Understanding the North American Natural Gas Market

DISCUSSION PAPER

PREPARED BY
THE CANADIAN GAS ASSOCIATION

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Introduction

This document is intended to provide the reader with a foundation for understanding the dynamics of natural gas markets in Canada. Natural gas is a key variable in securing Canada's energy future for many reasons.

- Natural gas meets over a quarter of Canada's primary energy demand.
- Natural gas is the most environmentally friendly fossil fuel.
- Natural gas is the fastest growing fuel of choice for electricity generation and distributed energy initiatives.
- Natural gas fuels are key to the development of the Canadian Tar Sands.
- Natural gas fuels are a primary element in lowering emissions of motor vehicles.

The past several years have witnessed growing evidence of the stress that Canada's energy systems are under – meeting demands for affordable, reliable energy while also meeting growingly stringent standards of environmental performance. Natural gas systems are among those that are under stress as evidenced by increasing prices and greater price volatility over the past two to three years.

The Canadian Gas Association (CGA) takes the view that governments and industry working together can take steps to mitigate the stresses on the system. Ensuring that we take the right steps – and avoid missteps – will require that we deepen and broaden understanding of gas markets among policy makers and their advisors and industry stakeholders. Our intention is that this document will contribute to the process.

The document is organized in four sections, each building on the other.

Section One

NATURAL GAS INDUSTRY: KEY FACTS AND CONCEPTS

Section One provides some background on the key factors that drive natural gas markets. Starting with the basic market structure, any examination of the natural gas industry in Canada should understand that the Canadian system is inextricably bound up in a North American marketplace. From there, we look at the principal sources of demand for gas and the principal sources of supply and how each is evolving.

Based on the principle that those who forget history are destined to repeat it, we provide a brief overview of the key changes in the natural gas industry, looking at the last twenty years or so of deregulation, free trade and price movements. In this context, Canadians have enjoyed very large benefits, as resource developers, producers and exporters and as consumers of low cost, reliable gas.

The section further explains the various components of the industry that account for the price of gas faced by consumers. The commodity cost, the most widely reported element, is priced in free markets. Other critical components, such as the natural gas delivery system of pipes, storage and related services, are natural monopolies and subject to regulatory oversight. Understanding how this structure works is critical to understanding how consumers are affected by the market.

This section concludes with a more detailed look at the key factors affecting natural gas prices, our ability to anticipate price movements and the demand drivers such as industrial production and weather, changes in deliverability, storage, and prices for energy substitutes.

Section Two

MARKET OUTLOOKS – INTEGRATED PERSPECTIVES

Section Two describes the composite picture of outlooks for demand and for supply going out as far as 2020. The composite is built from a variety of outlooks developed by government and private sector groups. It shows where there is consensus, where there are divergent views, and the key factors that underpin the different views of the future.

Broadly speaking there is strong consensus around several points. Demand growth will likely be in the range of 1.9% per year. Views on supply growth are much more widely varied but all outlooks agree that meeting demand growth as projected will require North America to rely increasingly on new sources of gas. It is also commonly viewed that there is an abundance of gas available but that new North American sources will be more costly than traditional sources and will need to be supplemented with increasing amounts of imported liquefied natural gas.

While many other factors will likely affect the outcome, the underlying demand and supply dynamics seem to point to gas prices in coming years higher than we experienced through the decade of the 1990's and to continuing price volatility.

Section Three

IMPLICATIONS

Section Three looks at the key implications for business and for policy that arise from the changing market conditions we envision. Three groups of implications stand out: the economic competitiveness of natural gas dependent industries; the environment due to the fuel choices driven by gas market dynamics; and implications for consumers, especially lower income consumers. More work needs to be done to better understand each of these areas. However, the CGA's position is that greater price elasticity of demand combined with growing impediments to adjustment in supply will mean that a high proportion of the market adjustment will take place on the demand side. In several respects, such adjustments will be difficult for both business and policy. Canadian governments should examine policy changes that might improve the responsiveness of the supply side at the same time that the overall responsiveness of the market is improved.

Section Four

POLICY DIRECTIONS

The concluding section broadly outlines the policy directions that we believe need to be examined. This is necessarily a very high level assessment. Apart from anything else, further assessment will need to draw on the views of other parts of the natural gas industry – upstream from the delivery system as well as other key related industries such as electricity.

Put simply, CGA believes that there is a need for a renewed dialogue on natural gas. This dialogue needs to be part of a broader energy policy dialogue and it needs to engage federal, provincial and territorial governments and the rest of the stakeholder community.

Section One

NATURAL GAS INDUSTRY: KEY FACTS AND CONCEPTS

Production & Consumption

In 2001, natural gas supplied 31% of the total primary energy consumption of the Canadian market place.[1] Canada consumed 3,225 BCF of natural gas in 2001 compared with 22,640 BCF consumed in the U.S[2] (fig. 1). To put these numbers into context, one billion cubic feet (BCF) of natural gas can supply the energy needs of over 11,000 homes or 2,000 commercial entities or 90 industrial concerns for one year.[3] The strong link between natural gas demand and the North American economy was reflected in declines in consumption during the recessionary periods of the early 80's and 90's.

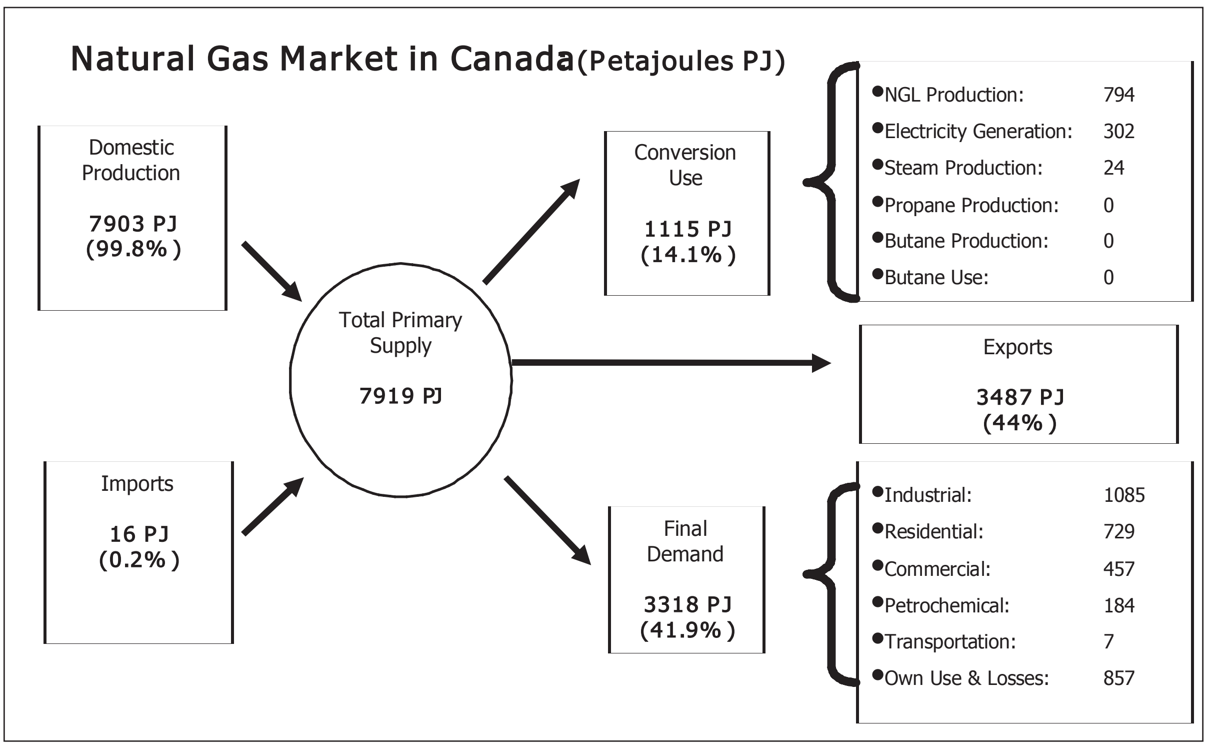


FIGURE 1

1 Energy Supply-Demand in Canada, Statistics Canada Catalogue no. 57-003-XPB; [Note: primary energy consumption is energy which is consumed either to make other energy or to fulfill a specific energy requirement]
2 Statistics Canada, National Petroleum Council (NPC), EIA
3 10 year averages derived from 1990-1999 sector consumption statistics contained in American Gas Association (AGA) 2000 Gas Facts; (Note: the energy content of 1 BCF of natural gas is equivalent to approximately 1 petajoule (PJ) or 1 trillion British thermal units (BTU); this energy content is also known as "heating value")

