National Energy Board

Office national de l'énergie

# Canadian **Natural Gas** Market

## **D**ynamics *and* **P**ricing: An Update

gas gas gas gas

An **ENERGY MARKET ASSESSMENT** • October 2002

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# ACRONYMS

| | |
|---|---|
| AECO-C or AECO | Alberta Energy Company storage facility |
| AEUB | Alberta Energy and Utilities Board |
| BC GAS | BC Gas Utility Ltd. |
| BCUC | British Columbia Utilities Commission |
| CENTRA B.C. | Centra Gas British Columbia Inc. |
| CENTRA GAS | Centra Gas Manitoba |
| CPL | Champion Pipe Line Corporation Limited |
| EGNB | Enbridge Gas New Brunswick |
| EMA | Energy Market Assessment |
| ENBRIDGE | Enbridge Gas Distribution Inc. |
| ENMAX | Enmax Energy Corporation |
| ENRON | Enron Corporation |
| EPCOR | Epcor Energy Services Inc. |
| FERC | Federal Energy Regulatory Commission |
| GDAR | Gas Distribution Access Rule |
| GMi | Gaz Métropolitain and Company, Limited Partnership |
| LDC | Local distribution company |
| LNG | Liquefied Natural Gas |
| M&NP | Maritimes and Northeast Pipeline |
| MBP | Market-Based Procedure |
| NEB | National Energy Board |
| NGMA | Natural Gas Market Assessment |
| NYMEX | New York Merchantile Exchange |
| OEB | Ontario Energy Board |
| P.E.I. | Prince Edward Island |
| PGVA | Purchase Gas Variance Account |
| PNG | Pacific Northern Gas Ltd. |
| PNW | Pacific Northwest |
| Régie | Régie de l'énergie du Québec |
| SASKENERGY | SaskEnergy Incorporated |
| SEMPRA ATLANTIC | Sempra Atlantic Gas Inc. |
| SOEP | Sable Offshore Energy Project |
| TQM | Trans Québec & Maritimes Pipeline Inc. |
| TRANSCANADA | TransCanada PipeLines Limited |
| TRANSGAS | TransGas Limited |
| UNION | Union Gas Limited |
| U.S. | United States |
| VECTOR | Vector Pipeline Inc. |
| WCSB | Western Canadian Sedimentary Basin |

# METRIC TO IMPERIAL

| *Metric* | *Imperial Equivalent Units* |
|---|---|
| 1 cubic metre of natural gas | = 35.301 01 cubic feet (14.73 psia and 60ºF) |
| 1 gigajoule (GJ) | = approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf |

# UNITS

| *Prefix* | *Multiple* |
|---|---|
| MMcf | = million cubic feet |
| Bcf | = billion cubic feet |
| Tcf | = trillion cubic feet |
| GJ | = $10^9$ joules |
| TJ | = $10^{12}$ joules |
| Btu | = British thermal unit |

All prices shown in this EMA are expressed in Canadian dollars, unless otherwise stated.

# FOREWORD

As part of its regulatory mandate, the National Energy Board (NEB or the Board) continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas and their by-products) and the demand for Canadian energy commodities in both domestic and export markets.

In 1987, the Board adopted the Market-Based Procedure (MBP) for assessing applications for long-term natural gas export licences. The MBP is based on the premise that the marketplace will generally operate such that Canadian requirements for natural gas will be met at fair market prices. The MBP consists of a public hearing component and a monitoring component.

The monitoring component of the MBP involves an ongoing assessment of Canadian energy markets and results in the publication of *Canadian Energy Supply and Demand* reports as well as a series of *Natural Gas Market Assessment* (NGMA) reports. As a result of the increasing level of integration within energy markets, the Board expanded its energy market monitoring program in the late 1990s to include studies related to all major energy commodities. The enhanced monitoring program led to the development of *Energy Market Assessments* (EMAs) and, to date, EMAs on natural gas, oil and electricity have been published. The EMA program includes what were previously known as NGMAs, as well as *Canadian Energy Supply and Demand* reports.

This EMA, entitled *Canadian Natural Gas Market Dynamics and Pricing: An Update*, discusses natural gas price formation and describes the current functioning of regional gas markets in Canada. However, this EMA does not provide a short-term outlook for supply, demand or prices in Canada. The Board is currently assessing the short-term outlook for gas supply from the Western Canada Sedimentary Basin (WCSB); more information on this project will be provided by the end of 2002.

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

# INTRODUCTION

This EMA is an update to the EMA entitled: *Canadian Natural Gas Market Dynamics and Pricing* published in November 2000. At the time of publishing that EMA, the price of natural gas in North America was increasing and the expectations were that the price would continue to increase substantially through the 2000/2001 winter heating season. Within this context, the EMA discussed the factors affecting the price of natural gas in Canada and examined natural gas markets on a region-by-region basis.

The *Canadian Natural Gas Market Dynamics and Pricing* EMA found that:

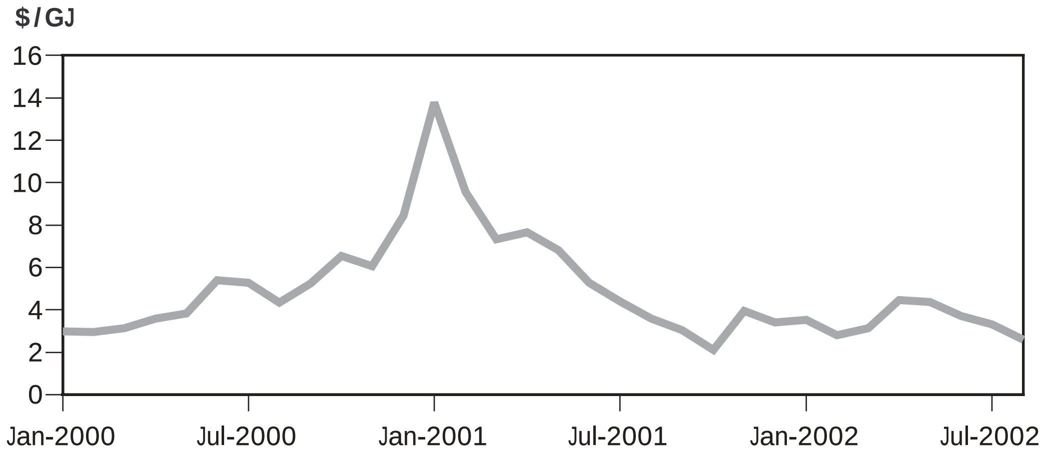
- Canada is part of an integrated North American market where natural gas is traded on a daily basis with prices reflecting demand and supply factors in both Canada and the United States;
- Strong growth in the demand for natural gas outpaced the growth in supply due to lower levels of drilling and production arising from reduced cash flows of producers during the low oil price environment of 1997/1998;
- Natural gas prices increased significantly from 1999 to 2000 in response to increased demand and lower levels of supply;
- A period of market adjustment is necessary any time the dynamic between supply, transportation and demand is significantly changed;
- Electronic trading systems have enhanced price discovery while active spot and futures markets allow market participants to manage price volatility by contracting on a forward basis; and
- Canadians have had access to natural gas on terms and conditions, including price, no less favourable than export customers.

Following the publication of the *Canadian Natural Gas Market Dynamics and Pricing* EMA in early November 2000, North American natural gas prices continued to rise reflecting unusually low levels of natural gas in storage at the start of the 2000/2001 winter heating season. Record cold weather later in November and during December 2000 exacerbated already high gas prices leading to price spikes as evidenced by an average spot price of $13.84/GJ for January 2001 at AECO-C in Alberta (Figure 1.1).

Moreover, natural gas price shocks were unevenly felt across the North American gas market. The continental market, which had been integrated for several years, became temporarily disconnected, with Western markets being strongly influenced by the California “energy crisis.” Very low rainfall in the Pacific Northwest (PNW) and California in 2000 significantly reduced the availability of hydroelectricity in these markets; consequently, gas-fired power generation was required to make up the difference. At the same time, California was also experiencing an exceptionally cold winter and

**F I G U R E 1 . 1**

***AECO-C Gas Prices***




Source: Canadian Natural Gas Focus

low gas storage levels. The resulting increase in gas demand due to weather and power generation strained an already full gas pipeline system into the region. Further, transmission capacity delivering natural gas to the California border exceeded the capacity of California's pipeline system to transport the gas within the state. These factors led to sharply increased gas prices in California which were transmitted back to British Columbia and resulted in prices at the border in the order of $20/GJ by early 2001.

In response to the unprecedented high gas prices in early 2001, residential and commercial consumers reacted by conserving natural gas use. Government agencies implemented a range of strategies to shield these consumers from high natural gas prices. Many industrial end-users switched to cheaper fuels; in some cases, plant operations were reduced or shut down to avoid high fuel costs. Producers also responded to the higher prices by drilling gas wells at an unprecedented rate.

By late January, the cold weather was replaced by milder weather across North America. Gas prices eased, although they remained relatively high. The effects of milder weather, conservation, fuel-switching and a weakening economy began to noticeably reduce natural gas demand and led to "demand destruction."[1] In spring 2001, gas demand continued to decrease as industrial consumers continued to switch fuels and reduce operations. As well, record drilling began to result in a small increase in gas production. With lower demand and higher production, gas was delivered to storage reservoirs at higher than normal rates. These factors combined to place downward pressure on gas prices.

The mild weather continued through summer 2001. Without the anticipated surge in demand for electricity to meet air-conditioning requirements, gas-fired generation, and hence the demand for gas, was reduced. Weak demand and increased production provided the opportunity to replenish storage reservoirs at a record pace. As a result, gas prices steadily declined to below US $2.00/MMBtu by the end of the summer. With lower prices, some industrial customers switched back to burning natural gas and other end-users resumed operations at their facilities. However, a weakening economy continued to temper industrial gas demand.

1 Refer to section 2.5.1 for further discussion of demand destruction.

The economy further stumbled following the acts of terrorism in the United States in September 2001. Natural gas production continued to increase in early fall and storage levels climbed to record levels. In fact, almost 68 $10^9m^3$ (2.4 Tcf) of natural gas is estimated to have been added to storage during 2001 - a rate 50 percent higher than the previous year. But, in anticipation of the upcoming heating season, gas prices began to rebound from their lowest levels in late summer to US $2.50 to $3.00/MMBtu at the beginning of the heating season.

The winter of 2001-2002 began as an almost exact opposite of the previous winter, as November and December 2001 were among the warmest ever across North America. Mild weather through most of the year, in combination with consumer responses to high prices at the beginning of the year, resulted in North American gas demand decreasing by five percent or 36.8 $10^9m^3$ (1.3 Tcf) in 2001. This was the biggest demand loss in North America since 1982. In Canada, industrial gas demand in 2001 declined by eight percent from 2000.

However, gas production increased only marginally despite record drilling in 2001. Following a 25 percent increase in gas well completions, Canadian gas production increased by only 1.7 percent to about 496 $10^6m^3$ per day (17.5 Bcf/d), reflecting a large increase in drilling less expensive, quick to drill, shallow gas wells which are generally low productivity wells. U.S. gas production in 2001 increased by 1.8 percent to about 1 470 $10^6m^3$ per day (51.9 Bcf/d).

Gas prices remained under US $3.00/MMBtu through early winter 2001/2002 as gas storage levels were very high and the outlook for gas demand was reduced by unseasonably warm weather. In turn, producers began to scale-down drilling operations.

By late winter, cold weather arrived in most North American gas markets; the large year-on-year storage surplus began to drop; the economy was showing some improvement; and gas production started to wane with reduced drilling. Gas prices began to increase in response to these "bullish" gas market fundamentals and to a sharp increase in crude oil prices.

Despite leaving the heating season with more gas in North American storage than when entering the heating season, gas prices remained robust amid concerns of declining U.S. gas production. A surprise to many industry analysts, preliminary estimates of U.S. gas production (based on surveys of producers) indicated a year-on-year decline of more than four percent by June 2002. Further, drilling activity has remained low through the summer, particularly in the United States, indicating that gas production is not likely to increase soon. Consequently, injections to storage during the refill season (normally April through October) have been weaker than last year, but storage levels have continued to be unusually high since the start of the refill season. At publication date, gas prices remain firm but tempered by high storage levels in North America and lower than expected gas demand as the U.S. economy remains sluggish. However, with the winter season of 2002/2003 approaching, a tightening between supply and demand is expected by some industry analysts to result in price volatility, despite the likelihood of entering winter with gas storage full. It is in this context that this update to the November 2000 EMA is presented.

This EMA begins with a discussion of natural gas price formation, covering the factors affecting natural gas pricing, the structure of market transactions and market adjustment mechanisms. The next chapter presents an overview of regional Canadian gas markets including local gas pricing. The final chapter describes current energy market issues and the EMA concludes with observations on the functioning of the Canadian natural gas market.

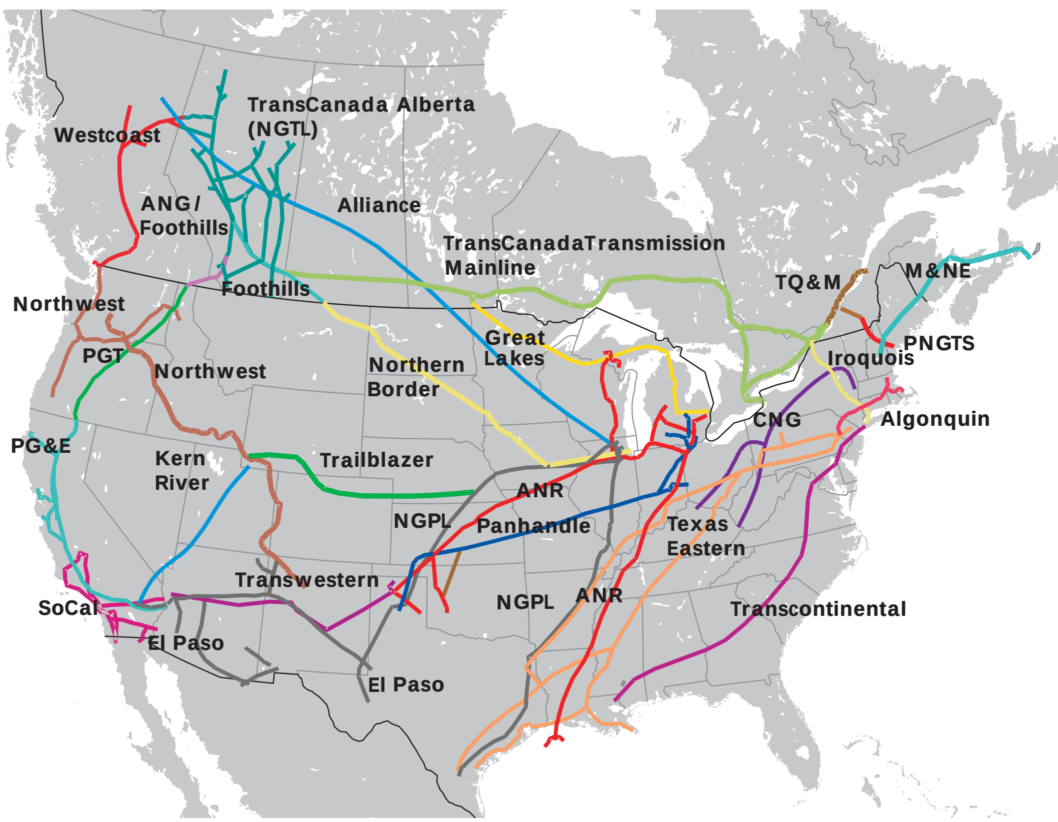
# NATURAL GAS PRICE FORMATION

## 2.1 Introduction

The price of natural gas that end-users such as residential consumers pay comprises the gas commodity, transportation and distribution charges, and depends on the volume of gas purchased. The transportation cost, which is the cost of moving gas by pipeline to a utility or distribution company, is determined by regulation. The NEB regulates interprovincial and international pipeline transportation in Canada and the Federal Energy Regulatory Commission (FERC) regulates interstate and international pipeline transportation in the United States. These Canadian and U.S. pipelines form the North American gas pipeline grid (Figure 2.1). In both countries, the distribution fees are normally regulated by provincial, territorial or state regulators.

FIGURE 2.1

***North American Gas Pipeline Grid***



Generally, until recently, the largest portion of the delivered price to residential customers has been the cost of transporting the gas from the supply basin to the end-user with the commodity cost contributing the second largest share. Interprovincial, interstate, and international pipelines require large capital investments, but as the flow through each segment is quite large, unit costs are low. Local distribution of gas is more costly on a unit basis because a massive network is required to deliver relatively smaller gas volumes at numerous delivery points. The large infrastructure required relative to the flow of gas results in higher capital and operating costs per unit. The differences in the prices to end-users reflect differences in the cost of the elements of the final delivery of gas services. In general, those with the highest load factor pay the lowest per unit price.

This report mainly focuses on the commodity price of gas, with some reference to transportation issues as they impact gas prices. Before 1985, gas was sold to end-users as part of a bundled product, including the cost of transportation, and it was traded under long-term contracts. In Canada, gas sales were unbundled in 1986 and in the U.S. in 1992. This development paved the way for the creation of competition in the natural gas sales market and quickly led to a revolution in the way natural gas was traded. The most important developments were:

- the commoditization of natural gas;
- a move to short-term sales; and
- the integration of several regional markets into a North American natural gas market.

This chapter discusses pricing of natural gas, including each of the above topics, as well as the factors that influence gas demand and supply, and price volatility.

## 2.2 Structure of Market Transactions

The trading of natural gas continues to evolve throughout Canada and the United States. Natural gas is contractually committed to be purchased and sold both on a short-term and long-term basis. Prices are referenced to specific locations, known as trading hubs, where natural gas is physically sold and purchased. The price of natural gas traded may be established on an intra-day, daily, monthly, seasonal, annual, or longer-term basis in reference to the particular trading hub. The sale of gas in the short-term (less than 30 days) is often referred to as the spot market. While natural gas may be contractually sold on a long-term basis, the actual contractual price is often based upon a monthly reference price at a trading hub that is different from the contractual location.

