount needed to maintain a constant reservoir pressure.