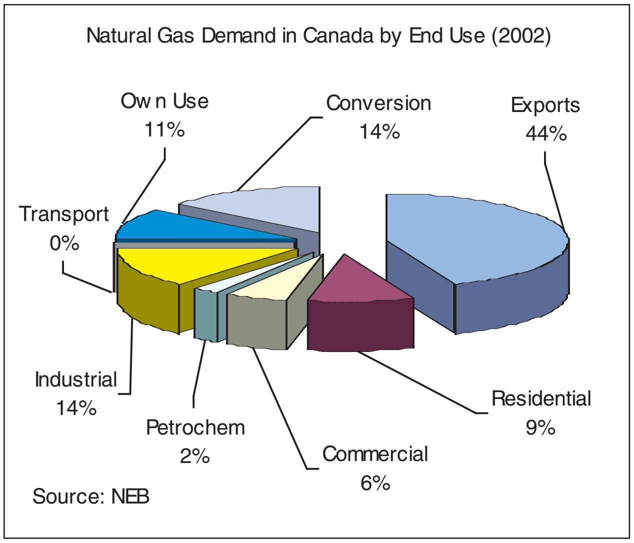


FIGURE 2

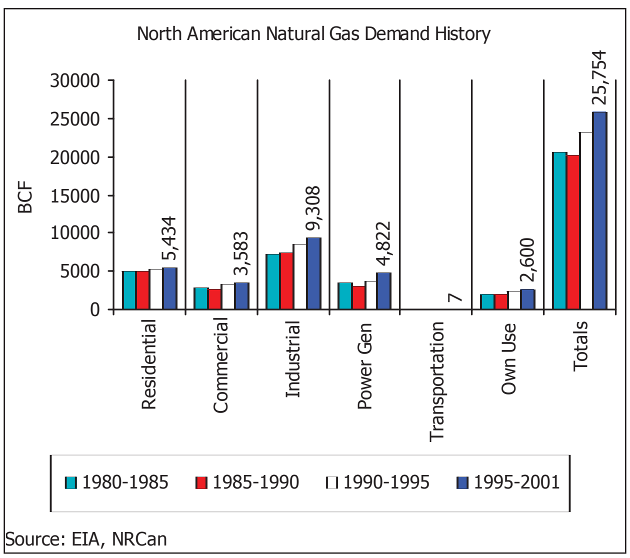


FIGURE 3

Forty-four percent of the natural gas currently produced in Canada annually and moved along the transmission system is destined for export to the U.S. (fig. 2). Domestically, the industrial sector consumes the next largest share at 14%. Other major users include the residential sector (9%), power generation (6%) and own use (11%). Own use, refers to consumption of natural gas by the energy industry to process and move natural gas to market (including export).[4]

North American demand growth has been more or less evenly distributed amongst the different sectors since the mid 80's, with the exception of the commercial and power generation sectors (fig. 3).

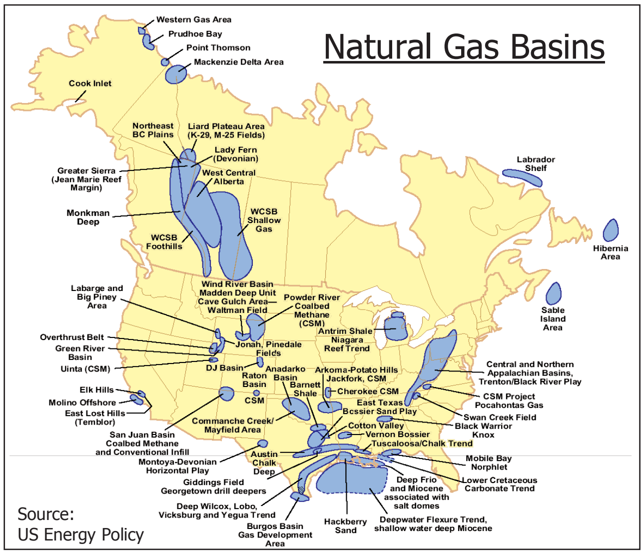
- The commercial sector grew at an average annual rate of 1.7% over the period between 1990 and 2001.
- Residential and industrial demand grew by 0.9% and 0.8% respectively over the same period.
- Natural gas for power generation has been the strongest sector in North America, having grown 4.9% between 1990 and 2001. Canadian natural gas demand for power generation grew at 11.8% over the period between 1990 and 2001.[5]

North American natural gas supply comes from three major areas (fig. 4): the Western Canadian Sedimentary Basin (WCSB) which is located primarily in Alberta; the Mid-continent composed of scattered basins throughout the central and mid-western U.S.; and the Gulf of Mexico region.

These areas are known as traditional or conventional supply basins and have contributed the bulk of natural gas supplies to North America over the past two decades (fig. 5).

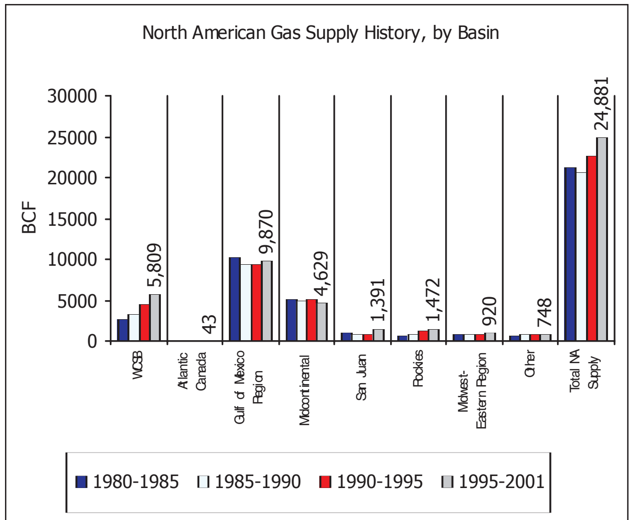
4 Statistics Canada, NPC, EIA; (Note: when that portion of "own use gas" dedicated to export transmission operations is included, then export accounts for 59% of demand)

5 Growth rates derived from data assembled to construct graph titled "Natural Gas Demand of North America (Can+US) Market Sectors"; Sources: AGA, API, EIA, NPC, IEA, StatsCan



Source:
US Energy Policy

FIGURE 4

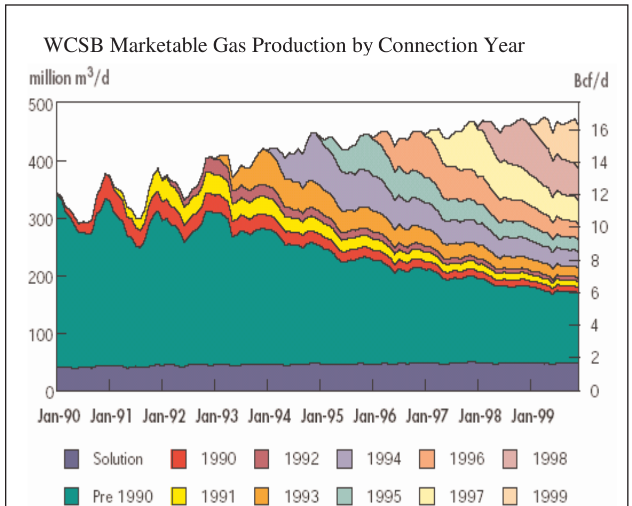


Source: EIA, NRCan

FIGURE 5

In 2001, the WCSB, Mid-continent and the Gulf region accounted for 24%, 17% and 39% of North American domestic natural gas production respectively[6].

While these three basins clearly supply the bulk of North American natural gas, two of these regions are also producing less total volume today than in prior decades. In 1980, the Gulf of Mexico and Mid-continental regions supplied 11,400 BCF and 5,800 BCF respectively compared to 10,000 BCF and 4,400 BCF respectively in 2001. Although the WCSB has increased its productive capacity since the 80's – 2,600 BCF in 1980 compared with 6,100 BCF in 2001 – due to widespread drilling activity, it has entered a phase of declining production rates as new wells are drilled[7] (fig. 6).



Source: NEB

FIGURE 6

In order to meet growing demand, supplies will need to be boosted via untapped conventional sources located in the Rockies and through improved drilling technology in and around existing basins in the WCSB, the Gulf coast, Arctic, and Atlantic Canada regions.

6 Canadian Association of Petroleum Producers (CAPP), PIRA

7 Production numbers derived from data assembled to construct graph titled "Natural Gas Contribution of North American (Can+US) Producing Regions of Basins"; Sources: CAPP, PIRA, API

New supplies will also be developed through innovation and technology initiatives focused on unconventional sources of natural gas such as Natural Gas from Coal (NGC), also called Coal-Bed-Methane, Liquid Natural Gas (LNG), and – over time – intensive R&D efforts could lead to successful development of vast hydrate sources of natural gas located on the oceans floor.

Currently, LNG imports from Angola, Nigeria, Algeria, Trinidad, Venezuela and the Middle East satisfy about 1% of North American demand. Worldwide LNG demand is growing at 6.4% per year. LNG represents 27% of cross-border international gas flows and 5.8% of world demand. Current NGC production in the US is close to 4 BCF/day, accounting for almost 8% of U.S. natural gas use. In Canada, NGC production is estimated to be 10-15 MMcf/day, with reserves estimated 20 to 60 TCF. The approval of new LNG terminal sites and issues of land access and water usage in NGC operations are limiting growth from these non-traditional sources.