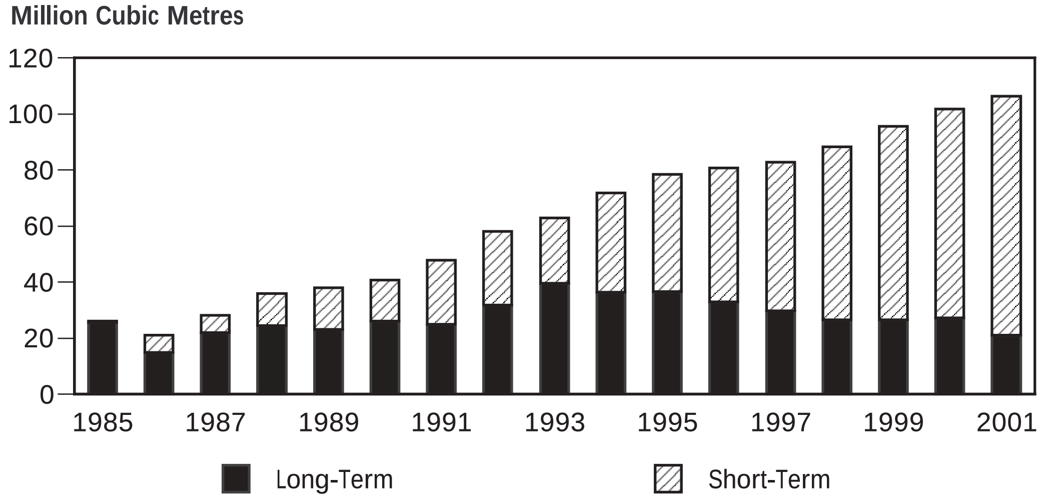
The liquidity of the market decreases as the contractual length of the term increases. The number and volume of trading transactions are greatest for one to three-month contracts. The trend towards a short-term focus of natural gas prices and trading is evidenced by the substantial increase in short-term export orders (which have a term of less than two years) to remove natural gas from Canada. Exports under short-term orders are increasing while exports under long-term licences, covering terms greater than two years, are decreasing (Figure 2.2).

## 2.3 Integration of the North American Market

Since 1985, the Canadian and U.S. gas markets have increasingly evolved into an integrated North American market. Natural gas can be bought from many supply sources and delivered to any market centre through an extensive North American pipeline grid. With the increased integration of markets, regional supply and demand forces are felt throughout the marketplace.

## FIGURE 2.2

### *Short-Term and Long-Term Gas Exports*




Source: NEB

Changing market conditions impact prices and influence North American gas flows. For example, suppose that the price of natural gas in the U.S. Midwest rose relative to California. In such a situation, Canadian and U.S. natural gas sellers would prefer to sell in the U.S. Midwest because the returns would be higher. More supplies would be offered in the U.S. Midwest and sellers would divert their volumes from California. As more supplies were offered in the U.S. Midwest, the price would tend to fall; conversely, as less natural gas was offered in California, the price would tend to rise. This process would continue until sellers were indifferent between selling in either market.

Gas moves between locations when there is a sufficient price differential between locations to cover the cost of operating the pipeline connecting the locations. In numerical terms, if the cost to move gas between two points was \$ 0.25/GJ and the difference in gas prices (price differential) between those two points was \$ 0.75/GJ, sellers of gas would earn \$ 0.50/GJ by shipping their gas to the location offering the higher price. However, adequate pipeline capacity is required for additional volumes of gas to move in response to price signals.

When pipeline capacity between locations is fully utilized, additional gas flows become constrained; consequently, gas prices in a particular region can "disconnect" from those in an integrated market. In a "disconnected region," gas prices can be significantly higher than in the integrated market, as illustrated by prices in California and British Columbia in the beginning of 2001. It is important, however, to have regard to the duration and size of the price disconnect. If a market is disconnected for a short period of time during the year, it may not justify an investment in costly new infrastructure. However, if gas prices between locations are frequently disconnected and the price differential remains above the transportation toll, or cost, for prolonged periods, the market receives a signal that additional capacity is needed. In other words, the price differential indicates that transportation capacity between these locations is constrained.

## 2.4 Market Hubs, Pricing Points and Basis Trading

Natural gas can be traded or priced at many locations in North America (Figure 2.3). Over time, some pricing points may evolve into trading hubs. This would occur when multiple pipeline interconnections are constructed thereby creating liquid physical exchanges where gas can be easily bought or sold. In addition to multiple pipeline interconnections, trading hubs usually have access to natural gas storage facilities, which enhance the trading options of buyers and sellers. Hence, trading hubs, whether a producing area hub located near a gas supply basin or a market area hub located near a market centre, are characterized by multiple transportation options and access to gas storage, which provide a setting for a large volume of gas and numerous market participants. Conversely, pricing points are not as liquid because they tend to lack storage facilities and there are fewer pipeline interconnections.

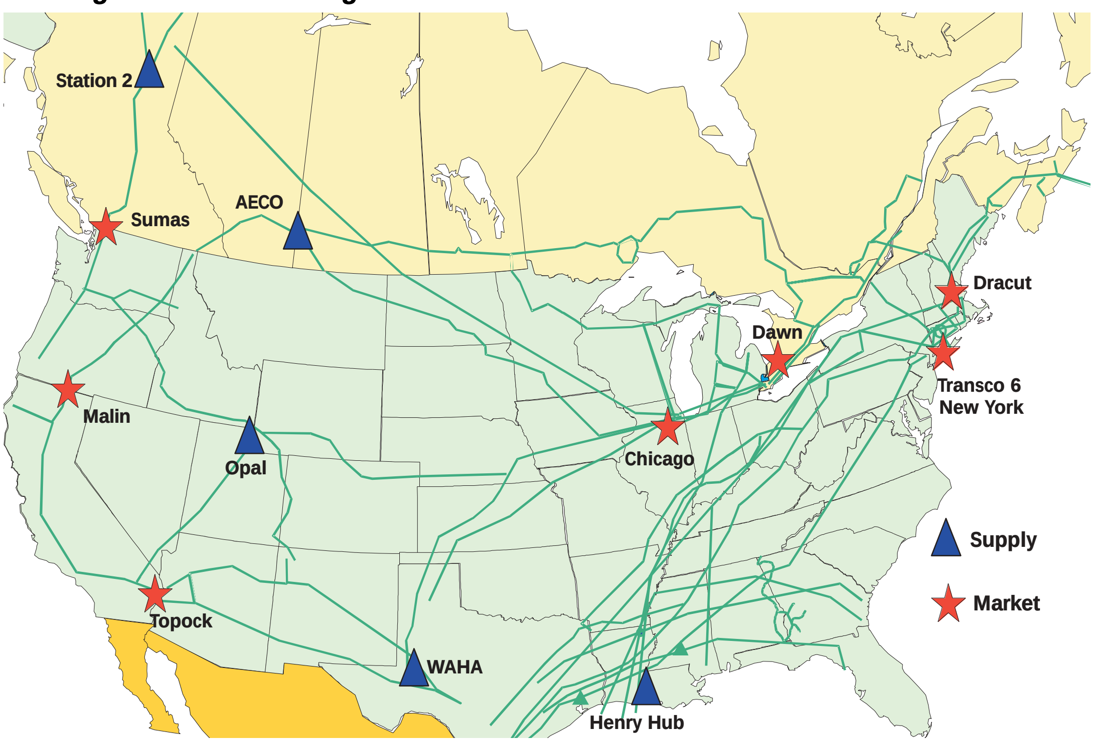
Some producing area hubs such as AECO-C, which is located near Suffield, west of the Alberta/Saskatchewan border and operated by EnCana Energy (formerly Alberta Energy Company), also represent market area trading due to the significant level of consumption of natural gas in the producing region.

In 1990, a futures contract on the New York Mercantile Exchange (NYMEX) was introduced. A futures contract is a commitment to deliver or take delivery of 10,000 MMBtu of gas at a future date. The delivery point of gas sold under NYMEX is Henry Hub, located near the major gas producing and consuming region of the Gulf of Mexico. This region accounts for over 40 percent of gas production and 30 percent of gas demand in North America.

The two key hubs on which pricing is based are both producing area hubs, AECO-C in Alberta and the Henry Hub in Louisiana. The prices, where they are quotable, at all other hubs, typically will be referenced as a differential between AECO or the Henry Hub (NYMEX).

**FIGURE 2.3**

***Trading Hubs and Pricing Points***



In forecasting natural gas prices, analysts will reference AECO and the NYMEX and then undertake a forecast of the likely price differential between these two reference points and the other trading hubs.

From the perspective of Canadians trading natural gas, the only trading hub outside of AECO is Dawn in southern Ontario. In addition, for consumers in the Maritimes and British Columbia, gas is traded at the Dracut, Massachusetts and Sumas, British Columbia pricing points.

AECO, located at the EnCana gas storage facility, is considered to be the primary reference-pricing hub for natural gas sold in western Canada. AECO is also a pricing point for some natural gas that is exported to the United States.

The AECO trading hub is typically more active at the end of the month. In 2001, almost half of all trading in monthly gas futures contracts occurred during the last five days of the month (Figure 2.4). This trading is, in general, as close to the month-end as possible to minimize the adverse impacts of gas price volatility.

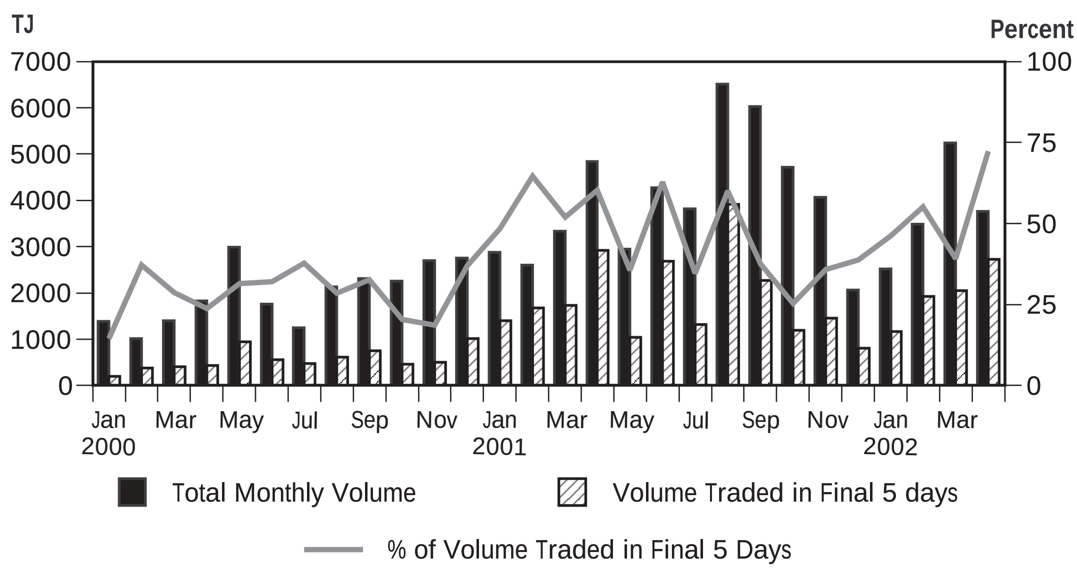
With the addition of natural gas pipeline capacity outside of Alberta and Saskatchewan over the past several years, the price of natural gas referenced at AECO has for the most part consistently reflected the gas markets throughout the remainder of Canada and the United States. At times, due to some specific market or supply conditions, there have been some short-term disconnects between AECO and other pricing regions. While these short-term disconnects continue to appear periodically, the markets relative to Canadian buyers and sellers can be considered to be working effectively.

***Dawn***

Dawn is a trading hub in southwest Ontario connected to pipelines from the United States and for which Union Gas has developed extensive storage facilities. With the construction of the Vector

FIGURE 2.4

***AECO Prompt Month* Trading Pattern***




Source: Ziff Energy Group

* "Prompt month: nearest month with open interest or the next month where the futures contract is open for trading, i.e. if it is currently August, the Sept. 2000 month contract is the prompt month for NYMEX NG contract. Once the September futures contract closes (end of August), then the Prompt month becomes October.

Pipeline system, Dawn has become a significant trading and pricing hub for natural gas into Ontario and Quebec.

The expansion of the pipeline systems into the southwest region of Ontario has greatly improved the access by customers in this region to alternative gas supplies. The increase in pipeline capacity has led to an increase in the liquidity of the Dawn hub and it can be expected that, over time, market participants will become increasingly willing to complete more of their trading transactions at Dawn. To date, there has been a significant increase in the magnitude of pipeline capacity into this region but the level of take-away transport capacity has not kept pace. Thus, there are some areas in Ontario and Quebec that have not experienced an increase in alternative supply options.

***Dracut***

Goldboro, Nova Scotia is the location where natural gas from offshore Nova Scotia comes onshore and is processed and connected to the Maritimes and Northeast Pipeline (M&NP) system. However, Dracut, Massachusetts, the interconnection point between M&NP (US) and the Tennessee Gas Pipeline system, is used as a reference point for the trading of natural gas. The liquidity of this point is quite low though, as most of the natural gas is purchased and sold south of this point.

It is important to recognize that the development of the natural gas market in the Maritimes is in its initial stages and there is limited disclosure of gas trades due to the small amount of volumes that are actually traded. While Dracut can act as a reference pricing point in determining the price of natural gas traded in the Maritimes (reference price less the cost of transportation on the M&NP system), it too has limited liquidity.

***Sumas***

Sumas is a pricing point located at the British Columbia/Washington border where the Westcoast Energy Inc.[1] system interconnects with the Northwest Pipeline system, which operates in a number of the PNW states. Station 2 is a major compression station on the xWestcoast system, near Chetwynd, B.C., where the northern and eastern transportation legs of the the system interconnect to its southern mainline system. Since contracting of capacity on these sections is done separately from the southern mainline, natural gas is often traded at this interconnection (Station 2).

Station 2 gas deliveries can come from natural gas produced in British Columbia, Alberta, or the territories north of British Columbia. Since natural gas can be sourced from several producing regions, the liquidity at Station 2 can often be greater than at Sumas.

## 2.5 Factors that Influence Gas Markets

### *2.5.1 Demand*

***Economic Growth***

A strong economy brings a growing demand for energy. The North American economy was quite strong during the 1990s. In the United States, economic growth boosted housing sales and new home construction. From 1991-1999, two-thirds of the new homes and 57 percent of the new multi-family buildings constructed were heated with natural gas. Increases in natural gas use also

1 The Westcoast Energy, Inc. system (Westcoast) was recently purchased by Duke Energy Gas Transmission Canada.

took place in the commercial and industrial sectors. Strong growth in North American demand for electricity, coupled with a desire for cleaner burning fuel and more stringent environmental standards, has resulted in more natural gas being used to generate power. In fact, electric power generation is expected to be the fastest growing sector of natural gas demand in North America over the next decade.

***Weather***

The most important factor in determining short-term price movements in North America is the weather, in particular the effect of temperature on the need for winter heating and summer cooling. Demand and prices for natural gas have normally been highest in the winter, because of the need for space heating by the residential and commercial sectors. Natural gas transmission and delivery systems are designed to meet peak demand requirements which usually occur in winter, when daily consumption in the combined residential and commercial sectors can be nearly double the annual average consumption on a per-day basis. In recent years, natural gas demand has increased in the summer, as more gas is used for electricity generation, in order to meet cooling needs. Prices tend to follow a seasonal cycle with higher prices in winter and summer and lower prices in spring and fall.

***Competing Fuel Prices***

Fuel switching is a temporary change from one fuel to another fuel at a particular facility and acts to limit gas price increases. The choice of which energy form to consume is frequently based on relative prices, relative combustion efficiency, availability or security of supply, emissions and other considerations. Dual-fuel capable equipment, found mostly in large commercial, industrial and electricity generation applications, can be adjusted to switch between one fuel and another, sometimes in a matter of hours. Generally, the ability to switch fuels is not as well developed in Canada as in the United States. The limited ability to switch fuels is due to the lack of alternative fuels available to consumers, resulting in part from constraints in infrastructure to deliver those fuels. The most common dual-fuel combinations are natural gas and distillate fuel oil and natural gas and residual fuel oil although in some markets, consumers can switch to electricity or hog fuel. Dual-fuel equipment provides flexibility and promotes integrated pricing between fuel markets.

Oil and gas prices tend to be somewhat inter-related. Consequently, as the price of oil fluctuates in response to world events, the price of natural gas will often follow suit. In late winter 2001/2002, a series of world events resulted in oil prices climbing sharply from approximately US $20/bbl to US $28/bbl in just a few weeks. At the same time, natural gas prices closely tracked the increase in oil prices and rose to US $3.40/MMBtu from US $2.50/MMBtu.

If gas prices and expected future gas prices keep rising relative to other fuels, certain consumers (for example, industrial firms) may permanently switch to another fuel, or move production to a cheaper, perhaps offshore, location. For example, during the winter of 2000/2001, a total demand loss or "demand destruction" of 142-170 $10^6m^3$ per day (5-6 Bcf/d) occurred in North America, of which switching to fuel oil accounted for about one-half of the demand destruction.

***Natural Gas Storage***

Storage facilities are essential to the North American natural gas industry. Underground natural gas storage inventories provide suppliers with the means to meet customer requirements during the heating season, especially on peak demand days. The heating season for natural gas markets is considered the five-month period from November through the following March. The other seven months, April through October, become an inventory building period called either the "non-heating season" or "refill season." In addition to meeting winter demand loads, storage is also used for load balancing on pipeline systems, short-term "parking" of gas until it is needed, and to provide a physical hedge against price volatility.