Regulation of the Natural Gas Industry

In Canada, the natural gas industry became a truly national industry in 1958 with the construction of the Trans-Canada pipeline that brought Alberta gas to developing markets in eastern Canada. In 1959, the National Energy Board (NEB) was created to regulate federal pipeline construction, tolls and tariffs and to regulate exports of Canada's energy resources[8].

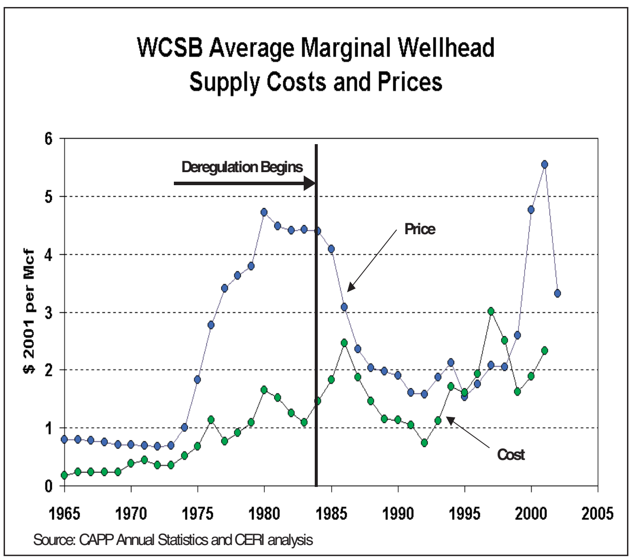


FIGURE 7

Up until the early 1980s, the NEB regulation framework included:

- Direct control over natural gas prices both domestic and export.
- Priority consideration of domestic consumption requirements over exports.
- A 30-year reserve surplus test before approving new export pipelines.
- Denial of equal access for Pipelines to the U.S. exports market.
- Use of Take-or-pay contractual agreements.

Through much of the 70's and 80's the Canadian industry experienced very high prices (fig. 7), and developed of a huge bubble of natural gas reserves. This combined with the oil crisis of the mid 1970s and the economic recession of the early 1980s left pipelines with huge commitments to buy gas that could not be sold. By the mid-80s it was obvious that price regulation was not sustainable.

Deregulation began in 1984 with the signing of agreements between the federal government and the producing provinces and led to significant structural changes in the industry including:

8 "The Future of Natural Gas in the World Energy Market"; Government Regulation, Natural Gas Industries and Markets: The Canadian Experience; J. Dwarkin

- Mandated 30-year reserve-to-production ratios were abolished, freeing up significant quantities of Canadian natural gas for export to the U.S.
- The NEB allowed third parties open access to pipelines and eventually allowed for a secondary market for pipeline space.
- Consumers were allowed to buy their gas commodity from someone other than their Local Distribution Company (LDC) including marketers and producers.

Price declines following deregulation were due in large part to the liquidation of the huge mandated inventories and gas on gas competition. Today, deregulated is still something of a misnomer given that items such as transmission tolls, distribution & storage fees, return on equity, and a number of other areas remain regulated or controlled by provincial regulators or the NEB. What has been deregulated is the market price of natural gas.

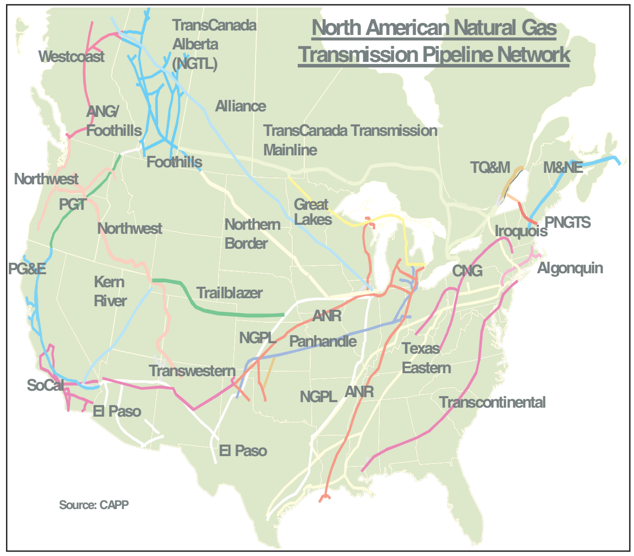


FIGURE 8

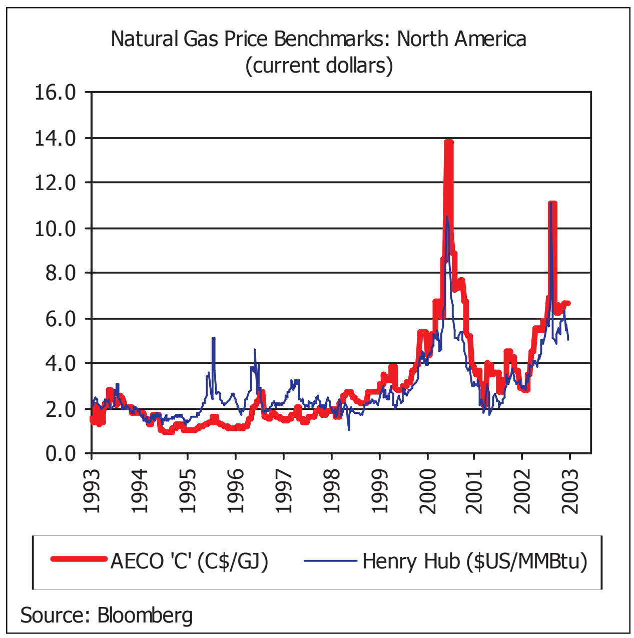


FIGURE 9

Infrastructure and Pricing

Today, the North American market is connected by a series of transmission pipelines (fig. 8) between producing basins and end-users all over the continent. However, a number of domestic natural gas sources (e.g. Arctic, untapped Rockies) have yet to gain transportation access to consuming markets.

By linking supply and market hubs, this pipeline transmission and distribution grid also allows commodity availability and price signals to flow between producers, movers, buyers and sellers efficiently and effectively.

In most jurisdictions, the total price paid by end-users of natural gas is made up of the following components:

- Commodity costs: the price paid for the natural gas commodity which is priced at a supply or market hub;
- Transmission costs: the charge to move the natural gas from sources of supply to a city gate of the LDC;

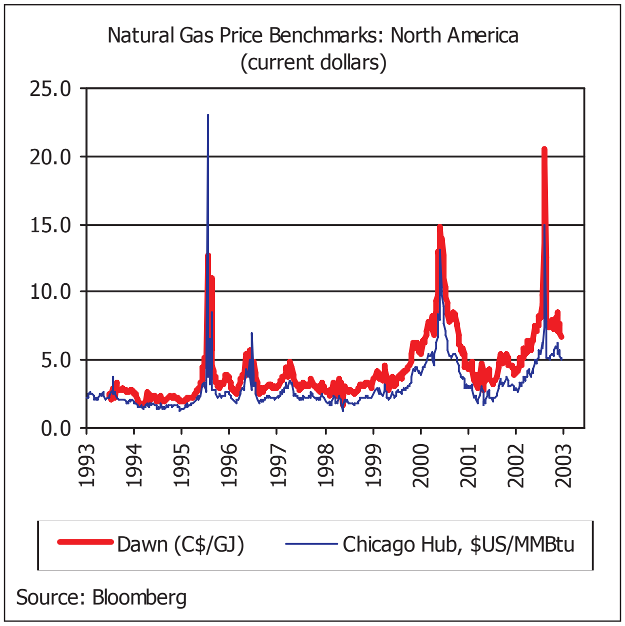


FIGURE 10

- Distribution costs: the cost to move gas over a LDC's franchise area, and includes service charges for storage and load balancing.

The natural gas spot markets provide commodity price signals at various supply and market hubs. These are the major price reference points in North America. Market participants (e.g. gas marketers, LDCs, end-use customers, market speculators) use hub prices as surrogate measures for the current wellhead price. Prices at major hubs are reported on a daily basis electronically and by several natural gas industry news publications.

Supply hubs, such as – AECO and Henry Hub (fig. 9) – are close to major producing regions and major pipeline connection points. AECO is in Alberta at the Nova Inventory Transfer point, and Henry Hub, in the Gulf of Mexico Region,[9] is a collection area for 49% of U.S. wellhead production.

Market hubs, like Chicago or Canada's Dawn hub are also critical pricing points (fig. 10) around which market transactions are made. Differences in prices between the different hubs or price points can reflect differences in costs to transport the natural gas to a market area and can also reflect local supply and demand conditions.

In addition to spot market prices – which track current prices on a daily basis – market participants can also reference futures pricing at Henry Hub and AECO[10]. Futures prices, literally the price for gas supplies sometime in the near future, provide an important risk management tool for the industry and consumers allowing them to build a hedge against possible volatility in the future price of the natural gas commodity.

It is estimated that more than half of Canadian natural gas is purchased directly by customers or their agent, marketer or broker intermediary. The balance of natural gas purchases are made by regulated LDCs on behalf of their customers. LDCs purchase gas using a mix of spot-price and fixed-price contracts and use financial instruments to manage price volatility. LDCs however, are often restricted by their provincial regulator from directly offering their customers the flexible pricing options available from marketers. For example, many regulated LDCs are not able to offer their customers fixed price contracts and must charge customers their variable rate of natural gas.

9 EIA; "U.S. Natural Gas Markets: Relationship Between Henry Hub Spot Prices and U.S. Wellhead Prices"; P. Budzik

10 EIA; Budzik; (Additionally with respect to speculators and futures trading, the Henry Hub is the largest centralized point for futures trading in the US. The New York Mercantile Exchange (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contract. The NYMEX gas futures contract began trading on April 3, 1990 and is currently traded 72 months into the future. It is the key indicator of industry analysts' thoughts and feelings on the forward direction of the market.)

Storage & Hedging Activities

Due to the seasonal nature of demand, natural gas is typically injected into storage between April and October, and withdrawn during the heavy usage period between November and March. Underground storage of natural gas takes place in depleted gas reservoirs (pools) found mostly in the north central U.S. (Michigan to Ohio) and in Ontario. Natural gas is also stored in man-made storage caverns mined in underground salt formations or even developed from depleted underground oil pools. These facilities are all developed through fieldwork and processes encompassing geological surveys, engineering science and field-testing to ensure geological and environmental stability. Storage is generally close to market, making it readily accessible to meet surges in demand. The ability to store gas can also be used as a form of physical hedge (insurance) against price volatility. Being able to store natural gas allows market participants to purchase some gas in the off-season when prices are typically lower and store it for use or delivery during peak season.

In recent years, regulatory approval and limits on return on investment have slowed additions to storage capacity. This, coupled with tighter land access and storage development regulations, has increased the cost and time required to bringing new underground storage on-line. In particular, storage development in the lower 48 states has declined significantly since the early 80s after decades of sustained growth. This has reduced the industry's flexibility to deal with surges in demand or interruptions in supply shown by a decline in the number days of forward gas demand cover available (fig. 11).

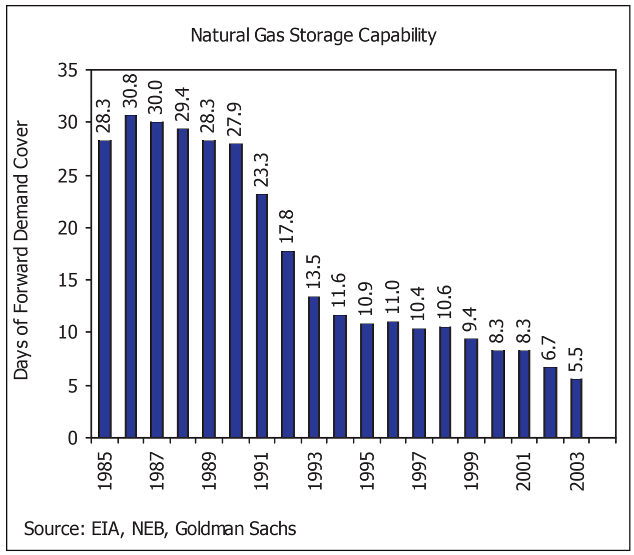


FIGURE 11

The U.S. Federal Energy Regulatory Commission's report into the causes of the natural gas price spike of February 2003 stated that the sharp price rise experienced across the U.S. "reflected relatively high short-term demand in the eastern and the mid-continental U.S. along with reduced ability to deliver natural gas from storage characteristic of the then prevailing low storage inventories". Price increases in specific regional markets reflected exhaustion of that market area's storage.

Beyond using storage, such options as fixed price contracts, futures contracts, swaps and options that lock-in the price for gas supplied at some future date, can also be used as a hedge against price volatility. It is important to note that not all agents in the market are allowed to use these instruments. Hedging can be effective in reducing the price volatility that consumers face but it does not guarantee the lowest possible price, simply a more stable price.

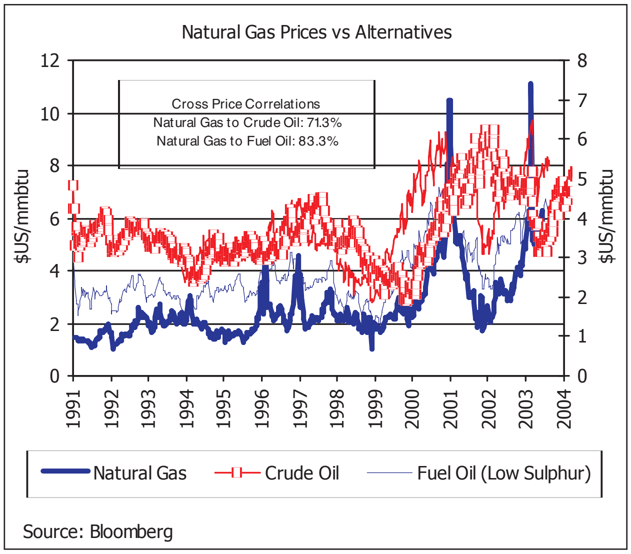


FIGURE 12

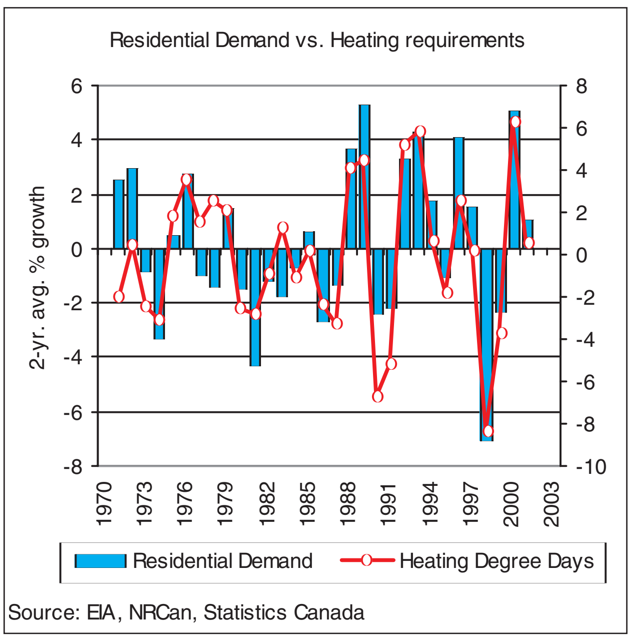


FIGURE 13

Oil Markets Influences

Natural gas prices and demand have historically shown a strong link to the price and supply availability of oil (fig. 12).

Fluctuations in world oil prices as a result of market forces or driven by global geopolitical events have significant influence on the market price for natural gas.

In some cases, certain refined petroleum products derived from crude oil are direct substitutes for natural gas. To the extent that their price is directly tied to oil prices, there is a strong direct impact on the corresponding natural gas commodity price and on the consumption of natural gas. Over the past decade daily natural gas prices have shown an over 71% correlation to crude oil prices and an over 83% correlation to the price of fuel oil.

Weather Influences

Colder than normal winter weather results in above average consumption of natural gas. This reflects the fact that natural gas is a primary residential and commercial space heating fuel and is used increasingly as a fuel for electricity generation (fig. 13).

Sustained colder than normal weather conditions in winter will deplete natural gas storage levels. Typically, this storage would be replenished during the lower demand summer months. However, summer storage refilling has been slowed by increased demand for power generation to run air conditioning and other cooling devices during the summer months. As a result, markets enter the winter heating season with below average natural gas storage inventory levels, increased prices and increased price volatility as the next winter heating season approaches.

Section Two

MARKET OUTLOOKS – INTEGRATED PERSPECTIVES

This section looks at a number of demand and supply forecasts from a variety of government and private sector outlooks. Our intention is simply to give readers an understanding of the range of views in play from authoritative sources. Appendix 1 gives some sense of what underlies the different views but the important conclusion is that there is a widespread consensus that markets will be tight at least into the 2010 timeframe.

The forecast ranges shown in figure 14 depict the potential maximum and minimum demand and supply scenarios for any given year out to 2020[11]. In general, experts see a future where potential demand for natural gas is strong and will require a significant supply response. That response will need to encompass all non-conventional sources if demand growth is to be sustained at the high end of the expected range.

North American natural gas markets are open markets where supply and demand will always eventually adjust to clear the market at a prevailing market price. Interference in the market process for natural gas, and more generally for energy, has significant impacts on this adjustment process. Given the long time lags involved in bringing new supply to a market, consumers bear the brunt of the adjustment required to clear the markets. This demand response is made mostly by large industrial gas users and power generators who have a higher flexibility than do residential and commercial customers. Such adjustments have significant implications for Canada's economic, environmental and social welfare.