The size of storage capacity and peak deliverability in North America means that expectations about future price and peak winter demand levels can have a considerable impact on spot prices, through their effect on short-term gas purchase and selling decisions. Weather forecasts are a key factor in decisions to stock or de-stock. Actual demand levels and expectations of demand determine prices at any given time.

### 2.5.2 Natural Gas Supply

Canadian gas requirements are all virtually met by domestic sources, although a small amount of imports arrive from the U.S. Canada is a large net exporter to the U.S., even though the U.S. is the world's largest producer of natural gas. The U.S. receives some liquefied natural gas (LNG) imports and is a net exporter of small gas volumes to Mexico.

The supply response to increased prices differs in the short run and longer run. As demand increases cause prices to rise, the immediate response is an attempt to provide a larger volume from the existing wells and facilities. Companies with spare capacity generally respond promptly to opportunities for additional sales. As utilization rises toward capacity limits, however, further supply increases become more difficult and costly. When utilization rates approach maximum levels, supply cannot respond as much and market adjustments primarily result in price increases.

Beyond higher utilization from existing wells, further increases in supply require the drilling of new wells. However, a longer term increase in supply requires time for activities such as securing investment capital, acquiring land, planning drilling programs, preparing sites, hiring and training personnel, and developing additional infrastructure. In other words, there is usually a lag before production from new wells is brought onstream in response to price signals.

### 2.5.3 Market Psychology

One of the factors that can influence the price of natural gas either in the short or long-term is the psychology of the market in reacting to the above noted factors (drivers), including drivers such as availability of pipeline transportation capacity. In examining the price of natural gas and how natural gas markets are working, it is important that market psychology be taken into consideration. Market psychology is very difficult to measure - it is an interpretation by traders and analysts of events that may often lead to a price level that otherwise would not have been expected.

In examining the price movements of natural gas, it is observed that prices may at times appear to overreact to a specific driver both in the short and longer term by moving either higher or lower than would be expected by the specific event. For example, markets that anticipate the construction of additional pipeline capacity to remove a capacity bottleneck, may see the price of natural gas decline significantly prior to the actual in-service date of the additional pipeline capacity. Similarly, the market may overreact to the announcement of a potential severe weather pattern by sending prices higher.

## 2.6 Price Volatility

The term price volatility is used to describe rapid price fluctuations of a commodity. Natural gas price volatility is measured by the day-to-day percentage difference in its price. The degree of variation defines the volatility of the market. As described in Chapter 1, gas prices have been extremely volatile over the past two years.

Various factors that impact natural gas prices may individually increase or reduce price volatility or interact to temper or exacerbate volatility. For example, fuel switching potential and storage capacity in North America tend to temper seasonal and temporal fluctuations in market prices.

With the rapid growth of gas-fired generation over the past few years, volatility in the electricity market is having a greater influence on natural gas price volatility. When extreme cold or warm air moves into a region, demand for electric power can quickly escalate to meet the increased requirement for heat or air-conditioning. In such circumstances, natural gas-fired "peaking units" (generators designed to operate during the highest daily or seasonal loads) will come on-line to supplement the normal or "baseload generation." Prices for this peaking generation will often be much higher than the prevailing price before the change in weather. Gas required for peaking generation is typically obtained from spot-market sales; hence, the price paid for gas by peaking generators will frequently follow the volatile electricity prices.

As outlined previously, a number of factors in the winter of 2000/2001 contributed to extreme price volatility. Unusually cold temperatures in November and December 2000 combined with low levels of gas in storage resulted in price increases in many parts of North America, particularly in the east. In the PNW and California, previously low levels of rain resulted in reduced availability of hydropower to produce electricity. Gas-fired generation was needed to make up for the power shortfall and gas demand substantially increased. There is a limited amount of gas storage in the region and pipeline capacity quickly became fully utilized. Although gas prices in most of North America were very high, the prices in California and the PNW disconnected and reached even higher levels. For a variety of reasons, prices in the electricity market in California also reached extreme levels and this drove gas prices even higher.

### *2.6.1 Financial Tools for Managing Volatility*

As the natural gas market has developed, parties involved in the trading of natural gas have looked at various mechanisms to manage volatility regarding both supply and price. The major factor involved in managing volatility for most parties is the reduction or elimination of risks associated with the buying and selling of natural gas. Risks associated with the delivery or receipt of gas have been managed through the various contractual mechanisms of assuring supply or markets; however, only in approximately the past decade has the focus been on reducing the risks of volatility associated with the price of natural gas. As previously discussed, natural gas markets have moved to much shorter term contracts where the parties' contractual commitments regarding gas price are now based on daily or monthly prices (even if the supply/market commitments are longer term). The future commitment for volumes (either commitment to sell or buy), without knowing what the actual price may be, has caused mechanisms to be developed so the trading parties can have the option to contract for a specific locked-in price with another third party. The natural gas market uses complex mechanisms analogous to individuals selecting the type of mortgage by which they can lower the volatility in interest rates (open versus closed, six months versus yearly versus multi-year).

The taking of any position where the gas price is not specifically fixed in the contract will involve some form of hedging to address the uncertainty related to the price of committed natural gas. Many parties currently assess the specific degree of risk (volatility) that they are prepared to accept and, based upon that measure of risk, will take a specific position regarding the price of natural gas.

Hedging practices can occur in both the retail and wholesale markets. For many years, small end-use consumers in many jurisdictions have been able to select a yearly equalization program from their local gas utility. Changes in seasonal fluctuations in both volume and price could be smoothed out over the year to reduce the high energy costs that can occur in the winter. As the market has evolved and there are more parties involved in the selling of natural gas, consumers have been in some cases able to elect to purchase their natural gas over a multi-year basis at a fixed price. These mechanisms provide the retail customer the ability to reduce the volatility associated with the changes in the price of natural gas.

For wholesale markets, there are extensive hedging mechanisms to deal with the commodity price, pipeline transportation rates and storage rates, as well as mechanisms to deal with the option to deliver or buy volumes. These mechanisms have been developed to respond to the volatility that exists within the natural gas industry.

## 2.7 Summary

Gas prices in primary trades are confidential; that is, the prices at which gas producers sell their gas are normally not disclosed. However, prices can be "discovered" at hubs where natural gas is physically sold and where a large amount of secondary market transactions occur. The activities of traders at these points improve liquidity and price transparency. In this sense, activities of traders provide a valuable market service.

The natural gas market has been moving to shorter-term transactions for many years. Hence, liquidity is highest for market transactions covering terms of one to three months. Liquidity decreases with increases in the contractual pricing term. When there is a high degree of liquidity, that is, a large number of trades, the market can have confidence that the prices represent real market activity. Consequently, the degree of liquidity at a hub is critical.

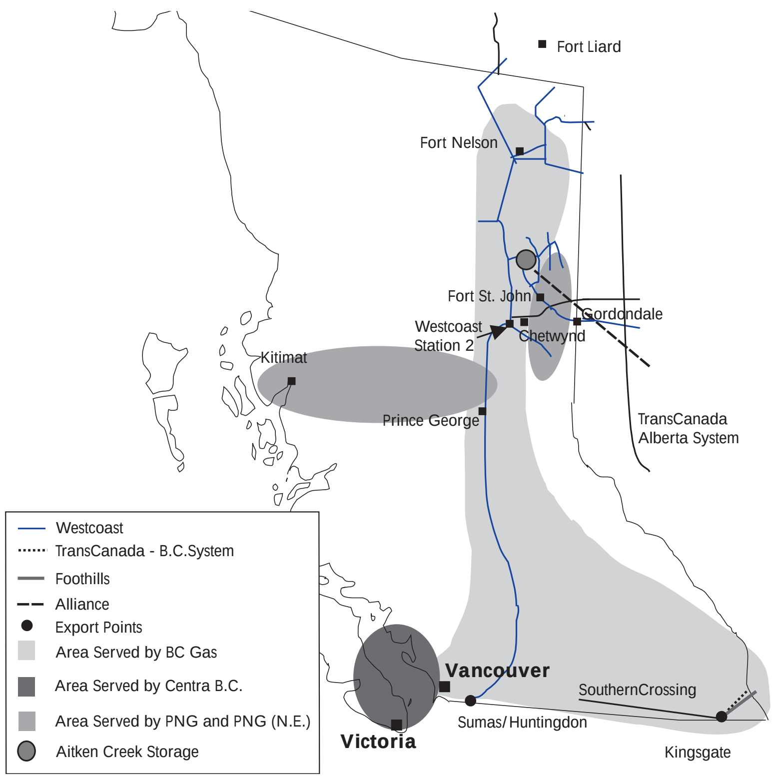
In Canada, liquidity at AECO and Dawn is very high. However, pricing points such as Sumas and Goldboro provide little liquidity; thus, concerns exist that the prices at these points may not represent the real value of gas in the market.

Natural gas continues to be the most volatile commodity traded on NYMEX. The volatility, or sudden price fluctuations, can be caused by several factors including severe weather. As well, the market's perception of supply and demand fundamentals, or market psychology, may often result in an overreaction in price response. Fortunately, there are risk management tools available whereby market participants can reduce their exposure to price volatility.

# REGIONAL CANADIAN GAS MARKETS

## 3.1 British Columbia

### *Market Overview*




British Columbia is the second largest producer of natural gas in Canada and the third largest consumer, following Ontario and Alberta. In 2001, B.C. consumed 8.4 $10^9 m^3$ (297 Bcf) of natural gas, with the residential sector accounting for 24 percent of demand, the industrial sector for 37 percent, the commercial sector for 16 percent and the power generation sector for 12 percent.

There are three local distribution companies (LDCs) in British Columbia: BC Gas Utility Ltd. (BC Gas), Pacific Northern Gas Ltd. (PNG) and Centra Gas British Columbia Inc.(Centra B.C.)[1]. BC Gas is the largest utility and serves over 767,000 customers, representing about 90 percent of natural gas consumers in the province. PNG and PNG (N.E.) deliver gas to about 40,000 customers in west-central B.C. and northeastern B.C. Centra B.C. serves about 72,000 customers on Vancouver Island and on the Sunshine Coast. The LDCs are regulated by the British Columbia Utilities Commission (BCUC). A number of marketers also operate in B.C. but they currently only serve industrial and large commercial customers.

The Westcoast system[2] is the major transmission system in British Columbia. Gas transported on Westcoast is delivered to B.C. domestic and export markets (principally in the PNW and California).

1 Purchased recently by BC Gas.

2 The Westcoast Energy Inc. System (Westcoast) was recently purchased by Duke Energy Gas Transmission Canada.

Gas is transported to export markets through interconnects with Northwest Pipeline and other smaller pipelines at Huntingdon, B.C./Sumas, Washington. The Westcoast system also interconnects with the TransCanada-Alberta system at Gordondale, Alberta. The Westcoast system delivers gas to LDCs and to various industrial plants and gas processing facilities connected to the pipeline.

The Alliance pipeline was completed in 2000, connecting B.C. gas production in the Aitken Creek and Fort St. John areas to Alberta and the Chicago market.

While BC Gas procures the majority of its supply from within the province, it also receives some volumes from Alberta via the TransCanada-B.C. system, which passes through southeast B.C. from Alberta to Kingsgate. BC Gas's Southern Crossing Pipeline, which connects to the TransCanada-B.C. system, was completed in November 2000 and provides peaking service for the Lower Mainland. There is producing area gas storage at Aitken Creek, but there are no market area storage reservoirs in B.C. On a peak day, BC Gas's incremental requirements are met by LNG and gas exchanges using, for example, storage in Washington and backhaul service on Northwest Pipeline. BC Gas relies on storage facilities in the U.S. to manage its gas supply portfolio.

***Regional Natural Gas Prices***

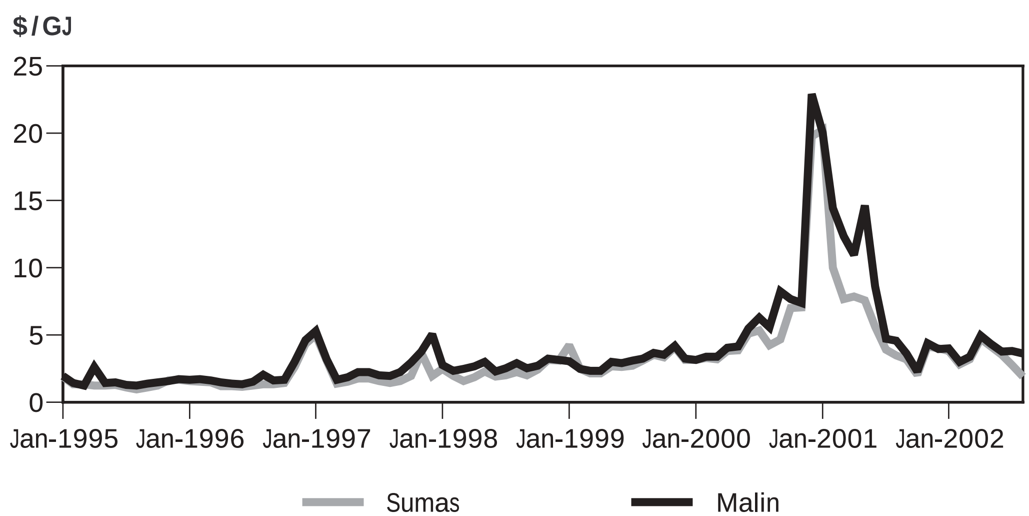
The two pricing points in B.C. are at Sumas/Huntingdon and Westcoast Station 2. Historically, changes in gas prices at Sumas more closely tracked gas price changes at Malin, CA than changes in prices at AECO (Figures 3.1.1 and 3.1.2). Gas prices at Station 2 tend to track prices at AECO. Pricing of gas at Sumas has been influenced by supply/demand dynamics in the PNW and California. Figure 3.1.3 illustrates residential gas price components for BC Gas. The prices assume a gas usage of 120 gigajoules per year.

***Managing Price Volatility***

BC Gas acquires about $800 million of gas each year. The company's Annual Contracting Plan, including hedging plans, is approved by the BCUC and the executive summary of the plan is made available to the public. BC Gas reported that in the winter of 2000/2001 it had contracted for gas

**F I G U R E 3 . 1 . 1**

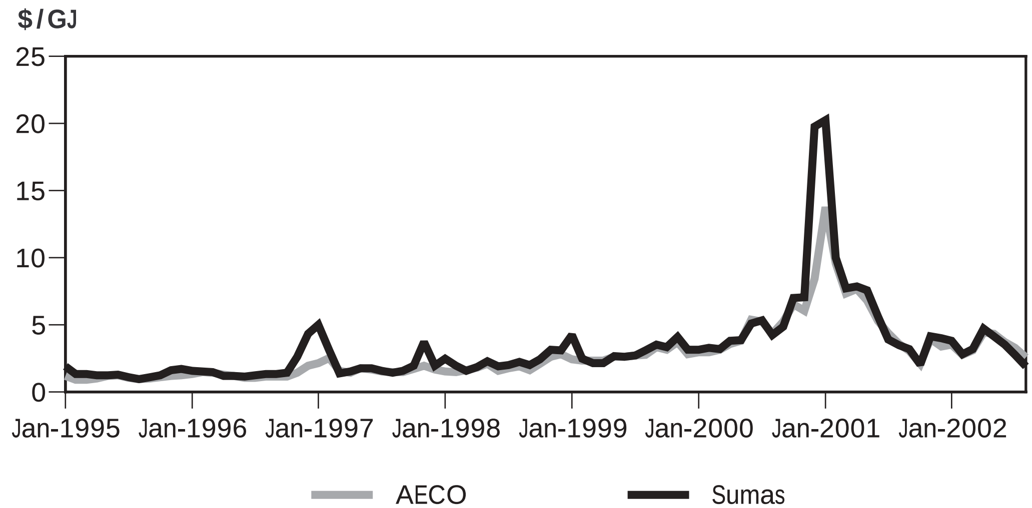
***Spot Gas Prices Sumas vs. Malin***




Source: Canadian Natural Gas Focus

FIGURE 3.1.2

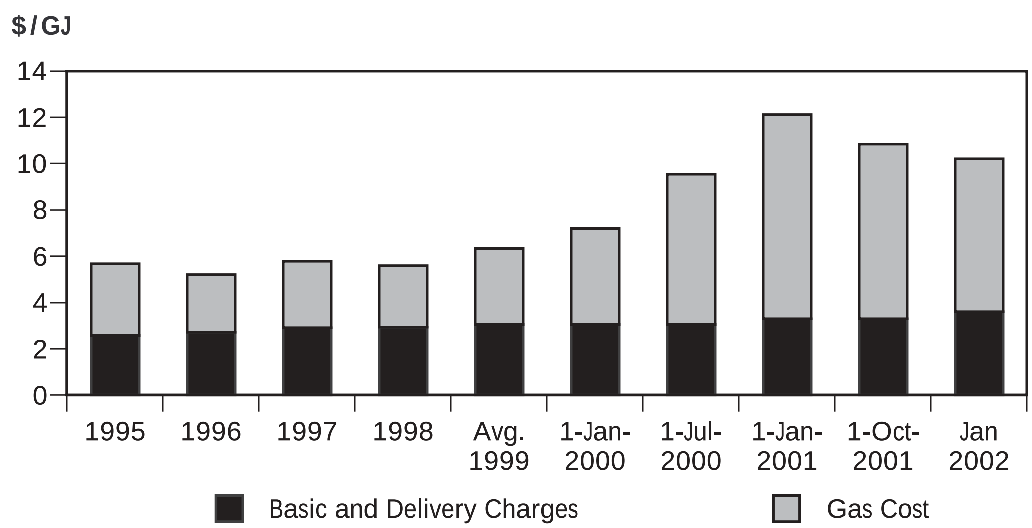
***Spot Gas Prices AECO vs. Sumas***




Source: Canadian Natural Gas Focus

FIGURE 3.1.3

***Residential Gas Price Components, BC Gas***




Source: BCUC

supply ahead of time and estimated that it saved about $500 million compared to what it would have had to pay for spot supplies. BC Gas is purchasing an increasing amount of its gas at Station 2 rather than at Sumas.

As a result of the price spikes in the winter of 2000/2001, and the accumulation of large debit balances by the utilities, the BCUC now requires utilities to review their gas prices quarterly, and gas rates are usually adjusted if there is a difference of five percent between forecast revenue and forcast costs for the following 12 months.

A number of large gas users in B.C. are able to fuel switch. During the 2000/2001 price spikes, BC Gas customers such as Central Heat, the University of British Columbia and Simon Fraser University, switched to fuel oil. A number of pulp and paper mills used hog fuel (wood waste).

Residential customers responded to high gas prices with energy conservation measures, which BC Gas believes has resulted in some sustained decrease in demand. Opening the residential market to competition is unlikely to occur until November 2004, since legislation is first needed for the licensing of gas marketers.

***Regional Issues***

There is considerable concern among some participants in the B.C. gas market regarding price transparency at Sumas, and the possibility of unfair trading practices. Since the demise of Enron Online, there is no easily accessible price discovery mechanism in B.C., although the Intercontinental Exchange may become such a mechanism. In the past year, the number of parties trading gas has declined. Certain end-users report that they have been unable to buy gas directly from producers and some other shippers on the Westcoast system. They also report a limited amount of transportation capacity on the secondary market.

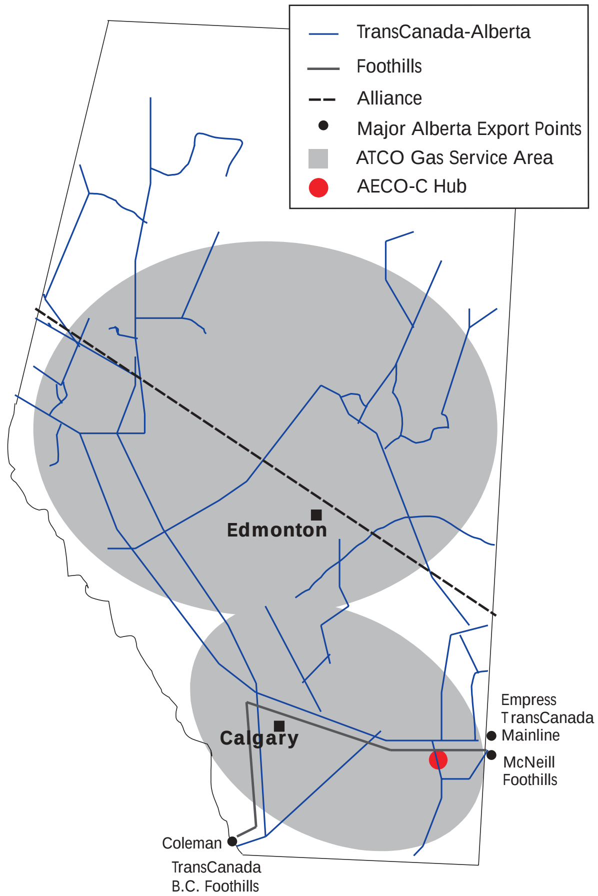
Some uneasiness was expressed regarding the future availability of gas supply and who would get priority access. Large gas users were aware of the large, growing demand for gas for power generation in the PNW. Westcoast has applied to expand its transmission system by 200,000 GJ/d for November 2003. BC Gas is pursuing the Inland Pacific Connector which would connect to the Southern Crossing Pipeline and would bring 5.7-8.5 $10^6m^3$ per day (200-300 MMcf/d) to Sumas from Alberta.

Williams Gas Pipeline Company, LLC and BC Hydro have sponsored an application to the NEB to build the Georgia Strait Crossing Pipeline. This proposed pipeline would provide additional gas to Vancouver Island and to a proposed generation facility on the Island.

The B.C. government is expected to release a new energy policy this fall. A main component is expected to relate to the reorganization of BC Hydro and changes to the electricity market. BC Hydro may be split into generation, transmission and distribution entities. Key issues are how the government will address electricity pricing and if it will move to more market-based pricing. These possible changes will also affect the gas market. It is expected that the demand for gas-fired power generation will increase in the coming years.

## 3.2 Alberta

***Market Overview***




Alberta is the largest producer of natural gas in Canada, providing almost 80 percent of total production. In terms of gas consumption, Alberta demand amounted to 20.6 $10^9 m^3$ (728 Bcf) in 2001, placing it second to Ontario. The large majority of gas consumption in Alberta is within the industrial sector. This sector comprises end-users such as petrochemical and fertilizer manufacturers, oil sands operators and electricity generators. Industrial demand accounts for about 70 percent of total gas consumption; the remainder is consumed by the residential and commercial sectors, primarily for heating.

Investor-owned utilities serve about 88 percent of the Alberta market with the balance of service provided by 69 rural gas co-operatives and 24 municipally-owned utilities, such as the city of Medicine Hat. ATCO Gas and AltaGas Utilities Inc. are the largest utilities in Alberta. ATCO Gas serves approximately 825,000 customers, or about 80 percent of the market. This includes ATCO Gas North which operates in Edmonton and northern Alberta and ATCO Gas South which operates in Calgary and southern Alberta. AltaGas Utilities Inc. distributes gas to approximately 56,000 customers. The LDCs are regulated by the Alberta Energy and Utilities Board (AEUB).

Albertans that purchase gas from either ATCO Gas or AltaGas Utilities Inc. have the option to purchase gas from a direct marketer. Municipally-owned utilities may allow customers to buy from direct marketers but they are not required to do so; customers of rural co-operatives do not have the option of buying from a marketer. There are eight licensed direct marketers for commercial customers but only two of these marketers are active in the residential market; namely, ENMAX Energy Corporation (ENMAX) and EPCOR Energy Services Inc. (EPCOR). At this stage in the market's development, very few residential and commercial customers buy their gas directly; thus, marketers serve only a small portion of the retail market. Direct marketers also serve the industrial sector but many of these large customers buy gas directly in the wholesale market from producers.

TransCanada-Alberta (formerly NGTL) is the primary gas gathering and transmission pipeline system in Alberta. This system collects gas from hundreds of producers across the province, including some volumes from British Columbia, and delivers gas to major transmission pipelines at the Alberta border for transport to Canadian and export markets. ATCO Pipelines is the major intra-Alberta distribution pipeline system. It interconnects with the TransCanada-Alberta system and distributes gas to LDCs and industrial customers.

Alberta has several commercial natural gas storage pools, including the large facility at the AECO-C hub, with a total capacity of about 6.4 $10^9 m^3$ (226 Bcf). Natural gas from numerous suppliers is stored at these facilities under various contractual arrangements.

***Regional Natural Gas Prices***

Gas prices at the AECO-C hub are illustrated in Figure 1.1. Residential gas price components for ATCO Gas North and ATCO Gas South are provided in Figures 3.2.1 and 3.2.2, respectively. The delivery component includes fixed and variable charges and assumes average household gas consumption of 150 gigajoules per year. The prices indicated are for January 1 of each year except for 2001, which is January 2. (Prices have been adjusted at various times throughout the years and since 1 April 2002, are adjusted monthly).

***Managing Price Volatility***

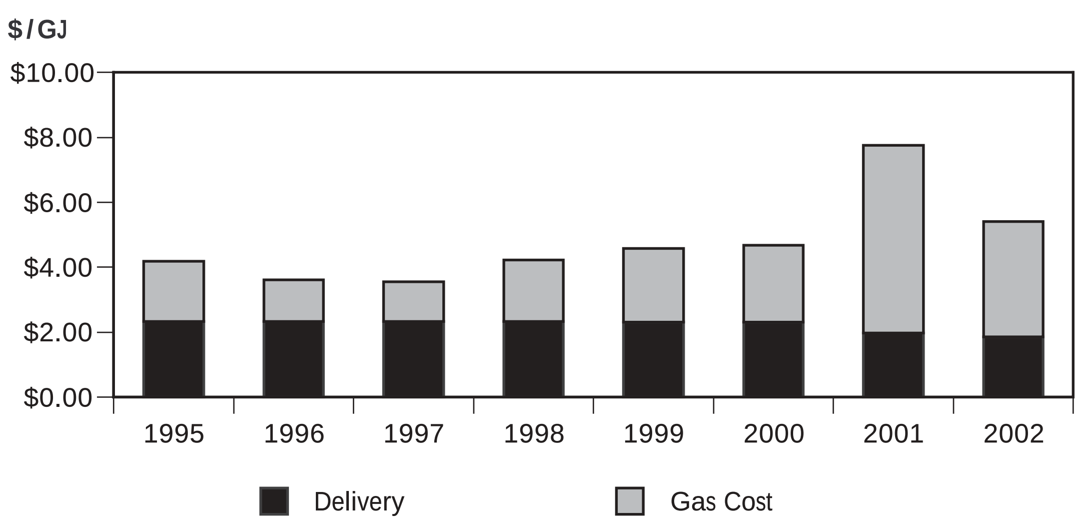
The AEUB regulates natural gas rates charged to consumers by investor-owned utilities such as ATCO Gas and AltaGas Utilities Inc. The rates charged to customers of marketers, rural co-operatives and municipally-owned utilities, as well as transactions in the wholesale market, are not regulated by the AEUB.

With the Alberta gas market centered within the WCSB, transportation costs to move gas from the producing wells to market centres are much lower than those experienced in other provinces. The major portion of a typical residential gas bill in Alberta is the cost of gas itself. Hence, Albertans may experience more volatility on their gas bills than other Canadians due to fluctuations in the price of the commodity.

Prior to April 2002, natural gas rates were set on a seasonal basis and were adjusted every November and April. While reflecting normal seasonal price trends, at times, this practice resulted in prices that were significantly different from market prices; consequently, large price adjustments were required to reflect market prices and deferral account balances. The AEUB has since provided for a monthly

FIGURE 3.2.1

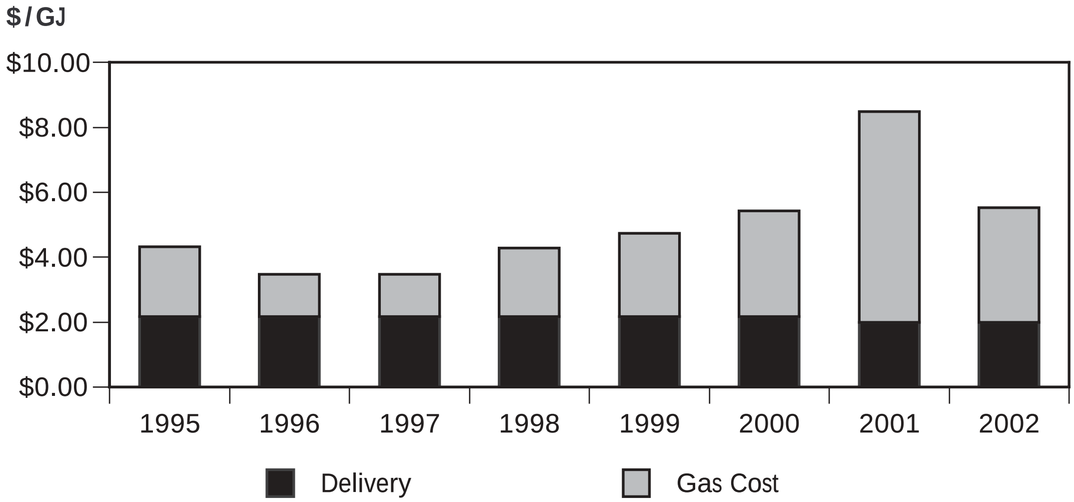
***Residential Gas Price Components - ATCO Gas North***




Source: ATCO Gas

FIGURE 3.2.2

***Residential Gas Price Components - ATCO Gas South***




Source: ATCO Gas

adjustment to prices. Utilities now apply to the AEUB for a monthly gas rate largely based on a forecast of market prices for the next month. As a result, customers will pay a rate that better reflects the market price for natural gas. Further, large rate adjustments to account for the differences between market prices and seasonal rates are prevented.

Gas consumers who prefer to hedge their gas costs must contract for gas from a gas marketer. The AEUB recently affirmed its direction that utilities must continue the practice of purchasing daily and monthly indexed gas supplies. Those gas consumers remaining with the utility would continue to pay a regulated rate. In the residential market, customers of ATCO Gas or AltaGas Utilities may contract with EPCOR or ENMAX for gas supplies at a fixed price per GJ over a fixed term of one, three or five years. In those circumstances, the local utility would continue to deliver the gas on its system and bill for service and delivery. Such a strategy may protect consumers from fluctuating gas prices but at any point the fixed price may be above market prices. Stability is also provided by the option of equalized payment plans available from utilities and marketers.

During the winter of 2000/2001, Alberta consumers managed volatile and increasing gas prices by reducing demand through conservation, fuel-switching and reducing industrial activity. Residential demand, adjusted for weather, decreased by eight percent and industrial demand decreased by 13 percent.

The Government of Alberta also assisted natural gas consumers paying high prices by providing rebates and energy tax refunds. The *Natural Gas Price Protection Act* continues today and provides for rebates once gas prices reach $5.50/GJ.

***Regional Issues***

The manner in which the Alberta gas market continues to evolve and develop is a key issue. In response to the lack of retail market development over the years for residential and commercial customers, or "core customers," the AEUB convened proceedings in early 2001. On 30 October 2001 the AEUB released its Decision (2001-75) with respect to natural gas rates and policy matters wherein several barriers of entry that existed in the core market were removed. The principle underpinning the AEUB's decision was the provision of reasonable opportunities for gas marketers to compete while ensuring that utilities are treated fairly and their customers remain protected.

Among the components of the AEUB's decision was the requirement of utilities to adjust gas cost rates on a monthly basis and the affirmation that utilities not be allowed to implement hedging programs (discussed earlier in this section). The latter issue, in particular, was determined to be critical as such a utility program may significantly impair retail gas market development.

In its decision, the AEUB also unbundled certain utility "customer care" functions, such as billing, call centres and customer information systems. Previously, utilities included these costs in their distribution rates meaning that customers of marketers paid for both the retailer's and the utility's customer care infrastructure. The utilities' customer care costs are now only paid by customers purchasing their gas supply from the utility.

Similarly, utilities were directed to include certain costs related to the acquisition of gas supply within its gas costs instead of within the distribution rate. The result of this decision provides for a better comparison between the gas costs of utilities and retailers.

The AEUB also implemented measures to ensure that all customers, whether they receive gas from a utility or marketer, benefit from "legacy assets" such as company-owned gas production. ATCO Gas North supplied about 15 percent of its requirements with proprietary production and recovered only the royalty costs associated with that production. Hence, customers of ATCO Gas North enjoyed a "physical hedge" as they were paying artificially low prices for gas. Among other factors, this prevented marketers from competing in that service territory. Since the AEUB's decision, ATCO Gas North has sold its gas reserves and distributed the proceeds to its customers. Gas rates for supply from ATCO Gas North are now closer to market prices and have converged with rates paid by gas consumers in southern Alberta.

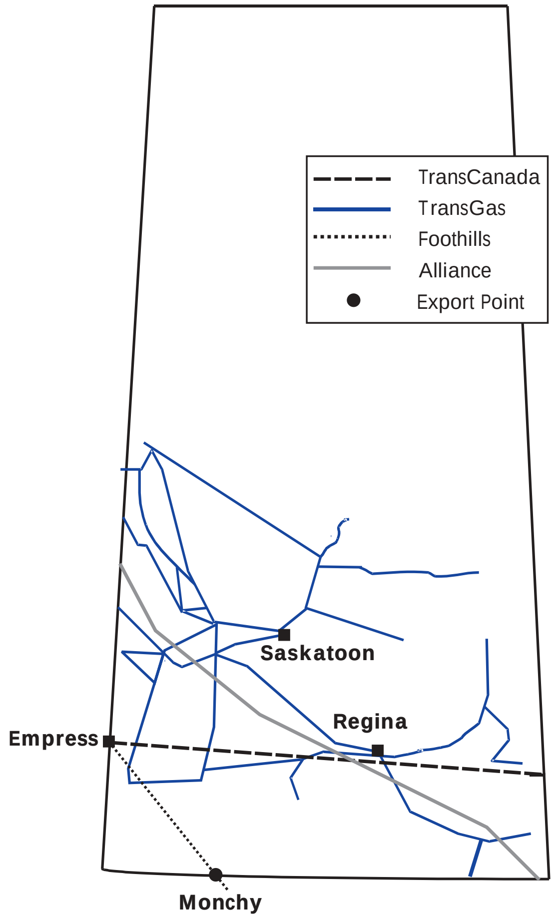
Notwithstanding the removal of several impediments to the development of the retail market, a number of unbundling issues remain such as Code of Conduct protocols for retail marketing affiliates of utilities, and retailer bonding requirements.

Access to gas is not an issue for the Alberta gas market considering its proximity to gas production. Further, the *Gas Resources Preservation Act* requires the AEUB to ensure that a rolling 15-year supply is maintained for core market customers.

## 3.3 Saskatchewan

***Market Overview***

Saskatchewan is the third largest producer of natural gas in Canada and the fifth largest consumer. In 2001, total consumption of natural gas reached 4.9 $10^9 m^3$ (173 Bcf), slightly lower than Quebec. The industrial market represents two-thirds of the consumption in Saskatchewan where the majority of gas is purchased directly by the industrial customers. Since 1987, residential customers have been able to purchase their gas directly from third-party marketers, but similar to Alberta, third-party marketers have not been successful in attracting residential customers away from the local gas distributor.




The local gas distributor is SaskEnergy Incorporated (SaskEnergy), which is a Crown corporation owned by the Province. SaskEnergy has been successful in expanding its operations throughout the rural areas of Saskatchewan over the past number of years. Natural gas is gathered and transported within Saskatchewan by TransGas Limited (TransGas), a related company to SaskEnergy.