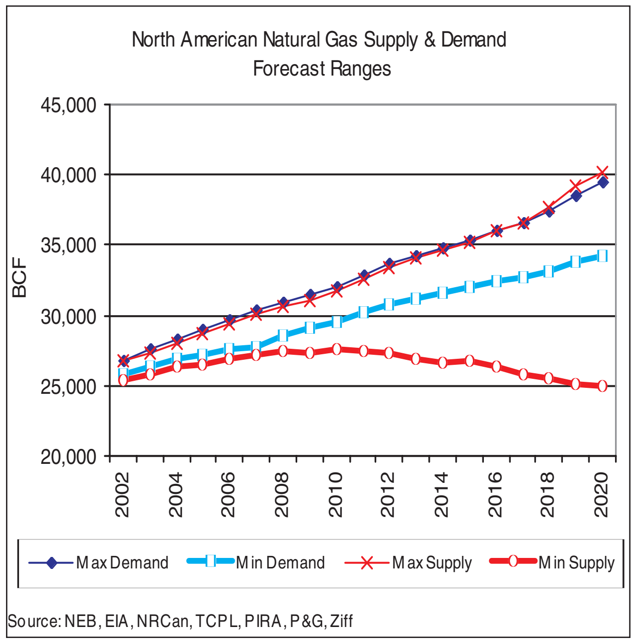


FIGURE 14

An example of such impacts came in January 2001 when supply-side tightness generated high prices forcing demand in North American natural gas markets through an estimated 4 to 10 BCF per day decrease adjustment (mostly in the north east U.S.). End-users cut back and/or switched away from their use of natural gas in an effort to reduce their energy costs[12]. At that time, extreme cold weather in central and eastern North America resulted in a scenario where supply-side responsiveness could not keep up with demand. Such periods of adjustment are not without consequence. Some estimates show that the loss in price-sensitive industrial demand

11 Appendix 2 contains all data from which the maximum, minimum and average forecasts were derived.
12 "Rising Gas Costs Bring Back 2000-01 Memories"; ENERGY Analects; March 3, 2003; Vol. 32, Issue No. 5

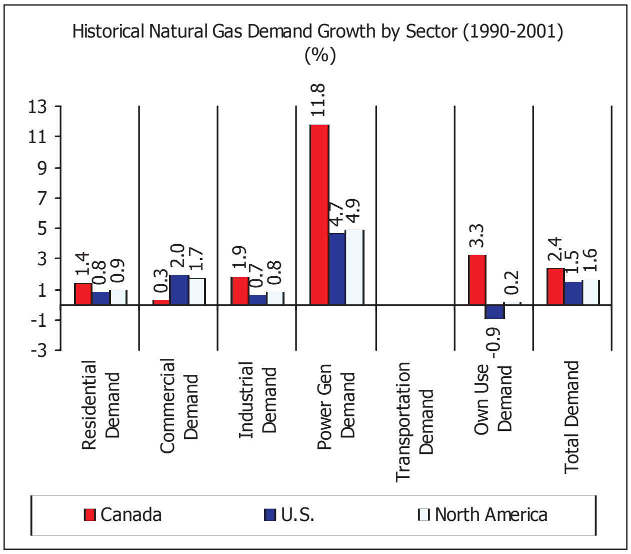


FIGURE 15

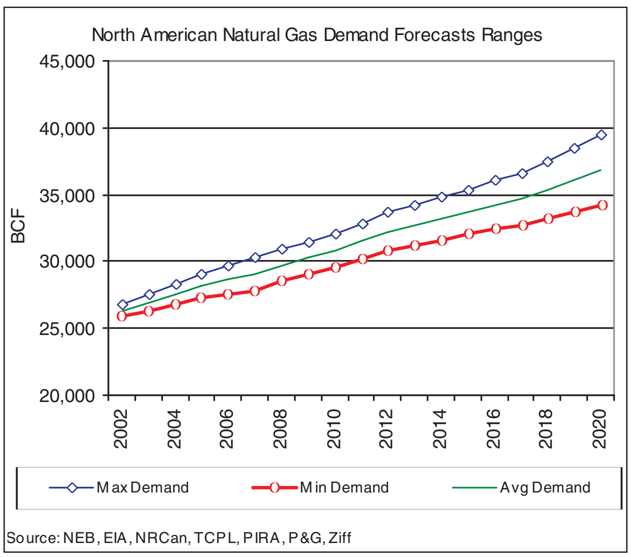


FIGURE 16

resulted in the loss of at least 200,000 manufacturing jobs in the U.S.[13] In addition, where a fuel-switching response was triggered, the switching was mainly to higher CO_2 emission fuels such as coal or oil.

Direct interference in a market-based energy market also has negative impacts. Consider the electricity price cap implemented in Ontario in mid-2003. This resulted in the postponing or abandonment of four natural gas cogeneration plants, totaling 1855 MW, that were in the planning stages[14]. Beyond the lost investment for the economy, these cancellations are particularly distressing in terms of the future negative impact on the reliability of electricity supply as well as the negative impact on the environment from continued reliance on coal fired generation capacity.

Demand Outlook

A survey of industry experts shows forecasted average annual growth in demand of 1.9% from 2002 to 2020 (fig. 15). Relative to 2002, increases in demand are expected to be 1.8 TCF by 2005, 4.5 TCF by 2010 and 10.5 TCF by 2020. Industry experts see North America breaking through the 30 TCF demand barrier within the medium-term (by 2009).

The composition of natural gas demand is expected to continue the shift seen over the past 10 years. The more efficient use of natural gas afforded by new appliances and furnaces will balance any demand growth derived from adding new customers. It is expected that growth in consumer demand will also be tempered by conservation measures and “demand side management” initiatives (fig. 16). Hence, overall residential demand growth will remain low

13 "US Natural Gas: A Vicious Cycle of Under-investment and Price Volatility"; Testimony before the House Committee on Energy and Commerce; J. Currie; June 10, 2003

14 Enbridge Gas Distribution Inc.

and stable. Similarly efficiency gains will generally lead to low growth in industrial gas demand. Conversely, natural gas for power generation will increasingly become the significant demand growth area driven by the environmental benefits of gas-fired electricity generation.

On balance, gas demand will be driven by the environmental performance of natural gas and by overall economic activity. Industrial production remains the key driver for industrial demand while residential demand will closely track heating requirements of consumers. It is expected that growth in consumer demand will be tempered by conservation measures and "demand side management" initiatives.

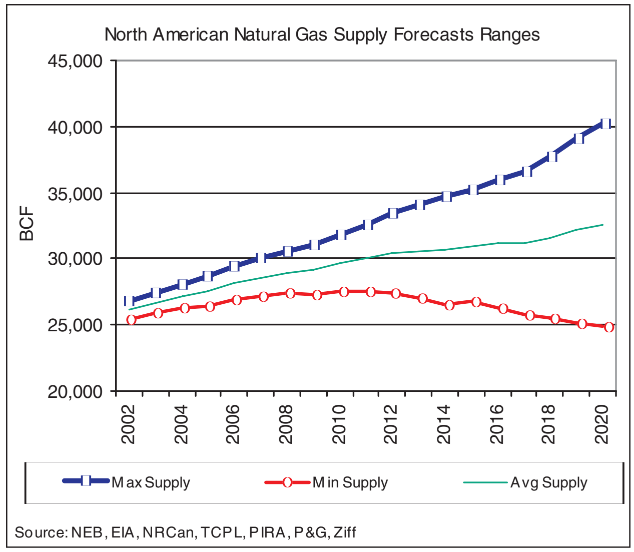


FIGURE 17

Supply Outlook

On supply, forecasters' views are much more divergent with growth rates ranging from 2.3% (max.) to -0.1% (min.) over the period 2002 to 2020 (fig. 17). Indeed, the variances between the maximum and minimum supply forecasts differ by as much as 25% by 2015[15].

On average, industry experts agree that the supply-responsiveness of the industry will have to accelerate to meet their forecast 30 TCF medium term demand level. Expected rigidities in the supply-side response generally lead to higher price outlooks for natural gas.

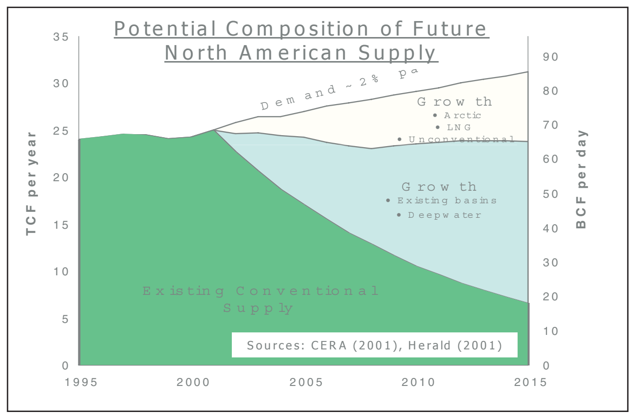


FIGURE 18

It is expected that significant growth of new natural gas supply in North America (fig. 18) will come from the Arctic, LNG, and unconventional supplies like coal-bed methane (CBM). And subject to the lifting of land access restrictions, future supplies to the North American market will also rely heavily on existing basins (e.g. Rockies) (fig. 19).