Saskatchewan has local natural gas storage facilities (reservoir storage) which assists in meeting winter peak demands and exports out of the province. TransGas manages and operates SaskEnergy's storage assets.

***Regional Gas Prices***

Gas for use in Saskatchewan is priced at Empress and adjusted for transportation (Figure 3.3.1). Therefore, there is no specific regional price reference hub in Saskatchewan. Figure 3.3.2 shows the residential gas price components for SaskEnergy. The transportation charge includes a basic monthly charge and a delivery charge and assumes gas consumption of 3500 $m^3$/year. An average price has been calculated for each year in the figure.

***Managing Price Volatility***

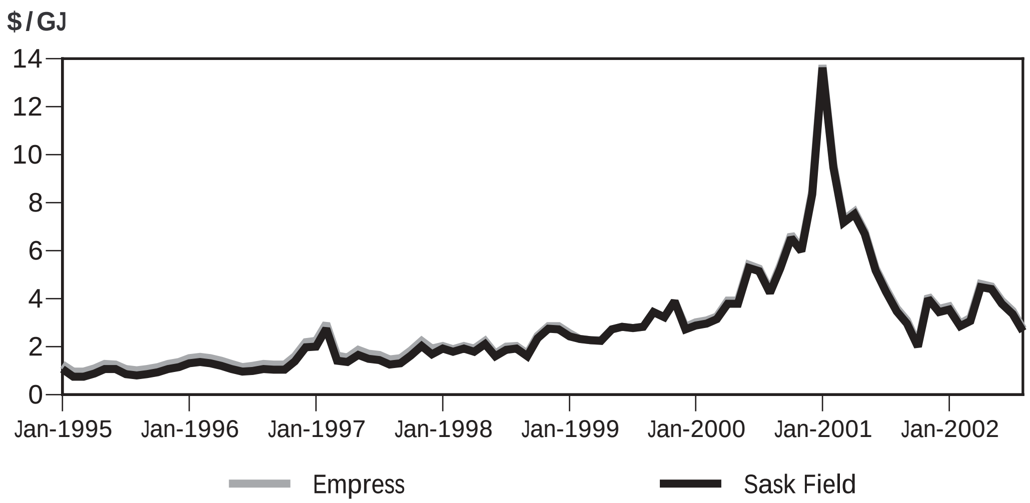
SaskEnergy, as a Crown corporation, is not regulated by a provincial regulator similar to other natural gas utilities in Canada, but its rates are reviewed by the government-established Rate Review Panel. SaskEnergy uses various benchmarks to compare its performance relative to other organizations in Canada. Price volatility is managed by a hedging program established to reduce the risk of significant price increases to SaskEnergy's customers.

### *Regional Issues*

Liquidity in the Saskatchewan market has remained strong due to the number of producers and ability to purchase gas from Alberta. Since Saskatchewan is a net exporter of natural gas, and there are adequate gathering and transmission facilities throughout the province, market participants did not raise transportation or supply concerns.

FIGURE 3.3.1

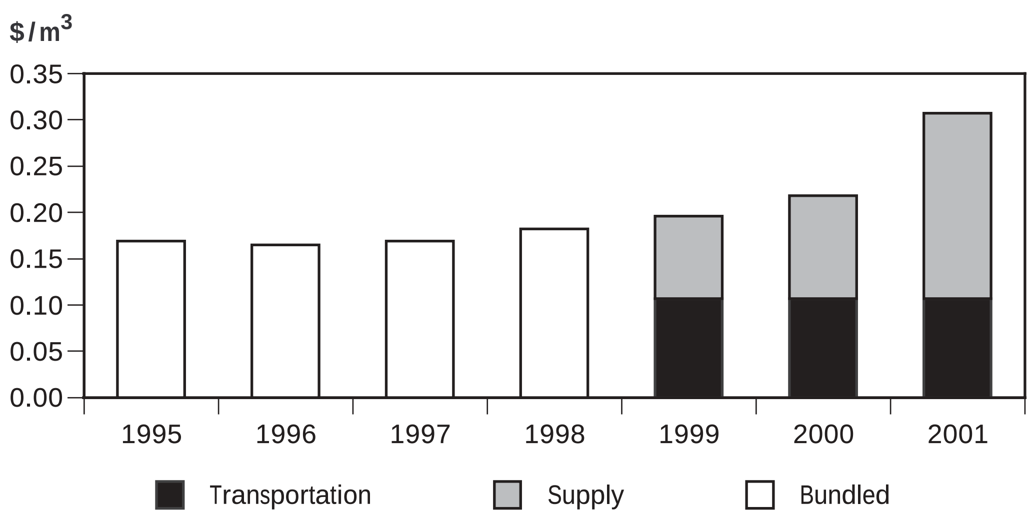
***Saskatchewan Fieldgate vs. Empress Gas Prices***




Source: Canadian Natural Gas Focus

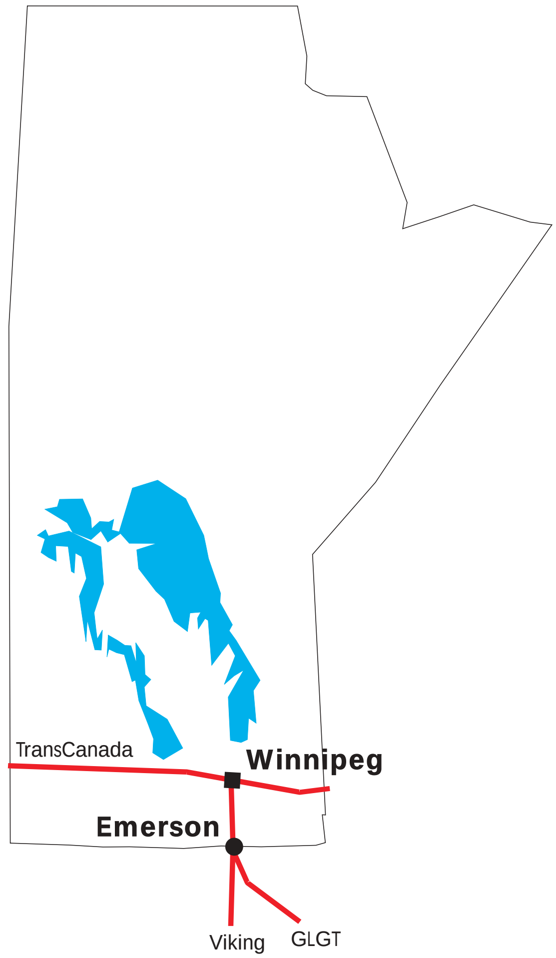
FIGURE 3.3.2

***Residential Gas Price Components - SaskEnergy***




Source: SaskEnergy

## 3.4 Manitoba




### *Market Overview*

Manitoba has traditionally been the smallest market in Canada (New Brunswick and Nova Scotia commenced consumption of natural gas in 2001). In 2001, Manitoba consumed approximately 2.0 $10^9m^3$ (72 Bcf) of natural gas. The industrial sector represents 75 percent of the demand while the remainder is in the small general service sector (commercial and residential combined). Direct sales into Manitoba represented approximately 0.7 $10^9m^3$ (25 Bcf) or one-third of total demand. While there are plans for future gas-fired electrical generation, none exist at this time.

Centra Gas Manitoba (Centra Gas) is the principal natural gas utility in Manitoba with more than 240,000 residential customers. Approximately 14 percent of these customers purchase their natural gas directly from third-party marketers. Centra Gas was purchased by Manitoba Hydro in 1999 from the Westcoast Energy group. While Centra Gas has remained in name, Manitoba Hydro has been gradually integrating the common management services of the two utilities. Natural gas in Manitoba has been available primarily in the urban areas, but over the past number of years various efforts have been made to increase the availability of natural gas in rural areas.

Centra Gas purchases more than 95 percent of its natural gas from the other western Canadian provinces. The remainder of its natural gas requirements are purchased in the United States for delivery to long-term contracted gas storage facilities in the U.S. Midwest. This stems from Centra Gas's strategy in the early 1990s to reduce its contracted capacity on TransCanada and its complete dependence on natural gas supplies from western Canada. Centra Gas contracted for long-term storage and related U.S. pipeline transportation capacity in the Midwest. Centra Gas's strategy of contracting downstream storage capacity is similar to that of BC Gas (although at far greater distances). As Centra Gas requires natural gas from storage, natural gas is diverted from TransCanada into the Manitoba market and an equal volume withdrawn from storage and delivered into TransCanada via its Great Lakes Gas Transmission system located in the U.S. Midwest.

### *Regional Gas Prices*

The majority of natural gas sold in the Manitoba market is set by prices at AECO plus transportation costs to Manitoba on the TransCanada Pipeline system (Figure 3.4.1). There are no regional pricing hubs for Manitoba. Figure 3.4.2 shows the residential gas price components for Centra Gas. Each bar on the graph represents the residential gas price for a particular point in time, e.g. 1 January 2001. (The gas price does not include the basic monthly charge.) Prices have been adjusted during the calendar year, and more often since 1999 to reflect actual gas costs.

### *Managing Price Volatility*

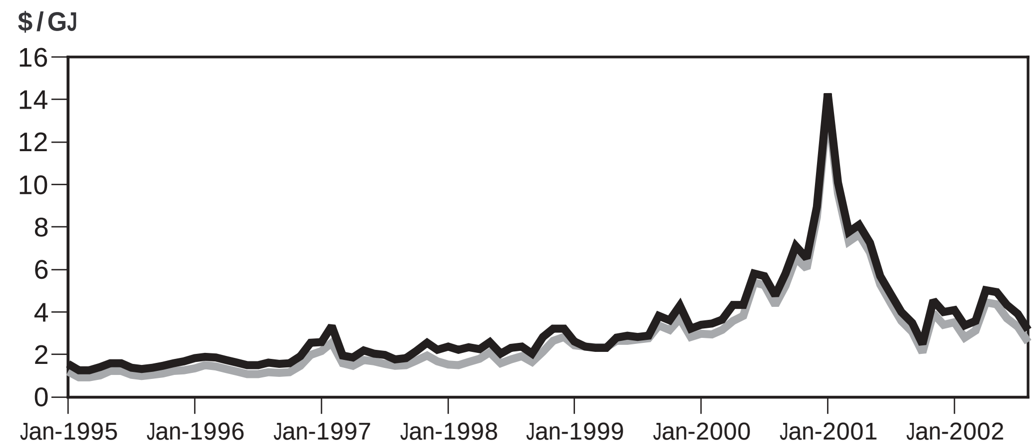
At this time, Centra Gas manages the volatility in natural gas prices by hedging 57 percent of its base load gas supply. Centra Gas's price management process is reviewed by the utility's regulator, the Public Utilities Board of Manitoba.

### *Regional Issues*

With more than 95 percent of its gas supply sourced from western Canada, some market participants in Manitoba have been concerned with the decline in contracted pipeline capacity on the TransCanada system. Since there does not appear to be any viable alternative transportation system, some believe that they are fully captive to TransCanada, and that they are not receiving the benefits

FIGURE 3.4.1

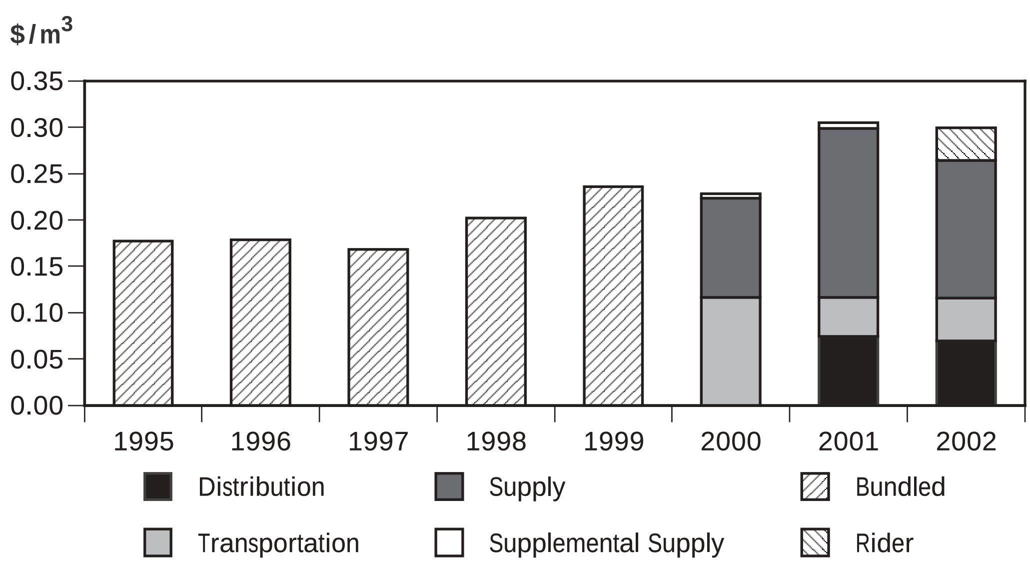
***AECO vs. Manitoba Citygate Prices***




Source: Canadian Natural Gas Focus

FIGURE 3.4.2

***Residential Gas Price Components - Centra Manitoba***



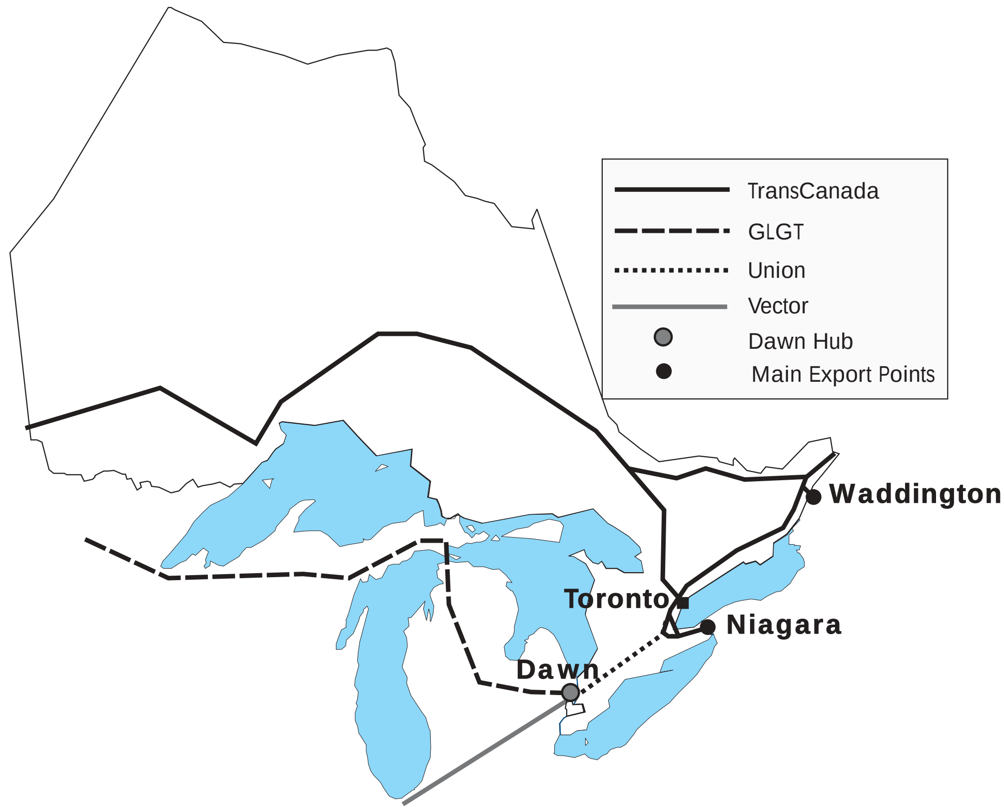

Source: Centra Manitoba

of diversified transportation alternatives received by producers in western Canada and some consumers in eastern Canada.

Some market participants advocated that changes be made to TransCanada's existing toll design and structure in order to reduce the burden of increased transportation costs that have been occurring due to the continuing decline in firm transportation contracts. There are further concerns about the lack of new gas discoveries in the WCSB following record drilling in 2001. This apparent lack of new supply coupled with the increase in pipeline capacity from western Canada may result in additional turnbacks of contracted capacity on TransCanada and increased Manitoba city-gate gas prices.

Due to the lack of a local regional price hub, there has been an expressed concern that liquidity has declined with the reduced number of counter-parties. Another concern relates to the degree of price transparency and a belief that there should be an increase in regulatory oversight. The decline in the number of parties capable of selling or willing to sell into a market like Manitoba (particularly the retail market), coupled with the lack of transparency in pricing, raises concerns among certain provincial market participants about market power held by the natural gas marketers.

## 3.5 Ontario




***Market Overview***

Ontario is the largest market for natural gas in Canada. In 2001, gas demand totaled 25.5 $10^9 m^3$ (899 Bcf). The industrial and residential sectors account for 36 percent and 31 percent of demand respectively. The commercial sector accounts for 20 percent and the power sector for about 11 percent.

The two major LDCs in Ontario are Union Gas Limited (Union)[1] and Enbridge Gas Distribution Inc. (Enbridge). Enbridge is Canada's largest LDC and serves over 1.5 million customers in central and eastern Ontario, southwestern Quebec and parts of northern New York state. Union provides distribution services to more than 1.1 million customers in northern, eastern and southwestern Ontario. The two largest gas marketers in Ontario are Direct Energy and the Ontario Energy Savings Corporation. According to the Ontario Energy Board (OEB), about 50 percent of residential consumers buy their gas from a marketer. The OEB regulates the LDCs and licenses gas marketers.

In addition to its distribution system, Union operates important transmission facilities that connect with the TransCanada Mainline system, Vector Pipeline Inc. (Vector) and several other pipelines from the U.S. Union transports gas for customers within and outside its franchise area. The customers outside its franchise area include TransCanada, other LDCs, and export customers delivering natural gas to markets in the U.S. Northeast. Enbridge has interconnections with the pipeline transmission facilities of TransCanada, Union, and some U.S. pipelines.

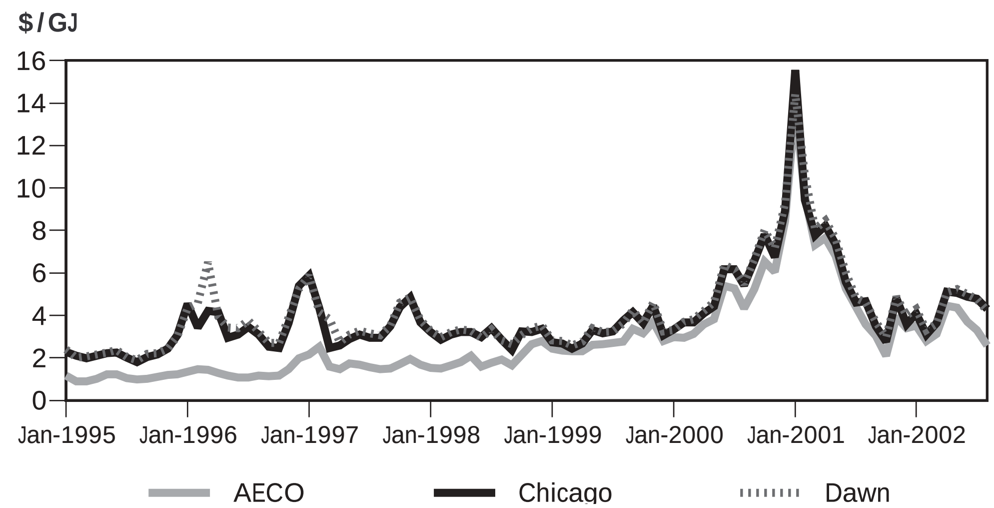
1 Owned by Duke Energy Gas Transmission Canada.

Union obtains most of its gas supply from western Canada (about 75 percent in 2002), with the remainder sourced from the United States and Dawn delivered supply.

Union owns and operates Canada's largest underground natural gas storage facility near Dawn, Ontario. The storage facilities have a working capacity of 4.1 $10^9m^3$ (145 Bcf). The combination of physical storage and multiple interconnecting pipelines provides Union with the opportunity to provide market hub services to assist other pipelines and shippers to balance upstream supply with downstream market demands. In 2001, an estimated 337 $10^6m^3$ per day (11.9 Bcf/d) of natural gas title transfers took place within Union's facilities at Dawn, and it has been the fastest growing hub in North America over the past five years. Union has stated that Dawn has become more liquid and its

FIGURE 3.5.1

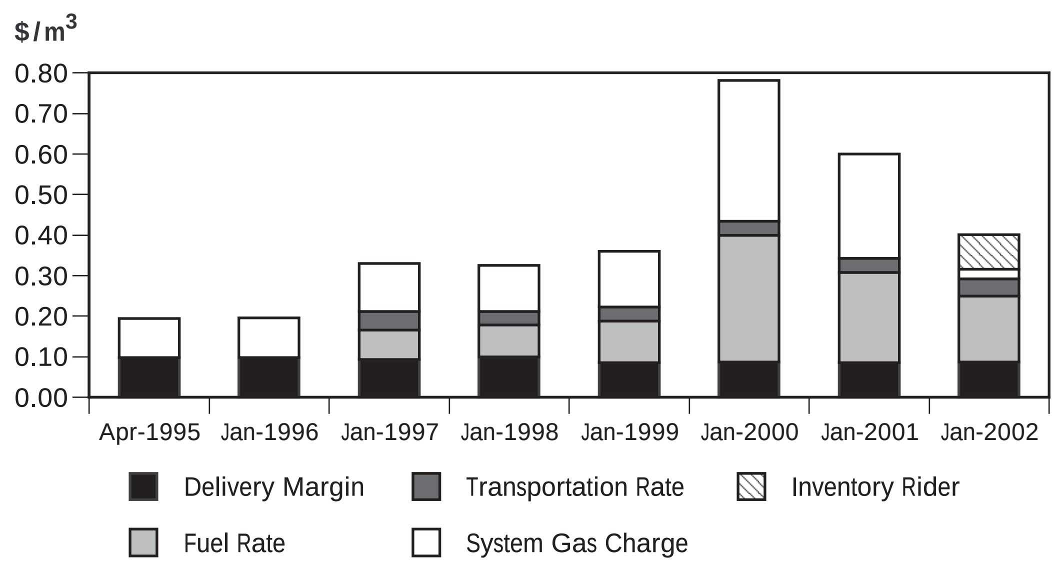
***AECO vs. Dawn vs. Chicago***




Source: Canadian Natural Gas Focus

FIGURE 3.5.2

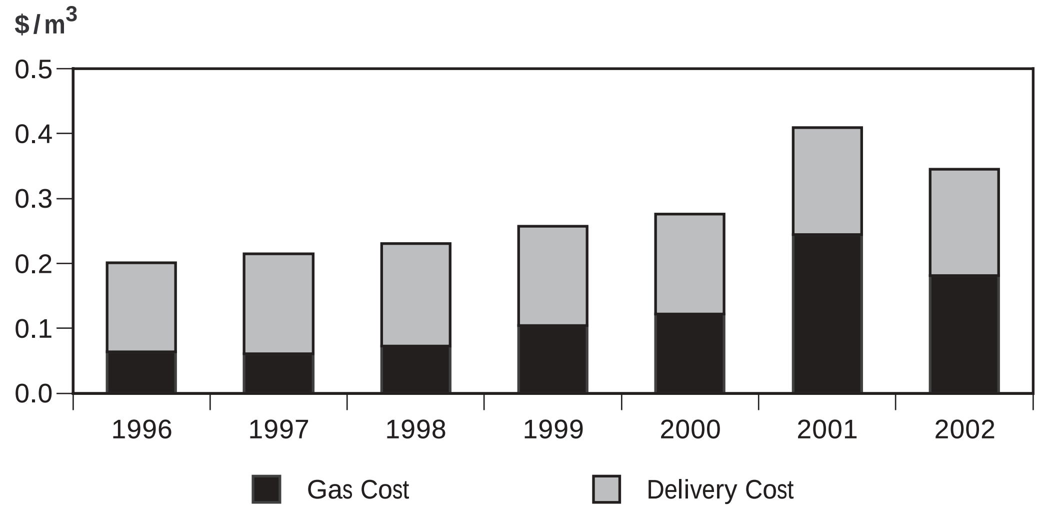
***Residential Gas Price Components - Union***




Source: Union Gas

FIGURE 3.5.3

***Residential Gas Price Components - Enbridge***




Source: Enbridge Gas Distribution Inc.

market has expanded due to the operation of the Alliance and Vector Pipelines beginning in 2000. Enbridge owns Tecumseh Gas Storage at Dawn, which has a working capacity of 2.6 $10^9 m^3$ (90 Bcf).

On 1 May 2002, the Ontario government opened the retail electricity market to competition. There was a fairly high initial response to competition in this market, with about 800,000 customers signing a contract with a retailer, out of four million total electricity accounts in Ontario.

***Regional Natural Gas Prices***

Figure 3.5.1 compares the price of natural gas at AECO with the price at Dawn, the major pricing point for natural gas supplies in Ontario and with the Chicago city-gate price, one of the primary pricing points for natural gas in the U.S. Midwest. The chart indicates that wholesale gas prices in Ontario and the U.S. were closely related over the entire period. The Ontario market has been integrated with the Alberta market since early 1999. Figures 3.5.2 and 3.5.3 show the residential gas price components for Union and Enbridge. Each bar in Figure 3.5.2 represents the residential gas price for a particular point in time. Prices have been adjusted at different times over the years. Union's gas prices have been unbundled into four components since 1997 plus an inventory rider added in 2002. The monthly delivery charge of $7.50 is not included in the chart. Each bar in Figure 3.5.3 represents the gas price per cubic metre in January of that year, for a family with an average consumption of 548 $m^3$ for the month. Again, prices have been adjusted at different times over the years.

***Managing Price Volatility***

In terms of purchasing gas supply, Enbridge is using a hedging/risk management program approved by the OEB. Enbridge has established a quarterly rate adjustment mechanism which began in October 2001.

Customer rates may change every three months to more accurately reflect the actual cost of natural gas. Enbridge sets its rates for customers based on a forecast for the cost of gas over 12 months (October 1 to September 30), but due to price fluctuation, there is an ongoing difference between the forecast cost charged to customers each month and the actual cost of gas. The price differences are tracked in the Purchase Gas Variance Account (PGVA). Rate adjustments may be made quarterly, but the PGVA is cleared on an annual basis.

As is true for Enbridge, Union has not had any difficulty obtaining gas supply, even at the most volatile times. Union uses a portfolio approach to purchase gas, and buys it throughout the year on daily, monthly, seasonal and yearly terms. Targets are set for buying gas in each season. The company hedges 20 to 40 percent of its supply in the summer, and 40 to 60 percent in the winter. Union uses financial instruments such as caps and collars to dampen unforeseen circumstances. In the long-term, Union's average price tracks the market, but the peaks and valleys are taken out. The OEB approves Union's gas purchasing strategy.

Similarly to Enbridge, Union reviews prices quarterly and adjusts its rates if the forecast price of gas over the next 12 months has changed from the previous quarter. Any cost deferrals or savings are passed on to customers once annually.

The retail market allows consumers the choice of selecting a fixed price contract for gas from marketers. So far, in most cases, the main benefit of direct purchasing gas for consumers has been cost control rather than cost saving.

***Regional Issues***

Financial issues are a key consideration for a number of gas market participants in Ontario. Union currently has to post lines of credit to conduct gas business, which it has never had to do before. A major buyer of gas checks the creditworthiness of suppliers and would rather buy from a "quality supplier" than the lowest bidder. Some relatively small gas users have found it very difficult to purchase supply without access to significant amounts of credit.

One district energy association in Ontario stated that gas price volatility was challenging to manage for its commercial customers, particularly building managers. In some cases, building managers could not pass on higher energy costs to tenants, and they were forced to declare bankruptcy. In other cases, money that was intended to pay for building renovations had to be diverted to pay for energy costs.

The OEB began work in January, 2000 to develop rules pertaining to access to distribution services. A new draft *Gas Distribution Access Rule* (GDAR) was released by the OEB in June 2002. This draft rule focuses on requiring gas distributors to conduct their relations with gas vendors in a non-discriminatory manner; becoming less prescriptive by providing gas distributors and vendors with greater flexibility in conducting their commercial relations within the parameters established by the Board; and provides for billing options and processing of service transaction requests comparable with those in the electricity sector.

The Consumers Association of Canada - Ontario Branch believes that Ontario consumers are becoming educated about buying gas, but more could be done. It has stated that there is limited competition in the retail market because three retailers have captured 90 percent of the direct sales market, and because the LDCs still control storage, billing and load balancing services. The OEB's proposed GDAR may resolve these issues.

In response to some consumer concerns and complaints related to energy marketers, the Ontario government passed the *Reliable Energy and Consumer Protection Act, 2002* in June. The legislation is intended to strengthen consumer rights by giving stronger enforcement powers to the OEB and to establish an Energy Consumers' Bill of Rights that would protect electricity and natural gas consumers against unfair market practices by retailers.

A number of energy market participants were concerned about the tolls on TransCanada, because the tolls have been increasing and the amount of capacity underpinned by long-term contracts has been declining. Some parties believe that costs and risk are being pushed onto captive customers at the receipt and delivery ends of the pipeline.

An issue for some gas market participants is the constraint on Union's system between Dawn and Parkway, and the obligation to deliver at Parkway 365 days a year. Union imposes this obligation because of its need to meet peak-day winter deliverability for itself and other LDCs. Parkway is not as liquid as Dawn and has no nearby storage facilities. Union does offer unbundled transportation, storage and distribution services, and a shipper could obtain unbundled service with an obligation to deliver at Parkway only 22 days a year. However, optimizing the use of physical assets is complex and requires a fair amount of knowledge. No industrial customers have purchased unbundled service.

## 3.6 Quebec

***Market Overview***


Quebec is the fourth largest gas consumer in Canada. In 2001, Quebec consumed 5.3 $10^9m^3$ (186 Bcf) of natural gas, of which the industrial sector accounted for 60 percent, followed by residential and commercial sectors at 28 and 12 percent, respectively. Quebec's energy needs are primarily met by hydroelectricity and imported oil.

Gaz Métropolitain and Company, Limited Partnership (GMi) is the largest LDC and delivers 97 percent of natural gas consumed in the province. The Gatineau-Hull area is served by Gazifère. The LDCs are regulated by the Régie de l'Énergie (Régie), a provincial regulatory board. Most industrial customers purchase their gas from marketers, but there is limited competition at the retail level. According to the Régie, gas marketers have not found the Quebec residential market attractive, because the market is dispersed and expensive to serve. At the same time, there has been opportunity for gas in some new upscale housing developments that feature gas appliances. Also, as noted below, electricity is the energy of choice in Quebec for home heating and cooling.

Almost all gas consumed in Quebec originates from the WCSB and is delivered to Quebec via the TransCanada Mainline system. GMi is involved in gas transportation through its wholly-owned subsidiary Champion Pipe Line Corporation Limited (CPL) and 50 percent-owned subsidiary, TransQuébec & Maritimes Pipeline Inc.[1] (TQM). CPL operates two gas pipelines northwest of GMi's main distribution network in the Abitibi and Témiscamingue areas. The TQM transmission system extends from the TransCanada Mainline system at Vaudreuil to Quebec City. Two U.S. export points are located on the Quebec border. The Philipsburg point interconnects with Vermont Gas Systems Inc. A TQM extension connects with the Portland Natural Gas Transmission System for deliveries to the U.S. Northeast market, at East Hereford, Quebec.

GMi has contracted storage capacity at Dawn, Ontario and has access to some storage capacity at St. Flavien and Pointe-du-Lac, Quebec to meet peak requirements. GMi operates a 0.06 $10^9m^3$ (two Bcf) LSR (liquefaction, storage and regazification) plant in East Montreal.

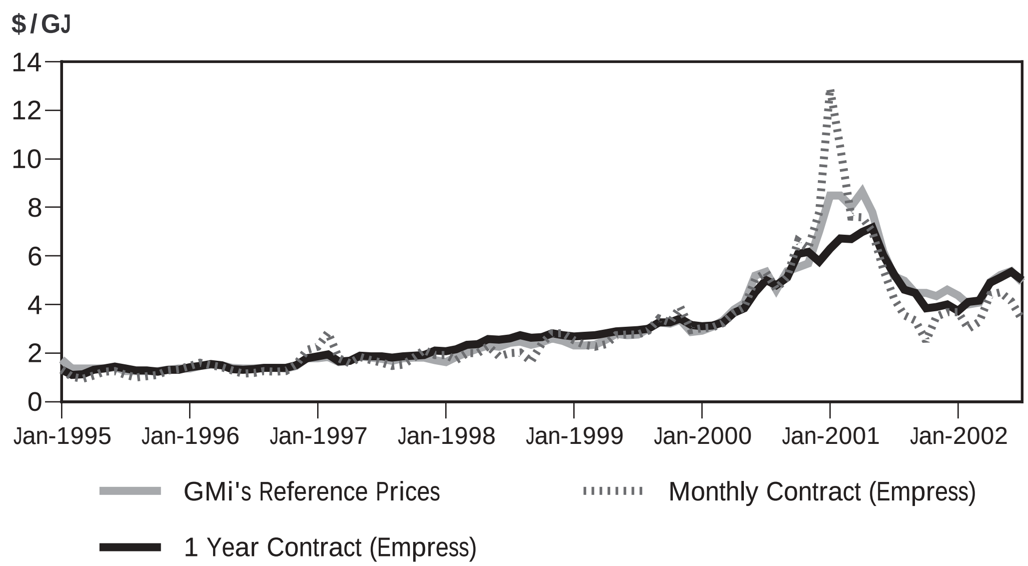
1 TQM is owned equally by GMi and TransCanada.

## *Regional Prices*

Core customers in Quebec typically rely on the LDC to provide them with an integrated gas service. GMi charges its core customers a weighted average cost of gas for its gas supply portfolio. Quebec end-use prices are closely tied to prevailing market prices in Alberta (Figure 3.6.1). Figure 3.6.2 shows GMi's residential gas price components. Each bar on the graph represents an annual unit cost rate for a typical residential consumer with an annual consumption of 3800 $m^3$. The delivery cost includes fuel, transportation, storage and distribution charges.

**FIGURE 3.6.1**

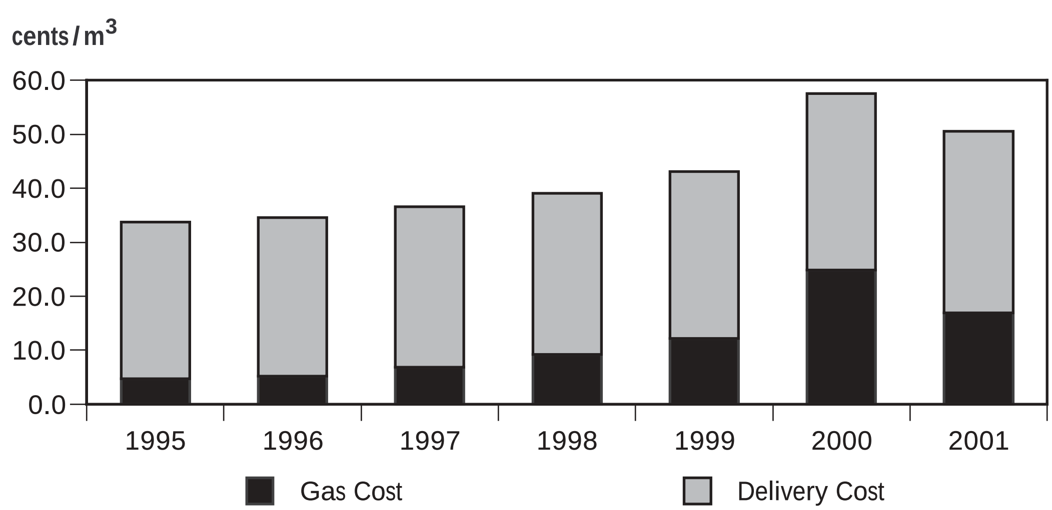
***Empress vs. GMi Reference Prices***




Source: GMi and Canadian Natural Gas Focus

**FIGURE 3.6.2**

***Residential Gas Price Components - GMi***




Source: GMi

### *Managing Price Volatility*

Currently, GMi hedges about 50 percent of its system supply. The company uses a full range of financial instruments in its hedging program, which is approved by the Régie. The Régie has fully supported GMi's hedging program with the understanding that the LDC is not allowed to speculate (and requires adherence to certain parameters). The key to GMi's program is locking in small volumes of gas frequently.