15 25% = difference in supply forecasts (max - min) as a percentage of max supply

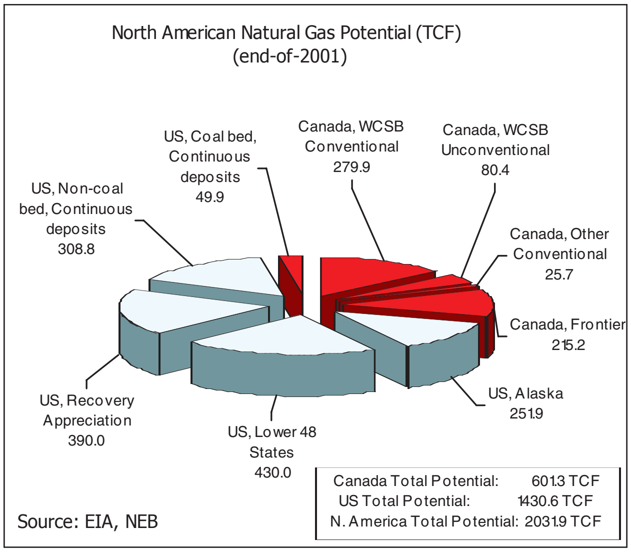


FIGURE 19

Accelerating supply-side responsiveness will be a North American-wide responsibility. Arctic gas in total (Alaska plus Mackenzie) as a shared supply, will contribute an estimated 412 TCF once fully developed[16]. This will help meet that responsibility – but the infrastructure needs to be built now, in order to be able to do so. The speed with which such significant investment dollars can be attracted and the capital projects completed is one of the key variables behind the wide range of opinion as to the possible levels of future gas supply in North America.

What follows are summaries of the demand and supply effects over the short, mid and long-term periods.

Short Term Outlook – to 2005

- Annual growth rate in demand of 2.1% to 2.4%.
- 1.8 TCF cumulative demand growth.
- Annual growth rate in supply of 1.5% to 2.1%.
- 1.5 TCF cumulative supply growth.

EXPECTED OUTCOMES:

- Price spikes may become more severe.
- Month-to-month price volatility gives rise to concerns about the liquidity of some marketers.
- Storage capacity is an on-going concern as new storage pool development continues to experience delays.
- Surge in drilling for new shallow wells. CBM increases it supply position.
- Significant financial and regulatory commitments are needed to bring LNG infrastructure on line in this timeframe[17].

16 "Industry Overview"; CAPP; P. Alvarez; April 2003
17 From: AGA Update; "Greenspan, English Testify on Natural Gas Supply in Congress"; June 10, 2003 and from AGA Update; "Market Providing a Short-Term Fix, Congress Must Find a Long-Term Solution, Natural Gas Utilities tell House Committee"; June 19, 2003 ' US Federal Board Chairman, Alan Greenspan testified before a Congressional Hearing in June 2003 that, "in his opinion, LNG is best positioned to get to the market in a relatively swift (in our opinion 3-5 year) time frame and he would like market forces to work and thinks they will."

Mid Term Outlook – 2006 to 2010

- Annual growth rate in demand of 1.5% to 2.3%
- 4.5 TCF cumulative demand growth (2.7 TCF over the period)
- Annual growth rate in supply of 0.8% to 2.1%
- 3.6 TCF cumulative supply growth (2.1 TCF over the period)

EXPECTED OUTCOMES:

- LNG development will come on board as terminals that were awaiting approval in the short-term, begin processing.
- Additional supplies are possible from known Atlantic gas fields Sable and Panuke.
- Mackenzie Delta and Alaska gas may be flowing by the end of the mid-term.
- Substantial investment from capital markets and/or income trust funds will take place subject to availability, bankable rates of return and hurdle rates being achievable by the end of the mid-term.

Long Term Outlook – beyond 2010

- Annual growth rate in demand of 1.3% to 2.4% (overall 1.9% average growth rate in demand over the 2002 to 2020 period)
- 10.5 TCF cumulative demand growth by 2020 (6.0 TCF over the period 2010 to 2020)
- Annual growth rate in supply of 0.3% to 1.7%
- 6.4 TCF cumulative supply growth by 2020 (2.8 TCF over the period 2010 to 2020)

EXPECTED OUTCOMES:

- Environmental issues are more than likely the main factor in the long-term.
- Natural gas will be looked upon favorably in the hierarchy of fuel choices with respect to climate change.
- Major effort will be expended to secure new supplies: CBM and LNG both have established significant share of supply
- Tight gas (Rockies) and deep water gas enter supply stream.

Section Three

IMPLICATIONS

Natural gas markets in North America have entered a fundamentally different era. Natural gas supply, once mostly from lower cost conventional basins, is increasingly derived from higher cost sources. Going forward, the market will likely clear at a higher equilibrium price and this has implications for economic, environmental and social welfare.

Price Implications

Higher average prices are a current reality and indications are for average prices to trend upwards. This is the fundamental result of open market economics where, at the margin, demand must equal supply, and the costs of new marginal supplies are higher than traditional sources of natural gas.

Price volatility is another consequence of finding a new equilibrium between supply and demand that has become more pronounced over each half decade since 1990. The lag in introducing new sources of non-conventional supply will contribute to this increase. Deregulation, that to-date has only included the commodity cost for natural gas, has allowed proper price signals that have spurred well drilling activity, innovation, and investment in some new sources for natural gas (e.g. LNG, coal bed methane). To the extent that these signals are clouded by economic regulation and other non-market forces, customers (demand) will be forced to shoulder more of the adjustment of the burden.

This disproportionate demand-side adjustment in turn has implications on several areas of policy interest: economic, environmental and social welfare.

Economic Impacts

A one-sided response in Canada's natural gas sector will have a substantial negative impact on our processing and manufacturing industries that use natural gas, and supply the US with natural gas derivative products. Natural gas is an important fuel and feedstock for Canada's processing and manufacturing industries in Canada. Canadian industry, if forced to use higher priced substitutes, would experience a loss of competitiveness. If Canadian natural gas exports were curtailed, a primary contributor to Canada's trade balance would be impaired. In 2002, 44% of the natural gas produced in Canada was exported, contributing over $25 billion to Canada's trade surplus with the US[18]. The natural gas transmission and distribution utility sector directly employed over 15,000 workers in 2001, and supports significant employment in related industry[19].

18 Statistics Canada, EIA, NPC; (Note: when that portion of "own use gas" dedicated to export transmission operations is included, then export accounts for 59% of demand)

19 "Natural Gas Transportation and Distribution 2001"; Statistics Canada catalogue no. 57-205-XIB

These industries continually look to leverage the "Canadian advantage" of a clean, secure, and cost-effective supply of natural gas. If natural gas is not readily available then these same industries will face a loss of competitiveness and possibly be forced to shutdown or relocate to more cost competitive environments.

Environmental Impacts

Natural gas is a key part of the response to climate change and air quality. Natural gas is seen by many to be a "bridge fuel" to potential but yet unproven hydrogen economy in the long-term. However, rigidities in the supply-side response put this vision at risk and without adequate supply responsiveness:

- Air and climate change agendas are setback as electricity generation plants; transportation fleets and commercial / industrial sectors use less clean alternate fuels;
- Commitments to reduce GHG emissions under Kyoto may be more difficult; and
- Commercialization of fuel cell technology using natural gas will be delayed.

Social Welfare Impacts

Consumers hardest hit by higher energy prices are in the "lowest income quintile" of end-use consumers for the following reasons:

- The essentials for life occupy a greater share of annual expenditure for lower income consumers;
- Elasticity of energy demand is lowest for low income consumers; and
- Limits on the LDCs to offer fixed price supply contracts has further curtailed all consumer's choice set.

Section Four

POLICY DIRECTIONS

The CGA believes policy efforts should focus on improving the responsiveness of Canada's natural gas market and particularly its supply elasticity. Well designed policies promoting a more robust supply response will help minimize the societal costs of demand response adjustments. Specific areas for consideration include:

- EXPLORATION & DEVELOPMENT – Timely permitting and granting of land access can shorten the 18 month lag that now exists between when prices signal stronger demand and new gas makes it to market. The development of non-conventional supply basins and sources such as LNG requires significant capital investment. Governments must take steps to mitigate these risks by streamlining approval processes and providing clear policy direction.
- PIPELINES – Timely pipeline construction is facilitated when investor's risk is lessened – in part by higher rates of return and government policy and regulatory certainty. Transmission and distribution grid expansion requires in excess of 10 years of extensive planning, environmental work and large amounts of capital.
- STORAGE – Expansion of storage capacity is also dependent upon permitting, land access and capital investment rules and regulations.

Land and Resource Access

Land access, permitting and the allocation of benefits to Aboriginals will be the major issues to developing new supplies in the mid-term.