Gas consumers in Quebec see gas prices change monthly. Each month the 12-month reference price (a combination of 30-day prices and one-year forward prices at Empress, Alberta) is compared with the average price of the purchased gas in GMi's portfolio. The monthly gas rate that a consumer pays is an average of these prices. The monthly gas price tends to lag the market price and volatility is mitigated.

In the winter of 2000/2001, about 20 percent of GMi's interruptible customers, including a number of pulp and paper plants, switched from gas to oil. This represented about 25 percent of the volumes on the distribution system.

### *Regional Issues*

According to the Régie, electricity is the energy of choice because provincial residents are less comfortable with gas, electric heating equipment is cheaper to install than gas furnaces and electricity is viewed as environmentally sustainable. Also, electricity rates are fixed in legislation and Hydro-Quebec's rates will be bundled at least until 2004.

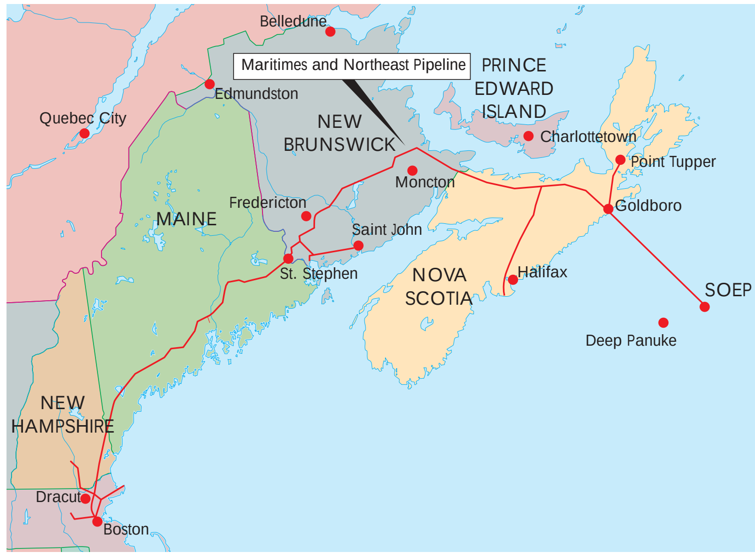
If individuals have a complaint regarding gas price or service, they are encouraged to try to resolve their issues with the LDC first. If this does not work, then a complaint can be filed with the Régie, to which the LDC has 60 days to respond. Régie staff stated that there have been few complaints related to gas issues.

As noted earlier, almost all gas consumed in Quebec originates in the WCSB. GMi is actively exploring ways to diversify its sources of supply. Possibilities include natural gas from offshore Nova Scotia and LNG. As well, the provincial government has recently completed a policy paper which supports the drilling for natural gas in the Gulf of St. Lawrence.

Some end-users are concerned about the potential for higher tolls on the TransCanada system, and that end-users may be facing higher transportation costs without immediate options to obtain gas elsewhere.

Various Quebec gas market participants have noticed a reduction in liquidity in the market. A number of players are no longer trading energy in the market, while others have reduced their trading activities. GMi has been dealing more directly with producers. Credit requirements are also an issue. One large end-user remarked that those requiring small volumes are unlikely to obtain them from a marketer or producer.

## 3.7 Maritime Canada




### *Market Overview*

In late 1999, natural gas production commenced from the Sable Offshore Energy Project (SOEP) development. This gas was exported solely to the U.S. Northeast market until domestic purchases began in late 2000, first in Nova Scotia, followed shortly thereafter by New Brunswick. Considerable preparatory work was necessary before domestic users could begin to take delivery of natural gas. Laterals had to be constructed from the mainline, distribution facilities had to be developed and end-users had to make the necessary investments to be able to receive and burn natural gas. Domestic firm contracts have increased the total contracted demand on the M&NP system; however, contracted volumes to the export market decreased to accommodate the growth in the domestic market.

The SOEP development includes six gas fields in the Sable Island area, approximately 160 to 300 km off the east coast of mainland Nova Scotia. SOEP currently produces an average of 15.6 $10^6m^3$ per day (550 MMcf/d). The natural gas produced from SOEP is delivered onshore at Goldboro to a processing plant. From Goldboro, the M&NP system transports natural gas to markets in Nova Scotia, New Brunswick and the U.S. northeast. There are no storage facilities in the region.

In addition to SOEP, the recently-discovered Deep Panuke gas field is estimated to contain 26.3 $10^9m^3$ (935 Bcf) of recoverable gas reserves. Four existing gas wells may begin production by early 2006 at a combined rate of 11.3 $10^6m^3$ per day (400 MMcf/d). The prospects for additional production in the future appear promising in light of the geological potential and exploration commitments that have been made by producers.

## *Distribution and Retail Sales*

### *New Brunswick*

In 1999 Enbridge Gas New Brunswick (EGNB) was awarded a 20-year franchise by the Province of New Brunswick to provide natural gas distribution in the province. In the spring of 2001, M&NP constructed laterals to Fredericton, Moncton, Saint John and St. George. Since that time, the extraordinarily high prices of natural gas experienced in late 2000/early 2001 have returned to levels closer to traditional fuel alternatives and EGNB is experiencing greater success in attracting additional load.

EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities. Unlike most other LDCs whose distribution rates are determined on a cost-of-service basis, EGNB's distribution rates are market-based. This provides EGNB with the flexibility to price its distribution services to maintain a competitive price relationship between the delivered price of natural gas and alternative fuels. Compared to fuel oil, the EGNB distribution rates would provide for a savings of 30 percent for residential and small businesses, 15 percent for medium to large institutions and five percent for industrial customers.

EGNB's approved residential rate is a two-part rate comprising a Monthly Distribution Customer Charge of $8.00 and a Monthly Distribution Delivery Charge of $3.3371 per GJ. Based on an annual consumption of 132 gigajoules, this would equate to approximately $4.06/GJ for distribution services. To obtain the total cost for natural gas service, the price of natural gas supply obtained from the marketer would have to be added to the distribution rates. In New Brunswick, there are a number of licensed retail gas marketers and agents including Enbridge Atlantic Canada, Irving Energy Services, Park Fuels, WPS Energy Services and GasCo Energy.

EGNB indicates that there are several alternatives available for consumers for the pricing of natural gas supply in New Brunswick including variable pricing, managed pricing, and fixed rate contracts. Under variable pricing, the price is set monthly based on the price the marketer paid for natural gas in the wholesale market. That price is passed on to consumers along with an administration fee and a profit margin. As prices are based on market conditions, variable pricing is the most volatile pricing option offering the advantage of market lows, but also the exposure to market highs. Managed pricing employs financial hedging strategies to manage prices paid by consumers. While the price is set each month by the marketer, the use of price floors and ceilings will help to moderate price volatility. Fixed rate contracts provide a fixed price per unit of natural gas supply for a given period of time. While prices may rise above or fall below the fixed rate, the consumer would have the benefit of certainty of energy costs.

#### *Nova Scotia*

In 1999, a gas distribution franchise was awarded in Nova Scotia to Sempra Atlantic Gas Inc. (Sempra Atlantic). The construction of a local distribution system began in 2000 but was abandoned by Sempra Atlantic after only 15 km of pipeline was constructed. The Nova Scotia Utility and Review Board has recommenced the process to select an LDC and a hearing to consider the applications is set for October 2002. Without an approved franchisee, it will be some time before significant progress is made in the construction of a local distribution system in Nova Scotia. In the meantime, industrial consumption is expected to be sensitive to the relative prices of natural gas and fuel oil.

#### *Prince Edward Island*

Prince Edward Island (P.E.I.) has traditionally relied upon imports of oil and electricity to meet its energy requirements. P.E.I. receives electricity from New Brunswick through underwater cables which are currently operating near capacity. The introduction of Scotian offshore natural gas to the Maritimes has provided an opportunity to increase the range of options for energy in the province. P.E.I. estimates that its natural gas requirements may reach 47,700 GJ within ten years of obtaining gas service.

### *Regional Issues*

The energy market in the Maritimes has developed over many years without any access to natural gas. With good tidewater access, oil has been readily available and has been widely used in electricity generation and home heating, as well as transportation. Coal has long been available from Cape Breton Island and has also been used for electricity generation. Electricity has been generated from oil, coal, hydro and from New Brunswick's nuclear power plant at Point LePreau.

The structure of the Maritimes energy market creates a number of competitive challenges for natural gas. First, the population of the Maritime provinces is quite small, about 1.8 million, and is also spread out in many smaller communities. Natural gas benefits from economies of scale and can best compete where there are large loads in a concentrated geographic region. Oil has an advantage over natural gas in smaller rural communities because it can be easily trucked in, avoiding the need to build a costly pipeline infrastructure. In addition, wood is still widely used in rural areas in combination with oil.

Although it is also expensive to build electricity infrastructure, power transmission and distribution lines are already in place throughout the Maritimes and electricity is widely used for home heating. It is extremely difficult for natural gas to compete with electricity in the residential market when home owners are faced with installing a forced air system in order to utilize gas.

Due to the difficulties in penetrating residential and commercial markets, the natural initial target markets for natural gas in the Maritimes will be large industrial loads and electric power generation projects. It is especially important to find a major customer to act as the anchor load where a new lateral is required to be constructed.

New Brunswick has more large industrial gas users than either Nova Scotia or P.E.I., primarily in the forestry and food processing industries. Hence, there is perhaps more potential for natural gas markets to develop quickly in this province. Some of the difficulties Nova Scotia has been experiencing were highlighted when Sempra abandoned its distribution franchise. Sempra determined that the terms of the franchise were too onerous, but the underlying market factors undoubtedly posed serious challenges. P.E.I. is seeking to build two gas-fired electric power plants on the Island that would act as the anchor market for a new lateral to the Island. Negotiations between the project developers, M&NP and EnCana are proceeding.

Another difficulty facing the domestic gas market is the uncertainty surrounding availability of additional gas supplies. Pending regulatory approval, the only project that appears likely to proceed in the next five years is EnCana's Deep Panuke project. Domestic energy users that are planning large investments in gas infrastructure, including perhaps both a lateral and gas-fired equipment, are seeking assurances that gas supply will be available on a long-term firm basis. However, producers may not be able to make unconditional commitments to supply this gas.

It is highly likely that additional gas will be found and developed, as evidenced by the promising announcement in August 2002 by Marathon Oil Corporation concerning its deepwater exploration well. However, in the absence of supply certainty, domestic users may have to assume considerable risk in proceeding with projects that require new infrastructure.

A further difficulty potential new gas users in the Maritimes face is competition with U.S. buyers. The U.S. market has a number of real and/or perceived advantages, which create challenges for Maritime gas buyers. First, the gas utilization infrastructure is already in place in the New England market; thus the market can readily take supplies from the Scotian basin. Secondly, there is a highly liquid market in New England, which guarantees sellers that they will always be able to sell their gas, whether or not a contracted buyer can take gas on any particular day. Of course, although it may be difficult for Maritime gas buyers to compete with U.S. buyers, it must be noted that without the existence of the U.S. market as an anchor for the original SOEP, there would not yet have been any development of Scotian offshore gas.

EnCana requires certainty that it can sell the output of Deep Panuke's production. Therefore, it has signed conditional transportation contracts with M&NP for 380,000 GJ for ten years. EnCana may step down its commitment up to 31 July 2003, but after that date it will be committed to pay transportation charges for the entire volume. EnCana has stated that it would still be willing to sell gas in the Maritimes, but that it would have to be compensated for its sunk transportation costs to the U.S. once it has committed to the transportation. This creates another challenge for domestic gas buyers because they must be able to develop their projects and make commitments to purchase the gas within this timeframe or they will be faced with paying an additional charge.

In summary, there are a number of challenges facing the Maritimes natural gas market. Some of these challenges are inherent in the nature of a relatively small market, with a geographically dispersed population that has a long history of using other fuels. Other challenges relate to the uncertainty of future supply availability and yet others relate to the relative attractiveness of the large U.S. market. Despite these challenges, natural gas use is growing in the Maritimes.

## 3.8 Summary

There is a wide range in the development of regional gas markets across Canada. Some areas in Alberta, for example, have been able to access natural gas for almost 100 years; on the other hand, New Brunswick and Nova Scotia have just recently commenced natural gas service, while P.E.I. and Newfoundland do not yet have access to gas. Considering the differing rates of regional market development, some gas market issues are regional in nature while others span several regions or the entire country.

The high natural gas prices experienced during winter 2000/2001 affected gas markets across the country and even the continent. The immediate reaction by many consumers was to reduce their natural gas requirements through conservation, reducing commercial operations or by switching to a less expensive fuel. In some cases, governments offered price rebates to assist in offsetting high natural gas bills. Those consumers that purchased gas from marketers or utilities that offered risk management options, such as hedges, were better insulated from the spike in gas prices during January 2001. However, utilizing hedges may also result in periods when the hedged price exceeds the prevailing market price.

Gas utilities in almost every province hedge a portion of their gas supplies with the approval of provincial regulatory bodies. Utilities in Alberta are not permitted to hedge their supplies; rather, gas marketers operating in the province provide this service. Interestingly, gas marketers operating in Alberta, and even in some other provinces, have not enjoyed the success experienced in Ontario especially in the residential and commercial sectors. This is likely attributable to the thin margins at the retail level and the relatively smaller sizes of regional markets outside of Ontario. Moreover, structural aspects of some markets, such as Alberta, are being changed to better facilitate market development at the retail level.

A trend that has developed in the past 18 months involves more frequent adjustments to gas costs paid by consumers. In some provinces, the gas costs realized by utilities were passed onto consumers through an annual or seasonal adjustment to bills. With volatile prices, these adjustments could be rather large. Today, gas costs are adjusted quarterly in provinces like British Columbia and Ontario or even monthly in provinces such as Alberta and Quebec. As well, most utilities and marketers offer the option of equal payment plans to further insulate consumers against high monthly bills.

In some markets such as B.C. and Maritime Canada, the limited size of the market, in terms of number of participants as well as limited supply and transportation options, have led to concerns regarding price transparency and access to natural gas supplies. Consumers in markets that are supplied from the WCSB (especially Manitoba, Ontario and Quebec) have recently been concerned about the long-term adequacy of gas supply and the trend of rising transportation rates on the TransCanada system. Hence, these consumers continue to examine alternate supply options.

# CURRENT MARKET ISSUES

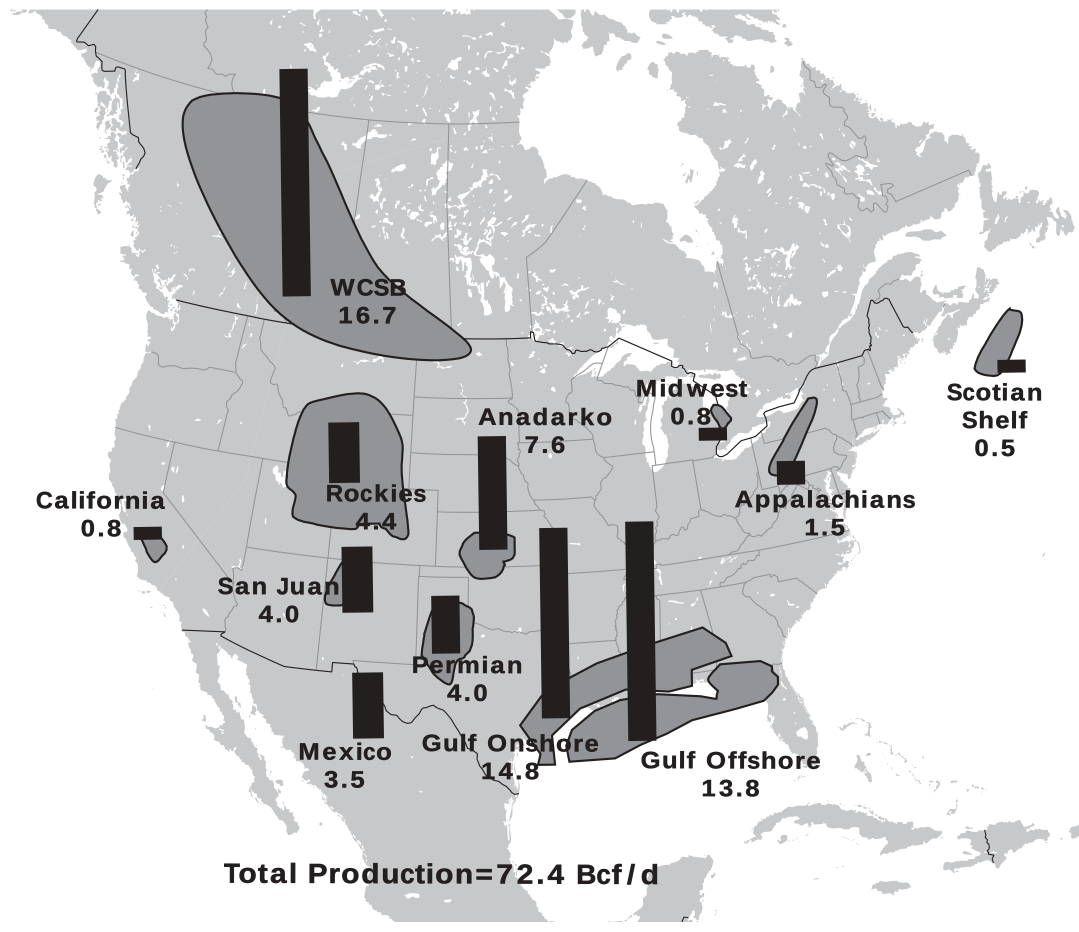
## 4.1 Maturing North American Supply Basins

The majority of Canadian natural gas reserves and production are situated in the WCSB. This geologic region includes most of Alberta, significant portions of B.C. and Saskatchewan, as well as parts of Manitoba and the Northwest Territories. Offshore Nova Scotia and Ontario also contain natural gas reserves and produce gas (Figure 4.1).

Remaining gas reserves in Canada are estimated to be 1 622 $10^9m^3$ (57.3 Tcf) as of year-end 2000. The WCSB accounts for 1 529 $10^9m^3$ (54.0 Tcf). Offshore Nova Scotia is estimated to hold 81 $10^9m^3$

FIGURE 4.1

*North American Supply Basins - Average 2001 Production (Bcf/d)*



(2.9 Tcf) of gas reserves while Ontario is estimated to have 12 $10^9m^3$ (0.4 Tcf) as of year-end 2000. Canadian natural gas production in 2001 totaled 177.8 $10^9m^3$ (6.3 Tcf). This corresponds to an average production of about 487 $10^6m^3$ per day (17.2 Bcf/d). Of this, Alberta accounted for 79 percent of total Canadian production, B.C. contributed 14 percent and three percent was produced from each of Saskatchewan and Nova Scotia. Canada accounts for a quarter of total North American gas production.

In the United States, gas production in 2001 averaged 1 470 $10^9m^3$ per day (51.9 Bcf/d) - a slight increase from the previous year. About half of total U.S. production is provided, about equally, from the offshore and onshore areas of the Gulf of Mexico, with the remainder provided by a half-dozen major natural gas basins.

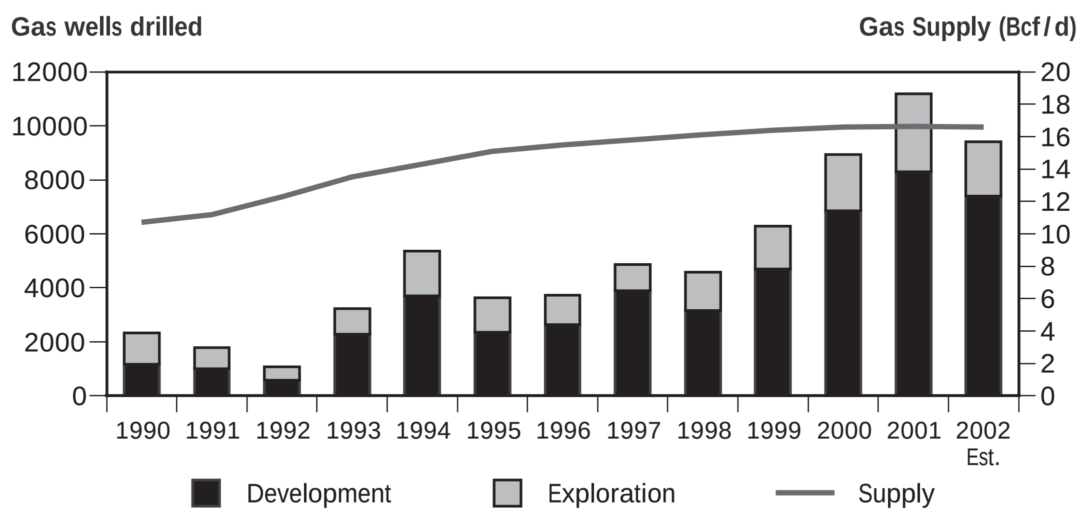
As noted in Chapter 1, producers across North America responded to a period of high gas prices from late 2000 to mid-2001 by stepping up drilling activity. In Canada, a record 11,200 gas wells were completed. Despite this level of drilling, Canadian gas production increased modestly: by less than two percent. This result is consistent with a trend that seemed to develop during the mid-1990s (Figure 4.2). A doubling in drilling, from 2000 to 4000 wells earlier in the decade increased supply by 30 percent. The recent doubling in drilling from 4000 to 8000 wells has increased supply by only 10 percent. This ever-diminishing supply response to increased drilling or, the "treadmill effect," causes many to speculate that the WCSB is reaching maturity.

Signs of basin maturity are also evident from the smaller and smaller pools that are being discovered and from diminishing well productivities and shorter production lives of wells. Over 25 percent of current production is gathered from wells drilled in the last two years. Further, existing production is declining at a rate of 85 $10^6m^3$ per day (3 Bcf/d), or over 20 percent, annually.

A direct impact from the increasing maturity of the WCSB is the amount of investment for drilling required by producers to increase supply. In 1993 this investment amounted to $3 billion. By the mid to late 1990s, this investment jumped to about $6 to 8 billion per year. With higher prices in 2000 and 2001, industry increased its expenditures further, reaching an unprecedented $10 billion per year.

**F I G U R E 4 . 2**

***WCSB Supply Response***




Source: NEB

Indications are that producers will be challenged to change current trends in the WCSB. However, there remain large pools to be discovered as evidenced by the highly prolific Ladyfern field in B.C. in 2000 and recent announcements by EnCana and Talisman of their discoveries in the Sierra and Monkman areas of B.C., respectively.

The United States has also been experiencing increased maturity within many of its basins. Preliminary data to mid-2002, based on surveys of producers, indicate that total U.S. gas production has declined by four percent year-on-year; a rate much sharper than many analysts had expected.

In summary, it would seem that North American basins have entered an era wherein supply responds quickly in a downward direction to gas prices but an increasing effort is required to expand gas production. These characteristics have led to speculation regarding the ability of North American gas supply to respond quickly to meet demand growth in the short-term and the adequacy of conventional gas supply to meet long-term growth in demand. Hence, in the past few years, a wide range of natural gas projects (including pipelines from the North, LNG, coal-bed methane, and offshore east coast prospects) are being considered to supplement conventional gas supplies from already maturing basins.

## 4.2 The "Enron Effect"

In December 2001, the largest energy trader in the U.S. collapsed with the bankruptcy of Enron Corporation (Enron). With the demise of Enron, there have been many accompanying allegations of trading impropriety in certain U.S. markets. This led to several investigations by various American agencies which continue today. No serious abuses have yet been identified in Canada. One of the direct effects of this situation has been closer scrutiny of the energy trading industry. Several companies involved in energy trading, particularly electric power trading, have acknowledged that their trading volumes (and financial revenues) for certain U.S. markets have been inflated due to a practice commonly referred to as "wash-trading." Consequently, confidence in these companies, and more broadly, the energy trading sector, has been shaken and their share prices have dropped sharply. Williams and Dynegy, for example, experienced share price declines of over 90 percent at one point.

Further, the financial ratings of merchant energy companies have been cut by rating agencies which has led to increased costs for debt and future borrowing. As well, greater collateral has been required to support trading operations placing many merchant energy companies into a "liquidity trap." In response, many of these U.S. energy companies have attempted to improve their creditworthiness by selling assets such as gas reserves or pipeline systems, issuing shares, restructuring debt, cutting costs, reducing planned spending and reducing or eliminating their trading practices, particularly speculative trading. As well, some of the companies continuing in the trading business have attempted to partner with other companies which have a higher credit rating. In the short term, these actions have improved balance sheets but credit rating agencies and investors remain wary of the energy merchant sector. Moreover, some of these agencies point out that sales of pipeline systems provide cash but remove assets with low business risk that provide the most stable cash flow in the company.

## 4.3 Effect of Reduced Liquidity in the Market

A major outcome of the activities surrounding the energy trading sector has been reduced liquidity. Simply put, there are fewer counter-parties to trade and the volumes being traded are significantly reduced. Aquila and Engage Energy are no longer trading and companies such as Williams, Dynegy and El Paso Corp. have significantly reduced trading operations. At the same time, higher credit standards are required to participate in energy trading thereby limiting the number of parties that can trade. Creditworthiness is now closely scrutinized by market participants.

These events have had an impact across the North American market, particularly for smaller buyers of energy who have found it increasingly difficult to buy and sell energy. With the scaled down trading operations of energy marketers, producers have been playing a greater role in selling directly to end-users; however, because of the large volumes of gas involved, most deals are executed with large consumers and not small purchasers of natural gas.

Banks and insurance companies are also playing a larger role by providing credit and engaging in or expanding their energy trading. During summer 2002, several industry analysts speculated that it could take 18 to 24 months before confidence is restored in the energy trading sector and business returns to normal. On the other hand, opportunities are available for companies with strong financial positions.

## 4.4 Impact of Creditworthiness Troubles on Gas-fired Power Generation

Hundreds of new gas-fired generation plants have been announced over the past few years in North America. These announcements have led many analysts to predict that a quickly growing natural gas market, driven by power-generation, will result in a 849 $10^9m^3$ (30 Tcf) market by 2010. While not every project will proceed, it is widely expected that the power generation projects which reach commercial status will account for most of the total growth in natural gas demand over the next ten years. However, some developers of power generation have also been impacted by the increased scrutiny of the energy trading business. Many of these developers rely heavily on debt-financing for their projects. With the debt-rating agencies reducing the investment grade of the developers' debt, debt has become much more costly; hence, many developers such as Calpine Energy Services and American Electric Power have scaled down the number of proposed generation plants. This will likely result in lower than anticipated gas demand in the short-term and defer reaching a 849 $10^9m^3$ (30 Tcf) market to beyond 2010; nevertheless, gas for power generation will continue to be increasingly important over the longer-term.

# Summary and Conclusions

Over the past 18 months, natural gas prices reached unprecedented high levels and then steadily declined to lower levels not experienced for several years, only to start rising again. This roller coaster ride tested the market like never before as the market was hit by the "perfect storm." During this time, gas prices responded to a variety of factors, demonstrating that natural gas prices remain truly unpredictable. At the same time, considering the extreme nature of the ride where prices quadrupled in a short period, the market responded extremely well.

The natural gas market responded quickly to changes in natural gas prices over the past 18 months. As natural gas prices rose steadily from mid-2000 and eventually spiked in early 2001, the price system worked to allocate available supplies to their highest value end-uses and away from processes such as ammonia production for fertilizer. The market reduced demand through conservation, fuel-switching and curtailment of commercial operations. At the same time, the producing sector increased drilling activity in order to develop additional gas supply. These activities, combined with changes in the weather, caused a reversal in the upward movement in prices. In time, as gas prices fell, some end-users switched back to natural gas service.

For the most part, governments in Canada refrained from intervening with respect to gas prices, preferring to let the market work. In some cases, rebates were given to residential customers, or utilities were required to recover increased costs over longer periods, thereby muting the short-term impact of high prices.

The dynamic natural gas market is expected to witness continuing fluctuations in gas prices brought on by a variety of factors. However, with the increasing maturity of North American supply basins, many expect that growth in natural gas demand will outpace the growth in conventional gas supplies in the future. This could result in increased volatility in gas prices, not necessarily higher spikes and lower troughs, but rather increased frequency of the reversal in price trends.

Notwithstanding the trend of increased investment in the WCSB, industry has been examining means to offset the flattening trend in conventional gas production. These options include: expanding offshore production, constructing pipelines from northern Canada, developing coal-bed methane production and importing liquefied natural gas.

Price volatility creates challenges for both producers and consumers. Parties planning long-term investments dependent on natural gas, such as electric power plants or frontier supply projects, may reconsider their plans in light of recent volatility. For example, enthusiasm to develop the Alaskan pipeline project waned after prices dropped.

To mitigate volatility in gas prices, a number of risk management tools are available, even at the residential level in some regional markets. The most common of these tools is to hedge against rapid price increases by purchasing a portion of future gas requirements in advance at a firm price. While this strategy protects against volatility, it may also result in customers paying above-market prices.

The advent of electronic trading systems has facilitated the functioning of the market and allows market participants to respond quickly to changing market conditions; consequently, natural gas prices react immediately to changes in supply and demand. At times, gas prices may appear to overreact to market conditions as “market psychology” can play a significant role. Market psychology is based on the perception of how the market is functioning and, as such, involves interpretation of data on the significance of political, physical or economic events.

Some companies, particularly in the U.S., engaged in unethical trading practices. No serious abuses have yet been identified in Canada, but confidence in the energy merchant sector has been shaken. Liquidity in the market has been reduced with the decline in creditworthiness of many energy traders. At this point, it is too early to predict how recent price volatility, along with the demise in confidence in energy traders, will affect the long-term growth of the industry.

In summary, the natural gas market continually adjusted to volatility in gas prices over the past 18 months. During this period, all consumers faced higher prices for natural gas but despite the difficulties caused by the extreme prices, gas continued to flow and the needs of Canadians were fairly met. The natural gas market demonstrated its resilience as it survived the “perfect storm.” The market is functioning.

Looking forward to winter 2002/2003, expectations are that gas storage in North America will be full upon entering the winter season. This suggests that the availability of natural gas will not be an issue this winter. At this point, some weather-forecasting agencies are predicting a generally normal winter with, perhaps, some areas in North America to experience milder weather as a result of a developing El Nino pattern. Canadian natural gas production has been generally flat but U.S. gas production has decreased about two per cent from last year. However, several deepwater projects in the Gulf of Mexico are expected to commence production later this year and this is expected to slow the decrease in total production. Growth in the U.S. economy continues to be weak; consequently, demand for gas, especially in the industrial sector, is muted. As a result of continuing weak demand, any continuing decreases in gas production should not significantly affect gas prices. The outlook for gas prices this winter, on the basis of expected supply and demand for gas, is for prices to be moderately higher, following normal seasonal patterns.

As noted in this EMA, gas prices can be strongly impacted by several factors. Through most of the summer and into the fall of 2002, natural gas prices have been influenced by crude oil prices. Several world events and expectations of hostility have caused crude oil prices to rise. Natural gas prices have followed the trend of rising crude oil prices despite high natural gas storage levels. Depending on how world events unfold, natural gas prices could rise or stabilize at lower levels that are supported by supply and demand for gas. In any event, partially due to unpredictable weather patterns, continuing volatility in gas prices can be expected.

# GLOSSARY

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| Backhaul Service | the transportation of natural gas by displacement on a pipeline system, so that the natural gas is redelivered upstream of its point of receipt. |
| Baseload Volumes | the minimum amount of natural gas delivered or required over a given period of time at a steady rate. |
| City Gate | the delivery point or the point of intersection between a gas transmission pipeline and a local distribution system. |
| Commercial Market | the portion of the natural gas market consisting of businesses and institutions including government, agriculture, the service sector, schools, hospitals and apartment buildings. |
| Core Customers | volumes that are typically supplied by the local distribution company to residential and commercial customers. |
| Deferral Account | used to record variances between forecast and actual costs of a particular type. |
| Direct Sales | gas purchase arrangements transacted directly between producers, brokers or marketers and end-users. |
| Displacement | in pipeline transportation, the substitution of a source of natural gas at one point for another source of natural gas at another point. Through displacement, natural gas can be transported by backhaul or exchange. |
| Distillate Fuel | one product of refined crude oil. It is primarily used as diesel engine fuel. |
| Electronic Trading | refers to gas purchases and sales which take place via an electronic trading system. These systems allow gas to be bought and sold on an anonymous basis and provide for price discovery. |
| Exchange Gas | natural gas that is received from, or delivered to, another party in exchange for natural gas delivered to, or received from that other party. |
| Hedging | hedging is the process of protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one transaction with another. A long position in an underlying instrument can be hedged or protected with an offsetting short position in a related underlying instrument. |

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| Hog Fuel | fuel consisting of pulverized bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills. |
| Hub | a geographical location where large numbers of buyers and sellers trade natural gas and where gas can be physically delivered. |
| Industrial Market | the portion of the natural gas market consisting of manufacturing, forestry and mining operations. |
| Interruptible Service | gas service provided to customers which may be curtailed due to supply or system capacity limitations. |
| Liquidity | a high level of trading. |
| Load Factor | the ratio of the average load over a designated period of time to the peak load occurring in that time period. |
| LNG | liquefied natural gas |
| Netback Price | the per-unit price received by a gas producer from the sale of gas in end-use markets, less applicable costs. These typically include transportation and marketing fees. |
| Option | an agreement which gives a seller (or buyer) the right, but not an obligation to sell (or buy) a set amount of gas at a predetermined price. |
| Peaking Service | a service that entitles a buyer to a certain quantity of natural gas delivered at the buyer's request during peak-demand periods. |
| Plantgate Price | the price received by producers for natural gas delivered to a pipeline system. |
| Price Differential | the difference in gas prices between two trading points. |
| Price Transparency | the degree to which prices and other aspects of trades (duration, volumes, etc.) can be determined or verified at trading points. |
| Residential Customers | the portion of the natural gas market consisting of private dwellings and larger residential units with individually-metered apartments. |
| Residual Fuel | the remaining refinery product after the removal of valuable fuels like gasoline. It is used primarily for power generation and various industrial processes. |
| Rider | a temporary adjustment to rates usually reflecting the disposition of deferral account balances. |
| Secondary market | the market in which shippers or marketers contract with parties other than pipelines for transportation services or delivered gas services. This market is unregulated. |

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| Spot Sale | transactions of gas which are generally for 30 days or less. |
| Swap | an agreement to exchange future cash flows. For example, a fixed-for-floating swap is the difference between a fixed price stream and a price stream based on an index such as the NYMEX. |
| Wash Trading | off-setting trades of an identical amount of energy at the same price and trading point. |