Exploration, drilling and storage all require land access. Land costs (e.g. permits and associated costs granting access to mostly federal or crown land) today are more expensive than they were years ago in part because of time delays to access land and excessive permitting requirements. Governments can take immediate steps to improve the supply response related to land access by:

- LIFTING RESTRICTIONS FOR EXPLORATION AND DEVELOPMENT – Significant portions of the North American natural gas domestic resource base is either off limits to development, or open under highly restrictive conditions[20].
- SMART ENVIRONMENTAL POLICY – The natural gas industry has proven that energy resources can be developed without harming the environment. Advances in exploration and production technology have greatly reduced the surface disturbance of rigs. And restoration work by the industry is second to none. These actions by the industry mean that policies designed to protect the environment can be made more efficient and cost effective.

20 AGA; Rattie

Infrastructure Investment

Attracting investment will be critical in order to grow Canada's transmission, distribution, storage capability and support the development of cogeneration and distributed energy power projects to meet the requirements of a growing economy. Policies that enhance supply responsiveness will be an important feature in providing the type of climate that will promote investment over the mid-term. Attracting capital is key. Without the investment much needed infrastructure expansion and development will not happen. There are a number of ways regulators and government can help:

- INCREASING THE ALLOWABLE RATES OF RETURN – The partial deregulation of the Canadian natural gas marketplace has led to increased competition and higher financial risks. Given that potential investors see the market as Global, not just North American or a Canadian market they expect returns to reflect these risks. LDCs in Canada spent over $300 million on capital expansion and renewal in 2001[21]. However, because the current allowable regulatory rates of return are often substantially lower (1%-2% lower) than comparable regulated rates of return on projects in the US, it is difficult to attract investment in Canada.
- CERTAIN AND EXPEDITIOUS REGULATORY CLIMATE – Inconsistent or non-existent government policy represents uncertainty and higher risk that is hurting the energy industries ability to attract capital. There must be stability and certainty in this area.
- FAIR TAX TREATMENT – Deregulation and technological advances have increased the competition for Canadian pipelines and increased the risk of investing in pipeline assets. This in turn has cut the useful economic life of pipeline assets, and shortened the period over which investors expect to earn a competitive return on their investment. To encourage the necessary investment in supply response initiatives these concerns must be addressed. There are a number of tax vehicles that can accomplish this:
  - Capital cost allowances that reflect the reduced useful economic life of pipeline assets, are competitive, and encourage investment in supply response solutions.
  - Incentives for innovative supply response investment (increased storage development and/or transmission and distribution system deliverability enhancement);
  - 100% capitalization treatment for research and development engaged in supply response innovation and technology.
- CANADIAN TAX HARMONIZATION WITH THE U.S. – The U.S. is considering reducing their tax depreciation for distribution pipelines from 20 to 15 years. Their rationale is that the industry will need to build 255,000 miles of new distribution pipe[22] if the U.S. is going to meet the "50% increase in demand for natural gas that is projected over the next 20 years". The American Gas Association (AGA) estimates that this will save utility members $2.5 billion in taxes. If Canada does not harmonize tax standards, there is a risk of critical pipeline capacity not being built in Canada as capital is better served in the U.S.

21 "Natural Gas Transportation and Distribution 2001"; Statistics Canada catalogue no. 57-205-XIB

Innovation and Technology – R&D

In the long-term, innovation and technology challenges will need to be overcome to unlock unconventional sources like: hydrates from the ocean floor; pellitized natural gas or Liquified Natural Gas (LNG) for transport; and compressed natural gas (CNG) for marine transport.

Research and Development (R&D) is an important component of developing new sources of supply, encouraging demand conservation and developing ease of fuel switching and fuel diversity technology. Accounting and taxation treatment that encourage R&D spending will be necessary. In 2001, total R&D spending by CGA member companies engaged in transmission and distribution equaled $17.8 million – federal government rebates and/or matching funds to these same companies in 2001 amounted to $0.66 million.[22]

Government can help promote market responsiveness by assisting in the following areas:

- EXPLORATION & DEVELOPMENT – In order to ensure adequate supplies of natural gas are brought to market quickly, exploratory drilling must go deeper, farther, faster, and more accurately than ever before.
- END-USE APPLIANCES – CGA member companies are sponsoring projects on the demand-side of the business that will lead to the development and use of more efficient appliances. There is a need to have these costs recognized as recoverable.
- UNCONVENTIONAL SOURCES OF SUPPLY – There are four areas of non-traditional supply that involve significant R&D funding: CBM, deep sea and tight gas (or stranded gas) in the Rockies, and hydrates. Support is needed for on-going scientific research seeking to unlock the natural gas energy in hydrates, deep sea gas, and tight gas in a safe, reliable and environmentally responsible manner.

Demand Side Management

CGA member companies actively invest in Demand Side Management (DSM) programs that promote customer awareness of more efficient technologies and conservation. This investment is subject to the regulatory environment allowing costs of DSM programs to be recovered by ratepayers in a timely manner. Consistent decisions as to the type and nature of recoverable costs are essential. Furthermore, having lost potential long-term revenue from demand side management, LDCs and ratepayers should be able to benefit from the potential future sale of carbon credits earned. This is beneficial to all parties involved and will also be an important policy tool for climate change.

In terms of DSM programs in general, there is a need for government and industry partnerships to drive conservation and change public culture with respect to energy consumption. This is an opportunity to positively affect environmental outcomes, and promote environmentally friendly supply and demand equilibrium. There is also a need to provide more incentives to LDCs to enhance their DSM program efforts and minimize the regulatory burden involved.

22 "Innovation and Technology Challenges"; CGA presentation to CCRA/SR&ED; J. Krill; June 2003

Allowing LDCs the right to offer long-term fixed price contracts to end-users on system supply, will help end use customers avoid the "demand shock" of volatile prices in the spot market. This will help to stabilize the overall natural gas demand profile. This type of policy adjustment is of benefit to consumer welfare while still allowing the market to work through accurate – albeit longer term – price signals.

Energy Supply and Fuel Choice Diversity

An available mix of fuel choices are a key factor in improving market responsiveness. Allowing the markets to work properly involves consumer choice and the ability to engage freely in market driven substitutability. An important component in making energy markets work properly is the removal of artificial barriers that either directly limit the type of energy consumers can use or gives false support for one fuel type over another. Clear market signals for all energy types also help ensure that scarce capital is allocated where it is most cost efficient.

Allowing all agents to provide a variety of natural gas supply options, and allowing all agents to use both physical and financial hedging instruments will help limit price volatility and broaden consumer's choices.

Appendix 1

NATURAL GAS FORECASTERS & INTEGRATION METHODOLOGY

Integration Methodology:

- Sources provided either a supply or a demand forecast (or sometimes both) for either Canada or the US (or again sometimes both).
- Where a single source provided a comprehensive North America wide forecast, this was taken at face value to be averaged with other forecasts.
- Where necessary, forecasts were combined (summed together) in order to develop as many "unique" North America wide forecasts as possible without compromising the integrity of the blended results.
- NEB forecasts of Canadian demand and supply were combined with the EIA forecasts of US demand and supply to create a single North America forecast of supply and demand.
- ZIFF forecast of US supply was combined with Canadian supply forecasts from both the NEB and TCPL to come up with two separate North America supply forecasts.

Following this procedure, 16 supply and eight demand forecasts for North America were created. The 16 North America supply forecasts were then aggregated to come up with an average North America supply forecast. As well, these forecasts were analyzed to identify the maximum and minimum supply trends. The same methodology was applied to the eight North America demand forecasts.

Source Type	Source	Supply Forecast		Demand Forecast		Forecast Year	Forecast Period
		Cdn	US	Cdn	US		
Government Agency	NEB	X		X		2003	to 2020
	EIA		X		X	2003	to 2020
	NRCan	X	X	X	X	2002	to 2010
Transmission	TCPL	X		X		2003	to 2020
Consultant	ZIFF	X	X			2002	to 2020
	PIRA	X	X	X	X	2002	to 2010
	P&G	X	X	X	X	2002	to 2010
	RSEG	X	X	X	X	2002	to 2005

Appendix 2

COMPILED FORECAST ASSUMPTIONS

Forecaster	Forecast	Price	Economy	Inflation	Technology	Environment
NEB	Min Supply and Max Demand	NYMEX Natural Gas Price at Henry Hub (US$ 2001/mmBTU): From low of 3.21 in 2003 to high of 3.59 in 2022	Real GDP: 2.7% 2001-10; 2.1% 2011-20; 1.4% 2021-25; Pop growth rate: 0.8% 2001-10; 0.6% 2011-20; 0.4% 2021-25	CPI: 1.9% 2001-10; 2.0% 2011-20; 2.1% 2021-25; Natural gas to crude oil price relationship of 83% rising to 90% by 2025	Gradual advances in technology	Limited action on the environment
NEB	Min Demand and Max Supply	NYMEX Natural Gas Price at Henry Hub (US$ 2001/mmBTU): From low of 3.34 in 2003 to high of 4.10 in 2022	Real GDP: 2.9% 2001-10; 2.6% 2011-20; 2.5% 2021-25; Pop growth rate: 0.8% 2001-10; 0.6% 2011-20; 0.4% 2021-25	CPI: 1.9% 2001-10; 2.0% 2011-20; 2.4% 2021-25; Natural gas to crude oil price parity by 2010	Rapid advances in technology	Broad action on the environment
EIA	Min Supply and Min Demand	(2001$US/mmcf) From wellhead low of 2.76 in 2006 to high of 3.96 in 2023	Low performance; GDP growth rate of 2.5% to 2025; Pop growth rate of 0.6% to 2025	Inflation rates of other energy to 2025: World Oil 0.5%; Coal (0.9%); Electricity (0.5%)	N/A	CO_2 emmissions growth rate of 1.2% to 2025
EIA	Max Supply and Max Demand	(2001$US/mmcf) From wellhead low of 2.92 in 2006 to high of 4.50 in 2025	High performance; GDP growth rate of 3.5% to 2025; Pop growth rate of 1.0% to 2025	Inflation rates of other energy to 2025: World Oil 1.0%; Coal (0.7%); Electricity (0.1%)	N/A	CO_2 emmissions growth rate of 1.8% to 2025
NRCan	Supply and Demand	Henry Hub high of 3.75 US$/mmBTU by 2008; Flat Allberta price of 4.40 Cdn$/GJ from 2006 onward	From 2003 to 2010: Approx 50% increase in power gen demand for natural gas; Historical to relatively flat res/com/ind demand growth	N/A	N/A	N/A
TCPL	Supply and Demand	NYMEX long run equilibrium price (2002 US$) of $3.50/mmBTU by 2006	GDP growth rate of 3% per annum indefinitely	2% per annum indefinitely	N/A	N/A
ZIFF	Min Supply	No significant upward pressure on gas prices for a 30 TCF market	N/A	N/A	Limited advancements (e.g. coalbed methane technology)	N/A
ZIFF	Max Supply	Prices approaching US$3.60/mmBTU (1999$'s) by 2020	N/A	N/A	Developments allow for significant growth in non-conventional sources (e.g. coalbed methane)	N/A
PIRA	Supply and Demand	N/A	N/A	N/A	N/A	N/A
P&G	Supply and Demand	N/A	N/A	N/A	N/A	N/A
RSEG	Supply and Demand	N/A	N/A	N/A	N/A	N/A

Appendix 3

COMPILED NATURAL GAS FORECAST DATA

North American Data for Graphing:
(BCF)

	2002	2003	2004	2005	2006	2007	2008	2009	2010
EIA-NEB Lo Demand	25,953	26,583	27,086	27,247	27,592	27,798	28,577	29,068	29,564
EIA-NEB Hi Demand	25,923	27,094	27,642	27,967	28,518	28,996	30,056	30,724	31,519
NRCan Demand	26,407	27,124	27,730	28,347	29,513	30,082	30,672	31,244	31,905
EIA-TCPL Lo Demand	26,028	26,699	27,298	27,526	27,935	28,206	29,032	29,666	30,170
EIA-TCPL Hi Demand	26,028	27,239	27,878	28,246	28,845	29,366	30,432	31,216	32,010
PIRA Demand	26,060	26,660	27,260	27,860	29,270	29,840	30,410	30,980	31,630
P&G Demand	26,775	27,559	28,271	29,021	29,693	30,319	30,876	31,423	32,005
RSEG Demand	25,860	26,340	26,840	27,530					
EIA-NEB Lo Supply	25,425	25,845	26,315	26,434	26,937	27,130	27,931	28,173	28,708
EIA-NEB Hi Supply	25,446	26,301	26,780	26,968	27,520	27,847	28,688	29,072	29,996
NRCan Supply	26,074	26,571	27,091	27,594	28,344	28,918	29,565	30,173	30,744
ZIFF Hi Supply	26,812	27,288	27,764	28,240	28,842	29,444	30,046	30,648	31,250
ZIFF Lo Supply	26,596	26,964	27,332	27,700	27,874	28,048	28,222	28,396	28,570
EIA-TCPL Lo Supply	25,643	26,055	26,589	26,769	27,184	27,380	28,207	29,000	29,413
EIA-TCPL Hi Supply	25,663	26,505	27,039	27,269	27,814	28,190	29,157	30,040	30,703
ZIFF-NEB Lo Supply	26,213	26,357	26,621	26,854	27,071	27,168	27,393	27,309	27,588
ZIFF-NEB Hi Supply	26,430	26,687	27,068	27,428	27,838	28,163	28,562	28,804	29,496
ZIFF-TCPL Lo Supply	26,431	26,567	26,895	27,189	27,318	27,418	27,669	28,136	28,293
ZIFF-TCPL Hi Supply	26,647	26,891	27,327	27,729	28,132	28,506	29,031	29,772	30,203
EIA-ZIFF Lo Supply	25,808	26,452	27,026	27,280	27,740	28,010	28,760	29,260	29,690
EIA-ZIFF Hi Supply	25,828	26,902	27,476	27,780	28,524	29,128	30,172	30,916	31,750
PIRA Supply	25,680	26,060	26,430	26,800	27,390	27,980	28,560	29,140	29,730
P&G Supply	26,720	27,380	28,040	28,710	29,380	30,020	30,570	31,110	31,650
RSEG Supply	26,430	26,760	27,100	27,280					

	2002	2003	2004	2005	2006	2007	2008	2009	2010
Max Demand	26,775	27,559	28,271	29,021	29,693	30,319	30,876	31,423	32,010
Min Demand	25,860	26,340	26,840	27,247	27,592	27,798	28,577	29,068	29,564
Avg Demand	26,317	26,950	27,556	28,134	28,642	29,059	29,727	30,246	30,787
Max Supply	26,812	27,380	28,040	28,710	29,380	30,020	30,570	31,110	31,750
Min Supply	25,425	25,845	26,315	26,434	26,937	27,130	27,393	27,309	27,588
Avg Supply	26,118	26,612	27,177	27,572	28,159	28,575	28,982	29,210	29,669

North American Data for Graphing:
(BCF)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
EIA-NEB Lo Demand	30,205	30,823	31,237	31,608	32,005	32,430	32,727	33,186	33,748	34,211
EIA-NEB Hi Demand	32,320	33,161	33,670	34,241	34,653	35,313	35,850	36,647	37,685	38,519
NRCan Demand										
EIA-TCPL Lo Demand	30,829	31,492	31,974	32,375	32,822	33,270	33,639	34,109	34,695	35,180
EIA-TCPL Hi Demand	32,799	33,672	34,214	34,825	35,342	36,030	36,599	37,409	38,525	39,470
PIRA Demand										
P&G Demand										
RSEG Demand										
EIA-NEB Lo Supply	29,124	29,483	29,483	29,384	29,991	29,987	29,961	30,224	30,493	30,749
EIA-NEB Hi Supply	30,601	31,264	31,596	31,850	32,874	33,232	33,550	34,466	35,506	36,358
NRCan Supply										
ZIFF Hi Supply	31,724	32,198	32,672	33,146	33,620	34,022	34,424	34,826	35,228	35,630
ZIFF Lo Supply	28,646	28,722	28,798	28,874	28,950	28,802	28,654	28,506	28,358	28,210
EIA-TCPL Lo Supply	29,940	31,854	32,356	32,710	33,160	33,510	33,685	33,818	33,936	33,818
EIA-TCPL Hi Supply	31,320	33,424	34,016	34,440	34,800	35,380	35,705	36,308	37,156	37,528
ZIFF-NEB Lo Supply	27,494	27,353	26,973	26,564	26,781	26,287	25,811	25,514	25,143	24,909
ZIFF-NEB Hi Supply	29,777	30,026	30,164	30,314	31,314	31,290	31,346	31,570	31,578	31,788
ZIFF-TCPL Lo Supply	28,310	29,724	29,846	29,890	29,950	29,810	29,535	29,108	28,586	27,978
ZIFF-TCPL Hi Supply	30,496	32,186	32,584	32,904	33,240	33,438	33,501	33,412	33,228	32,958
EIA-ZIFF Lo Supply	30,276	30,852	31,308	31,694	32,160	32,502	32,804	33,216	33,708	34,050
EIA-ZIFF Hi Supply	32,548	33,436	34,104	34,682	35,180	35,964	36,628	37,722	39,156	40,200
PIRA Supply										
P&G Supply										
RSEG Supply										

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Max Demand	32,799	33,672	34,214	34,825	35,342	36,030	36,599	37,409	38,525	39,470
Min Demand	30,205	30,823	31,237	31,608	32,005	32,430	32,727	33,186	33,748	34,211
Avg Demand	31,502	32,247	32,725	33,217	33,673	34,230	34,663	35,297	36,137	36,841
Max Supply	32,548	33,436	34,104	34,682	35,180	35,964	36,628	37,722	39,156	40,200
Min Supply	27,494	27,353	26,973	26,564	26,781	26,287	25,811	25,514	25,143	24,909
Avg Supply	30,021	30,394	30,539	30,623	30,981	31,126	31,219	31,618	32,150	32,554